

California Environmental Protection Agency



Air Resources Board

Proposed Regulation to Implement the Low Carbon Fuel Standard

Volume II

Appendices



Release Date: March 5, 2009

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

**STAFF REPORT: INITIAL STATEMENT OF REASONS
PROPOSED REGULATION TO IMPLEMENT
THE LOW CARBON FUEL STANDARD**

**VOLUME II
APPENDICES**

**Public Hearing to Consider the Proposed Regulation
to Implement the Low Carbon Fuel Standard**

**Date of Release: March 5, 2009
Scheduled for Consideration: April 23, 2009**

Location:

**California Air Resources Board
Byron Sher Auditorium
1001 I Street
Sacramento, California 95814**

This report has been reviewed by the staff of the Air Resources Board and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the Air Resources Board, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

This Page Left Intentionally Blank

Acknowledgments

This report was prepared with the assistance and support from many individuals within the Air Resources Board; only the principal contributors. In addition, staff would like to acknowledge the assistance and cooperation that we have received from many individuals and organizations, too numerous to list, whose contributions throughout the development process have been invaluable. Finally, staff would like to acknowledge the significant contributions from the numerous State, federal, and international governmental agencies that have provided assistance throughout the rulemaking process.

Special thanks goes to the late Professor Alexander Farrell, whose tireless efforts to promote the development of a low carbon fuel policy was an inspiration to us all. Thank you Alex.

Air Resources Board Stationary Source Division Principal Contributors

Kevin Cleary
James Duffy, Ph.D
Chris Gallenstein
Alan Glabe, Ph.D.
Wes Ingram, Ph.D.
Jill Locke
Reza Lorestany, M.S., M.B.A
Carolyn Lozo
Ron Oineza
Eric Patton, P.E

Jim Peterson, M.S.
Chan Pham
Anil Prabhu, Ph.D.
Manisha Singh, Ph.D.
Susan Solarz
Marcelle Surovik
Christina Zhang-Tillman, M.S.
Michelle Werner, Ph.D.
Jing Yuan, Ph.D.

Special Thanks To:

Office of Legal Affairs

Tom Jennings
Claudia Nagy

Office of Climate Change

Jeannie Blakeslee
Sam Wade

Research Division

Alvaro Alvarado, Ph.D
Reza Mahdavi, Ph.D

Enforcement Division

Steve Brisby, M.S.
Dickman Lum

Planning and Technical Support Division

Martin Johnson
Beth Schwehr
Jonathon Taylor

Mobile Source Control Division

Craig Childers, P.E.
Ben Deal, P.E.

Acknowledgments

(Continued)

State Water Resources Control Board

Robert Hodam, M.S. Division of Water Quality

California Integrated Waste Management Board

Brian Helmowski, M.S. Climate Change and Technology Section

California Energy Commission

McKinley Addy

Jim Page

Mike McCormack

University of California, Berkeley

Andrew Jones

Dan Kammen, Ph.D.

Michael O'Hare, Ph.D.

Richard Plevin

Sabrina Spatari

University of California, Davis

Bryan Jenkins, Ph.D.

Chris Knittel, Ph.D.

Nathan Parker

Dan Sumner, Ph.D.

Sonia Yeh, Ph.D.

Purdue University

Alla Golub, Ph.D.

Tom Hertel, Ph.D.

Wally Tyner, Ph.D.

Energy Foundation

Jason Mark, Director of Transportation Programs

Life Cycle Associates – Stephan Unasch

Tiax LLC – Jenny Pont

Reviewed by:

Michael H. Scheible, Deputy Executive Officer

Robert D. Fletcher, Chief, Stationary Source Division

Dean C. Simeroth, Chief, Criteria Pollutants Branch

John Courtis, Manager, Alternative Fuels Section

Hardip Judge, Manager, Program Review Section

Renee Littaua, Manager, Fuels Section

Floyd Vergara, Manager, Industrial Section

Michael Waugh, Manager, Program Assistance Section

List of Appendices

Appendix B: Supporting Documentation For The Technology Assessment

Appendix C: Supporting Documentation for Determination of Carbon Intensity Values

Appendix D: LCFS Credit Calculations

Appendix E: Supporting Documentation for the Compliance Scenarios

Appendix F: Supporting Documentation for Environmental Analysis

Appendix G: Supporting Documentation for Economic Analysis

APPENDIX B

Supporting Documentation for the Technology Assessment

This Page Intentionally Left Blank

Appendix B
Table of Contents
Supporting Documentation for the Technology Assessment

Part A – Technology Assessment of Potential Low Carbon Fuels

- A. Overview of Current California Transportation Fuels
- B. Current Technologies
 - 1. Ethanol from Grains and Sugars
 - 2. FAME Biodiesel
 - 3. Hydrogenation-Derived Renewable Diesel
 - 4. Biogas
 - 5. Natural Gas (CNG, LNG)
 - 6. Electricity
 - 7. Hydrogen
- C. Midterm – Technologies Projected by 2015
 - 1. Lignocellulosics to Ethanol
 - 2. Lignocellulosics to Renewable Diesel
 - 3. Lignocellulosics to Renewable Gasoline
 - 4. Classical Fischer-Tropsch Fuels
- D. Long Term – Technologies Projected after 2020
 - 1. Biofuels from Algae
 - 2. Butanol
 - 3. Carbon Capture and Geologic Sequestration

Part B - Tables

U.S. Fuel Ethanol Industry Plants and Production Capacity (Table B-15)

Commercial Biodiesel Plants as of 9/29/08 (Table B-16)

Ethanol Feedstocks and Conversion Technology (Table B-17)

Biodiesel and Renewable Diesel Feedstocks and Conversion Technology (Table B-18)

This Page Intentionally Left Blank

Appendix B

Part A

Technology Assessment of Potential Low Carbon Fuels

This Appendix contains a description of some of the fuels that might be used to comply with the LCFS. Also discussed for each case are conversion technologies and production pathways currently available (commercially) or under development. The diversity of promising low-carbon fuel options along with the massive research and development efforts to bring advanced technologies to the market leads us to conclude that compliance with the LCFS is feasible. The mandate of the federal Energy Independence and Security Act of 2007 (EISA) to use increasing amounts of advanced and cellulosic biofuel¹ beginning in 2009/2010 and continuing on through 2022 will further stimulate improvements to the current conversion technology of advanced biofuels.

A. Overview of Current California Transportation Fuels

1. Gasoline

Currently, most gasoline in California contains six percent ethanol by volume. Some blends of eight percent ethanol by volume are available for sale in the state. California consumed about 15.8 billion gallons of gasoline(1) in 2008. California's gasoline consumption represents about 11 percent of the total gasoline consumption in the United States(2). According to EMFAC2007, there are approximately 25 million gasoline powered vehicles in California. There are 15 refineries in California making gasoline and diesel fuel(3). Recently, Kinder Morgan, a common carrier pipeline and terminal operator, responsible for distribution of 60 percent of California's motor vehicle fuels announced that in 2010 gasoline distributed by them would have 10 percent ethanol.

2. Diesel

California diesel fuel must meet a 15 parts per million by weight sulfur standard and specifications limiting the aromatic hydrocarbon content to 10 percent for large refiners and 20 percent for small refiners. In California approximately 4.2 billion gallons of diesel fuel(4) were consumed in 2008. California's diesel consumption represents about eight percent of the total diesel fuel consumption in the United States. There are approximately 875,000 diesel fuel vehicles in California(4). A majority of those diesel fuel vehicles are heavy duty vehicles.

B. Current Technologies

This section presents the staff's assessment of fuels and conversion technologies that are currently available for commercial use. These are presented in the Table B-1 below, categorized by fuel type, fuel, and feedstocks/process.

¹ As defined in the Energy Independence and Security Act of 2007

**Table B-1
Current Technologies**

Fuel Type	Fuel	Feedstocks/Process
Biofuel	Ethanol	From grains, sugars/Enzymatic fermentation of starch and simple fermentation of sugars
	Biodiesel	From plant oils, yellow grease/Transesterification - Fatty acid to methyl ester (FAME)
	Renewable Diesel	From plant oils, yellow grease/Hydrogenation
	Biogas	Landfill gas, Digester gas
Natural Gas	CNG, LNG	
Electricity	Electricity	Coal, nuclear, natural gas, hydropower, renewables
Hydrogen	Hydrogen	Steam reforming of natural gas, coal/biomass gasification, water electrolysis

1. Ethanol from Grains and Sugars

Ethanol is an alcohol made by fermenting and distilling simple sugars. Therefore, any biological feedstock that contains sugar or that can be broken down into simple sugars is a potential source for ethanol production. The three main types of biomass feedstock for ethanol production are sugar syrup from sugar crops, starch from grains, and biomass containing cellulose. However, at present, ethanol is produced commercially in large quantities only from enzymatic fermentation of starch from grains and fermentation of sugars from sugar crops (sugarcane, sugar beets, sweet sorghum).

The easiest way to produce ethanol is to begin with sugar producing plants. For example, sugarcane, sugar beets, and sweet sorghum stalks contain high levels of sugar. The sugar syrup obtained when the feedstock is pressed can be fermented with minimal processing. In contrast, grains contain starch, a polymer of glucose, which must be broken apart before the sugar can be fermented. Therefore, ethanol production from starch-based feedstocks requires more effort than production from sugar-based feedstocks. The third type of biomass feedstock contains cellulose, such as trees, grasses, wood wastes, etc. The cellulose in these feedstocks is part of a lignocellulosic composite in the cell walls that resists degradation. Hence, more energy is required break down this feedstock to its component sugars than with grains or sugar crops. However, the energy requirements to grow cellulosic material are far less than for sugar or starch, which more than outweighs the difficulty of breaking apart the cellulosic biomass.(5) Lignocellulosic biomass to ethanol conversion technologies are discussed in the Midterm Technologies section of this chapter. This section focuses on ethanol production from grains and sugar crops.

a. Ethanol from Grains

Currently, corn is the primary feedstock for ethanol production in the United States. Studies indicate that approximately 98 percent of current ethanol production in the United States use corn, with about 80 percent of the ethanol produced from a dry mill process.(6) New plants are projected to be dry mill only, with the exception of a new 100 MGY wet mill plant for Iowa and a plant expansion project in Tennessee.(7) In California, the existing corn ethanol commercial plants have a production capacity of approximately 150 million gallons per year. Additional corn-to-ethanol plants are under construction that will greatly add to this capacity. Newer plants in operation or under construction in California are energy efficient, maximize co-product value, and produce low carbon intensity ethanol.

(1) Dry Mill

In the dry mill process the grain feedstock is milled into a flour or fine meal to expose the starch. Starch is a polymer of glucose and must be broken down before fermentation. The flour is mixed with water and then cooked at high temperatures with enzymes to convert the starch to sugar and reduce bacterial contamination. After the starch has been hydrolyzed to its component sugars (glucose), the glucose is fermented using yeast under anaerobic conditions. The hydrolysis and fermentation process usually takes 40-50 hours.(6) After fermentation, the ethanol is concentrated to 95 percent using conventional distillation and then dehydrated (molecular sieve system, distillation in presence of entrainer). The ethanol is denatured, usually by the addition of gasoline, to prevent consumption as an alcoholic beverage.

The whole stillage co-product contains any unfermented starch and the fiber, oil, and protein components of the original grain. The whole stillage is also known as distillers' grain and may be partially dried and mixed with solids to produce wet distillers' grains with solids (65 percent moisture) for direct use as an animal feed or further dried to 10 - 12 percent moisture to produce dry distillers' grain with solids. The drying process is energy intensive requiring up to 33 percent of the total energy needs.(6) Wet distillers' grains must be used within hours to days, whereas dry distillers' grain has a very long shelf life.

(2) Wet mill

Wet mill ethanol production differs from dry mill production in the initial processing steps. In the wet mill process, the grain is steeped in a mixture of water and dilute sulfurous acid for 24 to 48 hours. After steeping, the germ is separated and undergoes further processing to produce an oil product. The gluten is separated from the starch and may be used as a gluten meal for animal feed. The separated starch is then hydrolyzed, fermented, and distilled to produce ethanol as described above for the dry mill process. Corn is the only grain used in wet mill facilities. The wet mill process generates valuable co-products, although actual ethanol yield is a little lower than in the dry mill process.

b. Ethanol from Sugar Crops

The conversion of sugars to ethanol is simpler than the conversion of starch to ethanol as the sugar syrup from pressed sugarcane or sweet sorghum stalks (or obtained from sugar beets) may be readily fermented by yeast with little pre-processing. Under anaerobic conditions, yeast metabolizes sugar to produce ethanol. Fermentation is followed by distillation and purification of the ethanol.

The bagasse (leftover biomass) from sugarcane or sweet sorghum may be used as animal feed, as a potential feedstock for cellulosic ethanol, or burned for electricity. Pulp from sugar beets can be used for animal feed. Waste sugars (such as molasses) or surplus sugar from existing sugar refining plants are other possible feedstocks for ethanol production.

Sugar to ethanol conversion technology is fully commercial (mostly in Brazil). Sugarcane ethanol production is efficient and results in a low carbon intensity ethanol. However, indirect land use effects impact the carbon intensity.

Ethanol produced from sugar crops grown in the United States is also an option, though availability is limited. Ethanol is generally produced from sugars where there is a large supply of feedstock, such as sugarcane in Brazil and sugar beets in parts of Europe. Feedstocks in North America are limited but could be increased. The United States as a whole, and California considered separately, produce sugar crops for the sugar industry. USDA statistics show that the United States produced a total of 34 million tons of sugar beets and 30 million tons of sugarcane.⁽⁶⁾ In California, both sugarcane and sugar beets are farmed in the Imperial Valley. Sugar beets are also cultivated in parts of the Central Valley. Sweet sorghum grows well in California but has not been widely cultivated.

Staff is aware of one sugarcane-to-ethanol facility planned for California. The project is in the permitting phase. The facility will be powered by combusting bagasse and will be located in Brawley near the source of sugarcane cultivation. Production capacity is expected to be 55 million gallons per year.

c. Commercialization Status – Ethanol

In 2007, approximately 13 billion tons of ethanol were produced worldwide. Ethanol production in the United States, nearly all from grains, accounted for about half of the total. Grain to ethanol conversion technology is fully commercial. As of February 2009, the Renewable Fuels Association listed approximately 162 operating facilities in the United States that produced ethanol from grain (nearly all from corn), with a total annual production capacity of approximately 10.4 billion gallons of ethanol. Refer to Appendix B, Part B, for a listing based on the Renewable Fuels Association's list of fuel ethanol biorefineries in the United States, including location, feedstocks, and production capacity.(8) In California, there are approximately five ethanol plants with a production capacity of approximately 150 million gallons.

Ethanol production from sugar crops is also fully commercial. Ethanol production from sugarcane (almost all in Brazil) accounted for roughly 40 percent of the world's fuel ethanol in 2007. Sugar beets are used for ethanol production in parts of Europe. Refer to Table B-2 below for ethanol production in the top five producing nations in 2007.(9)

Table B-2
Ethanol Production in Top Five Producers and
World Ethanol Production Total in 2007*

Country	Millions of Gallons	Percent of Total
United States	6500	49.6
Brazil	5020	38.3
European Union	570	4.4
China	490	3.7
Canada	210	1.6
World Total	13,100	

* Numbers are rounded.

In addition to grain and sugar ethanol plants, there are approximately six facilities operating in the United States with a total production of approximately 20 million gallons per year of ethanol from food and beverage wastes. Although the technology is fully developed, there is limited opportunity for growth in this category. Table B-3 below gives information regarding the location, feedstocks, and operating capacity for these facilities. (The commercialization status of lignocellulosic ethanol facilities is discussed in the Mid-term section of this chapter.)

Table B-3
Ethanol from Waste Biorefineries in Operation in the United States
(Excluding Cellulosic Ethanol)

Company	Location	Feedstock	Operating Capacity (million gallons per year)
Golden Cheese Company of California	Corona, CA	Cheese Whey	5.0
Idaho Ethanol Processing	Caldwell, ID	Potato Waste	4.0
Land O' Lakes	Melrose, MN	Cheese Whey	2.6
Merrick & Company	Aurora, CO	Waste Beer	3.0
Parallel Products	Louisville, KY	Beverage Waste	5.4
Wind Gap Farms	Baconton, GA	Brewery waste	0.4

2. FAME Biodiesel

Biodiesel is a fuel composed of a mixture of fatty acid alkyl esters that can be made from almost any plant oil or animal fat. “Bio” refers to the biological source of the fuel in contrast to traditional petroleum-based diesel fuel. Biodiesel is an alternative fuel that can be blended with petroleum-based diesel or used in straight unblended form as B100. Biodiesel fuel blends are designated as “BX” where “X” is the percent biodiesel by volume in the fuel. Biodiesel that meets ASTM D975-08a, ASTM D7461-08, and ASTM D6751-08 is a legally registered fuel and fuel additive with the U.S. Environmental Protection Agency.

The choice of plant feedstocks used to make biodiesel is dependent upon the vegetable oils that are economically available. In the U.S. there are many potential plant oil feedstocks that can be used including soybean, peanut, canola, cottonseed and corn oil.(7) Most of the world’s production of biodiesel comes from plant oils such as soy bean, rapeseed (canola), and palm oil. About 90% of U.S. biodiesel is made from soybean feedstocks.(10) The process used to convert virgin oils into biodiesel involves the use of a catalyst and alcohol and is called transesterification.

Biodiesel can also be made from animal fats such as used restaurant grease (yellow grease) and tallow. These feedstocks are wastes so there is no CO₂ associated with land use as there is with crop based feedstocks. Biodiesel from wastes is referred to as advanced biodiesel in order to differentiate it from conventional biodiesel because of its lower carbon intensity. These waste animal fats can be converted into biodiesel through transesterification.

a. Processing Vegetable and Animal Oils into Biodiesel

Raw vegetable and animal oils consist of fatty acids and glycerin products. Though these oils can be directly used in diesel engines and give short term performance, this is highly discouraged as their use can cause severe engine problems. This is primarily due to the raw oils forming engine deposits, with coking and plugging in engine injector nozzles, piston rings, and lubricating oil. This happens due to polymerization of the triglycerides in the raw oils as the fuel is combusted. Therefore, it is necessary to convert the raw oils into a form of esters or biodiesel which prevents these issues.(7)

(1) Transesterification

The conventional biodiesel manufacturing process converts oils and fats into chemicals called long-chain mono alkyl esters. These chemicals are also referred to as fatty acid methyl esters (FAME) and the conversion process is referred to as transesterification.

Before transesterification is conducted, the raw oils and fats are filtered and pretreated to remove water and contaminants. Water in the feedstock leads to the formation of soaps which is an undesirable by-product, reduces the yield of biodiesel, and makes the separation of glycerin in the products more difficult.

Transesterification involves reacting triglyceride oils with alcohol (usually methanol) in the presence of a catalyst in a simple closed reactor system at low temperature and pressure. In the transesterification reaction vessel, the mixture of alcohol and oils is allowed to settle for one to eight hours.(6) The products of the transesterification reaction are methyl esters (crude biodiesel) and glycerin as a co-product. After transesterification a majority of the alcohol is removed from the glycerin and recycled back into the system to continue the process. The biodiesel from the process is purified and washed to remove residual catalyst and soaps. The glycerin from transesterification can be purified and sold to the pharmaceutical or cosmetic industries to be processed into lotions and creams.

There are two basic conversion routes for FAME production including base and direct acid catalyzed transesterification. The base catalyzed option tends to be the most economical for virgin oil feedstocks and as such is most commonly used to produce esters on a commercial scale. The processing equipment operates at relatively lower temperatures and pressures. The process has high conversion rates (around 98%) to methyl esters with low reaction times without producing intermediate compounds.(6)

Acid catalyzed transesterification is expected to be the preferred method for conversion of waste oils, since it is less sensitive to free fatty acids in the feedstock. This conversion method seems to be more economical than base catalyzed transesterification of waste oils, because an extra pretreatment step is required to remove fatty acid impurities before the base catalyzed process. For base transesterification the fatty acid content of feedstocks must generally be less than four percent. Although acid catalyzed transesterification has not been optimized for

commercial scale production, it is expected that this method could be operating commercially by 2015.(6)

In base catalyzed transesterification a strong base of sodium hydroxide or potassium hydroxide is usually used as the catalyst for the reaction. In the acid catalyzed process sulfuric acid is usually used as the catalyst. For the base catalyzed process the molar ratio of methanol to oil is about 6:1, while for an acid catalyzed process the ratio is about 50:1.

The purity and the yield of biodiesel from transesterification is affected by the molar ratio of glycerides to alcohol, the type of catalyst, the reaction time, the reaction temperature, the amount of free fatty acids, and the amount of water present in the feedstock.

b. Commercialization Status – FAME Biodiesel

According to the National Biodiesel Board as of September 2008 there were 176 operational commercial biodiesel production plants in the U.S. with a total production capacity of 2.61 billion gallons. There are about seven major plants in California with annual production capacities varying between 350,000 gallons to ten million gallons. The total capacity in California is nearly 35 million gallons per year. See Appendix B, Part B, for a biodiesel commercialization status summary from the National Biodiesel Board giving plant location, capacity, and feedstock of plants in the U.S.

3. Hydrogenation-Derived Renewable Diesel

Hydrogenation-derived renewable diesel (HDRD) is produced by refining fats or vegetable oils. This process is also known as the Fatty Acids to Hydrocarbon (FAHC – Hydrotreatment) process. Vegetable oils and animal fats can be upgraded into diesel, propane, and other light hydrocarbons through hydrotreatment with hydrogen. Biomass based diesel produced from the FAHC process is referred to as renewable or “green” diesel to differentiate it from biodiesel produced by transesterification. Renewable diesel has a chemical structure that is identical to petroleum based diesel since it is free of ester compounds.

The product distribution of the FAHC process results in (by weight) 83-86 percent diesel, two to five percent light hydrocarbons, carbon dioxide gas, and water. The oxygen within the ester compounds of the oils is removed through the release of the carbon dioxide and water.

Renewable diesel has several advantages to FAME and petroleum biodiesel. Renewable diesel has a superior emission profile. Usage of renewable diesel results in reduced particulates, NO_x, hydrocarbons, and CO emissions. Unlike FAME biodiesel, the production of renewable diesel through the FAHC process does not produce a glycerin co-product. Renewable diesel is produced using existing hydrotreatment process equipment in a petroleum refinery, resulting in an economic advantage, reducing the costs of production.

Renewable diesel has a lower sulfur content than petroleum diesel resulting in lower SOx emissions. Renewable diesel has a lower cloud point than conventional biodiesel; therefore, it has better low temperature operability and can be used in colder climates without gelling or clogging of fuel filters.

Waste animal fats can also be hydrogenated to produce diesel range hydrocarbons. Renewable diesel produced from wastes has a lower carbon intensity and is also referred to as “Advanced” renewable diesel.

a. Commercialization Status

ConocoPhilips completed a commercial demonstration plant in Cork, Ireland that makes renewable diesel using vegetable oil and crude oil feedstocks with the FAHC process that produced 42,000 gallons per day. ConocoPhilips also partnered with Tyson to build a facility that can process animal fats in the U.S. The facility opened in late 2007 with a capacity of 500,000 gallons per day of renewable diesel.(6)

Neste has developed a plant to process vegetable and animal fats into renewable diesel by the hydrotreatment process. The facility demonstrated at the Porvoo oil refinery in Finland with a capacity of 60 million gallons per year. The company is planning to build a second plant of the same size next to it to meet growing demand. The company also has plans to build plants in Austria and Singapore.

The Petrobras “H-BIO” process uses co-processing of vegetable oils to make renewable diesel. Petrobras plans to have H-BIO operations in at least three refineries by the end of 2007 with a total capacity to handle more than 250,000 tons of vegetable oil annually. Two more refineries were planned for 2008.

Other companies that have plans to produce renewable diesel through hydrogenation include Nippon Oil in Japan, BP in Australia, Syntroleum and Tyson Foods in the U.S., and UOP-Eni. The Nippon Oil plant expects to be operating commercially in three years. The BP plant is planned to have a demonstrated capacity of 80,000 gallons per day. Syntroleum and Tyson Foods are scheduled to start operation in 2010 with a capacity of 5000 barrels a day. UOP-Eni is an American and Italian project supported by the U.S. Department of Energy that is scheduled to come online in 2009. Table B-4 below summarizes the main HDRD projects in the world.

Table B-4
Renewable Diesel Plants (Worldwide)
[produced by hydrotreatment of oils]

Co. Name	Location	Capacity	Start-up	Status
ConocoPhilips	Ireland	42,000 gal/dy	12/2006	-Demonstration project -Soybean oil feed
ConocoPhilips & Tyson	U.S.	500K gal/dy	End of 2007	DOE: facility ramping up to as much as 11,000 barrels/dy by 2009
Neste Oil	Finland (Porvoo refinery)	60 million gal/yr	2007	-Has plans for plants in Austria, Singapore, and 2 nd Finland plant -Company uses patented "NExBTL" technology
Petrobras	Brazil	250K tons/yr veg. oil input, 112 million gal forecasted production 2008	Late 2007	-Three refineries -Two more plants planned for 2008 -Company uses patented "H-BIO" process
Nippon Oil	Japan	Not publicized yet	2011	Antares report: Commercial in 3 yrs. (2011)
BP	Australia	80K gal/dy	2007	-Demonstration facility
Syntroleum & Tyson Foods	U.S.	5000 barrels/dy Planned	2010	Planned production of jet fuel and HDRD
UOP-Eni	U.S. & Italy	6500 bbls/dy vegetable oil input planned	2009	-Planned -Supported by U.S. DOE

4. Biogas

Biogas typically refers to a gas produced by the biological breakdown of biodegradable organic matter in the absence of oxygen. This process is also referred to as anaerobic digestion. The resulting biogas consists of methane, carbon dioxide, and other trace amount of gases and can be used to generate heat, electricity, and alternative fuels. Depending on where it is produced, biogas can be categorized as "landfill gas" or "digester gas". Landfill gas is produced by decomposition of organic waste in a municipal solid waste landfill. Digester gas refers to applications using livestock-manure, sewage, food waste, etc. Biogas is also referred to as biomethane. It has properties similar to natural gas and can potentially be used for similar applications. For example, biomethane might be compressed and used as a transportation fuel in compressed natural gas vehicles.(5) The vehicle fuel potential in landfill and sewage

digester biomethane is equivalent to between 300 to 400 million gallons of gasoline, whether as compressed or liquefied gas (i.e; CNG or LNG) or converted to hydrogen.(5)

a. Landfill Gas (LFG)

The California Integrated Waste Management Board (CIWMB) has identified approximately 366 landfills with potential to generate landfill gas of which 145 are active permitted facilities receiving waste. Of the active landfills, approximately 66 percent are owned by public entities.(11) The total potential biomethane resource from landfills in California is estimated at 80 billion cubic feet per year (CEC-500-2005-066-D, April 2005). Active landfills must control landfill gas to control migration and reduce explosion risks to adjacent structures. LFG collection systems are well established and use a network of wells, headers, and blowers to collect the gas and route it to a treatment plant or a flare. Raw landfill gas is about 50 percent methane, 45 percent carbon dioxide and a small percentage of other compounds such as nitrogen and hydrogen sulfide. The average heating value is about 450 Btu/scf.

LFG is currently used for power generation, mostly with reciprocating engines and microturbines. The gas is also used with fuel cells, as boiler fuel, and as vehicle fuel although much is still flared without energy recovery. The potential use of LFG as a transportation fuel in the form of compressed natural gas (CNG) or liquefied natural gas (LNG) is discussed below.

(1) Vehicle Fuel from Landfill Gas

The main steps involved in processing landfill gas into compressed natural gas (CNG) are water removal, pretreatment to remove trace organics, membrane technology to separate CO₂, and final compression to about 3600psi.

Production of liquefied natural gas (LNG) from landfill gas is more challenging and requires additional steps in the form of purification and cryogenic systems.

(2) Commercialization Status - LFG

The technology for producing CNG from LFG is well established. The Los Angeles County Sanitation District has successfully converted LFG to CNG since 1994 at its Clean Fuels facility. This facility has a design capacity equivalent to 1000 gallons of gasoline per day. The total capital cost for this project was approximately \$1 million.(12) In Sonoma County, a landfill gas to CNG project will result in a system to fuel six buses.

The ECOGAS Corporation has operated an 8500 gallons per day LNG plant in Rosenberg, Texas, since 1995.(12) Currently, California does not have any commercial plants in operation for producing LNG. However, ARB and CIWMB have approved grants in 2007 for two commercial scale demonstration projects. These projects include a 13,000 gallons per day LNG plant at the Altamont Landfill (by Gas Technology

Institute) to be used for the waste hauler fleet and a 18600 gpd plant at the Bowerman Landfill (by Prometheus Energy Company) to provide fuel for the local bus fleet.(13) These plants are expected to be commissioned by June 2009 and will provide good data on technical feasibility and costs.

b. Digester Gas

Typical feedstocks for anaerobic digestion include manure from confined animal facilities such as dairies and feedlots, sewage sludge, and wastes from food processing. Anaerobic digestion is a biochemical process in which several types of bacteria work together in a series of steps to digest biomass in the absence of oxygen. First, bacteria break down the carbohydrates, proteins and fats present in biomass feedstock into fatty acids, alcohol, carbon dioxide, hydrogen, ammonia and sulfides. This stage is called "hydrolysis" or "liquefaction."

Next, acid-forming bacteria further metabolize the products of hydrolysis into acetic acid, hydrogen and carbon dioxide. Finally, methane forming (methanogenic) bacteria convert these products into biogas.(14)

The biogas generated by digesters contains methane, carbon dioxide, sulfur compounds, PM, and water. Because the methane in the biogas is dilute and contains contaminants, the biogas must be pretreated, conditioned, and compressed before use as a fuel. The energy content of biogas depends on the amount of methane it contains. Methane content may vary from about 55 percent to 80 percent.²

(1) Digester Gas Applications

Digester gas can be used in many applications. The level of pretreatment depends upon the application and is designed to remove carbon dioxide, sulfur compounds, particulates, water, and other contaminants. Typical applications are onsite use in reciprocating internal combustion engines, turbines, boilers, or fuel cells to produce energy. Biomethane can also be injected into a natural gas transmission pipeline or used for transportation purposes. Using digester methane generated onsite to power electricity-generating engines could replace electricity generated from fossil fuel power plants. In addition, biomethane generated from onsite digesters could power vehicles used for transportation unique to a particular industry (e.g. biomethane produced from dairy lagoon digesters can power converted diesel milk trucks).

(2) Commercialization Status – Digester Gas

Production of renewable energy, improvement on environmental pollution in air and water, reduction of agricultural wastes, and utilization of byproducts as fertilizers from anaerobic digestion has increased the attractiveness of this application. Anaerobic digestion technology to produce biogas is well developed worldwide. Currently, the European Union has a total generating capacity of 307 MW from this technology. In California only 0.37 MW of power is generated from existing five digesters although the total potential for animal waste to energy in dairies is over 105 MW. There are

approximately 2300 dairy farms in California. There are 10 sewage treatment plants in California with digesters that generate about 38 MW of electrical power.(15)

Use of digester gas to power vehicles is not prevalent but can be achieved. Hilarides Dairy was awarded a grant by ARB in 2007 to produce methane from the waste generated by the Dairy's 9,100 cows. This project is an attempt to manage environmental issues and create an onsite self contained system of energy supply. The biogas generated will power the dairy's four converted milk trucks (reduce diesel consumption by 650 gallons per day) and create an additional 250 kW of electricity for on-site use.(16)

5. Natural Gas (CNG, LNG)

The production of natural gas, in both compressed (CNG) and liquefied (LNG) forms, involves mature technologies and is clearly technologically feasible vis-à-vis the LCFS regulation. Britain was the first country to commercialize the use of natural gas. Around 1785, natural gas produced from coal was used to light houses, as well as streetlights.(17) In 1821, William Hart dug the first well in the U.S. (in Fredonia, New York) specifically intended to obtain natural gas.(17) Natural gas liquefaction dates back to the 19th century,(18) and the first commercial liquefaction plant began operation in West Virginia in 1917.(19) Today, the natural gas industry has existed in this country for over 100 years, and it continues to grow.(17)

CNG is typically transported by pipeline. According to the Energy Information Administration (EIA), the U.S. produced nearly 19.1 trillion cubic feet(20) (Tcf) of "dry" natural gas² and imported about 3.8 Tcf in 2007(21), primarily from Canada and a small percentage from Mexico.

LNG is typically transported by specialized tanker with insulated walls, and is kept in liquid form by autorefrigeration, a process in which the LNG is kept at its boiling point, so that any heat additions are countered by the energy lost from LNG vapor that is vented out of storage and used to power the vessel.(17) According to the EIA, the U.S. imported about 0.77 Tcf of LNG in 2007.(21) In 2008, the U.S. imported the vast majority of its LNG from Trinidad, Egypt, Nigeria and Algeria, with much smaller amounts from Qatar and Equitorial Guinea.(21)

The actual practice of processing natural gas to pipeline dry gas quality levels can be quite complex, but usually involves four main processes to remove the various impurities:

- Oil and Condensate Removal
- Water Removal
- Separation of Natural Gas Liquids
- Sulfur and Carbon Dioxide Removal.(17)

² Dry gas is natural gas that is almost entirely methane, produced from "wet" gas that is stripped of other molecules during processing or that is produced from non-associated gas fields as "dry" gas..

In addition to the four processes above, heaters and scrubbers are installed, usually at or near the wellhead. The scrubbers serve primarily to remove sand and other large-particle impurities. The heaters ensure that the temperature of the gas does not drop too low. With natural gas that contains even low quantities of water, natural gas hydrates have a tendency to form when temperatures drop. These hydrates are solid or semi-solid compounds, resembling ice like crystals. Should these hydrates accumulate, they can impede the passage of natural gas through valves and gathering systems. To reduce the occurrence of hydrates, small natural gas-fired heating units are typically installed along the gathering pipe wherever it is likely that hydrates may form.(21) For LNG, there is at least one additional step of liquefaction, which involves cooling natural gas at its initial production facility to about -260°F at normal pressure until the natural gas liquefies.(17) Upon arrival at its destination in the U.S., LNG is generally transferred to specially designed and secured storage tanks and then warmed to its gaseous state – a process called regasification.(22) The regasified natural gas is generally fed into pipelines for distribution to consumers. However, if the regasified natural gas is intended to be transported or otherwise used as LNG (e.g., in LNG vehicles), it would need to undergo a second liquefaction step, which would substantially increase the fuel's carbon intensity value.

6. Electricity

The power system (“the grid”) produces and delivers electrical energy to customers. Electricity is produced by power plants of different sizes and types, which can be fueled by a number of energy sources, such as coal, nuclear, natural gas, wind, solar, and hydropower.

Battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs) are examples of two technologies that use electricity as a transportation fuel. The status of zero emission vehicle technologies was examined by an independent expert review panel (Panel) established by ARB in 2006. The Panel organized its efforts around three main ZEV enabling technologies -energy storage, hydrogen storage, and fuel cells(23).

It is the Panel's opinion that PHEVs have the potential to provide significant direct societal benefits and are likely to become available in the near future. The Panel's projection is that PHEVs can achieve mass commercialization (100,000's of vehicles per year) based on global volumes in the 2015 (plus) timeframe.

Full Performance Battery Electric Vehicles capable of high speed United States urban/suburban freeway driving will grow more slowly due to customer acceptance of limited range and long recharge times. They are not likely to become mass market ZEVs in the foreseeable future. The Panel projects this technology to achieve early commercialization (10,000's of vehicles per year) based on global volumes in the 2015 timeframe.

a. Overview of California Electrical Generation Sources

California's power supply is generated by both fossil fuel and renewable energy sources. Fuel types include coal, natural gas, nuclear, and distillate fuel oil. Renewable energy sources include biomass, geothermal, solar, wind, and small hydroelectricity (30 megawatts or less). California's electrical load is also supported seasonally by large in-state and out of state hydroelectric facilities.

The generation is either located within California or imported from other regions in the West. Out of state electricity is imported from two geographical regions: the Northwest (NW) and the Southwest (SW).

California's "total system power" (TSP) is defined by the California Energy Commission (CEC) as "the sum of all in-state generation and net electricity imports by fuel type." (24) The total-system-power mix changes each year based on available hydroelectric generation. Additionally, the power plant fleet also varies as new facilities come on-line and existing facilities are rebuilt or retired.

Table B-5 delineates California's total system power generation for 2007.

Table B-5
California Total Power Generation, 2007

2007 Total System Power in Gigawatt Hours					
Fuel Type	In-State	NW	SW	TSP	TSP %
Coal*	4,190	6,546	39,275	50,012	16.6%
Large Hydro	23,283	9,263	2,686	35,232	11.7%
Natural Gas	118,228	1,838	16,363	136,063	45.2%
Nuclear	35,692	629	8,535	44,856	14.8%
<i>Renewables</i>	28,463	6,393	688	35,545	11.8%
<i>Biomass</i>	5,398	837	1	6,236	2.1%
<i>Geothermal</i>	12,999	0	440	13,439	4.5%
<i>Small Hydro</i>	3,675	4,700	18	8,393	2.8%
<i>Solar</i>	668	0	7	675	0.2%
<i>Wind</i>	5,723	857	222	6,802	2.3%
Total	209,856	24,669	67,547	302,072	100.0%

Source: California Energy Commission, 2007 Net System Power Report

A California statewide power plant map, showing the location and electricity generation fuels, is included as Figure B-1.

b. Projected Energy Mix for Marginal Electricity

The "Detailed California-Modified GREET Pathway for California Average and Marginal Electricity" (Draft Report January 20, 2009) assumes California's marginal electricity to be "...the marginal resource mix of electricity consumed in California...[is] natural gas combusted in combined cycle combustion turbines (CCCTs) and renewables."

Current law requires that California's investor owned utilities procure 20 percent of their electricity load from renewably fueled generation by 2010. (Although the utilities are not currently on target to meet this mandate, the projections contained in this summary assume that 20% of California's marginal electricity purchases are obtained from renewable generation sources by 2010). The Public Utilities Code requires the publically owned utilities to meet the same renewable energy percentage requirement, however they are governed locally and no state agency currently has authority to enforce any energy efficiency or renewable targets.

The California Energy Commission (CEC) projects an estimated annual load growth rate of 1.25%(25). CEC's "Net System Power Report" (26) reports total system power of 302 terawatt-hours (TWh) for 2007. Based on an annual 1.25% increase in load, in 2010, California's instate and imported electricity generation is projected to be approximately 325 TWh. If all power used in California were to meet the "Marginal Electricity" generation definition, CCCTs will generate 80 percent of the power in 2010, or 260 TWh. The balance of the demand or 65 TWh will be produced by "other" generation as that term is defined in the Report.

Governor Schwarzenegger's Executive Order (Executive Order Number S-14-08) mandates that California's retail electricity generation be composed of 33 percent renewably generated electricity by 2020. Consequently, the projected California electricity load for 2020 will be approximately 340 TWh -- 272 TW/h of which will be generated from CCCTs and 68 TW/h generated from renewable resources.

New generating resources available to meet California's projected load are found in Attachment 2.(27) This attachment is a spreadsheet which lists all currently proposed generators for both fossil-fueled and renewable generation scheduled to come on line in California from 2009 through 2020. This attachment also lists the many generating resource projects which have been proposed and cancelled or placed on hold.

These numbers do not address probable electricity efficiency measures which will reduce the demand and the percentage of renewable energy based upon the projected load. Additionally, these numbers do not reflect renewable energy credits purchased from out of state generators.

c. Emissions Data

Table B-6 below lists the statewide criteria pollutant emissions data for 2006 with projections for 2010 and 2020 from electric utilities and cogeneration. The criteria pollutants include: 1) carbon monoxide (CO); 2) oxides of nitrogen (NO_x); 3) oxides of sulfur (SO_x); 4) particulate matter (PM); 5) particulate matter less than 10 microns (PM₁₀); 6) particulate matter less than 2.5 microns (PM_{2.5}); 7) total organic gases (TOG); and 8) reactive organic gases (ROG).

Table B-6

Statewide Criteria Pollutant Emissions (Tons per Day) From Electric Utilities and Cogeneration			
	2006	2010	2020
CO	93.3	93.6	100.5
NO_x	48.8	51.9	60.4
SO_x	4.4	4.5	5.1
PM	11.2	11.4	13.4
PM₁₀	10.2	10.5	12.1
PM_{2.5}	9.8	10.1	12
TOG	44.5	43.1	48
ROG	6.5	6.7	7.3

Greenhouse gas emissions of carbon dioxide (CO₂) for 2006, from electric utilities and cogeneration, equaled 105.9 million metric tons CO₂ equivalent (MMTCO₂E). From electric utilities and cogeneration on a business as usual trajectory, the CO₂ greenhouse gas emission projections for 2010 equal 118.5 MMTCO₂E and for 2020 equal 132.2 MMTCO₂E.

d. Effect of Renewable Energy Sources on Emissions

The California Energy Commission estimates that approximately 12 percent of California's retail electricity is currently met with renewable energy resources. Renewable energy includes, but is not limited to, wind, solar, geothermal, small hydroelectric, biomass, anaerobic digestion, and landfill gas. Electricity from renewables is required to be 20 percent of total electricity generated by 2010 per California's current Renewables Portfolio Standard (RPS).

Increasing the use of renewable energy sources will decrease California's reliance on fossil fuels, thereby reducing emissions of greenhouse gases (GHG) from the electricity sector. Per Governor Schwarzenegger's order for a 33 percent RPS, it is anticipated that California will have 33 percent of its electricity provided by renewable resources by 2020.

California's total net system power load is estimated to increase to approximately 340 terawatt-hours (TWh) by the year 2020 (under current business-as-usual conditions), over today's system load of some 302 TWh. The additional energy efficiency measures in the draft scoping plan are expected to help slow and reduce the overall amount of projected load growth by 32 TWh by 2020.

The expanded RPS goals are expected to increase the amount of system power acquired from renewable energy resources to 103 TWh by 2020. This would eliminate any additional GHG emissions from estimated load growth plus reduce GHG and criteria pollutant emissions from the State's current electric system. Thus, there would be no GHG, and reduced criteria pollutant emissions from Plug-in Hybrid and Battery Electric Vehicles charged from grid power fed by renewable energy resources.

e. How Electric Vehicles Will Impact Capacity

Concerns have been raised about the potential impact of a growing number of plug-in hybrid or electric vehicles on the supply of available electrical power and the need for additional power plant development. Recent research has shown that there is an ample supply of idle electrical generation and transmission capacity to accommodate a significant increase in electric vehicle use.

A 2007 Department of Energy Study, found the nation's supply of fossil-fuel based, off-peak electricity production and transmission capacity could fuel up to 84% of the country's existing 220 million vehicles if they were all plug-in hybrids. The study assumed drivers would charge their vehicles overnight when demand for electricity is much lower and did not include hydroelectric, nuclear, renewable, or peaking power plants in its estimates.

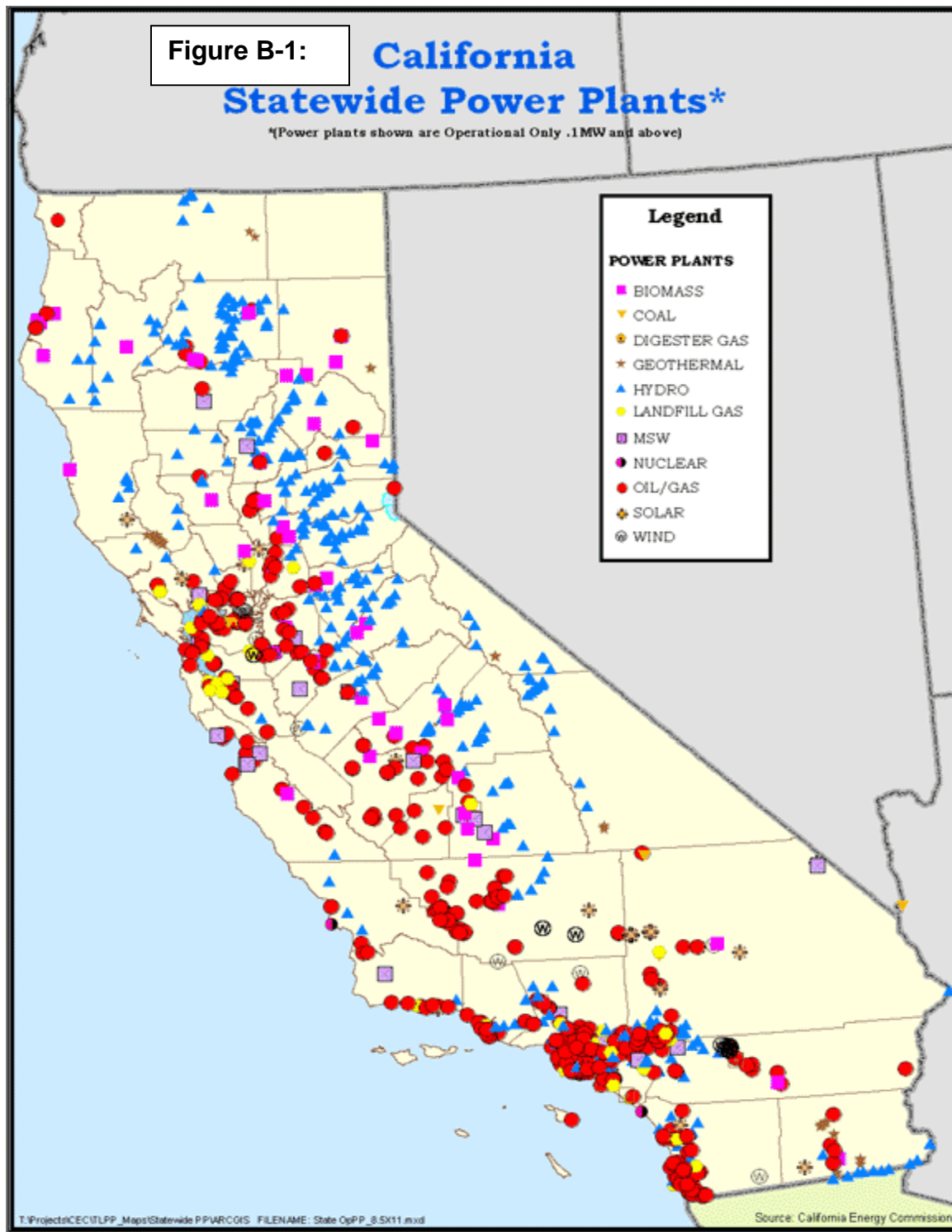
The study found that in the Midwest and East, there is sufficient off-peak electrical generation and transmission capacity to provide for all of today's vehicles if they ran solely on batteries. In parts of the West, and specifically the Pacific Northwest, where there is a large amount of hydroelectric generation that's already heavily utilized and cannot be easily expanded, there is a more limited supply of extra electrical generating capacity. However, the study found 15 to 23% of California and Nevada's 26 million light duty vehicles could be fueled with idle, off-peak electricity generating capacity within the California/Nevada study area.(28)

Research conducted by the Electric Power Research Institute found that more than 40% of the nation's electric generating capacity sits idle or operates at reduced loads overnight and could accommodate tens of millions of plug-in hybrids without requiring new plants.(29) The research also concludes utilities could better capitalize their power generating assets, by allowing for more efficient operation and gaining a new market for off-peak power that now sits idle.

The additional 1.8 million electric vehicles by the year 2020, assumed for this report are expected to increase the State's electric system load demand by 4.6 TWh by 2020. Since most of this additional demand would be supplied by off-peak power, electric vehicles would not create an adverse impact on California's supply of available electric power within the 2020 timeframe.

A potential benefit of plug-in or electric vehicles for the "smart" power grid of the future involves the concept of using the stored energy in electric vehicles to supply power to the grid during peak demand periods. This "vehicle-to-grid" (V2G) concept, would involve advanced technology that would allow future plugged-in vehicles to transmit their location and storage capacity to the electric power grid. Utilities could potentially draw small amounts of power from the vehicle's battery packs to provide voltage regulation, spinning reserves and other power balancing functions. While some V2G research has been conducted, deploying this technology will require significant

investments to evolve the existing grid and will require large-scale use of plug-in vehicles to provide any potential value to utilities or grid operators.(30)



Source: California Energy Commission <http://www.energy.ca.gov/2008publications/CEC-200-2008-002/CEC-200-2008-002.PDF>

7. Hydrogen

Hydrogen can be used in vehicles with high efficiency and zero tailpipe emissions. Hydrogen can be produced from a range of primary sources including fossil fuels (natural gas, coal, oil), renewables (biomass, wind, solar), or nuclear energy. Syngas-based processes like steam methane reforming or coal gasification are well established. Water electrolysis is a commercial technology that is used where low cost electricity is available. It should be noted that with the use of carbon capture and sequestration, hydrogen from traditional sources can be close or equivalent in carbon intensity to hydrogen from renewable sources.

For storage and transport to users, hydrogen is compressed to high pressure or liquefied at very low temperature. Hydrogen can be produced onsite at refueling stations (via small scale steam reforming of natural gas or water electrolysis) or in a large central plant and delivered to users in compressed gas or liquid hydrogen trucks or via gas pipelines.

The status of zero emission vehicle technologies was examined by an independent expert review panel (Panel) established by the ARB in 2006. It is the Panel's view that storing hydrogen on a vehicle to power it for adequate distance in a safe and cost effective manner without excessive weight is a serious challenge in the development of fuel cell electric vehicles. In the near term, the dominant form of storing hydrogen onboard light vehicles will continue to be compressed hydrogen gas. The Department of Energy has selected hydrogen storage parameters corresponding to a 300 mile range as a 2015 target. Liquid hydrogen storage is being demonstrated as workable but with limitations. The California Hydrogen Highway Network Blueprint Plan calls for a total of 50 hydrogen refueling stations by 2010, and as many as 250 in the longer term.(5)

Automotive fuel cell technology continues to make substantial progress but is not yet proven to be commercially viable. The Panel's 2007 report states that "there are still large technical barriers to be solved but these might well be overcome over the next 5 to 10 years." The Panel's projection is that the intense effort on fuel cell electric vehicles will result in technically capable vehicles by the 2015 to 2020 timeframe, but successful commercialization is dependent on meeting challenging cost goals and availability of an adequate hydrogen infrastructure. The Panel projects this technology to be in a pre-commercial stage (1000's per year) based on global volumes in the 2010 to 2020 timeframe.

A National Academy of Sciences study also suggests the possibility of introducing hydrogen fuel cell vehicles on a commercial basis in the United States in the 2015-2020 timeframe.(31)

C. Midterm– Technologies Projected by 2015

This section groups the fuels and conversion technologies expected to be available for commercial use in the 2015 timeframe. These are presented in Table B-7 below, categorized by fuel, and feedstocks/process.

Table B-7

Fuel Type	Fuel	Feedstocks/Process
Biofuel	Lignocellulosic Ethanol	Lignocellulosic feedstocks/Enzymatic fermentation
		Lignocellulosic feedstocks/Gasification and mixed alcohol synthesis
	Renewable Diesel	Lignocellulosic feedstocks Pyrolysis/Gasification followed by Fischer Tropsch
	Renewable Gasoline	Lignocellulosic feedstocks/ Gasification followed by Fischer Tropsch
Fossil Hydrocarbon Fuel	Classic Fischer-Tropsch Fuels	Natural gas, coal to liquid fuels/ Fischer-Tropsch process

1. Lignocellulosics to Ethanol

Producing ethanol from cellulose has the potential to greatly increase the volume of ethanol that can be produced. Cellulose is the main component of plant cell walls and is the most common organic compound on earth. The quantity and diversity of potential feedstocks is enormously expanded beyond starch and sugar crops. In addition to biomass from dedicated agricultural crops, crop and forest residues and waste biomass may be collected and used for cellulosic feedstock. In addition, cellulosic pathways to bioethanol and other biofuels have the potential to result in lower carbon intensity values and improved net-energy ratios than the traditional starch and sugar based ethanol production.(5)

This section discusses lignocellulosic feedstocks, the hydrolysis/ fermentation pathway, the gasification pathway, and the commercialization status of lignocellulosic ethanol production.

a. Lignocellulosic Feedstocks

Lignocellulosic feedstocks include dedicated crops, crop and forest residues, or wastes (municipal solid waste, furniture manufacturing wastes, etc.). Lignocellulosic biomass from all the principal feedstocks consists mainly of cellulose (40-60 dry weight percent) and hemicellulose (20-40 dry weight percent). Cellulose and hemicellulose are both sugar-based complex carbohydrates and, consequently, after hydrolysis to their component sugars may be fermented to ethanol. Most of the remaining fraction of

cellulosic biomass is lignin (10-28 dry weight percent), but there are also smaller amounts of proteins, lipids, and ash. Lignin cannot be fermented but can be used directly for fuel or thermochemically treated to produce syngas (gasification) or bio-oils (flash pyrolysis). Currently, the combustion of lignin is used to generate electricity and/or as a heat source for boilers in some existing small-scale fermentation pathway plants.

The chemical composition of a particular feedstock (cellulose/hemicellulose/lignin ratio) is an important factor in the ethanol yield for the hydrolysis/fermentation pathway. A lower lignin percentage results in a higher ethanol yield. Woody biomass has about 27 percent lignin, while grasses such as switchgrass have about 18 percent.

Several agricultural products are viable feedstock and seem to offer favorable long-term supply options. For example, an emerging source of cellulosic feedstock is native prairie grasses, such as switchgrass, that may be grown on marginal lands with little water and no fertilizer. This feedstock is particularly attractive for some Midwestern locations. Other potential cellulose-to-ethanol feedstocks include fast-growing woody crops such as poplar and willow trees.

Crop residues, such as corn stover or rice straw may be collected as a co-product of other crops. In other states, facilities have been proposed that utilize corn stover as a feedstock. However, studies have noted that crop residue removal can affect soil erosion or decrease soil organic composition, which can impact life-cycle greenhouse gas reductions. Other potential biomass feedstocks include bagasse from sugarcane or sweet sorghum, orchard prunings, and forest residues. Cellulosic waste feedstock includes municipal solid waste, wood waste from furniture manufacturing, and construction and demolition debris. The cellulosic ethanol plants projected to be built in California will use residues or wastes as feedstocks. Ethanol produced from wastes has no land use component for carbon intensity and qualifies as advanced renewable ethanol.

b. Lignocellulose to Ethanol Conversion Technologies

The traditional pathway to produce lignocellulosic ethanol from biomass is through hydrolysis and fermentation. This process is similar to production of ethanol from grains, except that it is significantly more difficult to hydrolyze lignocellulose than starch. An alternative pathway involves gasification of lignocellulosic biomass to produce syngas. The syngas can be converted to ethanol using a modified Fischer Tropsch synthesis or by fermentation techniques.

(1) Hydrolysis/Fermentation

There are different current production technologies that follow the hydrolysis/fermentation pathway. However, the basic steps common to the majority of production processes include initial mechanical pretreatment of the feedstock, additional physical or chemical pretreatment to hydrolyze the hemicellulose and expose the

cellulose, saccharification of the cellulose, fermentation of the component sugars of the hemicellulose and cellulose, and distillation of the ethanol. These steps are discussed below.

i. Pretreatment Steps

The first step is the initial mechanical pretreatment of the biomass. Dedicated crop biomass typically needs to be cleaned and chipped to the proper size. Crop and forest residues undergo similar cleaning and sizing. Municipal solid waste may require sorting in addition to the other steps of cleaning and sizing. Proper sizing of the biomass is necessary to produce adequate surface area to make subsequent processing steps effective.

Once the initial mechanical pretreatment is accomplished, chemical and/or further physical pretreatment follows to hydrolyze the hemicellulose to its component sugars. Saccharification of hemicellulose produces a mix of five carbon sugars (xylose, arabinose) and six carbon sugars (glucose, mannose, galactose). The saccharification of the hemicellulose is generally considered a pretreatment process. This pretreatment step also prepares the cellulose fiber for subsequent saccharification. The pretreatment and conditioning of the feedstock has a significant impact on the ethanol yield.

Several methods to hydrolyze hemicellulose are available. The main hemicellulose hydrolysis methods are chemical pretreatment with acid (dilute or concentrated), physical pretreatments (steam explosion, liquid hot water), and biological pretreatment with fungi. Dilute acid pretreatment is an older method that generally requires smaller sizing of feedstock. If enzymatic hydrolysis of cellulose follows, all acid must be removed. Low acid concentrations can be neutralized with lime producing gypsum, which may be filtered out. Concentrated acid pretreatment is an effective pretreatment but must be followed by concentrated acid hydrolysis of cellulose as the next processing step. Physical pretreatments to hydrolyze hemicellulose include steam explosion, which has sugar yields of 45 to 65 percent. Pretreatment with liquid hot water has higher sugar yields of 88 to 98 percent but is still in demonstration phase. Biological pretreatment with fungi has low conversion yields and long reaction times.(6)

ii. Cellulose Hydrolysis

The next step in the process is the hydrolysis of cellulose to the simple sugar, glucose. There are two principal methods to break down cellulose for ethanol production. The enzymatic hydrolysis process uses enzymes, while the acid hydrolysis process uses acids as catalysts. Both processes produce glucose that can be readily fermented into ethanol.

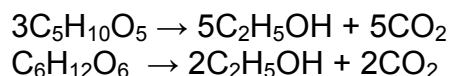
Cellulase is a multiple enzyme system that hydrolyzes cellulose to produce simple glucose units. While many microorganisms are capable of degrading cellulose, only a few of these produce large quantities of cell-free enzymes that can hydrolyze cellulose in a reactor. Cellulase enzymes used for ethanol production are commonly produced by

fungi (e.g., *Aspergillus niger*) though some bacteria also produce the enzymes. Cellulase enzymes convert cellulose to sugar under mild process conditions resulting in relatively high yields (75 to 85 percent) and lower maintenance costs than acid hydrolysis. The enzymes are currently very expensive, although research is underway that focuses on higher yields and lower costs. Yields are expected to increase to 85 to 95 percent by 2020. Recovery and reuse of the enzymes helps to lower costs, but the enzymes do degrade over time.(6)

Alternatively, concentrated acid hydrolysis does not use enzymes. This method is only used in conjunction with an acid hydrolysis pretreatment. Dilute acid hydrolysis is mature technology used in the oldest cellulose-to-ethanol conversion processes. Concentrated acid hydrolysis has higher conversion rates (about 90 percent) than the older dilute acid hydrolysis method.(6) However, any acids used need to be removed before fermentation. To maximize efficiency, acid is recovered and reused.

iii. Fermentation

During fermentation, microorganisms metabolize sugars under anaerobic conditions to produce ethanol. The primary difference between the fermentation process for lignocellulosic ethanol and sugar or starch based ethanol is that a variety of both five carbon sugars and six carbon sugars are fermented. Until recently, most of the five and six carbon sugars had to be fermented separately because different microorganisms were required for the separate fermentation pathways. However, certain strains of bacteria and yeast (e.g., the bacterium *Zymomonas mobilis*) have been genetically engineered that will ferment different types of five and six carbon sugars concurrently. The general chemical reactions for fermentation of five and six carbon sugars, respectively, are shown below.



iv. Distillation and Purification

The product stream from fermentation is a mixture of ethanol, cell mass, and water. Ethanol concentrations are a maximum of 10 percent, but a five percent ethanol concentration is more typical at temperatures needed for optimal cellulase activity. Ethanol is recovered in a distillation column where most of the water remains with the solids. The product is concentrated in a rectifying column to about 95 percent ethanol. To obtain water-free ethanol, several methods may be used including distilling in the presence of an entrainer (benzene) or using pervaporation or membranes.(32)

(2) Gasification and Alcohol Synthesis

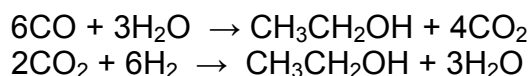
An alternative pathway to the hydrolysis/fermentation route begins with the gasification of lignocellulosic biomass. In this pathway, the biomass is thermochemically converted to syngas which is rich in carbon monoxide and hydrogen gas. The lignin part of the

biomass contributes directly to syngas formation. Pretreatment of lignocellulosic feedstocks is required to dry and size the biomass before gasification.(6)

After gasification, the syngas can be converted to ethanol using a modified Fischer Tropsch synthesis or by fermentation techniques. In the modified Fischer Tropsch process, the syngas is compressed and treated to have acid gas concentrations (H₂S, CO₂) reduced. Cleaned and conditioned syngas is further compressed and 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 an alcohol separation column to separate methanol and ethanol from the higher molecular weight alcohols.

Catalysts are proprietary in the projects under development. However, a National Renewable Energy Laboratory study modeled this process using a modified Fischer-Tropsch catalyst (molybdenum-disulfide based promoted with alkali metal salts) and alcohol synthesis reaction conditions of 1,000 psia and 570 degrees Fahrenheit. The catalyst and reaction conditions were selected to maximize ethanol production.(33)

In the fermentation route, the syngas is conditioned and compressed for fermentation. Genetically engineered microorganisms ferment syngas to ethanol. In the fermentor, anaerobic microorganisms ferment the syngas to produce ethanol. The syngas can contain various concentrations of carbon monoxide and hydrogen gas, but the microorganisms prefer carbon monoxide to hydrogen gas. The chemical reactions for ethanol production from this fermentation pathway are given below:(6)



The University of Arkansas and Bioengineering Resources have demonstrated this process with patented microorganisms.(6) A commercial facility is currently under development (New Planet Energy to be located in Verobeach, Florida) that will use this technology.

c. Commercialization Status – Lignocellulosic Ethanol

Current studies typically categorize lignocellulose-to-ethanol conversion technology as ready for commercialization in the midterm. However, current technology is available for limited near term (2010) production.(6)³ Good progress has been made during the last few years toward producing ethanol from cellulosic feedstocks.(7) Several technologies, proven in pilot scale facilities are moving toward commercialization.

³ The Antares Group 2008 paper (pg 26) categorized as near term (2010) dilute acid hydrolysis conversion technology. Small size facilities of 25 to 60 MGY were modeled. With current technology, a 35 percent conversion to ethanol and an overall process efficiency of about 60 percent were projected for the near term (pg 24). Mid term processes (2015 to 2020) were modeled with the assumption of higher conversion efficiencies and yields. With dilute acid pretreatment, a facility size of 60-100 MGY is modeled. Steam explosion pretreatment is modeled for large facilities > 100 MGY (pg 26).

Challenges remain in scaling the technologies, reducing production costs, and financing large scale plants.

There are a number of government and renewable fuels industry research and development programs dedicated to overcoming remaining hurdles to large-scale commercial production of renewable fuels from cellulosic biomass. Areas of interest for continued research include developing more efficient pretreatment technologies, developing lower cost and more effective cellulase enzymes, engineering strains of microorganisms that have higher conversion yields, and integrating multiple process steps into fewer reactors.

The Energy Policy Act of 2005 and the Energy Independence and Security Act of 2007 (EISA) provide for funds for research and development that should facilitate improvements to the available current conversion technologies. Both the United States Department of Energy and the United States Department of Agriculture are funding research to improve cellulosic conversion and to develop higher yielding biomass crops. On February 28, 2007, the Department of Energy announced that it would provide six grants of up to \$385 million in cost-share funding for the construction of six biorefinery projects over the next four years. These facilities were expected to produce more than 130 million gallons of cellulosic ethanol per year.⁽⁷⁾ Of the original six grant recipients, two have dropped out of the program. The remaining four recipients expect to complete commercial scale facilities between 2009 and 2012.

In addition to funding research and development, the EISA provides a compelling incentive for cellulosic ethanol production. Beginning in 2010 and continuing on through 2022, the EISA mandates that transportation fuels sold or introduced into commerce in the United States must include increasing amounts of cellulosic biofuels (a subset of advanced biofuels) as part of the Renewable Fuel Standard. By 2015, the EISA requires that transportation fuels contain at least 3.0 billion gallons of cellulosic biofuel. In 2020, the mandated volume of cellulosic biofuels increases to 10.5 billion gallons. By 2022, 16.0 billion gallons of transportation fuels must come from cellulosic feedstocks. Corresponding EISA mandated volumes of advanced biofuels for 2015, 2020, and 2022 are 5.5, 15.0, and 21.0 billion gallons, respectively.

Given the progress in current research and development efforts and the EISA mandate of at least 3.0 billion gallons of cellulosic biofuel (5.5 billion gallons of advanced biofuel) in 2015, staff is optimistic that significant volumes of cellulosic ethanol can be produced by 2015.

We have attempted to track the commercialization status of lignocellulosic-based ethanol plants. As part of this effort, we have identified lignocellulosic ethanol plants that are in various stages of operation and development. We have divided these plants into three categories: in operation, under construction, or under development.

In Operation

Staff is aware of four lignocellulosic ethanol plants currently in operation in the United States and Canada. Table B-8 below gives information regarding the location, technology, production capacity, and feedstocks for these facilities.

Table B-8
Lignocellulosic Ethanol Facilities in Operation

Company	Location	Technology/ Comments	Production Capacity (gallons per year)	Feedstock
KL Process Western Biomass Energy	Upton, WY	Thermal-mechanical process for pretreatment and enzymatic hydrolysis	1.5 million	Softwood, waste wood, including cardboard and paper
Verenium	Jennings, LA	5 carbon and 6 carbon fermentations	1.4 million	Sugarcane bagasse and specially-bred energy cane
logen	Ottawa, Canada	Steam explosion pretreatment; Recombinant DNA-produced enzymes hydrolyze cellulose; fermentation	1 million	Wheat straw, oat straw, barley straw
POET (pilot plant to optimize process before construction of commercial plant)	Scotland, SD	BFRAC™ separates the corn starch from the corn germ and corn fiber, the cellulosic casing that protect the corn kernel	20 thousand	Corn fiber, corn cobs and corn stalks

As shown in Table B-8 above, KL Process - Western Biomass Energy is currently operating the commercial demonstration facility in Upton, Wyoming. Western Biomass Energy uses wood waste (forest products) as a feedstock. The plant was completed in January 2008 after six years of development efforts between KL Process Design group and Dakota School of Mines and technology. The demonstration plant produces about 1.5 million gallons of cellulosic ethanol annually.(34) Verenium Corporation is operating a small demonstration facility in Jennings, Louisiana, which uses bagasse and specially bred energy cane as feedstock. Verenium uses an acid pretreatment process at high temperature and pressure followed by fermentations of five and six carbon sugars. Verenium produces approximately 1.4 million gallons of cellulosic ethanol per year.

logen Corporation operates a small-scale cellulosic ethanol plant in Ottawa, Canada. This commercial demonstration plant uses recombinant DNA-produced enzymes to hydrolyze cellulose and steam explosion for pretreatment. logen currently produces about one million gallons per year of ethanol from wheat, oat, and barley straw. logen also creates enzyme products. In addition to these commercial demonstration plants, POET is operating a pilot scale plant in South Dakota, with a production capacity of 20,000 gallons of ethanol per year. This pilot plant uses corn fiber, corn cobs, and corn

stalks as feedstocks. POET plans to use this plant to optimize production in preparation for its planned commercial scale plant in Emmetsburg, Iowa.

Under Construction

Staff is aware of one commercial scale lignocellulosic plant in the United States (Range Fuels) that is currently under construction. Table B-9 below gives information concerning the location, technology, production capacity, and feedstock for this facility.

**Table B-9
U.S. Cellulosic Ethanol Projects under Construction**

Company	Location	Technology/Comments	Production Capacity (gallons per year)	Feedstock
Range Fuels (DOE grant recipient)	Soperton, GA	Two-step thermo-chemical process. Gasification to produce syngas followed by proprietary catalytic process.	20 million	Wood residues and wood-based energy crops, grasses and corn stover

Range fuels received a \$76 million grant for construction of this two-step thermochemical biorefinery. The facility will use gasification to produce syngas followed by a proprietary catalytic process to produce mixed alcohols, maximized for ethanol production. Range Fuels expects to complete construction in late 2009 and to produce about 10 million gallons of ethanol in 2010. Range fuels plans to increase ethanol production in subsequent years to 40 millions per year.

Under Development

In addition to the plants in operation and under construction, there are approximately 17 lignocellulosic ethanol plants under various stages of development in the United States. As of February 2009, some of these projects appear to be constrained by funding. Table B-10 below lists the proposed facilities.

Table B-10
U.S. Cellulosic Ethanol Projects under Development(35)

Company	Location	Technology	Production Capacity (gal/yr)	Feedstock
Abengoa (DOE grant recipient)	Hugoton, KS	Lignocellulosic ethanol plant to be collocated with 85 million gallon per year corn ethanol plant.	11.6 million	Corn stover, wheat straw, milo stubble, switchgrass, and other biomass
Abengoa	York, NE		11.6 million	Corn stover, wheat straw, milo stubble, switchgrass, and other biomass
AE Biofuels	Butte, MT	Ambient temperature cellulose starch hydrolysis	Small scale	Switchgrass, grass seed, grass straw and corn stalks
Bluefire (DOE grant recipient)	Mecca, CA	Arkenol Process Technology (Concentrated acid hydrolysis technology process)	18 million	Green waste, wood waste, and other cellulosic urban wastes (post-sorted municipal solid waste)
Bluefire	Lancaster, CA	Arkenol Process Technology (Concentrated acid hydrolysis technology process)	3.1 million	Green waste, wood waste, and other cellulosic urban wastes (post-sorted municipal solid waste)
Coskata	Madison, PA	Biological fermentation technology; proprietary microorganisms and efficient bioreactor designs in a three-step conversion process that can turn most carbon-based feedstock into ethanol	40 thousand	Any carbon-based feedstock, including biomass, municipal solid waste, bagasse, and other agricultural waste
Dupont Danisco Cellulosic Ethanol LLC	Vonore, TN	Enzymatic Hydrolysis technology	250 thousand	Switch grass, corn stover, and corn cobs
Ecofin, LLC	Washington County, KY	Solid state fermentation process developed by Alltech	1.3 million	Corn cobs
ICM, Inc.	St. Joseph, MO	Fermentation of 5 and 6 carbon sugars. Lignin used for fuel. Co-located with grain ethanol facility.	0.5 million	Switchgrass, forage, sorghum, stover
Lignol innovations	Grand Junction, CO	Biochem-organismolve	2.5 million	Woody biomass, agricultural residues, hardwood and softwood
Mascoma (New York State Energy Research and Development Authority)	Rome, NY		5 million	Lignocellulosic biomass, including switchgrass, paper sludge and wood chips
New Planet Energy (DOE grant recipient)	Verobeach, FL	INEOS Bio Ethanol process (gasification, syngas fermentation, and distillation)	8 - 100 million	Municipal solid waste; Construction and demolition debris; tree, yard and vegetative waste; and energy crops
NewPage Corporation	Wisconsin Rapids, WI		5.5 million	Woody biomass, mill residues
Pacific Ethanol	Boardman, OR	BioGasol	2.7 million	Wheat straw, stover, and poplar residuals

Company	Location	Technology	Production Capacity (gal/yr)	Feedstock
POET "Project Liberty" (DOE grant recipient)	Emmetsburg, IA	Enzymatic hydrolysis and fermentation. BFRAC™ separates the corn starch from the corn germ and corn fiber, the cellulosic casing that protect the corn kernel. Co-located with existing corn ethanol plant.	31.25 million	Corn fiber, corn cobs and corn stalks
RSE Pulp & Chemical LLC	Old Towne, ME	University of Maine proprietary process for pre-extracting hemicelluloses during the pulping process	2.2 million	Woodchips (mixed hardwood)
ZeaChem	Boardman, OR		1.5 million	Poplar trees, sugar, wood chips

As shown in Table 10 above, there are promising cellulosic ethanol production plants proposed for California. BlueFire Ethanol, Inc. (based in Irvine) has planned two cellulosic ethanol plants for operation in California. BlueFire Ethanol is preparing to begin construction of a small-scale facility on a landfill near Lancaster (pending final funding arrangements as of January 2009), and is developing a larger plant to be built on a landfill in Riverside County. The Lancaster plant will produce up to 3.2 million gallons of ethanol per year. BlueFire Ethanol has received a DOE grant (up to \$40 million) for the second proposed plant to be built in Riverside County near the Salton Sea (Mecca) to produce 18 million gallons of ethanol a year. As feedstock, the plant will use 700 tons per day of sorted green waste and wood waste from landfills.(10) BlueFire Ethanol will use concentrated acid technology with acid recovery at both facilities. This is the same patented Arkenol technology demonstrated at a pilot plant near BlueFire Ethanol's headquarters in Irvine. This technology has also been demonstrated at a cellulosic ethanol plant in Izumi, Japan.

2. Lignocellulosics to Renewable Diesel

Biomass feedstocks including lignocellulosic crops, crop residues, and wastes can be synthesized into diesel range hydrocarbons. The two main pathways for the conversion of biomass into renewable diesel include the pyrolysis and hydrotreatment process to make renewable diesel and the gasification and Fischer Tropsch (FT) process to produce FT diesel. In general, the processes using biomass feedstocks to produce renewable diesel are more complex and less commercialized than those used to produce biodiesel from virgin plant oils and animal fats. However, the processing through lignocellulosic pathways, especially for wastes, can result in lower carbon intensity fuels.

a. Flash Pyrolysis to Renewable Diesel

Biomass feedstocks including wood bark, paper, bagasse, corn stover and other agricultural residues can be converted into renewable biodiesel through pyrolysis and subsequently through hydrotreatment. Biomass flash pyrolysis is a rapid thermal

process conducted in an environment without oxygen to prevent combustion. By controlling the temperature and reaction times the pyrolysis reaction is controlled to convert biomass materials into a low molecular weight, liquid “bio-oil” with fragments of lignin, cellulose, and hemicellulose. The bio-oil can then be refined into fuels, adhesives, resins, polymers, and other chemicals. Under optimum process conditions liquid bio-oil yields of 60 to 80 percent by weight can be realized.(6)

Before the pyrolysis reaction the biomass feedstock is dried to less than 10% moisture and sized to small relatively homogeneous particles. The small particle size helps ensure rapid heat transfer. The pyrolysis reaction occurs in a fluidized bed reactor using an inert material such as sand. The biomass is rapidly flash vaporized and becomes a mixture of gas, vapor, aerosols, and solid char. By maximizing the speed of the pyrolysis reaction the yield of the bio-oil liquid fraction is maximized. The pyrolysis occurs in a reactor within one second or less to several seconds at temperatures of 450 to 500 degrees Celsius. After the reaction the char is separated out using a cyclone. Gases pass through the cyclone, enter a quench tower, and are quickly cooled and condensed into liquid bio-oil. The remaining non condensable material is recycled within the process, and it is used as a fluidized gas for the pyrolysis reaction and as a fuel combined with the solid char to provide process heat.

Bio-oil is an oxygenated fuel that consists primarily of carbon, hydrogen, and oxygen and small amounts of nitrogen and sulfur. The exact composition of the product varies depending on the feedstock composition and the reaction conditions. Crude bio-oil or pyrolysis oil can be used directly to produce heat and power. However, bio-oil is less stable and its viscosity increases over time much faster than petroleum products. Highly viscous oils are not suitable motor fuels. Bio-oil also contains char fines that decrease stability. Bio-oil also has a relatively high oxygen and acid content which increases the difficulties of processing requiring more stainless steel vessels. However, bio-oil can be upgraded significantly through hydrotreatment to produce gasoline or renewable diesel.

(1) Commercialization Status – Renewable Diesel (Flash Pyrolysis)

The Ensyn Corporation and Dynamotive Energy Systems Corporation are the two main companies that have developed commercial pyrolysis oil technologies. Each of these companies has developed a patented pyrolysis technique and have a wide range of experience producing pyrolysis oil from different feedstocks. By 2005, Ensyn had seven commercial RTP™ biomass plants in the U.S. and Canada with the largest having a capacity of 160 green tons of wood per day. Dynamotive Energy System’s Ontario, Canada plant reached commercialization in 2004 with a capacity of 110 tons per day of biomass. However, only a small amount of the bio-oil from these plants is produced for fuel.(6) See Table B-11 below for a summary of these plants.

**Table B-11
Renewable Diesel Plants (Worldwide)**

Name	Location	Capacity	Start-up	Status
Ensyn Corp.	Ottawa, Canada (HQ) Renfrew, Ontario largest plant	100 tpd residual wood (input)	1989	-Company claim: The world's only rapid pyrolysis process operated on a long term commercial basis - Company uses patented "RTP" Biomass to liquid bio oil process.
Dynamotive Corp	Guelph plant Ontario, Canada	200 tpd wood residue to yield 130 barrels oil	6/2008	12/2008 contract signed for new plant in China and Taiwan
	West Lorne plant Ontario, Canada	130 tpd wood residue	2005	

b. Biomass to Renewable Diesel through Fischer Tropsch (FT) Process

Biomass can be synthesized into renewable diesel through gasification and FT synthesis. FT fuels can be made into gasoline or diesel range hydrocarbons (renewable gasoline or renewable diesel fuel).

(1) Gasification

Gasification is basically turning a solid fuel into a gaseous fuel. It is a process used to convert biomass feedstocks into a syngas rich in carbon monoxide and hydrogen. Gasification can be used on many biomass feedstocks and can be appealing for materials that are difficult or undesirable to combust directly (such as sludge and hazardous wastes). Once the syngas is cleaned of contaminants it can be used to make liquid fuels and chemicals.

The two main reactions that occur during gasification are shown below:

The Boudouard Reaction: $C + CO_2 \rightarrow 2CO$

The Water-Gas Reaction: $C + H_2O \rightarrow CO + H_2$

The two main types of gasifiers are fixed bed and fluidized bed. The fixed bed gasifier is simpler, less expensive, and produces low Btu gases, but fluidized bed is more complex, expensive, and produces higher Btu gases. In the fluidized bed air and/or steam is passed through a particle bed causing it to become fluidized. Fuel and an inert media such as sand or alumina is also added to the bed to improve heat transfer. The

type of biomass feedstock has a large effect on the process behavior and syngas conversion efficiency.(6)

(2) FT process

As described previously in the Classic Fischer Tropsch Section, the FT synthesis process is a method of generating hydrocarbons from a gaseous syngas composed of mixtures of CO and H₂ using a metal catalyst.

After the syngas is cleaned it is sent to a high temperature (300-350 degree Celsius) or a low temperature (200-240 degrees Celsius) FT reactor. A low temperature reactor is used to maximize the production of renewable diesel while the other is used to maximize renewable gasoline production. Product liquids from the FT reactor can be upgraded into diesel using a combination of hydrotreating, hydrocracking, and hydroisomeriation. Table B-12 below summarizes the plants producing renewable diesel using the Fischer Tropsch process with biomass feedstock.

Table B-12
Renewable Diesel through Fischer Tropsch (Worldwide)

Name	Location	Capacity	Start-up	Status
Renewable Diesel (gasification & Fischer Tropsch)				
Neste Oil, NSE Biofuels, Stora Enso, VTT, Foster Wheeler	Varkaus, Finland	100,000 tpy biowax	2015	-Demonstration plant under construction -Wood based biomass feed -Biowax refined into fuel at Porvoo refinery
Flambeau River Biofuels LLC	Park Falls, WI (USA)	6 million gal/yr	4/2009	Pilot plant that received \$3 million grant, woody biomass feed, operation will close if not economical

3. Lignocellulosics to Renewable Gasoline

As with renewable diesel, biomass feedstocks including lignocellulosic crops, crop residues, and wastes can be synthesized into gasoline range hydrocarbons. The two main pathways for the conversion of biomass into renewable gasoline include the pyrolysis and the hydrotreatment process to make renewable gasoline and the gasification and Fischer Tropsch (FT) process to produce FT gasoline. As with renewable diesel, the processing through lignocellulosic pathways, especially for wastes, can result in lower carbon intensity fuels. Gasification and the high temperature FT process used to produce renewable gasoline are described above.

4. Classic Fischer Tropsch Fuels

Synthetic liquid fuels are produced from fossil-fuel resources that cannot reasonably be classified as petroleum. The two fuels discussed here are natural gas-based synthetic fuels (also called gas-to-liquids, GTLs, or GTL synfuels) and coal-based synthetic fuels (also called coal-to-liquids, CTLs, or CTL synfuels). The classic Fischer Tropsch process is a catalyzed chemical reaction in which synthesis gas, a mixture of carbon monoxide and hydrogen, is converted into liquid hydrocarbons of various forms. Many refinements and adjustments have been made to the original process invented in the 1920s.

a. Coal to Liquids

The production of CTL fuels begins with coal as a raw material or feedstock. In indirect coal liquefaction, prepared coal is subjected to heat and pressure in the presence of steam and oxygen to create a synthesis gas. The synthesis gas is treated to remove impurities and is sent to a high temperature (300-350 degree Celsius) or a low temperature (200-240 degrees Celsius) Fischer Tropsch (FT) reactor. A low temperature reactor is used to maximize the production of renewable diesel while the other is used to maximize renewable gasoline production. The syngas must be cleaned by removing sulfur halides and nitrogen before it enters the reactor because they will poison the FT catalyst which is usually made of iron or cobalt. Four different types of beds have been used commercially including multi-tubular fixed bed, circulating fluidized bed, fixed fluidized bed, and fixed slurry bed reactors.

The control of the temperature is a critical in the reactor as it affects the product distribution and can harm the catalyst. Temperatures above 400 degrees Celsius encourage the formation of methane which is undesired. The catalyst can also lose activity due to sintering, carbon deposition, and oxidation.

The off gas from the FT process can be diverted and recycled back through the reactor to generate additional hydrocarbons or it can be used to generate power or steam. Product liquids from the FT reactor can be upgraded into diesel using a combination of hydrotreating, hydrocracking, and hydroisomerization.

In direct coal liquefaction, coal is pulverized and mixed with oil and hydrogen in a pressurized environment. This process converts the coal into a synthetic crude oil that can then be refined into a variety of fuel products.

Commercialization Status - CTL

Sasol in South Africa has been producing coal-derived fuels using FT technology since 1955. The total capacity of the South African CTL operations now stands in excess of 160,000 barrels per day of product. There are a number of CTL projects around the world at various stages of development, the most advanced being in China, the USA, and Australia.

b. Gas to Liquid (GTL) Fuels

Gas to Liquid (GTL) fuels are fuels derived by converting natural gas into longer-chain hydrocarbons by the low temperature Fischer-Tropsch process to produce diesel range fuels and co-products for the California market.(36) The GTL process is an umbrella term for a group of technologies that convert natural gas into these products. The processes are based on those first conducted by Sasol's plant mentioned above that uses natural gas as a feedstock for the FT process.

The GTL conversion process involves reforming the natural gas feedstock, and converting it into a syngas rich in hydrogen and carbon monoxide. The syngas is then run through the FT reactor. The products from the FT reactor are then upgraded into GTL diesel, naphtha, lubricant base oils, and normal paraffin.

Project proponents for GTL have claimed that their GTL products are low in sulfur and aromatics and in many cases have a lower carbon intensity than conventional refinery analogues. The low sulfur and aromatics result in a superior emission profile for GTL diesel.

Sasol Chevron has also stated that GTL diesel use can provide significant reductions in particulate matter, nitrogen oxides, carbon monoxide, and hydrocarbon emissions. GTL diesel can help extend a refinery's conventional diesel output and potentially increase the GHG efficiency of an entire refinery. Any upgrading with GTL diesel can reduce the need for hydrotreating in a refinery, which is GHG intensive.

In many respects GTL lubricants may match the benefits of more energy intensive chemically derived, synthetic lubricant base oils.(36) With increased energy efficiency GHG emissions are reduced. GTL lubricants help extend the time duration between oil drain intervals which increases vehicle mileage per quart of oil. This should also result in a GHG emission benefit.

A GTL facility can be designed to separate normal paraffin which can replace conventional normal paraffin extraction from kerosene as a means of producing linear alkyl benzene (LAB) for detergent manufacture. Producing LAB from GTL normal paraffin requires less steam, natural gas, and electricity and is therefore more efficient in terms of GHG emissions.(36)

Commercialization Status – GTL

In 2006 Shell's GTL Oryx plant in Qatar began commercial operation. Shell also has its Pearl project in Qatar under construction. As of November 2008, Chevron Nigeria and Nigerian National Petroleum Corporation had a GTL plant at Escravos, Nigeria under construction. See Table B-13 below for a summary of CTL and GTL plants.

Table B-13
CTL and GTL Plants (Worldwide)

Name	Location	Capacity	Start-up	Status
Coal to Liquids (CTL)				
Sasol	South Africa	160,000 bbl/dy	1955	Syngas made from coal and crude oil
Gas to Liquids (GTL)				
Sasol	South Africa (Moss gas plant)	1.1 million tpy	1990's	-Uses natural gas feedstock for GTL
Shell	Bintulu, Malaysia	0.6 million tpy produced, 14,700 bbl/yr capacity	1993	
Shell	Qatar -Pearl plant	140,000 bbl/dy	2010	Planned
	Qatar -Oryx plant		2006	
Chevron & Nigerian National Petroleum	Escravos, Nigeria	34,000 bbl/dy	2009	-Also produces LNG -Primarily for European market

D. Longterm – Technologies Projected after 2020

This section discusses the fuels and conversion technologies which are expected to be available on a commercial scale after 2020. In addition, a discussion of carbon capture and geologic sequestration is included in this section. An overview is presented in Table B-14 below, categorized by fuel type or technique, fuel, and feedstocks/process.

Table B-14

Fuel Type or Technique	Fuel	Feedstocks/Process
Biofuels	Biodiesel	From Microalgae
	Ethanol	From Macroalgae (Seaweed)
	Renewable Gasoline	Microalgae/bacteria
	Butanol	Grains, Sugar Crops, or Lignocellulosics
Carbon Capture and Geologic Sequestration	Multiple	This technique may be used at any large stationary source of carbon dioxide such as refineries and power plants.

1. Biofuels from Algae

The overall potential of biofuel production from algae is huge. It is generally accepted that approximately half of the global biomass originates in the oceans.(37) Algae use the energy from sunlight to produce simple sugars, then convert these simple sugars into oils or complex carbohydrates, and store these substances in cells. Cultivation of algae can be the route to multiple bioenergy sources and an especially effective way to reduce greenhouse gas emissions. Potential algal-derived fuels include biodiesel, ethanol, Fischer Tropsch fuels, hydrogen, alkanes, and methane. Typically, oils from microalgae (microscopic) are the feedstock for biodiesel production, whereas polysaccharides from macroalgae (seaweed) are the feedstock for ethanol. However, the biomass fraction of microalgae can also be converted to ethanol and other biofuels.(5) Current research and development efforts in the United States have largely focused on microalgae as a source of oils. Several species produce high oil yields that greatly outweigh yields from conventional crops.(5)

There are significant environmental benefits from cultivating algae for biofuel production. Algae fix atmospheric CO₂ normally but may also sequester CO₂ in waste streams from power plants, refineries, or other industrial sources. Algae can thrive in small areas of land that are unsuitable for conventional crops using high salinity water that is unfit for agricultural or domestic use. Algae also have value in managing nutrients in waste water treatment. Cultivation of algae may provide multiple benefits concurrently. For example, production of algae in conjunction with wastewater treatment (with CO₂ addition from combustion emissions) has the potential of fixing CO₂, removing soluble nitrogen and phosphorous in the wastewater, and producing O₂, as well as generating biomass for biofuel feedstock.

Biofuel production from algae has been a continuous topic of research since the 1970s. The DOE 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, using bioreactor systems that feed CO₂ combustion emissions to algae, and using algae grown in water systems to produce biofuel.

Although research is progressing, there are still a number of hurdles that must be overcome before commercial production of biofuels from algae is a reality. Algae have particular culture requirements that must be met in order to produce near their theoretical potential. Maintaining requirements for optimal algal growth can be a challenge. For example, light conditions change as the density of cultures increases, which can limit the ability of the algae to convert sunlight into biomass. Solutions to problems so far have been specific rather than general in application. As research progresses there are opportunities for breakthroughs, but it appears that the technology will not be fully commercialized until sometime after 2020. Harvesting, oil extraction, and cell wall deconstruction for sugars still present technical and economic hurdles.(5) To date, there are no commercially operating algae-to-biofuel production facilities in California.

Although there are numerous potential algal-derived fuels, staff has primarily limited the scope of the discussion to renewable biodiesel with brief consideration of other biofuels, sequestration of CO₂ emissions from combustion, and wastewater treatment.

a. Biodiesel from Algae

Algae are one of the most promising sources of biodiesel production. In fact, algae are the highest yielding feedstock for biodiesel. They can produce, for example, 250 times the amount of oil per acre as soybeans.(38)

There are over 100,000 different species of algae. Algae exist in many different forms, sizes, and colors varying from small unicellular photosynthetic organisms that can be found floating in ponds to large seaweed that live in the ocean. Small sized (microscopic) photosynthetic algae can generally be categorized as microalgae and tends to be the best for generating oil for biodiesel. Macroalgae are generally seaweed and are not widely used to produce biodiesel.

Algae can be grown in open ponds or in a closed system. The disadvantages of an open system is that the algae can become contaminated with less desirable types of algae, bacteria and organisms and it may be more exposed to weather conditions that may not always be ideal for algae growth. In a closed system algae is grown in a series of plastic bags in stacks which maximizes exposure to sunlight and protects the algae from contamination. The bags are fed nutrient rich water and carbon dioxide to speed algae growth. Sections of the algae bioreactor bags that have matured can be harvested for oil daily. New sections of bags can be added to keep the process going in a continuous loop. An open system generally consists of a series of open ponds. Open ponds can also fed nutrient rich water and carbon dioxide and the ponds can be rotated for growth and harvesting of algae.

Ongoing research has developed bio-engineered algae strains that maximize oil production. Keeping bio-engineered strain separated from the environment in closed systems is important to reduce possible contamination from other algae and bacteria which could reduce alga oil production.

The most common methods of removing oil from the algae consist of pressing the algae and use of hexane solvent. The algae is first pressed which removes a majority of the oil. The leftover algae are mixed with hexane. The oil dissolves easily with the hexane but water does not and is easily separated. The oil and hexane can then be separated by distillation. After the oil is extracted from the algae and cleaned, biodiesel is made from the oil through transesterification. Biomass is a by-product of oil extraction process which may have potential uses such as cattle feed, cosmetics, vitamins, or pigments.

The alga oil could also be refined into gasoline range hydrocarbons. Existing process equipment at a refinery including hydrotreatment and cracking operations may be able to be used for this purpose. It may one day be conducive to grow algae to produce fuel

on the property of existing refineries. The CO₂ at a refinery could potentially be used to grow algae. In addition, algae can help clean the large amounts of water that refineries process.

b. Other Applications

(1) Ethanol from Macroalgae

Internationally, some universities are investigating the use of macroalgae (seaweed) as a source of carbohydrates that could be converted to ethanol. In their natural environment, macroalgae grow on rocky surfaces and form perennial, layered vegetation that makes efficient use of sunlight.(37) Macroalgae are capable of producing high yields of material when compared to even the most productive land plants. Macroalgae have a high concentration of carbohydrates and are therefore a good potential feedstock for ethanol production. However, the sugars composing the structural and storage carbohydrates are not freely available for fermentation. For example, the primary carbohydrate in kelp is laminarin, which cannot be directly fermented by yeast.

Until recently, pretreatment of kelp with acid and/or high temperature was thought to be necessary to expose and hydrolyze the carbohydrates. A recent study in the United Kingdom demonstrated that pretreatment of kelp was not necessary to produce ethanol with the addition of appropriate enzymes to the fermentation mix. Researchers used samples of the brown alga *Saccharina latissima*, harvested from the coast of Wales. *Saccharina latissima* is a kelp which may contain up to 50 percent dry weight carbohydrates when harvested in the fall. When the enzyme laminarinase (breaks down the carbohydrate laminarin to glucose) was added to the fermentation mix, the laminarin was hydrolyzed (without acid or high temperature pretreatment) to glucose, that the yeast fermented to ethanol.(39)

(2) Methane from Algae

Biomethane production from marine biomass was researched in the 1970s and 1980s but largely dropped in the 1990s because of costs. However, researchers found that several species of marine algae were good substrates for biomethane generation. A recent study (funded by the European Commission) has suggested that the multi-purpose use of microalgal biomass could make methane production from digestion of the algal residues more cost effective.(37)

(3) Hydrogen from Algae

Microalgae have been studied for years as a source for production of hydrogen. To date, no process has been demonstrated that could be scaled up for commercial production.(40) However, research and development is continuing.. Recently, NREL has demonstrated that the green alga *Chlamydomonas reinhardtii* can produce hydrogen by splitting water through photobiological water splitting or biophotolysis. This

photosynthetic pathway produces H₂ without producing greenhouse gases. The ultimate goal of this work is to develop a water-splitting process that will result in a commercial H₂-producing system that is cost effective, scalable to large production, and non-polluting.(41)

(4) Renewable Gasoline from Algae

Sapphire, a San Diego company, has claimed that it has made a type of renewable gasoline using modified algae that meets fuel quality standards and is compatible with current gasoline. However, Sapphire's first facility will not be operational for another three years.(42) A related area of current research and development is the production of renewable gasoline (alkanes) from bacteria.

(5) Thermochemical Conversion of Algae

Researchers are investigating the use of microalgae harvested from lakes to both reduce algal blooms and to produce bio-oil from fast pyrolysis. One study found that up to 24 percent of the dry biomass was recovered as bio-oil and that the oil had better properties than oil from lignocellulosic feedstock. Since the bio-oil is composed of all organic compounds in the algae including proteins and carbohydrates as well as oil, the yield is higher than the yield from harvesting only the lipid content of the algae.(37)

(6) Sequestration of CO₂ Emissions from Combustion

Algae have great potential as a means to sequester or recycle CO₂ emissions from stack gases. Algae grow quickly and can be cultivated year round in limited spaces, co-located by the CO₂ emission source. The algal biomass can be used to produce biofuels and other valuable products such as animal feed.

The Arizona Public Service Company and GreenFuel Technologies Corporation have attempted to recycle the carbon dioxide emissions from stack gases of a commercial power plant by cultivating algae and then converting the algal biomass to transportation fuels. At the 1040 megawatt Redhawk Power Plant in Arlington, Arizona, plant design required specialized pipes to capture and transport CO₂ emissions from the stack to containers where algae are cultivated. In the presence of sunlight, as part of the photosynthetic process, the algae can use the waste CO₂ to grow. The project required the resulting algal biomass to have sufficient concentration of oils to be used as a feedstock to produce biodiesel.(43) However, the project only had limited success and has been shut down at this site due to technical and cost setbacks.(44)

(7) Wastewater Treatment

Microalgae ponds are currently used in waste water treatment applications, where algae provide oxygen needed for bacterial breakdown of organic matter in the wastewater, and in turn use the CO₂ generated by bacterial metabolism. Algae are also useful in managing nutrients in waste water treatment by removing soluble nitrogen and

phosphorous in the wastewater. Production of biofuels from algae grown in conjunction with wastewater treatment could potentially add value to the process. However, the lack of a reliable and cost effective algal harvesting process is a challenge. Bioflocculation settling appears promising but has not yet been demonstrated with a full-scale system.(40)

2. Butanol

Butanol is a four-carbon alcohol that is typically derived from petroleum refining and is used as an industrial solvent and an intermediate feedstock for the manufacture of other chemicals. This section discusses the feedstocks, pathways, and commercialization status of butanol produced from biomass. Efforts are being made to commercialize biobutanol for use in blends with gasoline to be offered for sale within California. The benefits of biobutanol as an alternative fuel are recognized through its explicit mention in the Renewable Fuel Standard in EISA.

The properties of biobutanol make it amenable to blending with gasoline. It is also compatible with ethanol blending and can improve the blending of ethanol with gasoline.(45) As a renewable fuel, butanol has a number of advantages over ethanol. Butanol has higher energy density than ethanol. Butanol can be mixed with gasoline in more flexible proportions than ethanol. Butanol is less corrosive, less volatile, and less water soluble than ethanol. As a result, butanol can be transported through existing fuel pipelines. However, the incomplete combustion of butanol can result in small amounts of butyric acid, which has a strong odor.(5)

a. Feedstocks

Biobutanol can be produced from the same feedstocks as ethanol. Any biological feedstock that contains sugar or that can be broken down into simple sugars is a potential source for biobutanol production via fermentation. The three main types of biomass feedstock for biobutanol production pathway are starch from corn, sugars from sugar crops, and biomass containing cellulose.

The easiest way to produce butanol via fermentation is to begin with sugar producing plants like sugarcane or sugar beets. The sugar syrup obtained when the feedstock is pressed can be fermented with minimal processing. In contrast, corn contains starch, a polymer of glucose, which must be broken apart before the sugar can be fermented, requiring more energy input. The third type of biomass feedstock contains cellulose, such as trees, grasses, wood wastes, etc. The cellulose in these feedstocks is part of a lignocellulosic composite in the cell walls that resists degradation. Hence, more energy is required break down this feedstock to its component sugars than with corn or sugar crops.

b. Conversion Technology

Several conversion technologies exist to produce butanol from biomass, including biochemical mechanisms (fermentation) and thermochemical mechanisms (gasification followed by a mixed alcohol reactor). However, alcohols derived from biomass (including butanol) are generally produced through fermentation. The traditional fermentation pathway that yields butanol is known as clostridial acetone butanol ethanol (ABE) fermentation. The ABE fermentation process to produce butanol has been known since World War I and was commonly used until the 1950s, when butanol derived from petroleum refining became widely available and more cost effective. During the oil crisis of the 1970s, interest resumed in biobutanol production for a while and then waned by the 1990s. At present, due to environmental and economic concerns active research is again underway to improve the technology and cost-effectiveness of biobutanol production.

The ABE pathway produces n-butanol, one of four possible butanol isomers. As the name of the fermentation pathway implies, in addition to butanol, acetone and ethanol are co-products. Hydrogen is also a co-product of ABE fermentation. Historically, a few naturally occurring species of the bacterial genus *Clostridium* were used in the ABE fermentation process. However, recent advances in genetic engineering have produced other types of microorganisms capable of making butanol. For example, researchers have demonstrated that genetically altered strains of the common yeast *Saccharomyces cerevisiae* (the yeast used for ethanol production) can produce butanol through the ABE fermentation process.(46)

In addition to ABE fermentation, other fermentation pathways with proprietary microorganisms are under research and development to produce butanol (n-butanol and other isomers). One project has demonstrated a patented dual pathway process that eliminates the co-products produced by the ABE fermentation process. This dual pathway process uses carbohydrates to produce butyric acid in the first stage, which is then converted to butanol in the second stage.(47)

c. Commercialization Status

Biobutanol production is currently being demonstrated in small scale plants, often in association with universities. BP/DuPont, ButylFuel, and other groups are conducting research and development efforts to improve conversion technology and cost-effectiveness. Staff is not aware of any facility producing biobutanol on a commercial basis. Although there are opportunities for breakthroughs, it appears that the technology will not be fully commercialized until sometime after 2020.

Biobutanol could be produced from new plants using corn and sugar crops (sugarcane, sugar beets, sweet sorghum, molasses) or by making modest retro-fits to existing ethanol plants. As technology develops further, production of biobutanol could be extended to include lignocellulosic feedstocks.

The Energy Independence and Security Act of 2007 provides an incentive for biobutanol production. The EISA includes butanol or other alcohols as produced through the conversion of organic matter from renewable biomass in the “Advanced Biofuel” category description. EISA definitions specify all corn based ethanol as a conventional biofuel. However, corn based butanol would be able to qualify for the Advanced Biofuel category, provided that it was able to meet the 50 percent reduction in lifecycle greenhouse gas performance from baseline gasoline.

3. Carbon Capture and Geologic Sequestration

Carbon capture and geologic sequestration (CCS) is the process of capturing CO₂, and then compressing, transporting, and injecting it into a suitable geologic formation for long-term isolation from the atmosphere. Alternatively, the CO₂ could be sequestered in novel ways such as industrial fixation of CO₂ into inorganic carbonates. Three main modes of application exist for CO₂ capture: post-combustion, pre-combustion, and oxy-combustion. Separation technologies used for each mode vary and include such methods as adsorption, absorption, membranes, cryogenics, and others. The level of development, cost, and efficiencies vary; breakthrough advances would greatly impact CCS viability.

Large stationary sources of carbon dioxide such as refineries and power plants are most viable candidates for CCS. Gasoline and diesel produced from such refineries could receive lower lifecycle carbon intensity values under the LCFS.

Refineries generally have three categories of emissions for post-combustion capture: high concentration sources associated with hydrogen production (5-20 percent of CO₂ emissions), flue gases (30-50 percent), and many small, low concentration sources (~30-70 percent). High concentration sources will have the lowest capture costs with flue gas having higher costs and the small, low concentration sources having significantly higher capture costs (Straelen et al, 2008)(48). In addition, energy will be needed to capture the CO₂.

With an estimated storage resource of between approximately 80 and 300 Gigatonnes (or 80,000 – 300,000 MMT), California has sufficient capacity for the annual CO₂ emissions from large stationary sources (CEC 2007(49)).

a. Commercialization Status

California has at least one CCS project could be operational before 2020 (approximately 1 MMT in total); this project is being pursued through the West Coast Regional Carbon Sequestration Partnership, a private-public partnership program managed and co-funded by the California Energy Commission. Additionally, a Hydrogen Energy project, slated for capture at a source in Kern County, California and injection in the nearby Elk Hills oil field, could be operational in 2014 with approximately 2 MMTCO₂ captured and sold annually for enhanced oil recovery. The associated greenhouse gas reductions may be limited in 2020 since the project may involve injection purely for enhanced oil recovery.

Internationally there are four large scale sequestration projects though all are associated with oil and gas production. Additionally, national and international research is underway and many additional demonstration projects are planned and will provide valuable knowledge and experience with CCS. DOE has invested \$480 million since 1997 into its carbon sequestration program, with an expected additional \$149 million in the next fiscal year. While more research and development needs to occur, the technology could be implemented at refineries or other large stationary CO₂ sources with necessary safeguards, including monitoring at the sequestration site.

Although there is considerable interest and research into this technology, numerous uncertainties and risks still remain, especially for the sequestration component. Experience in related areas such as enhanced oil recovery provides knowledge but the volumes, permanence needs, and subsurface buoyancy of CO₂ provide new challenges and risks. However, if sites are well selected and monitored, the Intergovernmental Panel on Climate Change expects over 99 percent of the CO₂ to remain sequestered and the risks to be comparable to currently practiced, similar activities.

Environmental justice organizations in California have expressed concerns over geologic sequestration risks. National-level environmental organizations are divided on CCS.

Given the current state of technology and the costs of CCS reductions as well as a number of outstanding questions concerning its long-term effectiveness and safety, CCS should be investigated to meet various AB32 goals but on a case-by-case basis to determine effectiveness and minimize risks. In order to cost-effectively meet long term goals, the investigation of the viability of this technology and its advancement past the demonstration phase is key.

Appendix B
Part B
Technology Assessment of Potential Low Carbon Fuels

Table B-15
U.S. Fuel Ethanol Industry Plants and Production Capacity(8)
(Adapted from the Renewable Fuels Association List updated February 5, 2009)

O- Operating	Company	Location	Feedstock	Nameplate Capacity (mgy)	Operating Production (mgy)	Under Construction / Expansion Capacity (mgy)
	Abengoa Bioenergy Corp. (Total)			198.0	168.0	176.0
UC	Abengoa Bioenergy Corp.	Madison, IL	Corn			
UC	Abengoa Bioenergy Corp.	Mt. Vernon, IN	Corn			
O	Abengoa Bioenergy Corp.	Colwich, KS	Corn/milo			
O	Abengoa Bioenergy Corp.	Ravenna, NE	Corn			
O	Abengoa Bioenergy Corp.	York, NE	Corn			
	Abengoa Bioenergy Corp.	Portales, NM	Corn			
O	Absolute Energy, LLC	St. Ansgar, IA	Corn	100.0	100.0	
O	ACE Ethanol, LLC	Stanley, WI	Corn	41.0	41.0	
O	Adkins Energy, LLC	Lena, IL	Corn	40.0	40.0	
O	Advanced Bioenergy, LLC	Fairmont, NE	Corn	100.0	100.0	
O	Advanced Bioenergy, LLC	Aberdeen, SD	Corn	50.0	50.0	
O	Advanced Bioenergy, LLC	Huron, SD	Corn	32.0	32.0	33.0
UC	Ag Energy Resources, Inc.	Benton, IL	Corn			5.0
O	AGP	Hastings, NE	Corn	52.0	52.0	
O	Agri-Energy, LLC	Luverne, MN	Corn	21.0	21.0	
O	AI-Corn Clean Fuel	Claremont, MN	Corn	42.0	42.0	
	Alchem Ltd. LLP	Grafton, ND	Corn	10.0		
	AltraBiofuels Coshocton Ethanol, LLC	Coshocton, OH	Corn	60.0		
	AltraBiofuels Indiana, LLC	Cloverdale, IN	Corn	92.0		
O	AltraBiofuels Phoenix Bio Industries, LLC	Goshen, CA	Corn	31.5	31.5	
UC	Amaizing Energy, LLC	Atlantic, IA	Corn			110.0

O- Operating	Company	Location	Feedstock	Nameplate Capacity (mgy)	Operating Production (mgy)	Under Construction / Expansion Capacity (mgy)
O	Amaizing Energy, LLC	Denison, IA	Corn	48.0	48.0	
	18 - Archer Daniels Midland (Total)			1,070.0	1,070.0	550.0
O	Archer Daniels Midland	Cedar Rapids, IA	Corn			
O	Archer Daniels Midland	Clinton, IA	Corn			
O	Archer Daniels Midland	Decatur, IL	Corn			
O	Archer Daniels Midland	Peoria, IL	Corn			
O	Archer Daniels Midland	Marshall, MN	Corn			
O	Archer Daniels Midland	Wallhalla, ND	Corn/barley			
O	Archer Daniels Midland	Columbus, NE	Corn			
O	Arkalon Energy, LLC	Liberal, KS	Corn	110.0	110.0	
	26 - Aventine Renewable Energy, LLC (Total)			207.0	207.0	
O	Aventine Renewable Energy, LLC	Pekin, IL	Corn			
O	Aventine Renewable Energy, LLC	Aurora, NE	Corn			
O	Badger State Ethanol, LLC*	Monroe, WI	Corn	48.0	48.0	
UC	Big River Resources Galva, LLC	Galva, IL	Corn			100.0
O	Big River Resources, LLC*	West Burlington, IA	Corn	92.0	92.0	
O	BioFuel Energy - Buffalo Lake Energy, LLC	Fairmont, MN	Corn	115.0	115.0	
O	BioFuel Energy - Pioneer Trail Energy, LLC	Wood River, NE	Corn	115.0	115.0	
UC	Bional Clearfield	Clearfield, PA	Corn			110.0
O	Blue Flint Ethanol	Underwood, ND	Corn	50.0	50.0	
O	Bonanza Energy, LLC	Garden City, KS	Corn/milo	55.0	55.0	
O	Bridgeport Ethanol	Bridgeport, NE	Corn	54.0	54.0	

O- Operating UC- Under Construc- tion	Company	Location	Feedstock	Nameplate Capacity (mgj)	Operating Production (mgj)	Under Construction / Expansion Capacity (mgj)
O	Bunge-Ergon Vicksburg	Vicksburg, MS	Corn	54.0	54.0	
O	Bushmills Ethanol, Inc.	Atwater, MN	Corn	50.0	50.0	
UC	Calgren Renewable Fuels, LLC	Pixley, CA	Corn			55.0
O	Cardinal Ethanol	Union City, IN	Corn	100.0	100.0	
O	Cargill, Inc.	Eddyville, IA	Corn	35.0	35.0	
O	Cargill, Inc.	Blair, NE	Corn	85.0	85.0	
O	Cascade Grain	Clatskanie, OR	Corn	108.0	108.0	
O	Castle Rock Renewable Fuels, LLC	Necedah, WI	Corn	50.0	50.0	
O	Center Ethanol Company	Sauget, IL	Corn	54.0	54.0	
O	Central Indiana Ethanol, LLC	Marion, IN	Corn	40.0	40.0	
O	Central MN Ethanol Coop	Little Falls, MN	Corn	21.5	21.5	
O	Chief Ethanol	Hastings, NE	Corn	62.0	62.0	
O	Chippewa Valley Ethanol Co.	Benson, MN	Corn	45.0	45.0	
UC	Cilion Ethanol	Keyes, CA	Corn			50.0
UC	Clean Burn Fuels, LLC	Raeford, NC	Corn			60.0
O	Commonwealth Agri-Energy, LLC	Hopkinsville, KY	Corn	33.0	33.0	
O	Corn Plus, LLP	Winnebago, MN	Corn	44.0	44.0	
O	Corn, LP	Goldfield, IA	Corn	55.0	55.0	
O	Cornhusker Energy Lexington, LLC	Lexington, NE	Corn	40.0	40.0	
O	Dakota Ethanol, LLC	Wentworth, SD	Corn	50.0	50.0	
	DENCO, LLC	Morris, MN	Corn	24.0		
O	Didion Ethanol	Cambria, WI	Corn	40.0	40.0	
UC	E Caruso (Goodland Energy Center)	Goodland, KS	Corn			20.0
O	E Energy Adams, LLC	Adams, NE	Corn	50.0	50.0	
	E3 Biofuels	Mead, NE	Corn	25.0		
O	East Kansas Agri- Energy, LLC	Garnett, KS	Corn	35.0	35.0	
O	ESE Alcohol Inc.	Leoti, KS	Seed Corn	1.5	1.5	

O- Operating UC- Under Construc- tion	Company	Location	Feedstock	Nameplate Capacity (mgy)	Operating Production (mgy)	Under Construction / Expansion Capacity (mgy)
O	Ethanol Grain Processors, LLC	Obion, TN	Corn	100.0	100.0	
O	Front Range Energy, LLC	Windsor, CO	Corn	40.0	40.0	
	Gateway Ethanol	Pratt, KS	Corn	55.0		
	Glacial Lakes Energy, LLC - Mina	Mina, SD	Corn	107.0		
O	Glacial Lakes Energy, LLC	Watertown, SD	Corn	100.0	100.0	
O	Global Ethanol/Midwest Grain Processors	Lakota, IA	Corn	97.0	97.0	
O	Global Ethanol/Midwest Grain Processors	Riga, MI	Corn	57.0	57.0	
O	Golden Cheese Company of California	Corona, CA	Cheese whey	5.0	5.0	
O	Golden Grain Energy, LLC	Mason City, IA	Corn	115.0	115.0	
O	Golden Triangle Energy, LLC	Craig, MO	Corn	20.0	20.0	
O	Grain Processing Corp.	Muscatine, IA	Corn	20.0	20.0	
O	Granite Falls Energy, LLC	Granite Falls, MN	Corn	52.0	52.0	
	Greater Ohio Ethanol, LLC	Lima, OH	Corn	54.0		
O	Green Plains Renewable Energy	Shenandoah, IA	Corn	55.0	55.0	
O	Green Plains Renewable Energy	Superior, IA	Corn	55.0	55.0	
O	Hawkeye Renewables, LLC	Fairbank, IA	Corn	120.0	120.0	
O	Hawkeye Renewables, LLC	Iowa Falls, IA	Corn	105.0	105.0	
O	Hawkeye Renewables, LLC	Menlo, IA	Corn	110.0	110.0	
O	Hawkeye Renewables, LLC	Shell Rock, IA	Corn	110.0	110.0	
O	Heartland Corn Products	Winthrop, MN	Corn	100.0	100.0	
O	Heron Lake BioEnergy, LLC	Heron Lake, MN	Corn	50.0	50.0	

O- Operating UC- Under Construc- tion	Company	Location	Feedstock	Nameplate Capacity (mgy)	Operating Production (mgy)	Under Construction / Expansion Capacity (mgy)
UC	Highwater Ethanol LLC	Lamberton, MN	Corn			50.0
UC	Homeland Energy	New Hampton, IA	Corn			100.0
O	Husker Ag, LLC	Plainview, NE	Corn	75.0	75.0	
O	Idaho Ethanol Processing	Caldwell, ID	Potato Waste	4.0	4.0	
O	Illinois River Energy, LLC	Rochelle, IL	Corn	100.0	100.0	
O	Indiana Bio-Energy	Bluffton, IN	Corn	101.0	101.0	
O	Iroquois Bio-Energy Company, LLC	Rensselaer, IN	Corn	40.0	40.0	
O	KAAPA Ethanol, LLC	Minden, NE	Corn	40.0	40.0	
O	Kansas Ethanol, LLC	Lyons, KS	Corn	55.0	55.0	
O	KL Process Design Group	Upton, WY	Wood waste	1.5	1.5	
O	Land O' Lakes	Melrose, MN	Cheese whey	2.6	2.6	
UC	LDCCommodities	Grand Junction, IA	Corn			100.0
O	LDCCommodities	Norfolk, NE	Corn	45.0	45.0	
O	Levelland/Hockley County Ethanol, LLC	Levelland, TX	Corn	40.0	40.0	
O	Lifeline Foods, LLC	St. Joseph, MO	Corn	40.0	40.0	
O	Lincolnland Agri-Energy, LLC	Palestine, IL	Corn	48.0	48.0	
O	Lincolnway Energy, LLC	Nevada, IA	Corn	50.0	50.0	
O	Little Sioux Corn Processors, LP	Marcus, IA	Corn	92.0	92.0	
O	Marquis Energy, LLC	Hennepin, IL	Corn	100.0	100.0	
O	Marysville Ethanol, LLC	Marysville, MI	Corn	50.0	50.0	
O	Merrick & Company	Aurora, CO	Waste beer	3.0	3.0	
O	Mid America Agri Products/Horizon	Cambridge, NE	Corn	44.0	44.0	
O	Mid America Agri Products/Wheatland	Madrid, NE	Corn	44.0	44.0	
O	Mid-Missouri Energy, Inc.	Malta Bend, MO	Corn	50.0	50.0	

O- Operating UC- Under Construc- tion	Company	Location	Feedstock	Nameplate Capacity (mgy)	Operating Production (mgy)	Under Construction / Expansion Capacity (mgy)
O	Midwest Renewable Energy, LLC	Sutherland, NE	Corn	25.0	25.0	
O	Minnesota Energy	Buffalo Lake, MN	Corn	18.0	18.0	
UC	NEDAK Ethanol	Atkinson, NE	Corn			44.0
O	Nesika Energy, LLC	Scandia, KS	Corn	10.0	10.0	
O	New Energy Corp.	South Bend, IN	Corn	102.0	102.0	
O	North Country Ethanol, LLC	Rosholt, SD	Corn	20.0	20.0	
	Northeast Biofuels	Volney, NY	Corn	114.0		
UC	Northwest Renewable, LLC	Longview, WA	Corn			55.0
UC	One Earth Energy	Gibson City, IL	Corn			100.0
O	Otter Tail Ag Enterprises	Fergus Falls, MN	Corn	57.5	57.5	
	Pacific Ethanol	Madera, CA	Corn	40.0		
O	Pacific Ethanol	Stockton, CA	Corn	60.0	60.0	
O	Pacific Ethanol	Burley, ID	Corn	50.0	50.0	
O	Pacific Ethanol	Boardman, OR	Corn	40.0	40.0	
UC	Panda Ethanol	Hereford, TX	Corn/milo			115.0
O	Parallel Products	Rancho Cucamonga, CA				
O	Parallel Products	Louisville, KY	Beverage waste	5.4	5.4	
O	Patriot Renewable Fuels, LLC	Annawan, IL	Corn	100.0	100.0	
O	Penford Products	Cedar Rapids, IA	Corn	45.0	45.0	
O	Pinal Energy, LLC	Maricopa, AZ	Corn	55.0	55.0	
O	Pine Lake Corn Processors, LLC	Steamboat Rock, IA	Corn	30.0	30.0	
O	Platinum Ethanol, LLC	Arthur, IA	Corn	110.0	110.0	
O	Plymouth Ethanol, LLC	Merrill, IA	Corn	50.0	50.0	
O	POET Biorefining - Alexandria	Alexandria, IN	Corn	68.0	68.0	
O	POET Biorefining - Ashton	Ashton, IA	Corn	56.0	56.0	
O	POET Biorefining - Big Stone	Big Stone City, SD	Corn	79.0	79.0	

O- Operating UC- Under Construc- tion	Company	Location	Feedstock	Nameplate Capacity (mgy)	Operating Production (mgy)	Under Construction / Expansion Capacity (mgy)
O	POET Biorefining - Bingham Lake	Bingham Lake, MN		35.0	35.0	
O	POET Biorefining - Caro	Caro, MI	Corn	53.0	53.0	
O	POET Biorefining - Chancellor	Chancellor, SD	Corn	110.0	110.0	
O	POET Biorefining - Coon Rapids	Coon Rapids, IA	Corn	54.0	54.0	
O	POET Biorefining - Corning	Corning, IA	Corn	65.0	65.0	
O	POET Biorefining - Emmetsburg	Emmetsburg, IA	Corn	55.0	55.0	
O	POET Biorefining - Fostoria	Fostoria, OH	Corn	68.0	68.0	
O	POET Biorefining - Glenville	Albert Lea, MN	Corn	42.0	42.0	
O	POET Biorefining - Gowrie	Gowrie, IA	Corn	69.0	69.0	
O	POET Biorefining - Hanlontown	Hanlontown, IA	Corn	56.0	56.0	
O	POET Biorefining - Hudson	Hudson, SD	Corn	56.0	56.0	
O	POET Biorefining - Jewell	Jewell, IA	Corn	69.0	69.0	
O	POET Biorefining - Laddonia	Laddonia, MO	Corn	50.0	50.0	5.0
O	POET Biorefining - Lake Crystal	Lake Crystal, MN	Corn	56.0	56.0	
O	POET Biorefining - Leipsic	Leipsic, OH	Corn	68.0	68.0	
O	POET Biorefining - Macon	Macon, MO	Corn	46.0	46.0	
UC	POET Biorefining - Marion	Marion, OH	Corn			65.0
O	POET Biorefining - Mitchell	Mitchell, SD	Corn	68.0	68.0	
O	POET Biorefining - North Manchester	North Manchester, IN	Corn	68.0	68.0	
O	POET Biorefining - Portland	Portland, IN	Corn	68.0	68.0	
O	POET Biorefining - Preston	Preston, MN	Corn	46.0	46.0	
O	POET Biorefining - Scotland	Scotland, SD	Corn	11.0	11.0	

O- Operating UC- Under Construc- tion	Company	Location	Feedstock	Nameplate Capacity (mgy)	Operating Production (mgy)	Under Construction / Expansion Capacity (mgy)
O	POET Biorefining-Groton	Groton, SD	Corn	53.0	53.0	
O	Prairie Horizon Agri-Energy, LLC	Phillipsburg, KS	Corn	40.0	40.0	
O	Quad-County Corn Processors	Galva, IA	Corn	30.0	30.0	
UC	Range Fuels	Soperton, GA	Wood waste			20.0
O	Red Trail Energy, LLC	Richardton, ND	Corn	50.0	50.0	
O	Redfield Energy, LLC	Redfield, SD	Corn	50.0	50.0	
O	Reeve Agri-Energy	Garden City, KS	Corn/milo	12.0	12.0	
O	Renew Energy	Jefferson Junction, WI	Corn	130.0	130.0	
O	Renova Energy	Torrington, WY	Corn	5.0	5.0	
O	Riverland Biofuels	Canton, IL	Corn	37.0	37.0	
O	Show Me Ethanol	Carrollton, MO	Corn	55.0	55.0	
O	Siouxland Energy & Livestock Coop	Sioux Center, IA	Corn	60.0	60.0	
O	Siouxland Ethanol, LLC	Jackson, NE	Corn	50.0	50.0	
O	Southwest Georgia Ethanol, LLC	Camilla, GA	Corn	100.0	100.0	
O	Southwest Iowa Renewable Energy, LLC	Council Bluffs, IA	Corn	110.0	110.0	
O	Sterling Ethanol, LLC	Sterling, CO	Corn	42.0	42.0	
UC	Tate & Lyle	Ft. Dodge, IA	Corn			105.0
O	Tate & Lyle	Loudon, TN	Corn	67.0	67.0	38.0
O	Tharaldson Ethanol	Casselton, ND	Corn	110.0	110.0	
O	The Andersons Albion Ethanol LLC	Albion, MI	Corn	55.0	55.0	
O	The Andersons Clymers Ethanol, LLC	Clymers, IN	Corn	110.0	110.0	
O	The Andersons Marathon Ethanol, LLC	Greenville, OH	Corn	110.0	110.0	
O	Trenton Agri Products, LLC	Trenton, NE	Corn	40.0	40.0	

O- Operating UC- Under Construc- tion	Company	Location	Feedstock	Nameplate Capacity (mgy)	Operating Production (mgy)	Under Construction / Expansion Capacity (mgy)
O	United Ethanol	Milton, WI	Corn	52.0	52.0	
O	United WI Grain Producers, LLC	Friesland, WI	Corn	49.0	49.0	
O	Utica Energy, LLC	Oshkosh, WI	Corn	48.0	48.0	
	VeraSun Energy Corp.	Dyersville, IA	Corn			
	VeraSun Energy Corp.	Linden, IN	Corn			
	VeraSun Energy Corp.	Lake Odessa, MI	Corn			
	VeraSun Energy Corp.	Janesville, MN	Corn			
	VeraSun Energy Corp.	Welcome, MN	Corn			
	VeraSun Energy Corp.	Hankinson, ND	Corn			
	VeraSun Energy Corp.	Albion, NE	Corn			
	VeraSun Energy Corp.	Central City, NE	Corn			
	VeraSun Energy Corp.	Ord, NE	Corn			
	VeraSun Energy Corp.	Bloomington , OH	Corn			
	VeraSun Energy Corp.	Marion, SD	Corn			
	178 - VeraSun Energy Corporation (Total)			1,635.0	450.0	
	VeraSun Energy Corporation	Albert City, IA	Corn			
O	VeraSun Energy Corporation	Charles City, IA	Corn			
O	VeraSun Energy Corporation	Ft. Dodge, IA	Corn			
O	VeraSun Energy Corporation	Hartley, IA	Corn			
UC	VeraSun Energy Corporation	Welcome, MN	Corn			
O	VeraSun Energy Corporation	Aurora, SD	Corn			
O	Verenium	Jennings, LA	Sugar Cane bagasse	1.5	1.5	
O	Western New York Energy LLC	Shelby, NY		50.0	50.0	

O- Operating UC- Under Construc- tion	Company	Location	Feedstock	Nameplate Capacity (mgy)	Operating Production (mgy)	Under Construction / Expansion Capacity (mgy)
O	Western Plains Energy, LLC	Campus, KS	Corn	45.0	45.0	
O	Western Wisconsin Renewable Energy, LLC	Boyceville, WI	Corn	40.0	40.0	
O	White Energy	Russell, KS	Milo/wheat starch	48.0	48.0	
O	White Energy	Hereford, TX	Corn/Milo	100.0	100.0	
O	White Energy	Plainview, TX	Corn	110.0		
O	Wind Gap Farms	Baconton, GA	Brewery waste	0.4	0.4	
O	Xethanol BioFuels, LLC	Blairstown, IA	Corn	5.0	5.0	
O	Yuma Ethanol	Yuma, CO	Corn	40.0	40.0	
	TOTALS			12,375.4	10,469.4	2,066.0
				mgy for 193 nameplate refineries	mgy for 170 operating refineries	mgy for under construction/ expanding refineries

Table B-16
Commercial Biodiesel Plants as of 9/29/08
(According to the National Biodiesel Board)

Company	City	Annual Production Capacity	Verified*	Primary Feedstock(s)	Operating Since
AL					
Allied Renewable Energy, LLC	Birmingham	15,000,000		Soy	May 2007
Athens Biodiesel, LLC	Athens				August 2008
Eagle Biodiesel, Inc.	Bridgeport	30,000,000		Soy	April 2007
Green River Biodiesel, Inc.	Moundville			Soy	July 2008
Perihelion Global, Inc.	Opp	10,000,000		Multi Feedstock	June 2008
AR					
Arkansas SoyEnergy Group	DeWitt	10,000,000		Soy	September 2007
FutureFuel Chemical Company	Batesville	24,000,000	X	Multi Feedstock	October 2005
Pinnacle Biofuels, Inc.	Crossett	10,000,000		Multi Feedstock	May 2008
AZ					
Amereco Biofuels Corp	Arlington	15,000,000		Multi Feedstock	September 2007
CA					
Blue Sky Bio-Fuels, Inc.	Oakland			Multi Feedstock	January 2007
Community Fuels	Stockton	10,000,000		Multi Feedstock	June 2008
Energy Alternative Solutions, Inc	Gonzales	1,000,000		Multi Feedstock	December 2006
Imperial Western Products	Coachella	8,000,000	X	Multi Feedstock	October 2001
Renewable Energy Products, LLC	Santa Fe Springs	10,000,000		Multi Feedstock	July 2008
Wright Biofuels, Inc.	San Jacinto	5,500,000		Multi Feedstock	September 2007
Yokayo Biofuels, Inc.	Ukiah	350,000		Recycled Cooking Oil	April 2006
CT					
BioDiesel One Ltd	Southington	4,000,000		Recycled Cooking Oil	August 2008
BioPur Inc.	Bethlehem	1,000,000		Multi Feedstock	July 2006
FL					
Agri-Source Fuels, Inc.	Dade City	30,000,000		Multi Feedstock	October 2007
World Energy Alternatives, LLC	Lakeland	18,000,000	X	Soy, Animal Fats, Yellow Grease	July 1996

Company	City	Annual Production Capacity	Verified	Primary Feedstock(s)	Operating Since
GA					
Alterra Bioenergy of Middle Georgia, LLC	Gordon	15,000,000		Multi Feedstock	August 2007
BullDog BioDiesel	Ellenwood	18,000,000		Multi Feedstock	January 2008
ECO Solutions, LLC	Chatsworth	25,000,000		Multi Feedstock	August 2007
Georgia Biofuels Corp.	Loganville	1,000,000		Multi Feedstock	January 2007
Middle Georgia Biofuels	East Dublin	1,500,000		Poultry Fat, Tallow	April 2006
Peach State Labs	Rome			Soy	January 2005
Seminole Biodiesel	Bainbridge	10,000,000		Multi Feedstock	January 2008
Sunshine BioFuels, LLC	Camilla	6,000,000		Soy	August 2006
US Biofuels Inc.	Rome	10,000,000		Multi Feedstock	April 2004
HI					
Pacific Biodiesel	Kahului	500,000		Multi Feedstock	August 1996
Pacific Biodiesel	Honolulu	1,000,000		Multi Feedstock	May 2002
IA					
AGP	Sergeant Bluff	30,000,000		Soy	August 1996
Cargill	Iowa Falls	37,500,000		Soy	June 2006
Central Iowa Energy, LLC	Newton	30,000,000	X	Multi Feedstock	April 2007
East Fork Biodiesel, LLC	Algona	60,000,000		Refined Vegetable Oils	December 2007
Freedom Fuels, LLC	Mason City	30,000,000	X	Soy	June 2007
Iowa Renewable Energy, LLC	Washington	30,000,000	X	Multi Feedstock	July 2007
REG Ralston, LLC	Ralston	12,000,000		Multi Feedstock	September 1996
Riksch BioFuels, LLC	Crawfordsville	10,000,000	X	Multi Feedstock	December 2006
Sioux Biochemical, Inc.	Sioux Center	2,000,000		Corn, Soy	December 2006
Soy Solutions	Milford	2,000,000		Soy	July 2003
Tri-City Energy	Keokuk	5,000,000		Soy	January 2007
Western Dubuque Biodiesel	Farley	30,000,000	X	Crude or Refined Vegetable Oils	August 2007
Western Iowa Energy, LLC	Wall Lake	30,000,000		Multi Feedstock	June 2006

Company	City	Annual Production Capacity	Verified	Primary Feedstock(s)	Operating Since
ID					
Blue Sky Biodiesel, LLC	New Plymouth	10,000,000		Soy	July 2006
Pleasant Valley Biofuels, LLC	American Falls				August 2008
IL					
Diamond Biofuels	Mazon	500,000		Animal Fats, Recycled Cooking Oil	May 2008
Heartland Biodiesel, Inc.	Marion	3,000,000		Soy	December 2007
Incobrasa Industries, Ltd.	Gilman	31,000,000		Soy	January 2007
Midwest Biodiesel Products, Inc.	South Roxanna	30,000,000		Multi Feedstock	May 2007
Nova Biosource	Senaca	60,000,000		Multi Feedstock	July 2008
Stepan Company	Millsdale	22,000,000		Multi Feedstock	January 2001
IN					
e-biofuels, LLC	Middletown	25,000,000		Multi Feedstock	June 2007
Evergreen Renewables	Hammond	5,000,000		Soy	May 2006
Indiana Flex Fuels	LaPorte	5,000,000		Multi Feedstock	April 2008
Integrity Biofuels	Morristown	10,000,000		Soy	August 2006
Louis Dreyfus Agricultural Industries, LLC	Claypool	80,000,000		Soy	January 2008
KS					
Healy Biodiesel, Inc.	Sedgwick	1,000,000		Recycled Cooking Oil	June 2007
Krystal Clean Biofuels	Kansas City			Multi Feedstock	May 2007
KY					
Griffin Industries	Butler	1,750,000	X	Multi Feedstock	December 1998
Owensboro Grain	Owensboro	50,000,000		Soy	January 2008
Union County Biodiesel Company, LLC	Sturgis	5,000,000		Poultry Fat	November 2004
LA					
Vanguard Synfuels, LLC	Pollock	12,000,000		Multi Feedstock	April 2006
MA					
MBP Bioenergy, LLC	Attleboro	500,000		Recycled Cooking Oil	November 2006

Company	City	Annual Production Capacity	Verified	Primary Feedstock(s)	Operating Since
MD					
Eagle Creek Fuel Services, LLC	Baltimore	1,000,000			August 2008
Greenlight Biofuels, LLC	Princess Anne	4,000,000		Multi Feedstock	October 2007
Maryland Biodiesel	Berlin	1,000,000		Soy	June 2006
MI					
Ag Solutions, Inc.	Gladstone	5,000,000		Multi Feedstock	January 2007
Michigan Biodiesel, LLC	Bangor	10,000,000		Multi Feedstock	January 2007
NextDiesel	Adrian	20,000,000		Multi Feedstock, Corn Oil	August 2007
TPA Inc.	Warren	20,000,000		Multi Feedstock	July 2008
MN					
FUMPA BioFuels	Redwood Falls	3,000,000	X	Multi Feedstock	December 2004
Green Range Renewable Energy	Ironton	150,000		Recycled Cooking Oil	July 2006
Minnesota Soybean Processors	Brewster	30,000,000		Soy	August 2005
MO					
AGP	St. Joseph	29,900,000		Soy	September 2007
Global Fuels, LLC	Dexter	3,000,000		Multi Feedstock	April 2007
High Hill Biodiesel, Inc.	High Hill	5,000,000		Multi Feedstock	July 2007
Mid America Biofuels, LLC	Mexico	30,000,000	X	Soy	December 2006
Natural Biodiesel Plant, LLC	Hayti	5,000,000		Multi Feedstock	April 2007
Northwest Missouri Biofuels, LLC	St. Joseph	15,000,000		Multi Feedstock	April 2007
Paseo Cargill Energy, LLC	Kansas City	37,500,000		Soy, Animal Fats	March 2008
Prairie Pride	Deerfield	30,000,000		Soy	December 2007
MS					
CFC Transportation, Inc	Columbus	1,500,000		Multi Feedstock	August 2006
Delta Biofuels, Inc.	Natchez	80,000,000	X	Multi Feedstock	May 2007
North Mississippi Biodiesel	New Albany	7,000,000		Soy	October 2006
Scott Petroleum Corporation	Greenville	20,000,000		Multi Feedstock	October 2007
MT					
Earl Fisher Bio Fuels	Chester				April 2008

Company	City	Annual Production Capacity	Verified	Primary Feedstock(s)	Operating Since
NC					
Blue Ridge Biofuels	Asheville	1,000,000		Multi Feedstock	May 2006
Carolina Biodiesel, LLC	Durham				June 2008
Evans Environmental Energies, Inc.	Wilson	3,000,000			May 2007
Foothills Bio-Energies, LLC	Lenoir	5,000,000		Multi Feedstock	September 2006
Gortman Biofuel, LLC	Winston Salem	100,000			January 2007
Leland Organic Corporation	Leland	30,000,000		Multi Feedstock	September 2008
North Carolina BioFuels, LLC	Seaboard	1,000,000		Multi Feedstock	April 2007
Piedmont Biofuels	Pittsboro	4,000,000		Multi Feedstock	November 2006
Triangle Biofuels Industries, Inc.	Wilson	3,000,000		Multi Feedstock	January 2008
ND					
ADM	Velva	85,000,000	X	Canola	August 2007
NE					
Horizon Biofuels, Inc.	Arlington	400,000	X	Animal Fat	October 2006
Northeast Nebraska Biodiesel, LLC	Scribner	5,000,000		Soy	February 2008
Wyobrasca Biodiesel, LLC	Gering	10,000,000		Soy	March 2007
NJ					
Fuel Bio One, LLC	Elizabeth	50,000,000	X	Multi Feedstock	March 2007
Innovation Fuels	Newark	40,000,000	X	Multi Feedstock	July 2004
NM					
Rio Valley Biofuels, LLC	Anthony	750,000	X	Multi Feedstock	July 2006
NV					
Bently Biofuels	Minden	1,000,000	X	Multi Feedstock	November 2005
Biodiesel of Las Vegas	Las Vegas	8,000,000		Multi Feedstock	May 2004
NY					
Buffalo Biodiesel, Inc	Tonawanda	1,500,000		Recycled Cooking Oil	June 2008
Northern Biodiesel, Inc.	Ontario				June 2008
OH					
Agrifuels, LLC	Bremen	1,000,000		Multi Feedstock	March 2007
American Ag Fuels, LLC	Defiance	7,000,000		Multi Feedstock	July 2005

Company	City	Annual Production Capacity	Verified	Primary Feedstock(s)	Operating Since
American Made Fuels, Inc.	Canton	5,000,000		Multi Feedstock	January 2008
Arlington Energy, LLC	Mansfield	4,000,000		Multi Feedstock	July 2008
Center Alternative Energy Company	Cleveland	5,000,000		Soy, Choice White Grease	May 2007
Jatrodiesel Inc.	Miamisburg	5,000,000		Multi Feedstock	June 2007
Peter Cremer	Cincinnati	30,000,000		Soy	October 2002
PK Biodiesel	Woodstock	5,000,000		Multi Feedstock	August 2008
OK					
High Plains Bioenergy	Guymon	30,000,000		Multi Feedstock	March 2008
Tulsa Biofuels, LLC	Tulsa				November 2007
OR					
Green Fuels of Oregon, Inc.	Klamath Falls	1,000,000		Canola	March 2007
SeQuential-Pacific Biodiesel, LLC	Salem	5,000,000		Multi Feedstock	August 2005
PA					
Biodiesel of Pennsylvania, Inc.	White Deer	1,500,000		Multi Feedstock	March 2007
Keystone BioFuels, Inc.	Shiremanstown			Multi Feedstock	March 2006
Lake Erie Biofuels	Erie	45,000,000		Soy	September 2007
Middletown Biofuels, LLC	Middletown	5,000,000		Soy	June 2007
Soy Energy, Inc.	New Oxford	1,500,000		Soy	February 2007
United Biofuels, Inc.	York	3,000,000		Multi Feedstock	April 2006
United Oil Company	Pittsburgh	5,000,000	X	Multi Feedstock	December 2005
RI					
Mason Biodiesel, LLC	Westerly	2,500,000		Recycled Cooking Oil	June 2007
Newport Biodiesel, LLC	Newport	300,000		Recycled Cooking Oil	January 2008
SC					
Carbon Neutral Solutions, LLC	Mauldin				August 2008
Carolina Biofuels, LLC	Greenville	50,000,000		Soy	March 2006
Ecogy Biofuels, LLC	Estill	30,000,000		Soy	December 2007
Southeast BioDiesel, LLC	N. Charleston	8,000,000		Multi Feedstock	January 2007

Company	City	Annual Production Capacity	Verified	Primary Feedstock(s)	Operating Since
SD					
Midwest BioDiesel Producers, LLC	Alexandria	7,000,000		Multi Feedstock	March 2006
TN					
Blue Sky Biodiesel, Inc.	Kingston	3,000,000		Multi Feedstock	December 2006
Memphis Biofuels, LLC	Memphis	50,000,000		Multi Feedstock	January 2007
Milagro Biofuels of Memphis	Memphis	5,000,000		Multi Feedstock	October 2006
Nu-Energie, LLC	Surgoinsville	5,000,000		Multi Feedstock	January 2008
NuOil	Counce	1,500,000		Multi Feedstock	January 2006
SunsOil, LLC	Athens	1,500,000	X	Multi Feedstock	October 2007
TX					
Agribiofuels, LLC	Dayton	12,000,000		Multi Feedstock	December 2006
AgriMax Fuels, LLC	Channelview	3,000,000		Soy	March 2007
Beacon Energy	Cleburne	12,000,000		Multi Feedstock	March 2006
Biodiesel of Texas, Inc.	Denton			August 2008	
BioSelect Fuels (GBBLP)	Galveston	30,000,000		Multi Feedstock	May 2007
Brownfield Biodiesel, LLC	Ralls	2,000,000		Cottonseed, Soy, Canola	April 2006
Central Texas Biofuels	Giddings	600,000		Waste Vegetable Oil	November 2005
Direct Fuels	Euless	10,000,000		Multi Feedstock	March 2008
Double Diamond Biofuels, Inc	Dimmitt	8,000,000		Multi Feedstock	January 2008
Fuel & Lube, LLC	Richmond	1,000,000		Recycled Cooking Oil	August 2008
GeoGreen Fuels, LLC	Gonzales	3,000,000		Multi Feedstock	September 2006
Green Earth Fuels of Houston, LLC	Galena Park	90,000,000		Multi Feedstock	July 2007
GreenHunter BioFuels, Inc.	Houston	105,000,000		Multi Feedstock	July 2008
Greenlight Biofuels, Ltd.	Littlefield	5,000,000		Multi Feedstock	August 2007
Huish Detergents	Pasadena	15,000,000		Palm	June 2005
Johann Haltermann Ltd	Houston	12,000,000		Multi Feedstock	October 2004
Momentum Biofuels, Inc.	Pasadena	20,000,000		Multi Feedstock	May 2007
New Energy Fuels, Inc.	Waller	5,000,000		Multi Feedstock	October 2007
New Fuel Company	Dallas	250,000		Multi Feedstock	April 2006

Company	City	Annual Production Capacity	Verified	Primary Feedstock(s)	Operating Since
TX (continued)					
Organic Fuels, LLC	Galena Park	45,000,000		Multi Feedstock	January 2006
Pacific Biodiesel Texas	Hillsboro	2,500,000		Multi Feedstock	August 2006
Red River Biodiesel Ltd.	New Boston	15,000,000		Multi Feedstock	May 2008
REG Houston, LLC	Seabrook	35,000,000		Refined Vegetable Oils	July 2008
Safe Renewable Corp.	Conroe	30,000,000		Multi Feedstock	July 2002
Valco Bioenergy	Harlingen	3,000,000		Recycled Cooking Oil	May 2007
VA					
Chesapeake Custom Chemical	Ridgeway	5,500,000	X	Multi Feedstock	January 2006
RECO Biodiesel, LLC	Richmond	10,000,000		Multi Feedstock	December 2006
Red Birch Energy, Inc.	Bassett	2,500,000		Multi Feedstock	June 2008
Virginia Biodiesel Refinery	West Point	7,000,000		Multi Feedstock	October 2003
WA					
Central Washington Biodiesel, LLC	Ellensburg		X	Multi Feedstock	January 2007
Gen-X Energy Group, Inc.	Burbank	15,000,000		Multi Feedstock	June 2007
Imperium Grays Harbor	Hoquiam	100,000,000	X	Multi Feedstock	August 2007
Seattle Biodiesel	Seattle	5,000,000	X	Soy, Canola	May 2005
WI					
Best Biodiesel, Inc.	Cashton	10,000,000			January 2008
Sanimax Energy Inc.	Deforest	20,000,000		Multi Feedstock	April 2007
Walsh Bio Diesel, LLC	Mauston	5,000,000		Multi Feedstock	May 2007
WV					
AC & S, Inc.	Nitro	3,000,000		Soy	December 2007

*Verified: The company has provided documentation verifying their stated production capacity. However, companies may not be producing at their capacity and some may be producing at very low levels due to current economic conditions.

Table B-17
Ethanol Feedstocks and Conversion Technology

Reference Name	Feedstock	Conversion Technology Process	Comments
Current			
Grain to Ethanol-Dry Mill	<u>Grain/Starch</u> -Corn (>90%) -Sorghum (Grain)	-Grind grain to flour -Starch is converted to sugar with enzymes and fermented to produce ethanol. -Distill ethanol	Co products can be wet stillage or dry stillage used for cattle feed. Shelf life will depend on extent of onsite drying which is energy intensive. Newer plants that maximize co-product value and are more energy efficient may produce low CI or RFS compliant ethanol.
Grain to Ethanol-Wet Mill	<u>Corn</u>	-Corn steeped in dilute acid to separate components -Separated starch is hydrolyzed, fermented, and distilled. -Germ can be processed into an oil product -Gluten can be used for animal feed.	Co-products include stillage (described above), corn germ oil, and gluten.
Sugar to Ethanol	<u>Sugar</u> -Sugarcane -Sweet Sorghum (Stalks) -Sugar Beets -Waste Sugars	-Sugar syrup extracted from sugar crop feedstock -Simple fermentation -Distill ethanol	Bagasse may be used for animal feed, as a feedstock for ligno-cellulosic ethanol, or as a fuel source. Process is more efficient than conversion of starches. Feedstock availability is limited in US

Table B-17
Ethanol Feedstocks and Conversion Technology
(continued)

Midterm – Technologies Projected by 2015			
Ligno-Cellulosic Ethanol	<u>Dedicated Crops</u> -Switch Grass -High Diversity Grass -Poplar	Sugar Platform <u>Pretreatment:</u> -Initial mechanical pretreatment includes cleaning the feedstock and chipping the feedstock to the right size for further treatment -Pretreatment includes saccharification of hemicellulose which yields both 5 carbon sugars and 6 carbon sugars. There are 3 main possible routes for hemicellulose saccharification: -Chemical pretreatment with dilute acid is currently available. Acids need to be removed before enzymatic hydrolysis of cellulose -Physical pretreatment processes include steam explosion (sugar yields of 45-65%) and liquid hot water (yields of 88-98%). Liquid hot water treatment is in demonstration phase. -Biological pretreatment with fungi requires less energy but has low yields and long reaction times. <u>Hydrolysis of Cellulose to Glucose:</u> -Enzymatic hydrolysis with cellulase (yields 75-85% expected to increase in future). Enzyme is expensive. -Acid hydrolysis of cellulose uses no enzymes. Dilute acid process is oldest but not competitive. -Concentrated acid hydrolysis has high sugar yield (90%) but also high costs. <u>Fermentation:</u> -Co-fermentation of 5 and 6 carbon sugars with new strains of microbes that can ferment a variety of sugars. <u>Distillation and Purification:</u> -Ethanol is recovered in a distillation column where most of the water remains with the solids. Product is concentrated in a rectifying column to about 95 percent ethanol. -Ethanol is dehydrated and denatured. Syngas Platform -Syngas converted to mixed alcohols by catalyzed process. -In another route, syngas can be fermented to ethanol.	-The “sugar platform” for producing cellulosic ethanol from biomass is the approach of pretreating the biomass, then hydrolyzing the components into sugars followed by fermentation. This is the primary approach to produce ethanol from cellulosic feedstock. -In the “syngas platform” or the “gas-to-liquid” approach, cellulosic biomass is gasified to produce syngas. Cleaned and conditioned syngas can be converted to mixed alcohols in a fixed bed reactor. In another route, the syngas can also be fermented to ethanol. -Physical pretreatment will depend upon feedstock. -Several processing routes are available with newer methods achieving higher yields. -Cellulosic ethanol production is projected to be commercial by 2015.
Ligno-Cellulosic Ethanol	<u>Residues</u> -Corn Stover -Rice Straw -Bagasse -Orchard Prunings -Forest Residues		
Advanced Ligno-Cellulosic Ethanol	<u>Waste</u> -Food Waste -Yard Waste -Paper Waste -Other Municipal Solid Waste -Construction and Demo Debris -Forest Products -Industry Waste		

Table B-18
Biodiesel and Renewable Diesel Feedstocks and Conversion Technology

Reference Name	Feedstock	Conversion Technology Process	Comments
Biodiesel	-Derived from crops: soybeans, cottonseed oil, canola oil (rapeseed oil [Europe])	Fatty Acid to Methyl Esters (FAME): Base catalyzed Transesterification with alcohol (usually methanol) and a catalyst (usually sodium hydroxide or potassium hydroxide)	-Tends to be the most economic conversion process for virgin feedstocks, so is usually used on a commercial scale -Glycerin is a by product of Transesterification, its uses include lotions and creams, large volumes may produce marketing issues -C.I. is about 70 gCO ₂ /MJ
Advanced Biodiesel	Waste oils : Tallow, yellow grease	Fatty Acid to Methyl Esters (FAME): Direct acid catalyzed Transesterification. Base catalyzed process can be used if first pretreated	-Base catalyzed Transesterification can also be used as a conversion process if the feedstock is pretreated to reduce the fatty acid content below 4%
Renewable Diesel (green diesel)	-Derived from algae	Fatty Acid to Methyl Esters (FAME): Base catalyzed Transesterification	Only one commercial operation (Petro Sun in Texas)
	-Derived from crops: soybeans, cottonseed oil, canola oil (rapeseed oil [Europe]) -Derived from algae	-Fatty Acid to Hydrocarbon – hydrotreatment (FAHC): vegetable or animal fats are upgraded to lighter diesel hydrocarbons using hydrogen gas and a catalyst	-Chemically identical to petro diesel since it is free of esters and contains alkanes -No glycerin is produced (an advantage)
	Biomass from Crop Residues: corn stover, rice straw	-Pyrolysis - for biomass feedstocks: A rapid thermal process without O ₂ that converts biomass to bio-oil. Bio-oil then hydrotreated into diesel	-C.I. is about 70 gCO ₂ /MJ (higher C.I. may result due to land use factors) [Algae and biomass should have a lower C.I.]
Advanced Renewable (green) Diesel	Waste oils : Tallow, yellow grease	Fatty Acid to Hydrocarbon – hydrotreatment (FAHC): vegetable or animal fats are upgraded to lighter diesel hydrocarbons using hydrogen gas and a catalyst	-Chemically identical to petro diesel since it is free of esters and contains alkanes
	Biomass from Wastes: (i.e. Municipal Solid Waste, forest waste)	-Pyrolysis: A rapid thermal process without O ₂ that converts biomass to bio-oil. Bio-oil then hydrotreated into diesel	-Due to absence of land use factors has lower Carbon intensity (20 gCO ₂ /MJ)

Reference Name	Feedstock	Conversion Technology Process	Comments
Fischer Tropsch (FT) Diesel Fuels	Biomass (Ligno-Cellulosic materials): wood, bark, paper, bagasse, corn stover, rice straw	<u>Syngas Platform:</u> Biomass is sized and dried, gasification then conducted to produce syngas. Cleaned and compressed syngas then processed in low temperature FT reactor to form product liquids which are then upgraded into FT fuels through hydrotreating, hydrocracking, hydroisomerization	Has a more consistent chemistry than transesterified biodiesel

References:

1. California Board of Equalization. (2008). "Fuel tax rates." Retrieved, from <http://www.boe.ca.gov/sptaxprog/spftrpts.htm>.
2. EIA. (2007). "U.S. Product Supplied for Crude Oil and Petroleum Products." Retrieved, from http://tonto.eia.doe.gov/dnav/pet/pet_cons_psup_dc_nus_mbbl_a.htm.
3. CEC. (2009). "California's Oil Refineries " Retrieved, from <http://energyalmanac.ca.gov/petroleum/refineries.html>.
4. ARB (2007). Emfac 2007. Air Resources Board.
5. Alexander E Farrell, Daniel Sperling, and et al. (2007). A Low-Carbon Fuel Standard for California Part 1: Technical Analysis
6. Antares Group (2008). Strategic Assessment of Bioenergy Development in the West.
7. US EPA (2007). Regulatory Impact Analysis: Renewable Fuel Standard Program. O.o.T.a.A. Quality. 116-170.
8. RFA (2009). Renewable Fuels Association Biorefineries Locations. Renewable Fuels Association.
9. Renewable Fuels Association. (2007). "Renewable Fuels Association Ethanol Industry Statistics." Retrieved, from <http://www.ethanolrfa.org/industry/statistics/#E>.
10. (2007). Congressional Research Service Report for Congress; Agriculture Based Renewable Energy Production.
11. (2008). Attachment E for Landfill Methane as a Biomass Renewable Energy Source.
12. ARB (1998). Noncombustion Landfill Gas Control Technologies. California Air Resources Board.
13. GTI and Prometheus Energy Company (2007). GTI and Prometheus Energy Company Grant Application Package. California Air Resources Board.
14. Oregon. (2007). "Biomass Energy Homepage." Retrieved, from [http://www.oregon.gov/ENERGY/RENEW/Biomass/biogas.shtml#Anaerobic Digestion](http://www.oregon.gov/ENERGY/RENEW/Biomass/biogas.shtml#Anaerobic_Digestion).
15. CEC. (2008). "Biomass - Anaerobic Digestion." Retrieved, from www.energy.ca.gov/research/renewable/biomass/anaerobic_digestion/index.html.
16. Hilarides (2007). Hilarides Dairy Grant Application Package. California Air Resources Board.
17. NGSA (2004). Overview of Natural Gas. Natural Gas Supply Association.
18. Michelle Fost (2007). Introduction to LNG. UT Austin.
19. CEC (2009). Significant Events in the History of LNG. California Energy Commission.
20. EIA. (2009). "Natural Gas Plant Processing." Retrieved, from http://tonto.eia.doe.gov/dnav/ng/ng_prod_pp_dcu_nus_a.htm.
21. EIA. (2009). "U.S. Natural Gas Imports by Country " Retrieved, from http://tonto.eia.doe.gov/dnav/ng/ng_move_imp_s1_a.htm.

22. CLNG. (2008). "Bringing LNG to the United States." Retrieved, from <http://www.lngfacts.org/LNG-Today/Bringing-LNG.asp>.
23. Fritz R. Kalhammer, Bruce M Kopf, and et al. (2007). Report of the ARB Independent Expert Panel. Air Resources Board.
24. CEC (2008). 2007 Net System Power Report. California Energy Commission.
25. CEC (2007). Transportation Energy Forecasts for the 2007 Integrated Energy Policy Report. California Energy Commission.
26. CEC. (2007). "Total Electricity System Power." Retrieved, from http://energyalmanac.ca.gov/electricity/total_system_power.html.
27. CEC. (2008). "Proposed Generation Within the Western Electricity Coordinating Council " Retrieved, from http://energyalmanac.ca.gov/electricity/wecc_proposed_generation.html.
28. Michael Kintner-Meyer, Kevin Schneider, and Robert Pratt (2007). Impacts Assessment of Plug-in Hybrid Vehicles on Electric Utilities and Regional U.S. Power Grids Part 1: Technical Analysis. Pacific Northwest National Laboratory.
29. Lucy Sanna (2005). "Driving the Solution: The Plug-In Hybrid Vehicle." EPRI Journal.
30. Rolf Schreiber. (2008). "Vehicle to grid (V2G) overview." Retrieved, from <http://rechargeit.blogspot.com/2008/09/vehicle-to-grid-v2g-overview.html>.
31. NAP. (2008). "Transitions to Alternative Transportation Technologies: A Focus on Hydrogen." Retrieved, from http://www.nap.edu/catalog.php?record_id=12222.
32. Carlo N Hamelinck and et al. (2005). "Ethanol from Lignocellulosic Biomass: Techno-Economic performance in Short-, Middle- and Long-Term." Biomass and Bioenergy 28(4): 384-410.
33. S. Phillips, et al. (2007). Thermochemical Ethanol via Indirect Gasification and Mixed Alcohol Sythesis of Lignocellulosic biomass. National Renewable Energy Laboratory.
34. Craig W Rismiller and Wallace E Tyner (2008). Biofuels Comparison Model: Model description and Economic Analysis of Base Case. Department of Agricultural Economics, Purdue University.
35. Renewable Fuels Association. (2008). "U.S. Cellulosic Ethanol Projects under Development and Construction." Retrieved, from <http://www.ethanolrfa.org/resource/cellulosic/documents/RFACellulosicPlantHandout.pdf>.
36. Sasol Chevron (2008). The Greenhouse Gas Impact of Gas to Liquids (GTL), An Industry Perspective. Chevron.
37. Anders S Carlsson, et al. (2007). Micro- and Macro-Algae: Utility for Industrial Applications. Outputs from the EPOBIO Project.
38. A.B.M. Sharif Hossain, et al. (2008). "Biodiesel Fuel Production from Algae as Renewable Energy." American Journal of Biochemistry and Biotechnology 4(3): 250-254.
39. Jessica M Adams and et al. (2008). "Fermentation Study on Saccharina latissima for Bioethanol." Journal of Applied Phycology.
40. John R Benemann (2008). Microalgae Biofuels: A Brief Introduction.
41. NREL (2008). Photobiological Water Splitting. National Renewable Energy Laboratory.

42. Green Car Congress. (2008). "Sapphire Energy Introduces Algae-Derived Bio-Gasoline." Retrieved, from <http://www.greencarcongress.com/2008/05/sapphire-energy.html>.
43. CSR Wire. (2006). "Arizona Public Service and GreenFuel Technologies Corp. Successfully Recycle Power Plant Flue Gases into Transportation-Grade Biodiesel and Ethanol." Retrieved, from <http://www.csrwire.com/News/6959.html>.
44. Robert Buderl. (2007). "Metcalf Takes Reins at GreenFuel After Key Setbacks; Company Lays Off Half its Staff, Seeks to Raise Cash." Retrieved, from <http://www.xconomy.com/boston/2007/07/01/metcalf-takes-reins-at-greenfuel-after-key-setbacks-company-lays-off-half-its-staff-and-seeks-to-raise-cash/>.
45. DOE. (2009). "Alternative and Advanced Fuels, Butanol as an Alternative Fuel." Retrieved, from http://www.afdc.energy.gov/afdc/fuels/emerging_biobutanol_what_is.html.
46. Eric J Steen and et al. (2008). "Metabolic engineering of *Saccharomyces cerevisiae* for the production of n-butanol." *Microbial Cell Factories* 7(36).
47. David; Yang Ramey, Shang-Tian (2004). Work performed under contract number: DE-F-G02-00ER86106 for U.S. Department of Energy. US Department of Energy.
48. Jiri van Straelen (2008). CO2 Capture for refineries, a practical approach. ScienceDirect.com.
49. CEC (2007). WEST COAST REGIONAL CARBON SEQUESTRATION PARTNERSHIP: SOURCE-SINK CHARACTERIZATION AND GEOGRAPHIC INFORMATION SYSTEM-BASED MATCHING. California Energy Commission.

APPENDIX C

Supporting Documentation for Determination of Carbon Intensity Values

This Page Intentionally Left Blank

Appendix C
Supporting Documentation for Determination of Carbon Intensity Values

Table of Contents

- C1. Determination of Energy Economy Ratios
- C2. Discussion of Economic Models Considered by ARB
- C3. Discussion of the Three Time Accounting Methods Considered by ARB
- C4. Discussion of Issues Associated with Time Accounting of LUC Emissions
- C5. Discussion of Yield Adjustment and Sensitivity Analysis Results for Corn Ethanol
- C6. Discussion of Yield Adjustment and Sensitivity Analysis Results for Sugarcane Ethanol
- C7. Discussion of Yield Adjustment and Sensitivity Analysis Results for Soy Biodiesel
- C8. Corn and Soybean Export Data
- C9. Food versus Fuel Summary Calculations
- C10. Adjustment of GTAP Model Output for Increasing Crop Yields
- C11. Co-product Credit Analysis when Using Distiller's Grains derived from Corn Ethanol Production
- C12. Greenhouse Gas Emissions from the Recovery of Various Crudes Used in California

This Page Intentionally Left Blank

Appendix C1

Determination of Energy Economy Ratios (EERs)

The Low Carbon Fuel Standard (LCFS) regulation includes the use of factors to recognize the fact that some fuels and vehicles are more energy efficient than others. The more energy efficient fuels and vehicles will travel more miles per unit of energy input to the vehicle, thus resulting in less fuel consumption and CO₂ emissions. Total emissions are dependent on both the emissions per unit of energy consumed and the fuel economy of the vehicle. This dependence can be illustrated with the following formula:

$$\text{grams CO}_2/\text{mile} = \text{grams CO}_2/\text{MJ} \times \text{MJ}/\text{mile}$$

Because the LCFS standard is in units of mass per energy (gCO₂e/MJ), and not in units of mass per mile (gCO₂e/mile), the standard would not recognize the benefits of more energy efficient fuels and vehicles without the inclusion of an additional factor that represents the fuel economy.

For example, the wells-to-wheels CO₂ emissions from electric vehicles, in units of grams of CO₂ per MJ of energy delivered to the vehicle, are generally higher than for gasoline vehicles. However, electric vehicles have significantly greater fuel economy (i.e., lower MJ/mi). As a result of their much lower per mile energy consumption, electric vehicles emit less greenhouse gases than gasoline vehicles on a per mile basis, even though they emit more per unit of energy consumed. Therefore, an LCFS regulation based only on the emissions per energy consumed would not recognize the benefits of electric vehicles without the inclusion of a factor that can be used to place the emissions from electric vehicles on a per mile basis.

For purposes of the LCFS, staff has adopted the term “Energy Economy Ratio,” or EER, to refer to the factor that is used to account for differences in energy efficiency among different types of fuels and vehicles. The term EER was used by TIAX, Inc., in its study for the California Energy Commission (Energy Commission) pursuant to the requirements of Assembly Bill (AB) 1007.(1) The term EER has proved to be a convenient index by which to measure energy efficiency differences between different types of fuels and vehicles. The use of the EER in the LCFS allows the use of the per energy emission metric (i.e., gCO₂e/MJ), but in a manner that can be used to give an indication of total emissions (i.e., gCO₂e/mile).

How is the EER Determined?

The EER is defined as the ratio of the number of miles driven per unit energy consumed for a fuel of interest to the miles driven per unit energy for a reference fuel. For purposes of the LCFS, the reference fuel is gasoline for light-duty vehicles, and diesel for heavy-duty vehicles. Thus, the EER for light-duty vehicles for a given fuel is defined as the ratio of the miles driven per energy consumed for that fuel to the miles driven per energy consumed for a comparable vehicle using gasoline. The EER for heavy-duty

vehicles is the same ratio with the reference fuel being diesel. Therefore, the EER for gasoline is always 1.0 for light-duty vehicles and 1.0 for diesel for heavy-duty vehicles.

In general, the values for the number of miles driven per unit energy used are based on data or estimates of fuel economy, in units of miles per gallon, and the energy density of the fuel, in units of energy (Btu or Joules) per gallon. However, for advanced technology or emerging vehicles such as battery electric vehicles (BEV), plug-in hybrid electric vehicles (PHEV), fuel cell vehicles (FEV), and heavy-duty compressed natural gas (CNG) or liquefied natural gas (LNG) vehicles, the data are limited to, at most, a few vehicles per category. Therefore, the staff has provided preliminary EER values that are to be used until such time that there is more robust data available to better establish the EER. As there will only be a limited number of these advanced vehicles available in the first few years of the LCFS, the amount of credits generated is not likely to be significantly affected. Staff is committed to review and update these and other EERs as more robust data become available.

How is the Adjustment Factor Used?

The EER can be used as a factor to adjust the wells-to-wheels carbon intensity values that are produced from lifecycle emissions models such as CA-GREET in order to reflect differences in fuel economy among different types of fuels. As mentioned above, the gram per MJ metric does not give a complete indication of total greenhouse gas emissions because it neglects the effect of vehicle fuel economy on total emissions. Making an adjustment to the wells-to-wheels emissions in the gram per MJ metric with the EER has the effect of including differences in fuel economy. Making this adjustment provides a complete indication of the relative difference in total wells-to-wheels emissions among different types of fuels. When the gram CO₂ per MJ values output by CA-GREET are divided by the EER for a particular fuel and vehicle, the resulting quotient will give an indication of the total emissions for that fuel and vehicle relative to the reference fuel that was used to calculate the EER.

Electric vehicles provide an indication of how the EER is used. For the California marginal electricity generation mix, the carbon intensity value produced by CA-GREET for electric vehicles is about 104.7 grams CO₂ per MJ. For gasoline vehicles using California reformulated gasoline, the carbon intensity is about 95.9 grams CO₂ per MJ. These values indicate that, on the basis of energy delivered to the vehicle and consumed, electric vehicles have higher greenhouse gas emissions than gasoline vehicles. However, electric vehicles have significantly greater energy efficiency than gasoline vehicles, which results in substantially lower total greenhouse gas emissions. The following example illustrates this.

According to the data available to the staff, and discussed below, light duty battery electric vehicles consume, on average, about 280 watt hours of electricity per mile, or about 1.0 MJ per mile (1.0 mile per MJ). This is equivalent to about 115 miles per gallon of gasoline equivalent. The fuel economy for a comparable sized gasoline vehicle is currently about 29 miles per gallon. When the ARB's regulations

implementing the requirements of AB1493 are fully implemented, a fuel economy increase of about 30 percent can be expected, which would increase the fuel economy of a comparable sized gasoline vehicle to about 38 miles per gallon. This equates to about 0.33 miles per MJ. The future EER for light-duty electric vehicles can be calculated from the formula:

$$\text{EER} = \text{miles per MJ electricity} / \text{miles per MJ gasoline} = 1.0 / 0.33 = 3.0.$$

The total per mile CO₂ emissions for both electric and gasoline can be calculated from the following formula:

$$\text{gram CO}_2/\text{mile} = \text{gram CO}_2/\text{MJ} \times \text{MJ}/\text{mile}$$

$$\text{For electric vehicles: gram CO}_2/\text{mile} = 104.7 \times 1.0 = 105$$

$$\text{For a comparable size gasoline vehicle after implementation of the ARB's AB1493 regulations: gram CO}_2/\text{mile} = 95.9 \times (1/0.33) = 291$$

This calculation shows that the total wells-to-wheels CO₂ emissions for a future light-duty gasoline vehicle meeting the ARB's AB1493 regulations will be about 2.8 times the total CO₂ emissions from an electric vehicle, on a per mile basis.

This result can also be demonstrated by applying the EER for electric vehicles directly to carbon intensity value for electricity produced by the CA-GREET model. The carbon intensity value for electric vehicles can be divided by the EER for electricity as follows to give what is referred to an adjusted carbon intensity value for electric cars:

$$104.7 \text{ g CO}_2/\text{MJ} / 3.0 = 34.9 \text{ gCO}_2/\text{MJ} \text{ for light-duty electric vehicles}$$

Because the EER for light duty gasoline vehicles is 1.0 (gasoline is the reference), the adjusted carbon intensity for light duty gasoline vehicles is the same as the unadjusted carbon intensity, or 95.9 gCO₂/MJ. Dividing the adjusted carbon intensity of gasoline by the adjusted carbon intensity of electricity gives about 2.8 (95.9/26.7), the same ratio calculated using the per mile emission rates for gasoline and electricity. This shows that the adjusted carbon intensities, in units of grams per MJ, are indications of gram per mile emission rates, and thus give a more complete indication of total emissions for different fuels. The EER values can thus be used to compare the total CO₂ emissions from different types of fuels and vehicles without having to calculate gram per mile values. This allows the metric of grams CO₂ per MJ to be used in the LCFS regulation, which is a much more convenient metric for regulatory and enforcement purposes than the gram per mile metric.

It is necessary to use the EER in the LCFS for setting carbon intensity standards, calculating credits for compliance and for inherently lower carbon intensity fuels that are not subject to the regulation, and for purposes of projecting the amount of energy that will be used in the transportation sector for various numbers of different types of vehicles that will be used.

Determination of EER Values

This section presents the method that staff used to determine the EER values for fuels, other than gasoline and diesel, that are likely to be used to help achieve compliance with the LCFS. As mentioned above, EER values are determined based on fuel economy data. The staff used the fuel economy data published by the U.S. EPA and DOE in the Fuel Economy Guide for light duty CNG vehicles, battery electric vehicles (BEVs), and fuel cell (FC) vehicles. In addition, the staff estimated energy efficiency and fuel economy for some light duty BEVs, and plug-in-hybrid electric vehicles (PHEVs) operating in the grid electricity mode using information on vehicle range and battery capacity. Other sources, discussed below, were used to estimate the EERs for heavy duty electric vehicles and fuel cell vehicles.

For light duty electric vehicles, the U.S. EPA has not updated its fuel economy values in the Fuel Economy Guide to reflect the changes that have been made by EPA in estimating fuel economy. Therefore, to maintain consistency, the staff compared the EPA's old fuel economy data for electric vehicles to the old fuel economy data for the comparable gasoline reference vehicle. The staff made one additional assumption in calculating the EERs for light duty BEVs, PHEVs, and FC vehicles. The staff assumed that the fuel economies of the reference gasoline vehicles against which these vehicles are compared would increase by 30 percent between now and 2016. This assumption reflects the implementation of the regulations adopted by the ARB pursuant to the requirements of AB 1493 (Pavley).

Battery Electric Vehicles (BEVs)

The staff used data for three BEVs that have been used recently. These vehicles are the 2000 Nissan Altra, the 2003 Toyota RAV4, and the 2006 AC Propulsion eBox. The staff believes that these vehicles are the most representative in terms of size and technology of the BEVs that will likely be produced and used in the future. The EERs for the Nissan Altra, the Toyota RAV4, and their corresponding gasoline reference vehicles were calculated using fuel economy data from the U.S. EPA/DOE Fuel Economy Guide. For the AC Propulsion eBox, the energy efficiency and fuel economy was estimated from published data on the vehicle's range and battery capacity, while the EPA/DOE Fuel Economy Guide was used to obtain the fuel economy of the gasoline reference vehicle, the Scion xB. Table C1-1 summarizes the information that was used to calculate the EERs for these vehicles.

Table C1-1
Summary of Basis for Calculating EERs for Battery Electric Vehicles

BEV Vehicle	mpgge	Reference Gasoline Vehicle	mpgge	EER	Adjusted EER¹
2000 Nissan Altra	123	2003 Toyota RAV4	31	4.0	3.1
2003 Toyota RAV4	112	2003 Toyota RAV4	31	3.6	2.8
2006 AC Propulsion eBox	99 ²	2006 Scion xB	28	3.5	2.7
Average					2.9

1 - The adjusted EER is equal to the EER divided by 1.3, under the assumption that the fuel economy of the reference gasoline vehicle will increase by 30 percent between now and 2016.

2 - Calculated using a range of 135 miles, a battery capacity of 35 kW-hr, and a battery charger efficiency of 80 percent.

Plug-in Hybrid Electric Vehicles (PHEVs)

The EER for PHEVs operating in the grid electricity mode was calculating assuming that PHEVs would achieve energy efficiency and fuel economy comparable to that of the Chevy Volt, since the Chevy Volt is expected to be sold commercially in 2010. Because there is not yet any test data available on the Chevy Volt's fuel economy, the staff estimated the fuel economy on the basis of the estimated range of the vehicle and the battery capacity. Table C1-2 summarizes the EER calculation for the Chevy Volt.

Table C1-2
Summary of Basis for Calculating EERs for Plug-In Hybrid Vehicles

PHEV Vehicle	mpgge	Reference Gasoline Vehicle	mpgge	EER	Adjusted EER¹
Chevy Volt	128 ²	Chevy Cobalt	28	4.6	3.5

1 -The adjusted EER is equal to the EER divided by 1.3, under the assumption that the fuel economy of the reference gasoline vehicle will increase by 30 percent between now and 2016.

2 – Calculated using a range of 40 miles, a battery capacity of 8 kW-hr, and a charger efficiency of 80 percent.

A number of published studies on the conversion of Prius hybrids to the plug-in hybrid mode are available. These studies provide fuel economy estimates for the Prius in the plug-in mode. However, the staff does not believe that these estimates are relevant for estimating EERs for plug-in hybrids using grid electricity because the Prius plug-in conversions operate in a blended mode, meaning they are continuously using a mixture

of grid electricity and gasoline from the internal combustion engine. Therefore, any EER calculated from the Prius conversion data would not reflect the energy efficiency of a plug-in hybrid operating on grid electricity alone. The LCFS would provide credit only for the grid electricity used by PHEVs. Therefore, the staff is interested in how much gasoline is saved for each kilowatt hour of electricity the PHEV draws from the grid due to the driver's choice of driving a PHEV instead of a gasoline vehicle. The first approximately 20 miles of driving after the battery has been fully charged, referred to as the charge depleting mode, use a relatively high percentage of grid electricity as the total energy. The fuel economy and energy efficiency during this time is very high, approaching or even equaling the fuel economy of BEVs and the calculated fuel economy for the Volt. Therefore, had the staff included the fuel economy data for Prius conversions operating in the charge depleting mode, the calculated EER would not have been greatly different from the EER calculated for the Chevy Volt.

Combination of Light Duty BEVs and PHEVs

Due to the limited amount of relevant data on fuel economy for BEVs and PHEVs, and the fact that some of the fuel economy estimates are based on driving cycle data while others are based on calculations, the staff is not confident that the difference in estimated EER between BEVs and PHEVs reflect real differences. Therefore, the staff decided to average the four adjusted EER values for BEVs and PHEVs, and use this average as the EER for both BEVs and PHEVs. The average EER for BEVs and PHEVs then becomes 3.0 (The average of 3.1, 2.8, 2.7, and 3.5).

The staff will refine the calculation of EER for BEVs and PHEVs as their presence in the fleet increases and more driving cycle data become available on their fuel economy.

Fuel Cell Vehicles (FCVs)

The staff's estimate of EER for light duty FCVs is based on the fuel economy of the Honda Clarity FCX, as this vehicle is currently commercially available. Table C1-3 shows the fuel economy values that were used to estimate the EER for light duty fuel cell vehicles.

**Table C1-3
Summary of Basis for Calculating EERs for Fuel Cell Vehicles**

FC Vehicle	mpgge	Reference Gasoline Vehicle	mpgge	EER	Adjusted EER¹
2008 Honda Clarity FCX	74	2009 Honda Accord	25	3.0	2.3

1-The adjusted EER is equal to the EER divided by 1.3, under the assumption that the fuel economy of the reference gasoline vehicle will increase by 30 percent between now and 2016.

Light Duty CNG Vehicles

The staff's estimate of EER for light duty CNG vehicles is based on the fuel economy of the Honda Civic. This vehicle is currently commercially available. Table C1-4 shows the fuel economy values that were used to estimate the EER for light duty CNG vehicles.

Table C1-4
Summary of Basis for Calculating EERs for Light-Duty CNG Vehicles

CNG Vehicle	mpgge	Reference Gasoline Vehicle	mpgge	EER
2008 Honda Civic	29	2008 Honda Civic	28	1.0

Heavy Duty Fuel Cell Vehicles (FCVs)

The staff's EER for heavy duty FCVs is based on the results of an NREL-funded test program conducted on transit buses. Three transit districts operated fuel cell buses during the test program. These were AC Transit District in Alameda and Contra Costa Counties, California, SunLine Transit District in Riverside County, California, and Connecticut Transit Agency. These three transit districts operated fuel cell transit buses for over a year as part of the test program. During the test program, the average fuel economy for the fuel cell bus at AC Transit was about 7.0 miles per gallon (diesel equivalent), while for SunLine Transit District it was about 8.3 miles per gallon (diesel equivalent), and for Connecticut Transit it was about 5.4 miles per gallon (diesel equivalent). The corresponding EERs for the fuel cell buses in this test program are the following: AC Transit: 1.8, SunLine Transit: 2.1, and Connecticut Transit: 1.7. The staff used the average of these three EERs, which is about 1.9.

Heavy Duty Engines Using CNG

There is widespread use of CNG in heavy duty vehicles. Most of this use is in transit buses. Therefore, there is a substantial amount of data on the fuel economy of CNG relative to diesel in transit buses. Most of this data show a significant fuel economy penalty for CNG relative to diesel, ranging from about 10 percent to about 25 percent, depending on driving cycle. However, many of the CNG engines used in transit buses are older model years. Improvements to CNG engine efficiency have been achieved in more recent model year engines.

Cummins Westport LLC has recently developed a spark ignited, stoichiometric-cooled exhaust gas recirculation heavy duty CNG engine, referred to as ISL G, which meets the ARB's 2010 NOx and PM standards. The ISL G engine has less of a fuel penalty relative to diesel, than most of the CNG engines that are currently being used in transit buses. According to the data used to certify the ISL G engine to the ARB's 2010 NOx and PM standards, the fuel penalty for the ISL G engine is about 10 percent. This translates to an EER of 0.9. The staff believes that this engine and emissions control

technology will likely play an increasingly greater role in the use of CNG in heavy duty engines beginning in 2010 as engine manufacturers comply with the 2010 standards. For this reason, the staff has decided to use the fuel economy of the ISL G engine as the basis for its EER for heavy duty CNG engines.

The staff will continue to review the test data from other CNG engine technologies as these technologies are used to meet the 2010 standards, and will make any needed revisions to the EER for heavy duty CNG engines.

Heavy Duty Battery Electric (BEV), or Plug-in Hybrid Electric (PHEV) Vehicles

The staff is not aware of any test or in-use data that can be used to estimate the EER for heavy duty BEVs and PHEVs. For this reason, the staff is using the EER of 2.7 published by TIAX LLC in its June 2007 report to the California Energy Commission, titled "Full Fuel Cycle Assessment: Tank to Wheels Emissions and Energy Consumption." This report was published pursuant to the requirements of California Assembly Bill 1007, passed by the California Legislature in 2005.

Summary of EERs

Table C1-5 summarizes the staff's EERs.

**Table C1-5
Summary of EER Values**

Fuel	Light Duty EER	Heavy Duty EER
CNG	1.0	0.9
PHEVs, BEVs	3.0	2.7
FCVs	2.3	1.9

Appendix C2

Discussion of Economic Models Considered by ARB

The indirect land use change effects of a large expansion in biofuel production will occur internationally: a sufficiently large increase in production in the U.S. will cause non-agricultural land to be converted to crop land both in the U.S. and in other countries. Models used to estimate land use change impacts must be international in scope. In cooperation with researchers from the University of California, Berkeley (UCB) and Purdue University, ARB staff evaluated three possible models for conducting the analysis. The available models utilize two different approaches: computable general equilibrium (CGE) and optimization modeling.

CGE models are built around data tables that describe many significant transactions that occur within an economy, a portion of an economy, or two or more linked economies. These tables include, for example, how much corn is used for fuel ethanol, as well as the amount paid to farmers (agribusiness) for that corn. Models that include two or more national economies will contain tables that describe significant trade exchanges that occur between each pair of nations (in addition to each nation's internal transactions tables).

CGE models are designed to seek equilibrium. If a change is introduced—increased demand for crop-based fuels, for example—fuel crops, fuels themselves, and a number of related prices will all change. Prices that rise (such as the demand-driven price for corn to be made into ethanol) will stimulate higher production. Prices that drop will have the opposite effect. A CGE model will seek that point at which demand (expressed in terms of price) is satisfied by supply (the quantity produced) throughout the modeled economy. Once a new economy-wide equilibrium is reached, the model reports all changes that occurred, as well as the net, economy-wide change.

CGE models can be extended to evaluate different categories of changes; so long as those categories respond to economic stimuli as do the traditional economic sectors already included in the model. Data tables and transactions that describe impacts such as pollution levels (including GHG generation), water supply, and land use patterns can be added to CGE models. The impacts of changes affecting these new areas (usually stimulated by policy changes) can then be estimated along with the corresponding changes in the more traditional areas of economic activity.

Optimization models are developed to seek optimal allocations of goods, resources, funds, etc. among competing uses, subject to user-specified constraints. Unlike CGE models, which are specifically designed and used to evaluate economic impacts, optimization models are more general-purpose in nature: many complex allocation problems can be solved using an optimization model. The optimization model that ARB staff evaluated allocates available lands to competing uses based on the same basic economic principals used in CGE models. As such, it will generally produce impact estimates similar to those generated by CGE models.

The two CGE models ARB staff evaluated are the Global Trade Analysis Project (GTAP) model, and the Food and Agricultural Policy Research Institute (FAPRI) model. The optimization model evaluated was the Forest and Agricultural Sector Optimization Model (FASOM). Of these models, the most comprehensive is the GTAP.

Within the GTAP's scope are 111 world regions, some of which consist of single countries, others of which are comprised of multiple neighboring countries. Each region contains data tables that describe every national economy in that region, as well as all significant intra- and inter-regional trade relationships. The data for this model are contributed and maintained by more than 6,000 local experts. GTAP has been extended for use in land-use change modeling by adding data on 18 worldwide agro-ecological zones, a carbon emissions factor table, and a co-products table (which adjusts GHG emission impacts based on the market displacement effects of co-products such as the dried distillers' grains with solubles which the ethanol production process yields). Predicted land use change impacts are aggregated by affected land use types (forest, pasture, wetland, etc.).

The FAPRI model is a partial equilibrium model: it estimates agricultural sector impacts in countries with which the U.S. maintains agricultural trade relationships. The American economy is not within in the FAPRI model's scope. The FAPRI model is able to estimate changes in biofuel demand and land use in the countries that are within its scope. Although the model can estimate the number of hectares that will be converted to agricultural uses in response to a policy change, it cannot provide any specific information about that converted land (prior land uses; cover type, etc.).

The FASOM is an optimization model that functions much like a partial equilibrium model that includes within its scope only the U.S. It models the responses of the American forest and agricultural sectors to policy changes. It accomplishes this by seeking optimal allocations of available land to competing agricultural and forestry uses, subject to economic constraints. It then estimates the impacts on the commodity markets supplied by these lands and the net greenhouse gas (GHG) emissions associated with these changes. The outputs of the model include estimates of the technical, economic, and environmental impacts of the modeled policy changes, and GHG mitigation opportunities.

Based primarily on its global scope, public availability and its long history of use in modeling complex international economic effects, ARB staff determined the GTAP was most suitable for use in estimating the land use change impacts of several crop based biofuels that will be regulated under the LCFS. The GTAP is relatively mature, having been frequently tested on large-scale economic and policy issues. It has been used to assess the impacts of a variety of international economic initiatives, dating back to the Uruguay and Doha Rounds of the World Trade Organization's General Agreement on Tariffs and Trade.¹ More recently, it has been used to examine the expansion of the European Union, regional trade agreements and multi-national climate change accords.

¹ The Uruguay Round began in September of 1986 and concluded in April, 1994. The Doha Round began in November of 2001 and is ongoing.

Appendix C3

Discussion of the Three Time Accounting Methods Considered by ARB

We assess three different accounting schemes for calculating LUC impacts for corn ethanol.

The first is an averaging method which adds all carbon dioxide emissions attributable to land use change (which may include emissions credits for land reversion if deemed appropriate) and dividing the total by the total fuel production (MJ) over the assumed project horizon. This value for LUC carbon intensity is then added to the direct carbon intensity associated with corn-ethanol production resulting in the overall carbon intensity of the biofuel when used in the LCFS. This method is termed “annualized” in this document.

$$LUC\ Carbon\ Intensity = \frac{\sum LUC\ GHG\ emissions}{Total\ fuel\ production\ (MJ)\ over\ project\ horizon}$$

The second method utilizes a net present value (NPV) calculation to weight time-varying greenhouse gas emission flows. This approach is analogous to methods used for economic analysis of projects. The discount rate selected for the NPV calculation determines how earlier emissions will be weighted relative to emissions occurring later. A positive discount rate weights carbon emissions today as having larger impacts than future emissions and results in a larger burden on biofuels due to their initial “burst” of emissions from land use change. To calculate the contribution of land use change to the carbon intensity of a biofuel such as corn ethanol, the annual greenhouse gas emissions flows for corn ethanol and gasoline are first discounted to a NPV. Then, the ratio of the “emissions NPV” of corn ethanol to that of gasoline is multiplied by the carbon intensity of gasoline thereby providing a single value for the carbon intensity of corn ethanol. Using this method, one must choose an appropriate discount rate to reflect the cost or damage caused by earlier, rather than later emissions of greenhouse gases.

$$CI_{biofuel} = \frac{NPV\ biofuel\ emission\ flows}{NPV\ gasoline\ emission\ flows} \times CI_{gasoline}$$

The third method was developed by researchers within the UC Berkeley Energy, UC Davis and Union of Concerned Scientists and involves the calculation of a “physical” Fuel Warming Potential (FWP) to compare fuels with different greenhouse gas time emission profiles.(2) This value is calculated for a fuel in question by comparing its cumulative radiative forcing against that of a reference fuel such as gasoline. The ratio provides an estimate of the global warming impact of the fuel relative to the reference fuel. When this ratio is multiplied by the carbon intensity (CI) of the reference fuel, it provides the CI for the fuel in question. Details of the method are provided here.

O'Hare et al. calculated a time dependent abundance of CO₂ ($C_i(t)$) in the atmosphere from fuel production and use by using the Bern carbon cycle model.(3) This model estimates a net CO₂ abundance in the atmosphere established by equilibrium between CO₂ sources and sinks. The additional atmospheric abundance of CO₂ leads to a time dependent annual radiative forcing ($RF_i(t)$) attributable to use of the fuel.

$$RF_i(t) = a_i C_i(t)$$

where a_i is the radiative forcing efficiency

Integrating this over the analytic timeframe, $0 < t < t_a$, gives the cumulative radiative forcing

$$CRF_i = \int_0^{t_a} RF_i(t) dt,$$

which they propose could be used as a proxy for total damage to the planet resulting from increased CO₂ concentrations in the atmosphere. Based on this metric, they define a fuel warming potential or FWP as the ratio of the CRF for the biofuel to that of the reference fuel, gasoline:

$$FWP_p \equiv \frac{CRF_{biofuel}}{CRF_{gasoline}}.$$

The ratio is then multiplied by the carbon intensity (CI) of the reference fuel (e.g. gasoline) to provide a Fuel Warming Intensity (FWI) or carbon intensity for the biofuel.

$$FWI_{biofuel} = FWP_p \times CI_{gasoline}$$

Comparing the CRF of two fuels with different emission profiles, over a single time horizon, is consistent with the use of Global Warming Potential (GWP) values by the IPCC.

Appendix C4

Discussion of Issues Associated with Time Accounting of LUC Emissions

In the following, we discuss a number of issues related to the discussion of time treatment of emissions and present scenarios that attempt to realistically represent these issues. This exercise is an attempt to place bounds on the uncertainty associated with the carbon intensity value assigned to land use change emissions. To avoid too much clutter in the plots, we only represent the annualized and FWP methods in this analysis. In the discussion for each scenario, we will compare carbon intensity values to those of the base case which was presented in the staff report and is summarized briefly below. These scenarios were prepared using a modified version of Biofuel Time-Integrated Model of Emission (BTIME) software developed by O'Hare et. al.(2)

Base Case: Figure C4-1 shows the LUC time emissions profile and Figure C4-2 presents the LUC carbon intensity values for the base case presented in Chapter IV of the staff report. The land use change emissions profile depicted in Figure C4-1 assumes that:

- All above-ground carbon is released in year one due to burning of native vegetation to clear the land for cultivation;
- The majority of below-ground release occurs over the first five years followed by a much slower release over the next 15 years; and
- Forgone sequestration occurs over the entire project period.

Figure C4-1
Land Use Change Emissions Profile for Base Case

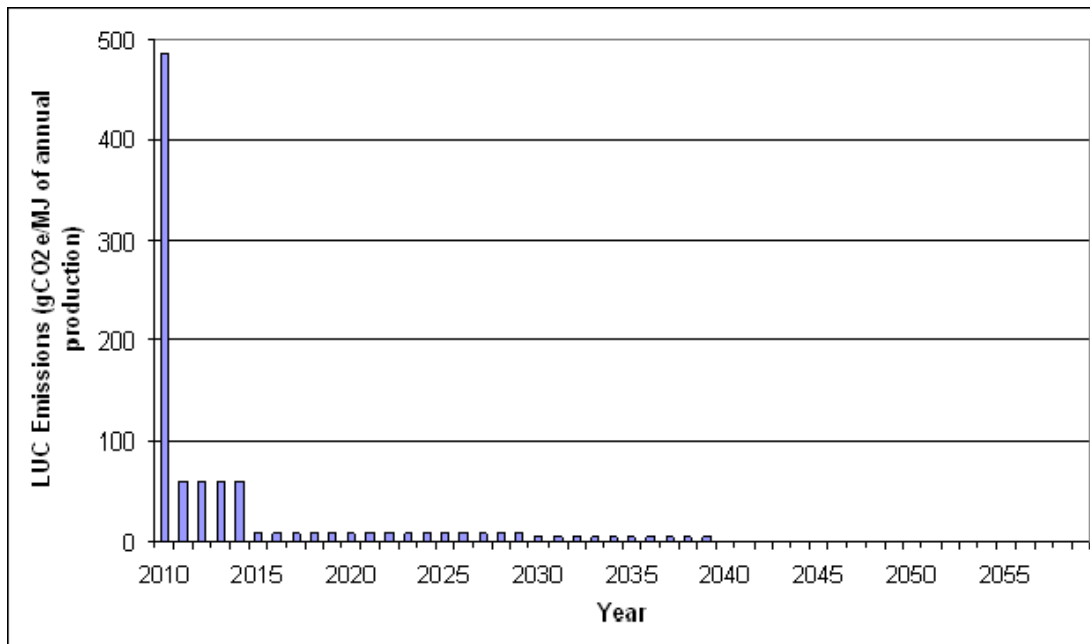
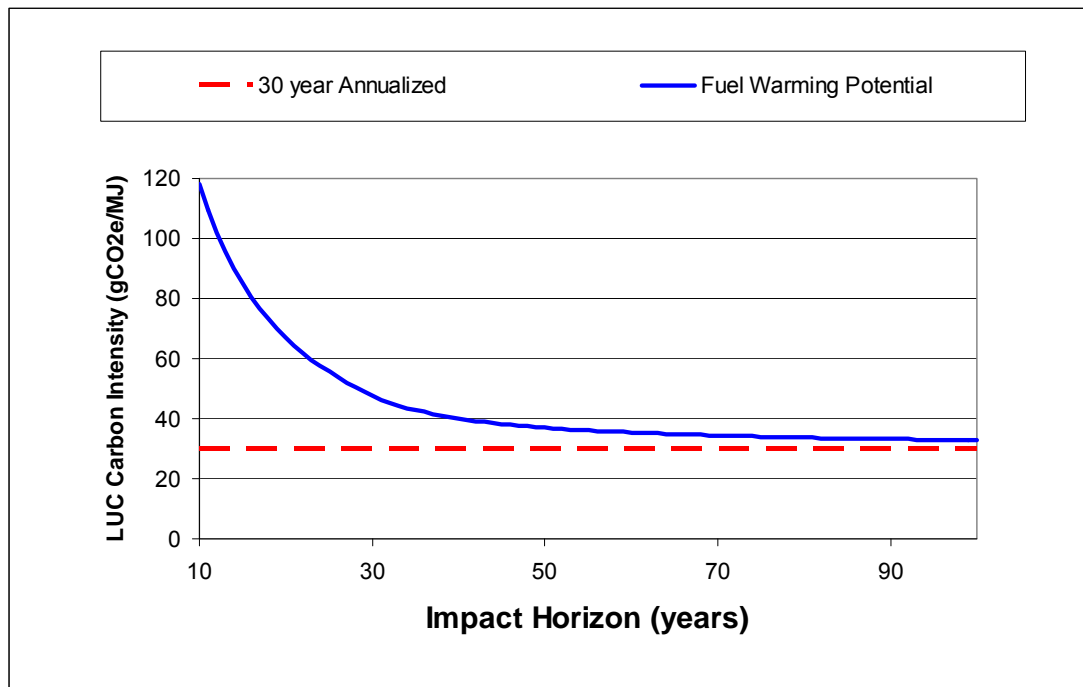


Figure C4-2
Comparison of Time Accounting Methods for the Base Case



Issue 1: The above analysis gave no credit for potential land reversion following the end of the project horizon (30 years). If corn ethanol production declines when producers no longer receive LCFS credits, pressure on food crops will be reduced. This will result in a “reversed” land use change in which land somewhere in the world may be allowed to revert to native vegetation (e.g. forest or grassland).

Figure C4-3 shows a representative emissions profile that allows for some reversion of land. This profile assumes that 30% of the land use change emissions (above and below-ground) are “re-sequestered” due to land reversion occurring over a period of twenty years (arbitrarily chosen values) following the end of the project horizon. This reversion is indicated by negative emissions flows in years 2040 to 2060.

Figure C4-3
Land Use Change Emissions Profile with Land Reversion

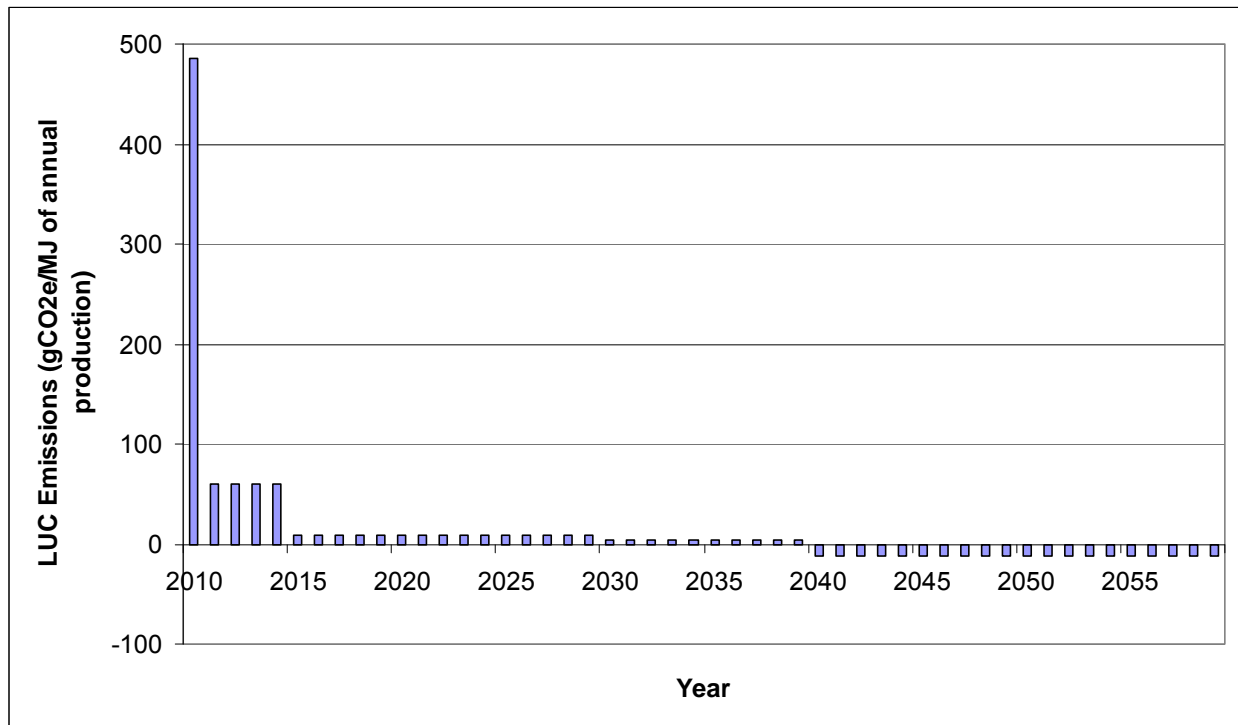
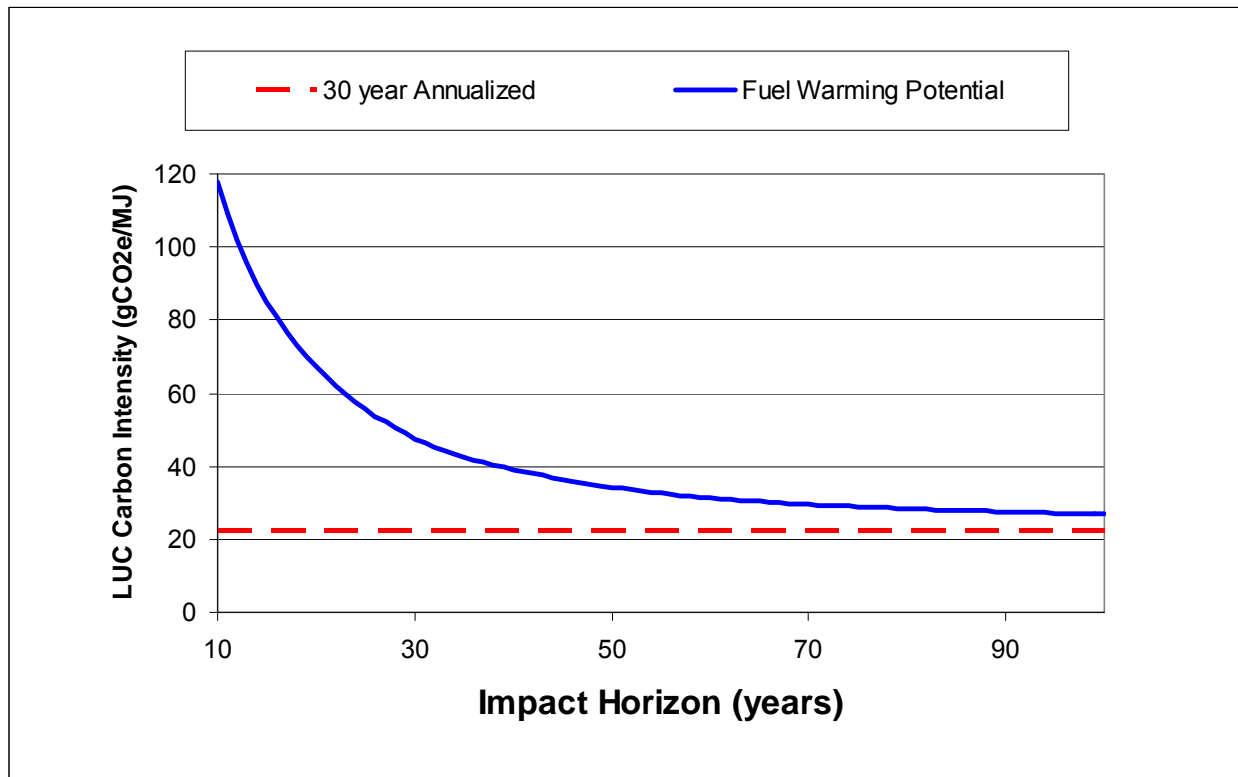


Figure C4-4 shows LUC carbon intensity values for the two methods using the emissions profile data represented in Figure C4-3. For the fuel warming potential method, the allowance for land reversion results in reduced carbon intensity values for impact horizons longer than the project horizon (i.e. impact horizons long enough to include sequestration due to land reversion). For a 50 year impact horizon, the carbon intensity is 34 gCO₂e/MJ as compared to the base case of 37 gCO₂e/MJ. The 30-year annualized value is reduced from 30 to 22 gCO₂e/MJ. If one were instead to assume 100% land reversion, the annualized carbon intensity will approach zero. We note however that annualizing emissions that occur over 50 years is problematic given the large variation of emissions flows (highly positive to negative) occurring over such a long time period. Counting a ton of carbon dioxide sequestered 50 years in the future as offsetting a ton released in the first year is not appropriate given the cumulative effects of warming over time and the potential for irreversible damages resulting from near-term climate change. Therefore, staff does not recommend using the annualized method if land reversion is to be included.

Figure C4-4
Comparison of Time Accounting Methods (with Land Reversion)

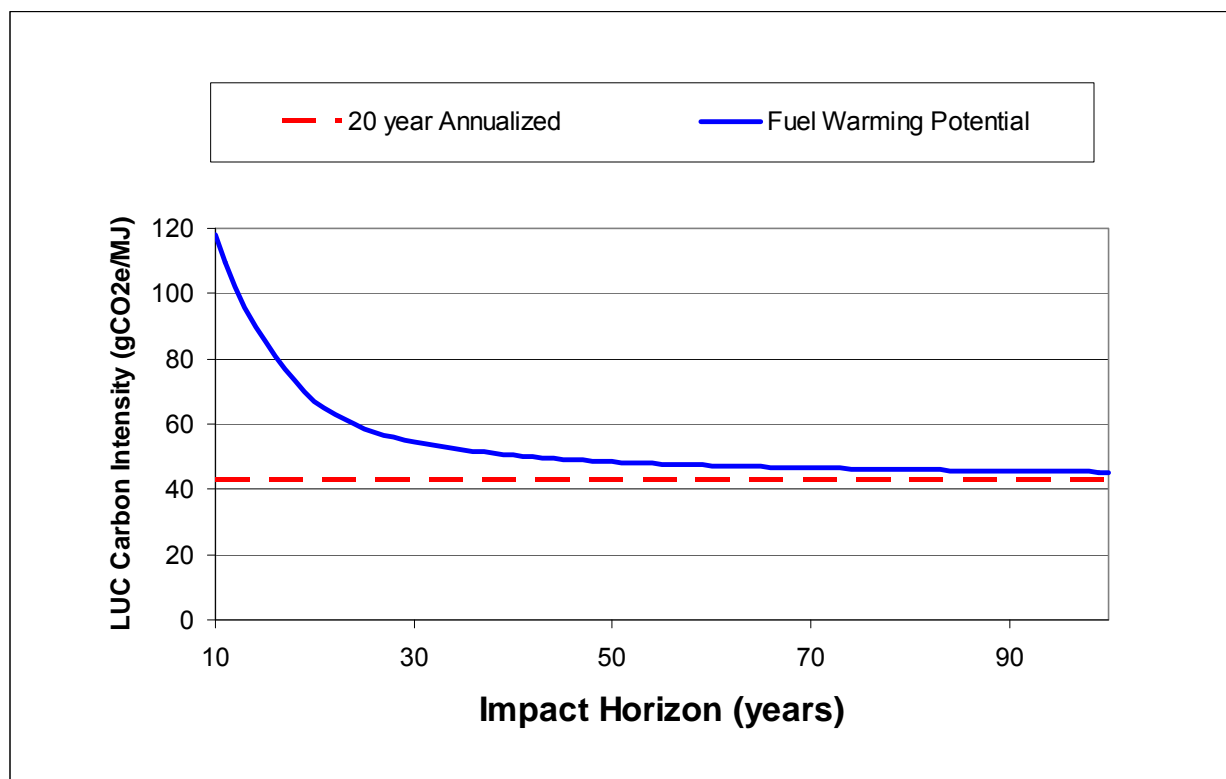


Furthermore, granting a credit for land reversion first assumes that ethanol production will cease at facilities following the end of the project horizon. However, because of the existence of federal programs which provide substantial support for crop based biofuel, facilities are not likely to end production just because they no longer earn credit under the LCFS. Moreover, in the event that some facilities do end production, there is no guarantee that land will be allowed to revert to the native vegetation. Therefore, staff does not recommend giving emissions credit for land reversion which may not occur.

Issue 2: A 30 year project horizon does not place the necessary emphasis on quickly reducing emissions. For crop based biofuel, a 20 year (or shorter) project horizon is more appropriate because the shift to very low carbon intensity fuels must occur rapidly in order to meet the longer term targets of the LCFS.

Figure C4-5 compares the two accounting methods assuming a 20 year project horizon. This analysis used the emissions time profile in Figure C4-1 except emissions were set to zero after 20 years. The 20-year annualized carbon intensity is 43 gCO₂e/MJ as compared to the 30 year value of 30 gCO₂e/MJ. For the FWP method, a shorter project horizon also results in larger LUC carbon intensity values at impact horizons greater than 20 years. For an impact horizon of 50 years the carbon intensity value is 48 gCO₂e/MJ compared to the base case value of 37 gCO₂e/MJ.

Figure C4-5
Comparison of Time Accounting Methods – 20 Year Project Horizon



The choice of a proper project horizon is best discussed in terms of total carbon intensity of the biofuel (direct emissions and LUC emissions) compared to that of the reference fuel (e.g. gasoline). Based on CA-GREET modeling, the “best available” California based ethanol production facilities (dry mill, wet DGS co-product, 80% natural gas/20% biomass fueled) have a direct emission carbon intensity of 47 gCO₂e/MJ. Using a 30 year annualized LUC carbon intensity of 30 gCO₂e/MJ results in an overall carbon intensity of 77 gCO₂e/MJ. This represents a 20% improvement over gasoline

which has a carbon intensity of 96 gCO₂e/MJ. Ethanol produced in California (using these assumptions) will earn credits under the LCFS beyond the year 2020. Moreover, the LCFS provides incentives for producers to further reduce the carbon intensity associated with direct emissions. Innovative producers may very well produce crop based fuels that play a significant role within the LCFS for 20 to 30 years depending on the producer's ability to lower direct emissions and the specific LCFS carbon intensity targets set for 2020 to 2050. If instead we assign a LUC carbon intensity of 43 gCO₂e/MJ (e.g. 20 year assumed project horizon), the total carbon intensity for corn ethanol from a California facility would be 90 gCO₂e/MJ. Under this scenario, corn ethanol would qualify for credits under the LCFS for less than 10 years. Again, if significant reductions in direct emissions were made, corn ethanol could still play a role within the LCFS for 15 to 20 years. The preceding discussion shows that the choice of project horizon is an extremely important policy decision and greatly influences the role crop based biofuels will play within the LCFS. Staff believes that a project horizon of twenty to thirty years is appropriate for crop based biofuels.

Issue 3: The preceding analyses assumed that above-ground emissions occur in year one (i.e. by burning vegetation to clear land). It is much more likely that these emissions will be distributed over several years as conversion of new land to agriculture will not occur instantaneously and some of the native vegetation will be allowed to decay over time rather than being burned.

The emissions profile depicted in Figure C4-6 assumes above ground emissions occur evenly over a period of 10 years rather than all in the first year.

Figure C4-6
Altered Land Use Change Emissions Profile

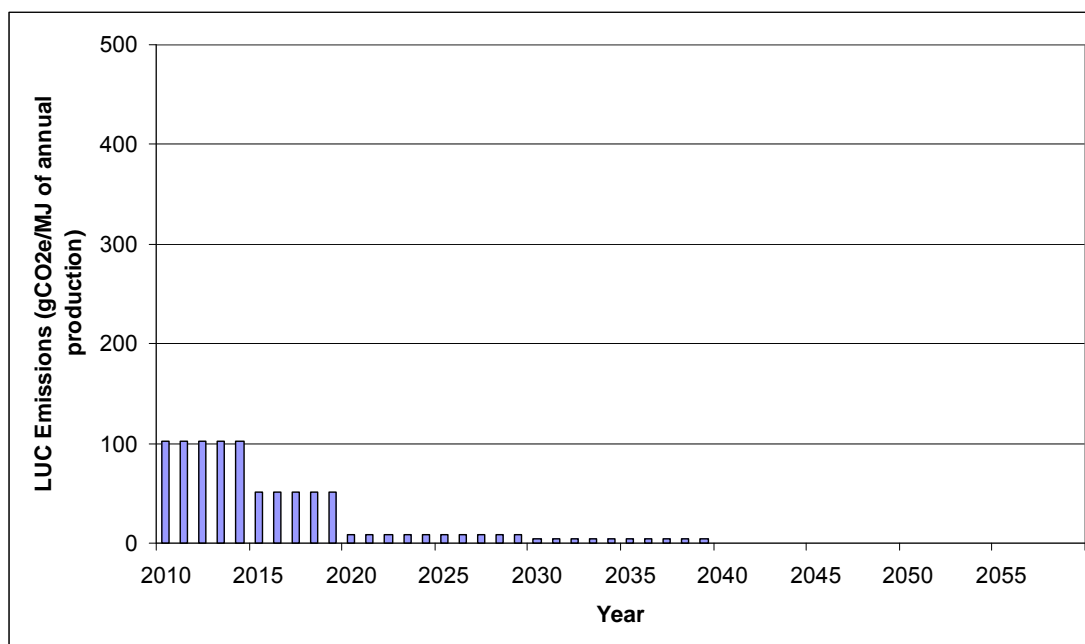
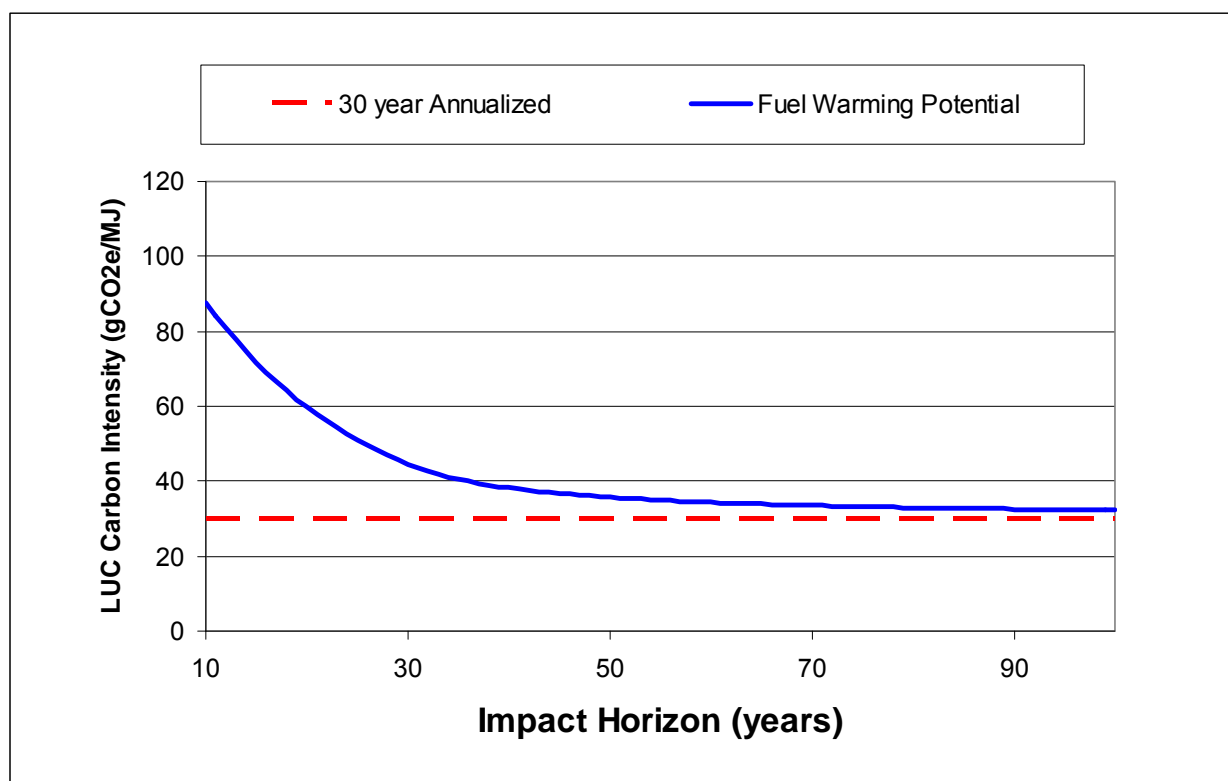


Figure C4-7 compares the two time accounting methods using this altered emissions profile. For the FWP method, distributing the above ground emissions over 10 years yields lower carbon intensity values. This effect is appreciable for short impact horizons but diminishes for longer impact horizons. For a 30 year impact horizon, the carbon intensity is 44 gCO₂e/MJ compared to the base case of 48 gCO₂e/MJ and for a 50 year impact horizon the carbon intensity is 36 gCO₂e/MJ compared to the base case of 37 gCO₂e/MJ. The 30 year annualized value is not affected because the total emissions attributable to land use change remain the same. Therefore, distributing the above ground emissions over a longer time period only significantly affects the carbon intensity calculations for the FWP method at short impact horizons.

Figure C4-7
Comparison of Time Accounting Methods – Altered Emissions Profile

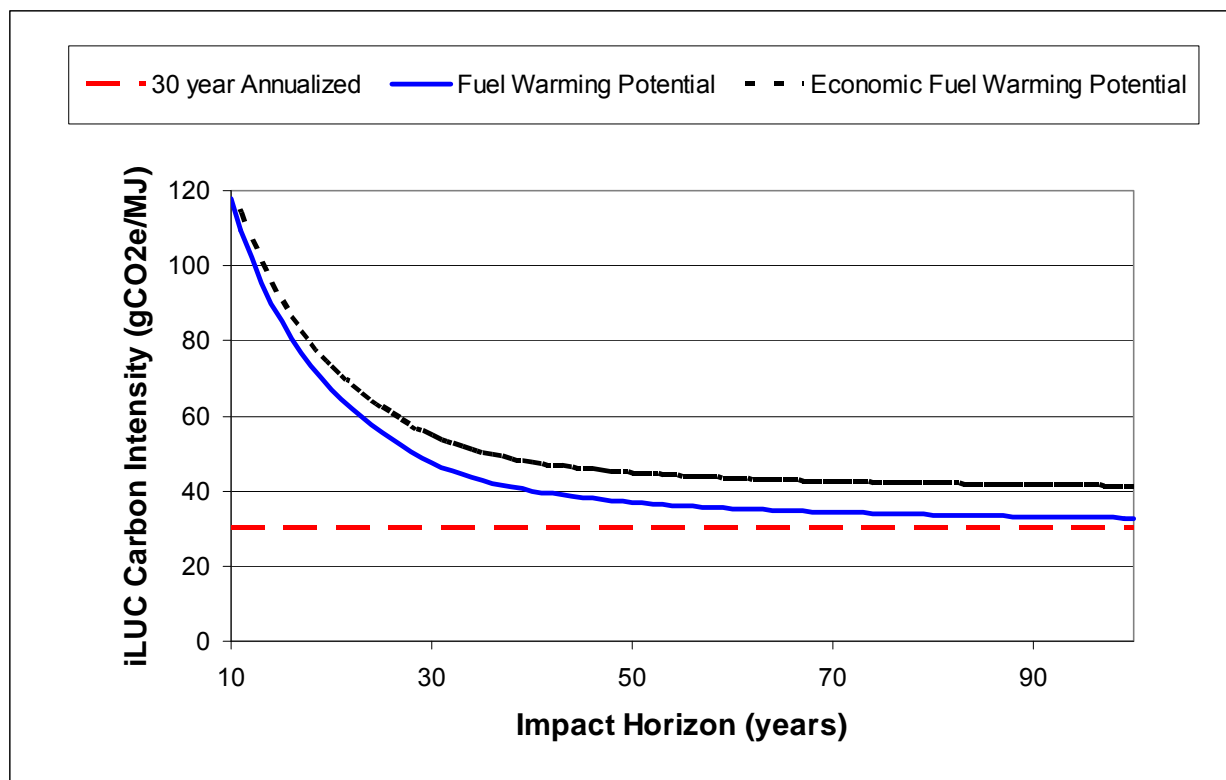


Issue 4: “The purely physical assessment of radiative forcing can be amended to incorporate social preferences typically included in policy analyses, the simplest being the preference to have benefits sooner rather than later as reflected by computing a net present value (NPV) using a discount rate.”(2) Although we have stated earlier in this section that discounting is correctly applied only to economic rather than physical quantities, the calculation of radiative forcing within the FWP method does provide a plausible link between physical emissions and damage (i.e. economic quantities). As a first (highly simplified) approximation, O’Hare et. al. have assumed that damage from emissions is directly proportional to radiative forcing. The radiative forcing values are then discounted to a NPV using an appropriate discount rate to reflect the social

preference of early emission reductions. The ratio of the NPV for the biofuel to that of the reference fuel (e.g. gasoline) is then multiplied by the carbon intensity of the reference fuel thereby providing a carbon intensity value for the biofuel. This carbon intensity represents both physical damage resulting from emissions and the social preference for early emissions reductions. O'Hare et. al. refer to this carbon intensity value as an "economic" fuel warming intensity.

Figure C4-8 compares the land use change carbon intensity values for the annualized, fuel warming potential (FWP), and economic fuel warming potential (FWP_e) methods. We chose a 3% discount rate to reflect the social preference for early emissions reductions in this comparison.

Figure C4-8
Comparison of Time Accounting Methods – Economic Fuel Warming Potential



As expected, the FWP_e method yields larger carbon intensity values than the FWP method. For the FWP_e method, O'Hare et. al. recommend using a longer impact horizon (e.g. 100 years). This yields a carbon intensity of 41 gCO₂e/MJ as compared to the FWP (50 year impact horizon) value of 37 gCO₂e/MJ and the 30 year annualized value of 30 gCO₂e/MJ.

Final scenario: One final scenario was run in which all issues were incorporated. This scenario assumes a 20 year project horizon, distributed above ground emissions, and

incorporation of land reversion (30% over 20 years). Figure C4-9 shows the emissions profile for this scenario and Figure C4-10 depicts the carbon intensity calculations for the three methods. The 20 year annualized carbon intensity value is 31 gCO₂e/MJ as compared to 30 gCO₂e/MJ in the base case (Figure C4-2). The effects of shorter time horizon and land reversion offset each other (for the conditions specified for this scenario). For both the FWP and FWP_e methods, carbon intensity values for short impact horizons are lower than those of the base case because of the effect of distributing early above ground emissions. For longer impact horizons, the carbon intensity values are very similar to the base case because the effect of shorter time horizon offsets the effect of land reversion. Again, we note that the choice of 30% land reversion occurring over 20 years is largely arbitrary. Changing this assumption will affect these results.

Figure C4-9
Land Use Change Emissions Profile - All Stakeholder Comments

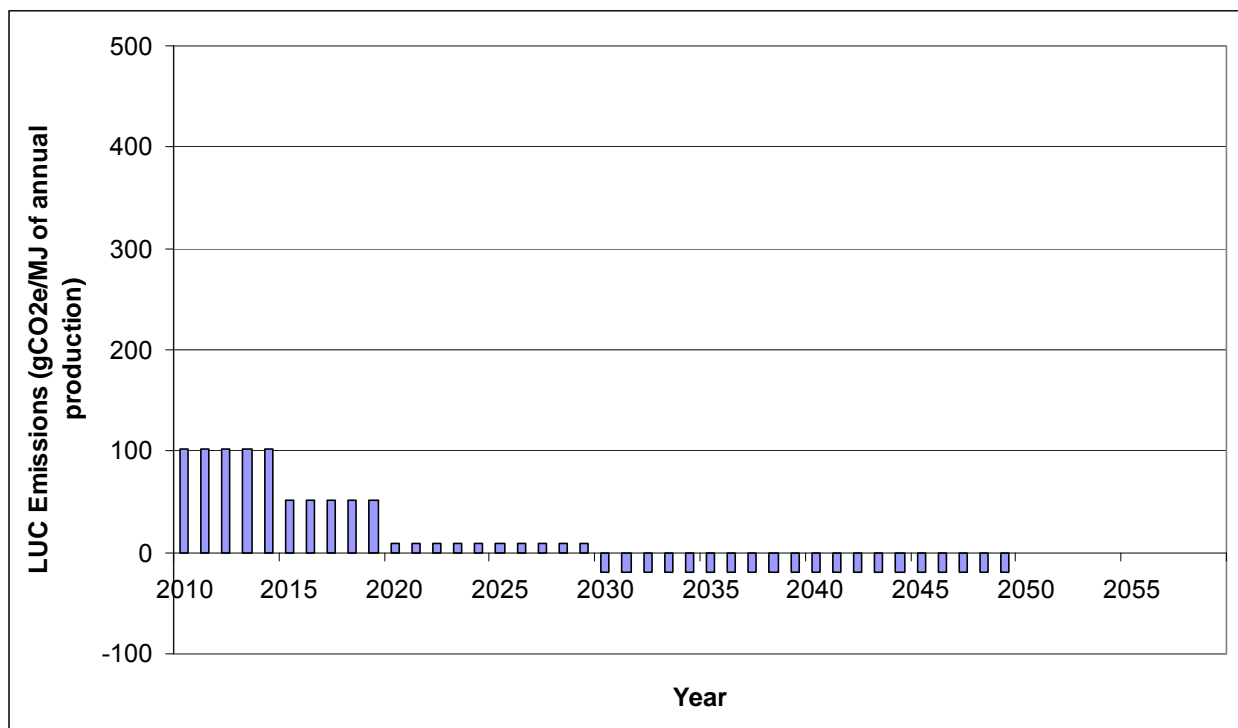
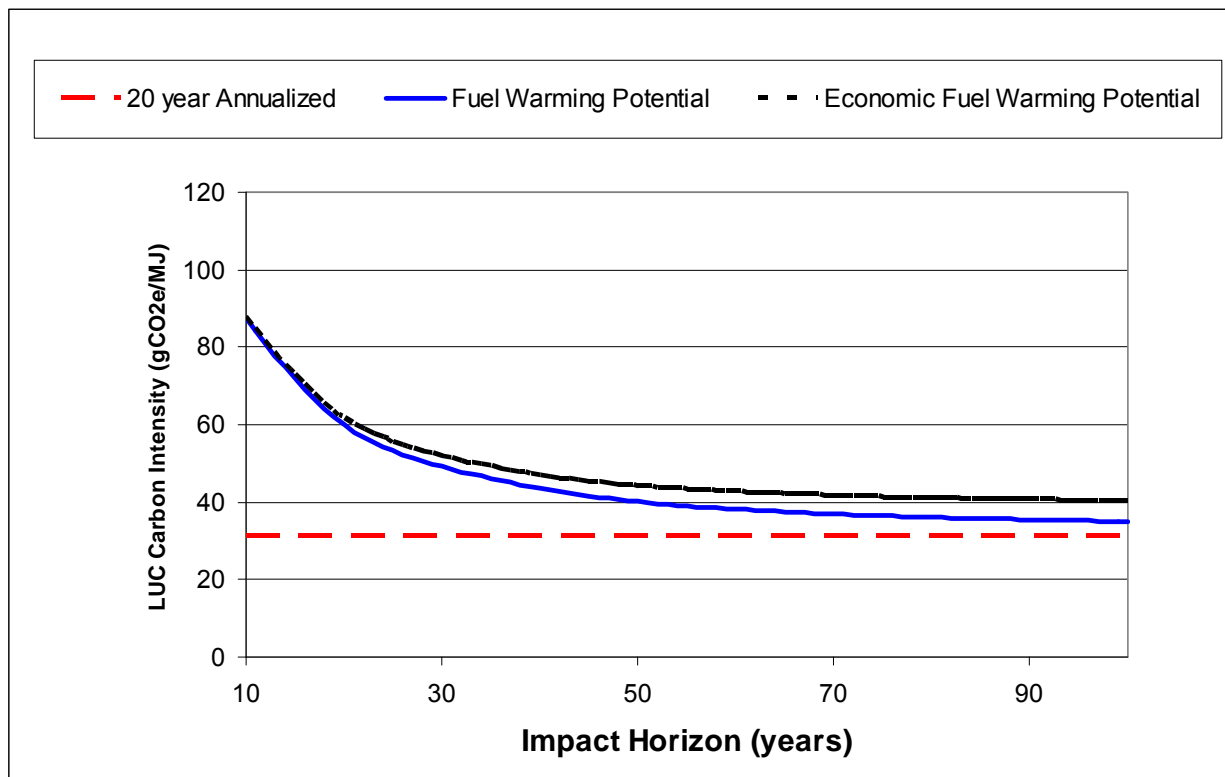


Figure C4-10
Comparison of time accounting methods (all issues included)



Summary: In the above scenarios, we show that decreasing the project horizon yields significantly higher carbon intensity values for all methods. Including land reversion yields lower carbon intensity values as well as a greater difference between the annualized and FWP values. Distributing the above ground carbon emissions over a longer time period yields slightly lower carbon intensity values from the FWP method but does not change the annualized carbon intensity value. For the annualized method, we presented LUC carbon intensity values ranging from 22 to 43 gCO₂e/MJ; for the FWP method (30 year impact horizon) we presented values ranging from 44 to 55 gCO₂e/MJ; and for the FWP method (50 year impact horizon) we presented values ranging from 34 to 48 gCO₂e/MJ.

In conclusion, policy decisions which include choosing a time accounting method, setting the project and impact horizons, and incorporating land reversion will significantly affect the carbon intensity value assigned to land use change and largely determine the role crop based biofuels will play within the LCFS.

Appendix C5

Discussion of Yield Adjustment and Sensitivity Analysis Results for Corn Ethanol

The corn ethanol land use change results presented below were produced using the GTAP global economic model which employed a 2001 baseline. The 2001 GTAP database builds on the most recent global harvested crop land and land cover data base representing the combined efforts of the United Nations Food and Agricultural Organization (UN-FAO), the International Food Policy Research Institute (IFPRI) and the University of Wisconsin Center for Sustainability and the Global Environment (SAGE).

Model output was adjusted (outside the model) to reflect the 9.5% increase in corn yields observed between 2001 yield and the more current 2006 to 2008 average. In 2001, the U.S. corn yield was 138.2 bushels per acre and for 2006 to 2008 (weighted average) the yield was 151.3 bushels per acre.(4)

The primary input to computable general equilibrium models such as GTAP is the specification of the changes that will result in a new equilibrium. Such changes can be driven by the implementation of new policies, other human events such as armed conflicts, or the completion of large-scale public works projects, and non-human events, such as natural disasters. In addition to specifying the change to be evaluated, the GTAP modeler must specify the various elasticities that define the strength of the relationships between the various forces that, together, determine the configuration of the new equilibrium that is eventually reached.

An important step in most modeling efforts is to determine the sensitivity of the model's outputs to changes in the values taken on by the input variables. Sensitivity analysis, as this process is known, is used to determine the range of possible output values, but it is also used to identify model inputs that may require more rigorous specification. Input variables are in need of more exacting specification if (a) outputs are highly sensitive to them, and (b) there is insufficient empirical evidence to support the selection of appropriate values for them. The LCFS GTAP analysis considered variation in the magnitude of the policy change—increased corn ethanol production—and in all but one of the model elasticities.

Sensitivity Analysis Results

The sensitivity results are summarized in Table C5-1 and discussed in the following sections.

Table C5-1
Sensitivity Analysis Results for Corn Ethanol

Input variable	Input Variable Ranges		Output Variable Ranges (grams of CO ₂ Equivalent per megajoule)		
	Low Value	High Value	From Low Input Value	From High Input Value	% Change
EtOH production increase (billion gallons)	8.25	13.25	33.1	33.6	2%
Crop Yield Elasticity	0.1	0.6	52.4	26.8	-49%
Elasticity of Harvested Acreage Response	0.5	0.5	Not varied		
Elasticity of land transformation	0.1	0.3	27.1	35.3	30%
Elasticity of crop yields with respect to area expansion	0.25	0.75	80.4	18.3	-77%
Trade elasticity	1 Std. Dev. Below	1 Std. Dev. Above	33.9	33.3	-2%

Ethanol Production Increase: Modeling runs were performed for ethanol production increases of 8.25 and 13.25 billion gallons. As shown in Table C5-1, the model predicts that the rate of GHG production is not very sensitive to the volume increment of ethanol being produced. Even though the actual 13.25 billion gallon production increase would occur over the course of several years, the model is largely indifferent between a more “realistic” annual increase and a large one-time increase that is the sum of multiple expected annual increases. All subsequent modeling runs were conducted using an ethanol production increase of 13.25 billion gallons.

Crop yield elasticity: Corn yields (amount of corn produced per acre) vary with corn price. The relationship between price and yield is captured in what is known as the price-yield elasticity. Based on a review of the literature on corn yields, the historical average yield response in the U.S. had been 0.4. However, there is evidence that the corn yield elasticity has been falling over time; the most recent study produced a yield response of 0.27.(5) The interpretation of this parameter is straightforward: a P% increase in the price of corn, relative to input cost, will result in a percentage increase in corn yields equal to P% times the corn yield elasticity. The higher the elasticity, the greater the yield increases in response to a price increase. For purposes of testing the sensitivity of the modeled GHG outputs to price-yield elasticity, lower and upper bounds of 0.1 to 0.6 were used for this parameter. Predicted GHG emissions were decreased by about 49% when the corn yield elasticity was increased from 0.1 to 0.6.

Elasticity of harvested acreage response: This parameter expresses the maximum extent to which the number of acres devoted to a crop will change in response to an increase in the cost of land. The change in the number of acres devoted to a specific crop is the product of this value, and a factor expressing that crop’s relative importance (its proportional share of all land costs paid in the region). If the harvested acreage response elasticity is zero, all agricultural land in the region is devoted to a single crop,

and conversions to other crops in response to changes in land costs do not occur. The GTAP modelers applied a relatively high value of 0.5 for this parameter. The higher the value, the more cropping patterns will change in response to land costs. Variation in this value is known to have little effect on GHG emission estimates; it was therefore not included in the sensitivity analysis.

Elasticity of land transformation across cropland, pasture, and forestry: This parameter functions exactly like the elasticity of harvested acreage response parameter, above. The land use conversions it includes, however, are not restricted to currently cultivated land areas. In addition to agricultural land uses, pasture and forest lands are included. Because the available evidence indicates that land use changes across agricultural, forest and pasture cover types are not readily triggered by changes in land costs, this parameter was set to the relatively low value of 0.2. For the sensitivity analysis, it was varied between 0.1 and 0.3 which produced a 30 percent variation in the GHG emission estimate.

Elasticity of crop yields with respect to area expansion: Because almost all of the land that is well-suited to crop production has already been converted to agricultural uses, yields on newly converted lands are almost always lower than corresponding yields on existing crop lands. This parameter expresses the yields that will be realized from newly converted lands relative to yields on acreage previously devoted to that crop (in economic terms, the ratio of marginal to average yields within an agro-ecological zone). Although this is a critical input parameter, little empirical evidence exists to guide the modelers in selecting the most appropriate value. Based on the best available professional judgment of those with experience in this area, the modelers selected a value of 0.50 for their central case. For purposes of the sensitivity analysis this parameter was varied from 0.25 to 0.75, which produces a 77% variation in the GHG emission estimate.

Trade elasticity: Based on an analysis of bilateral trade data from a variety of nations in the western hemisphere, the GTAP authors estimated the trade elasticity values shown in Table C5-2. These elasticity values express the upper bound on the extent to which the importer will respond to a price increase from a given exporter by switching to a different exporter for the more expensive commodity. For example, the trade elasticity for cereal grains is 2.6. If a given cereal exporter raises its price by 5 percent, the importer will purchase (at most) 2.6 times 5 percent of its cereal grain imports from a different exporter. The total change is diminished as the exporter's share of a given market rises. Table C5-2 also reports the elasticity ranges used in the sensitivity analysis. These values were varied from one standard deviation below the central value to one standard deviation above the central value. The results show that GHG emission estimate changed by only 2 percent over this range.

Table C5-2
Trade Elasticity Ranges

Commodity	Elasticity of Substitution Among Imports from Different Sources	Sensitivity Analysis Values	
		1 Standard Deviation below	1 Standard Deviation above
Cereal Grains	2.6	1.5	3.7
Other Grains	9.1	5.1	13.1
Oilseeds	4.9	4.1	5.7
Sugar	5.4	3.4	7.4
Other Agricultural Commodities	4.14	3.14	5.14

Appendix C6

Discussion of Yield Adjustment and Sensitivity Analysis Results for Sugarcane Ethanol

The sugarcane ethanol land use change results presented below were produced using the GTAP global economic model which employed a 2001 baseline as the starting point. The 2001 GTAP database builds on the most recent global harvested crop land and land cover data base representing the combined efforts of the United Nations Food and Agricultural Organization (UN-FAO), the International Food Policy Research Institute (IFPRI) and the University of Wisconsin Center for Sustainability and the Global Environment (SAGE).

Model output was adjusted (outside the model) to reflect the 8.2% increase in Brazilian sugarcane yields observed between 2001 yield (69.44 ton/ha) and the more current 2006 to 2008 average (75.13 ton/ha).²

The primary input to computable general equilibrium models such as GTAP is the specification of the changes that will result in a new equilibrium. Such changes can be driven by the implementation of new policies, other human events such as armed conflicts or the completion of large-scale public works projects, and non-human events, such as natural disasters. For the current modeling, the specified change was an increase in Brazilian sugarcane ethanol production of 2.0 billion gallons. In addition to specifying the change to be evaluated, the GTAP modeler must specify the various elasticities that define the strength of the relationships between the various forces that, together, determine the configuration of the new equilibrium that is eventually reached.

An important step in most modeling efforts is to determine the sensitivity of the model's outputs to changes in the values taken on by the input variables. Sensitivity analysis, as this process is known, is used to determine the range of possible output values, but it is also used to identify model inputs that may require more rigorous specification. Input variables are in need of more exacting specification if (a) outputs are highly sensitive to them, and (b) there is insufficient empirical evidence to support the selection of appropriate values for them. The LCFS GTAP analysis considered variation in all but one of the model elasticities.

² Ministério Da Agricultura, Pecuária E Bastecimento, Secretaria De Produção E Groenergia, Departamento da Cana-de-Açúcar e Agroenergia. "Brazilian Sugar Cane Productivity Evolution." (Ca. 2008)

The results of all sensitivity runs are summarized in Table C6-1. All modeling runs for were conducted assuming an increase in sugarcane ethanol production of 2.0 billion gallons.

Table C6-1
Sensitivity Analysis Results for Sugarcane Ethanol

Input variable	Input Variable Ranges		Output Variable Ranges (grams of CO ₂ Equivalent per megajoule)		
	Low Value	High Value	From Low Input Value	From High Input Value	% Change
Crop Yield Elasticity	0.1	0.5	68	45	-34%
Elasticity of land transformation	0.1	0.3	48	55	15%
Elasticity of crop yields with respect to area expansion	0.25	0.75	131	32	-76%
Trade elasticity	1 Std. Dev. Below	1 Std. Dev. Above	58	56	-3%

Crop yield elasticity: For purposes of testing the sensitivity of the modeled GHG outputs to the crop yield elasticity, lower and upper bounds of 0.1 and 0.5 were used. Predicted GHG emissions were decreased by about 34% when the crop yield elasticity was increased from the lower to the upper bound of this range.

Elasticity of harvested acreage response: The GTAP modelers determined that a relatively high value of 0.5 is warranted for this parameter. The higher the value, the more cropping patterns will change in response to land costs. This value was not varied in the current sensitivity analysis.

Elasticity of land transformation across cropland, pasture, and forest land: Because the available evidence indicates that land use changes across agricultural, forest and pasture cover types are not readily triggered by changes in land costs, this parameter was set to the relatively low value of 0.2. To determine the model's sensitivity to this variable, it was varied between 0.1 and 0.3. The result was a 15 percent variation in the output variable.

Elasticity of crop yields with respect to area expansion: Although this is an important input parameter, little empirical evidence exists to guide the modelers in selecting the most appropriate value. For purposes of the sensitivity analysis this parameter was varied between values of 0.25 and 0.75, which produced a 76% variation in the output variable. Model outputs are significantly more sensitive to changes in this input variable than to changes in any other variable.

Trade elasticity: The values used to test the sensitivity of this variable ranged from one standard deviation below, to one standard deviation above, the central value (see Table C5-2 for trade elasticity values). In response to this level of variation, the GHG output variable changed by only 3 percent.

This Page Intentionally Left Blank

Appendix C7

Discussion of Yield Adjustment and Sensitivity Analysis Results for Soy Biodiesel

Note: The biodiesel estimates presented in this section are very preliminary. Biodiesel carbon intensity does not appear in the LCFS regulatory lookup table. Its only use, beyond this section, has been the preparation of the diesel fuel compliance scenarios appearing in Chapter VI. When a value sufficiently robust for use in the regulation has been estimated, that value will be published.

The soy biodiesel land use change results presented below were produced using the GTAP global economic model which employed a 2001 baseline as the starting point. The 2001 GTAP database builds on the most recent global harvested crop land and land cover data base representing the combined efforts of the United Nations Food and Agricultural Organization (UN-FAO), the International Food Policy Research Institute (IFPRI) and the University of Wisconsin Center for Sustainability and the Global Environment (SAGE).

For soy biodiesel, the GTAP modeled aggregated oil seeds scenario and not strictly soybeans. The average yield for aggregate oilseeds biodiesel used in the model was 2.06 gal/bushel as compared to a yield for soy based biodiesel of 1.47 gal/bushel. To address this difference, the land conversion was adjusted by the ratio of 2.06/1.47 outside of the model. The GTAP model also does not account for soy meal co-product credit. As an initial estimate we assume a 75% land conversion credit for soy meal co-product (i.e. land conversion values are reduced by 75%).

The primary input to computable general equilibrium models such as GTAP is the specification of the changes that will result in a new equilibrium. Such changes can be driven by the implementation of new policies, other human events such as armed conflicts or the completion of large-scale public works projects, and non-human events, such as natural disasters. For the current modeling, the specified change was an increase in U.S. soy biodiesel production of 0.695 billion gallons. In addition to specifying the change to be evaluated, the GTAP modeler must specify the various elasticities that define the strength of the relationships between the various forces that, together, determine the configuration of the new equilibrium that is eventually reached.

An important step in most modeling efforts is to determine the sensitivity of the model's outputs to changes in the values taken on by the input variables. Sensitivity analysis, as this process is known, is used to determine the range of possible output values, but it is also used to identify model inputs that may require more rigorous specification. Input variables are in need of more exacting specification if (a) outputs are highly sensitive to them, and (b) there is insufficient empirical evidence to support the selection of appropriate values for them. The LCFS GTAP analysis considered variation in the magnitude of the policy change—increased soy biodiesel production—and in all but one of the model elasticities.

The results of the sensitivity analysis runs are shown in Table C7-1. Starting with the 2001 soy biodiesel production level of 0.005 billion gallons, the GTAP sensitivity analysis considered two production increments: 0.295 billion gallons and 0.695 billion gallons. The model was quite insensitive to variation in production volumes over this range. As a result, all subsequent sensitivity runs on elasticity values were based on a 0.695 billion gallon biodiesel production increase.

Table C7-1
Sensitivity Analysis Results for Soy Biodiesel

Input variable	Input Variable Ranges		Output Variable Ranges (gCO ₂ /MJ)		
	Low Value	High Value	From Low Input Value	From High Input Value	% Change
Biodiesel production increase (billion gallons)	0.295	0.695	48.0	49.0	2
Crop Yield Elasticity	0.1	0.5	61.3	36.8	-40
Elasticity of land transformation	0.1	0.3	40.3	50.8	26
Elasticity of crop yields with respect to area expansion	0.25	0.75	114	27.7	-76
Trade elasticity	1 Std. Dev. Below	1 Std. Dev. Above	50.8	48.7	-4

Crop yield elasticity: For purposes of testing the sensitivity of the modeled GHG outputs to the crop yield elasticity, lower and upper bounds of 0.1 and 0.5 were used. Predicted GHG emissions were decreased by about 40% when the crop yield elasticity was increased from the lower to the upper bound of this range.

Elasticity of harvested acreage response: The GTAP modelers determined that a relatively high value of 0.5 is warranted for this parameter. The higher the value, the more cropping patterns will change in response to land costs. This value was not varied in the current sensitivity analysis.

Elasticity of land transformation across cropland, pasture, and forest land: Because the available evidence indicates that land use changes across agricultural, forest and pasture cover types are not readily triggered by changes in land costs, this parameter was set to the relatively low value of 0.2. To determine the model's sensitivity to this variable, it was varied between 0.1 and 0.3. The result was a 26 percent variation in the output variable.

Elasticity of crop yields with respect to area expansion: Although this is an important input parameter, little empirical evidence exists to guide the modelers in selecting the most appropriate value. For purposes of the sensitivity analysis this parameter was varied between values of 0.25 and 0.75, which produced a 76% variation in the output

variable. Model outputs are significantly more sensitive to changes in this input variable than to changes in any other variable.

Trade elasticity: The values used to test the sensitivity of this variable ranged from one standard deviation below, to one standard deviation above, the central value (see Table C5-2 for trade elasticity values). In response to this level of variation, the GHG output variable changed by only 4 percent.

This Page Intentionally Left Blank

Appendix C8
Corn and Soybean Export Data(6)

Figure C8-1
Corn Acres Harvested

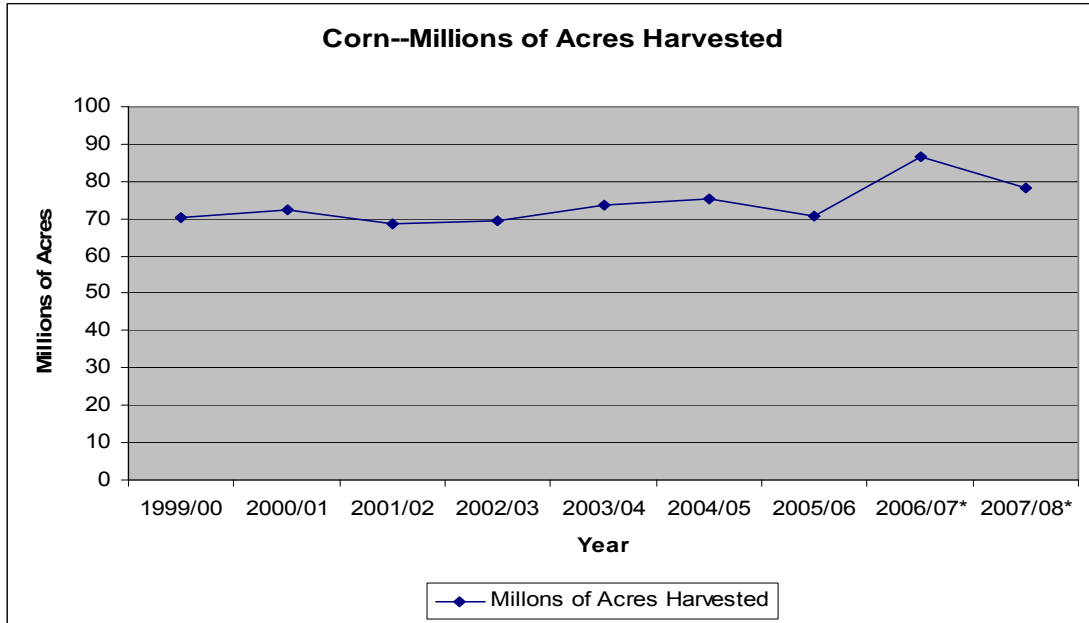
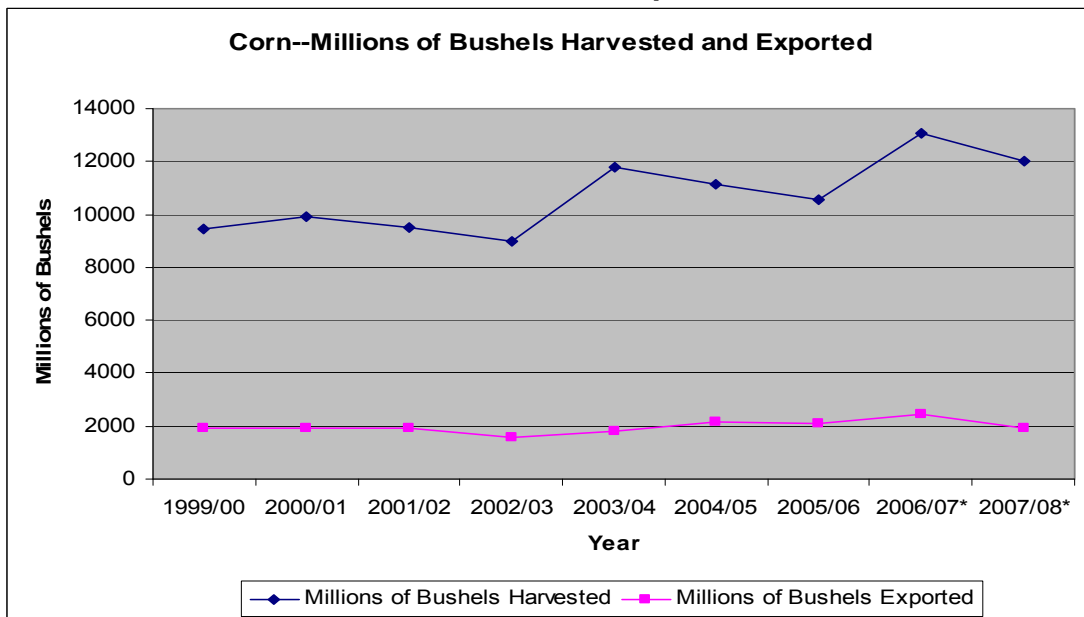
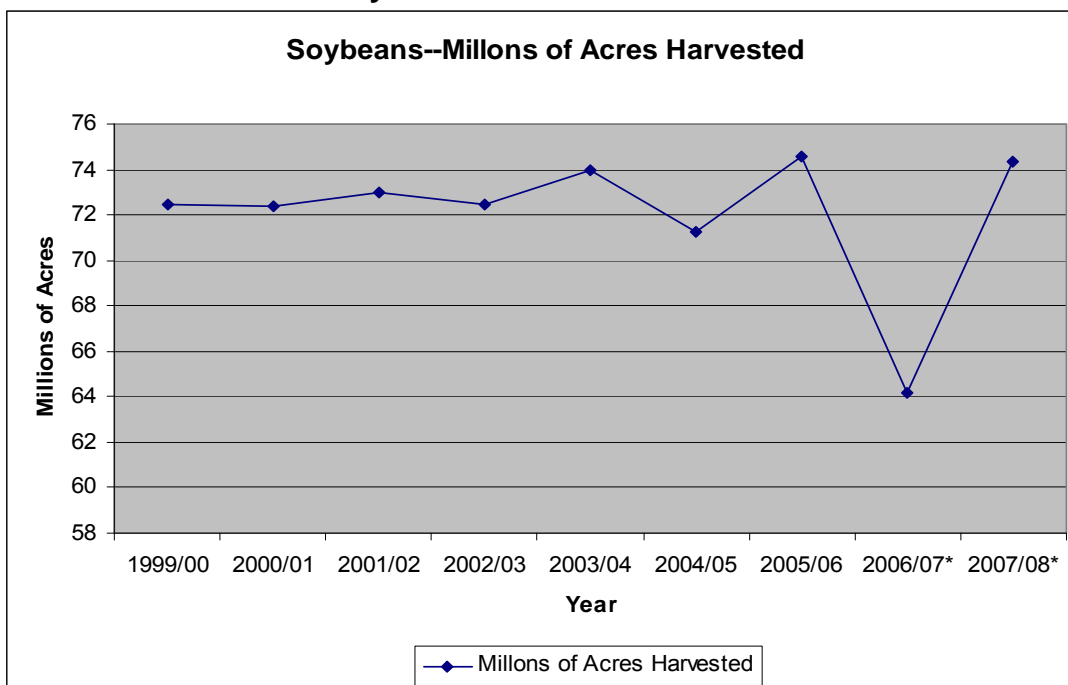


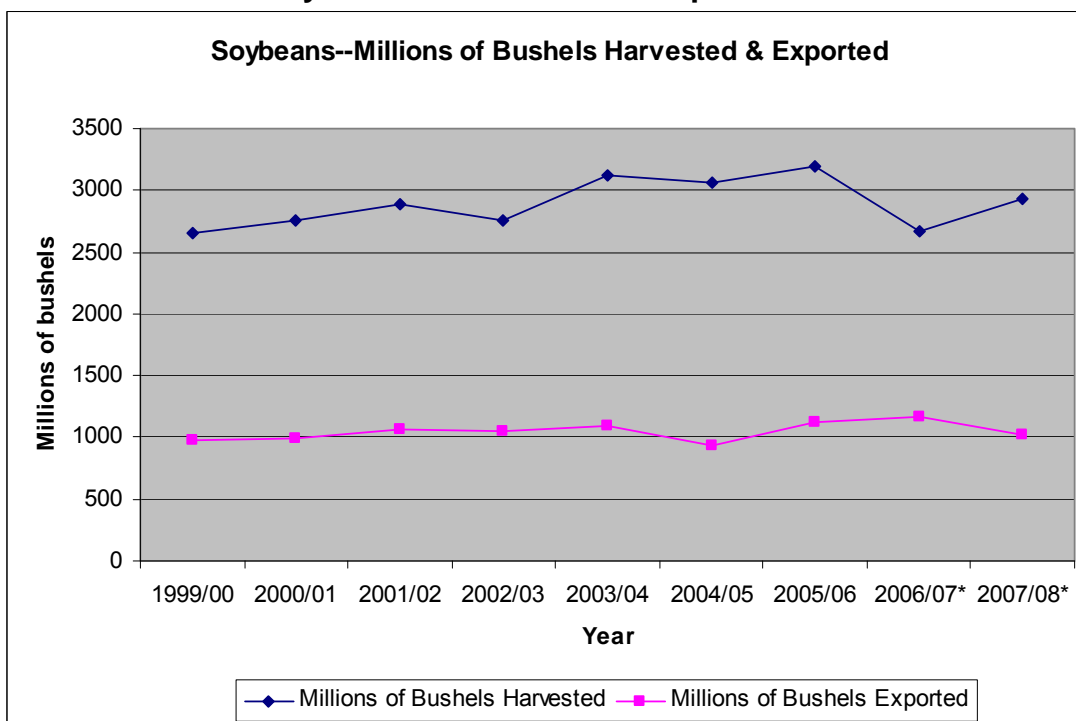
Figure C8-2
Corn Harvested and Exported



**Figure C8-3
Soybean Acres Harvested**



**Figure C8-4
Soybeans Harvested and Exported**



Appendix C9

Food versus Fuel Summary Calculations

The following bulleted list was included in the section titled “Food versus Fuel Analysis”. These calculated values are meant to be illustrative and not exact and therefore use many approximate values.

A 50 million gallon per year corn ethanol plant operated in California would:

- Provide enough fuel for approximately 80,000 vehicles capable of operating on E-85.

$$50 \frac{\text{million gal. EtOH}}{\text{yr}} \times \frac{0.67 \text{ gal. gas.}}{\text{gal. EtOH}} \times \frac{1}{0.85} \times \frac{1 \text{ vehicle}^* \text{ yr}}{500 \text{ gal. gas.}} = 79,000 \text{ vehicles}$$

- Displace about 34 million gallons of petroleum fuel.

$$50 \text{ million gal. EtOH} \times \frac{76,330 \text{ BTU} / \text{gal. EtOH}}{113,300 \text{ BTU} / \text{gal. gasoline}} = 33.7 \text{ million gal. gasoline}$$

- Reduce direct GHG emissions by about 0.19 million metric tons per year.

$$50 \frac{\text{million gal}}{\text{year}} \times 80.53 \frac{\text{MJ}}{\text{gal}} \times (96 - 50) \frac{\text{gCO}_{2e}}{\text{MJ}} \times \frac{1 \text{ MMT}}{10^{12} \text{ g}} = 0.19 \frac{\text{MMT}}{\text{year}}$$

- Require almost 18 million bushels of corn per year.

$$50 \frac{\text{million gal.}}{\text{year}} \times \frac{1 \text{ bushel}}{2.8 \text{ gal.}} = 17.9 \frac{\text{million bushel}}{\text{year}}$$

- Require about 110,000 acres of U.S. farmland to produce the feedstock.

$$17.9 \frac{\text{million bushel}}{\text{year}} \times \frac{1 \text{ acre}}{160 \text{ bushel}} = 112,000 \frac{\text{acres}}{\text{year}}$$

- Result in about 36,000 acres of indirect land conversion, 14,000 acres of which would be in the U.S.

$$50 \text{ million gal.} \times \frac{3.89 \text{ million ha}}{13.25 \text{ billion gal.}} \times 2.471 \frac{\text{acre}}{\text{ha}} = 36,000 \text{ acres}$$

- Result in the release of 3.6 million metric tons of greenhouse gases due to land conversions.

$$50 \text{ million gal.} \times 80.53 \frac{\text{MJ}}{\text{gal}} \times 900 \frac{\text{gCO}_{2e}}{\text{MJ}} \times \frac{1 \text{ MMT}}{10^{12} \text{ g}} = 3.62 \text{ MMT CO}_{2e}$$

- Result in a net greenhouse gas emission benefit after 19 years of production.

$$3.62 \text{ MMT CO}_{2e} \times \frac{1 \text{ year}}{0.19 \text{ MMT CO}_{2e}} = 19 \text{ year}$$

Appendix C10

Adjustment of GTAP Model Output for Increasing Crop Yields

Correspondence provided by Tom Hertel of Purdue University on 1/11/09:

The Issue of Baseline Yields: To understand the role of baseline yields in determining global land use change, we turn to a simple example, which will be illustrated mathematically, and then numerically. We consider the simplest possible case with two regions: USA and Rest of World, and two commodities: corn and soybeans.

Begin with the market clearing condition for *non-biofuel* corn demand, which may be written as follows:

$$A_C^{US} Y_C^{US} + A_C^{RW} Y_C^{RW} = D_C^{WLD} \quad (1)$$

where A corresponds to area devoted to non-biofuel production and Y to yield. Subscript C refers to Corn, and superscripted US to the United States and RW to the Rest of the World. We want to know how much land use change is required in RW if corn area devoted to food/feed production is reduced by a given amount -- say 15 million hectares, which is the amount of land required to meet a 13.25 bgy increase in corn ethanol when starting from a 2001 base at 2001 yields.

In order to isolate the impact of yields on land use requirements in the RoW, rearrange (1) as follows so that area required in RW may be seen to depend on global non-biofuel demand for corn, deflated by RW yields, and US area devoted to corn, multiplied by the ratio of US to RW yields:

$$A_C^{RW} = D_C^{WLD} / Y_C^{RW} - A_C^{US} Y_C^{US} / Y_C^{RW} \quad (2)$$

Now assume that: (a) the global demand for non-biofuel use of corn is unchanging (this is the case of extreme price inelasticity of food demand -- a more sophisticated model would capture the price-responsiveness of demand), and, (b) yields are exogenous (this is the baseline yield assumption -- comparable to what is typically assumed in the FAPRI model). Then totally differentiating (2), we obtain the following expression for the change in land use in RW as a function of changing corn land use in the US:

$$dA_C^{RW} = -[Y_C^{US} / Y_C^{RW}] dA_C^{US} \quad (3)$$

Equation (3) states that, for a given diversion of corn acreage from food/feed production (e.g., 15 mill. hectares), the change in corn acreage in the Rest of the World is dependent on the ratio of US to RW yields. If yields in RW are only half as large as those in the US, then this ratio is two and 30 million hectares of land in RW will be required to offset this loss of corn land in the US.

In the multiple commodity case, equation (3) remains valid. Only now we alter the subscripts to reflect the other commodity (e.g., soybeans). If US coarse grains area expands at the expense of soybeans, then this will moderate the reduction area on the RHS of (3). So the resulting expansion in coarse grains area in RW will be diminished. However, now there will be a similar market clearing condition for soybeans for which US area will be declining on the RHS. Once again, the change in RW area due to this area change in the US will be solely a function of the yield ratio. Therefore, if soybean yields in the US and RW grow at the same rate, then the resulting change in RW land area change will be unaffected.

Clearly having an accurate assessment of the US/RW yield ratio is very important. This is why it makes sense to pick a base year for which the best possible yield data are available globally. And these data should be measured in a comparable manner -- otherwise the ratio will embody measurement error. If, for example, RW yields were only half as large as estimated, then the amount of land conversion required would be twice as much as estimated. The year 2001 is the latest year for which a global data base on harvested area and yields is available (Monfreda et al., 2008; it is actually an average of the period 1997-2003). These are the data used in GTAP. A comparison of these with FAPRI yields for the coarse grains aggregate is provided in Figure 1. From this we see observe that: (a) the FAPRI yields (from 2001/2 year) are generally a bit higher, but more importantly (b) the differences are relatively modest. A more comprehensive comparison along these lines would be very helpful.

Given that we adopt a base year of 2001, we are immediately led to the question: What if we update yields to reflect 2007, or even projected 2015 values? How will this change our findings? As noted above, we know that US corn yields rose by about 10% over the 2001-2007 period. Thus, an amount of ethanol that requires 15 Mha to produce in 2001 will only require about $15.2 * 1/1.1 = 13.8$ Mha in 2007. *This direct adjustment to land use is essential* and it will reduce the initial land use change impulse in equation (2). Beyond that, there is a question about whether further adjustments are required. Equation (3) tells us that this will not be necessary, provided yields in the US and RoW increase at the same rate, such that their ratio remains unchanged. In other words, once we have adjusted the US area change downwards from 15.2 to 13.8 Mha, the remaining impulse for land use change in RoW will be unaltered.

At first blush, this may seem counter-intuitive: higher yields in RW would seem to offer scope for offsetting more of the biofuel demand from existing cultivated area, as opposed to requiring expansion at the extensive margin. *But if yields also rise in the US, the amount of corn displaced by a given area reduction is now larger as well.* If both yields rise by the same percentage, then these effects are precisely offsetting.

Further intuition may be obtained via the following numerical example which is developed in detail in Table 0. The top part of this table considers the global market equilibrium for coarse grains in 2001, in which the US harvests 36.3 Mha and RW harvests 252 Mha, with yields of 335 bu/ha and 109 bu/ha respectively. Global demand is 39,647 Mbu and excess demand is zero (the market is in equilibrium). Now introduce

a new demand for corn for use in ethanol. If yields do not change due to the biofuel mandate, and if 13.75 bgy are required, then, at 2001 yields, 15.2 Mha of coarse grains land must be made available to meet this mandate. In this example, we assume that total US coarse grains area remains unchanged, i.e. none of this land comes from other crops. How much additional land conversion will be required in the Rest of the World? Assuming that the new land has the same yield as the current coarse grains land (2001 yields of 109 bu/ha) then 46.7 Mha of additional coarse grains acreage will be required in RW.

Now move forward in time and redo this analysis. The assertion made above is that, in the presence of balanced growth (i.e. equal growth rates in yields and demand), we need only deflate the 2001-based land use change by the cumulative growth rate in yields to reflect the fact that the mandate is now less demanding of corn land. This calculation is done at the top of the lower section in Table 0, where RW land use change in 2007 is estimated by multiplying the 2001 based estimate (46.7 Mha) by the deflation factor $= 0.909 = 1/1.10$. This yields a 2007 estimate of 42.5 Mha.

The remainder of Table 0 simply develops the full blown 2007 commodity market equilibrium to show that this is indeed the correct estimate. Thus, yields and demands are scaled up by the common factor (1.10) to give a new equilibrium. At these higher yields, the coarse grains area required to meet the mandate is now lower ($36.3 - 22.5$) $= 14.3$ Mha. However, measured in bushels, the excess demand (prior to RW area adjustment) is still equal to the 5,092 Mbu required to produce the desired amount of ethanol. But, since RW yields have also risen, they now need less land to meet this excess demand. Indeed, the reduction in RW area change is precisely the same proportion as suggested by the deflation factor.

We conclude that, provided the baseline exhibits balanced growth in demand and yields, the base year is not particularly critical. Land use change results can be scaled to the appropriate future year by applying a simple deflation factor to reflect yield growth over the intervening period. Given the importance of relative yields in equation (3), the overriding consideration should be to choose a base year for which reliable estimates of yields are available on a global basis. Furthermore, it is highly recommended that discussion of baselines focus on the evolution of *relative yields* from the benchmark year for which data are available.

By not explicitly developing a baseline, the GTAP-based analysis of biofuels *assumes this yield ratio does not change from 2001 for exogenous reasons*. Of course, with endogenous yield response, the ratio will change due to changes in commodity prices, as well as changes in yields due to area expansion/contraction. These are factors that we consider in detail in the subsequent analysis.

Table 0. Determining global land use change in the context of baseline yield changes

2001 Coarse Grains market (Mha and Mbu)

Initial Equilibrium

US			RW			World	
Area	Yield	Prod	Area	Yield	Prod	Demand	Excess Dmd
36.34285	335		252.0438	109			
		12174.85408			27472.77	39647.63	0
<i>US 15bgy, no adjustment RW, no cross-commodity effect</i>							
21.14285	335		252.0438	109			
		7082.85408			27472.77	39647.63	-5092
<i>US 15bgy, area adjustment RW, no cross-commodity effect</i>							
21.14285	335		298.7594	109			
		7082.85408			32564.77	39647.63	0
Change in RW Area			46.7156				

2007 Coarse Grains market (Mha and Mbu): yields and demand are 10% higher

GTAP estimate of RW land use change, based on higher yields

2001 est Deflated by yields

46.7156 0.909091 **42.46872**

2007 equilibrium in presence of balanced yield and demand growth

US			RW			World	
Area	Yield	Prod	Area	Yield	Prod	Demand	Excess Dmd
36.34285	368.5		252.0438	119.9			
		13392.33949			30220.05	43612.39	0
<i>US 15bgy, deflated by yield growth, no adjustment RW, no cross-commodity effect</i>							
22.52467	368.5		252.0438	119.9			
		8300.339488			30220.05	43612.39	-5092
<i>US 15bgy, area adjustment RW, no cross-commodity effect</i>							
22.52467	368.5		294.5125	119.9			
		8300.339488			35312.05	43612.39	0
Change in RW Area			42.46872				

Conclusion: The only adjustment required is to deflate the initial land use impulse in US

Correspondence provided by Alla Golub and Tom Hertel from Purdue University on 2/9/09: Actually, we assume that yields increase globally for ALL crops on ALL lands. However, since these yield increases are assumed to be the same for all regions, the only required adjustment to our land use estimates is to direct use of land in feedstock production. This is because higher yields overseas are offset by higher yields on the U.S. crop land displaced by biofuels.

An example is helpful in clarifying these points. For simplicity of representation, we make few assumptions:

- 1) There are only two regions: US and all other countries of the world (ROW).
- 2) There is only one commodity: corn.
- 3) There are no changes in prices due to diversion of corn from food production to ethanol production.
- 4) Yields may increase over time, but also global non-ethanol demand for corn.

The purpose of this example is illustrative. In this example, we do not attempt to calculate land use change due to increased biofuel production, but only demonstrate that post GTAP adjustment to **the net change in cropland** due to increased biofuel production is sufficient and no further adjustments are necessarily to reflect higher current yields.

In 2001, US corn yield is 335 bu/ha and ROW corn yield is 109 bu/ha.
In US cultivated area is 36.34 Mha. In the ROW cultivated area is 252.04 Mha

Total world demand (which is equal to total world supply) for corn is

$$335 \text{ bu/ha} * 36.34 \text{ Mha} + 109 \text{ bu/ha} * 252.04 \text{ Mha} = 39646 \text{ Mbu.}$$

To produce 13.25 billion gallons of corn ethanol, we would need 5096 Mbu of corn. We take these bushels from US non-ethanol market. So, now non-ethanol production of corn in US is smaller by 5096 Mbu. Given that world demand for 39646 Mbu of corn should be met, 5096 Mbu are produced outside US in the ROW at lower yields. Land required for this production is:

$5096 \text{ Mbu} / 109 \text{ bu} = 47 \text{ Mha}$ in the ROW. So, in this simple calculation, **the net change in cropland is 47 Mha.**

If we compare average corn yield over 2006-2008 and our base year (2001) corn yield for U.S., we find that U.S. corn yield had grown by 9.5%. Not only U.S. yields changed over this period, but also yields in ROW and global non-ethanol demand for corn. Here we assume balanced growth: everything grows at the same 9.5% rate. Under the balanced growth scenario:

- global non-ethanol demand have grown from 39646 Mbu to $39646 * 1.095 = 43412 \text{ Mbu}$;

- US corn yields have grown from 335 bu/ha to $335 * 1.095 = 367$ bu/ha on all corn land in US;
- ROW corn yields have grown from 109 bu/ha to $109 * 1.095 = 119$ bu/ha on all corn land in ROW.

$$367 \text{ bu/ha} * 36.34 \text{ Mha} + 119 \text{ bu/ha} * 252.04 \text{ Mha} = 43412 \text{ Mbu.}$$

Question: What is **the net change in cropland** due to increased ethanol production at higher yields? Again, to produce 13.25 billion gallons of corn ethanol, we would need 5096 Mbu of corn. We take these bushels from US non-ethanol market. So, now non-ethanol production of corn in US is smaller by 5096 Mbu. Given that world demand for 43412 Mbu of corn should be met, 5096 Mbu are produced outside US in the ROW. Land required for this production is:

$5096 \text{ Mbu} / 119 \text{ bu/ha} = 43 \text{ Mha}$ in the ROW. At higher yields, **the net change in cropland is 43 Mha.**

Now, compare 47 Mha and 43 Mha. One could obtain 43 Mha by simply adjusting 47 Mha to reflect higher current corn yields:

$$47/(1+0.095) = 43 \text{ Mha.}$$

This idea is behind the post GTAP adjustment applied to **the net change in cropland** obtained at 2001 yields. So, to know the net change in cropland at higher current yields, it is sufficient to apply factor $1/(1+\text{percent change in corn yield}/100)$ to the GTAP net change in cropland due to increased ethanol expansion obtained at 2001 yields.

Though adjustment is applied to **the net change in cropland**, the illustrative calculation assumes that all yields on all land were adjusted upwards in the baseline (see above: ROW yield was increased from 109 bu/ha to 119 bu/ha).

What if global non-ethanol demand for corn is fixed? Then, at higher yields we would need less land to produce corn for food globally:

$$367 \text{ bu/ha} * 36.34/1.095 \text{ Mha} + 119 \text{ bu/ha} * 252.04/1.095 \text{ Mha} = 39646 \text{ Mbu.}$$

That is, in the U.S. we would need $36.34/1.095 = 33$ Mha and in the ROW we would need $252.04/1.095 = 230$ Mha. The assumption of no growth (or different from 9.5% growth) in non-ethanol corn demand does not change post GTAP adjustment. To produce 13.25 billion gallons of corn ethanol, we would need 5096 Mbu of corn. We take these bushels from US non-ethanol market. So, now non-ethanol production of corn in US is smaller by 5096 Mbu. Given that world demand for 39646 Mbu of corn should be met, 5096 Mbu are produced outside US in the ROW. Land required for this production is:

5096 Mbu / 119 bu/ha = 43 Mha in the ROW. At higher yields and no growth in global non-ethanol demand, **the net change in cropland is 43 Mha.**

While the assumption about growth in global non-ethanol demand for corn is not important, the assumption of equal rates of growth in US and ROW corn yields is critical here:

- *If US corn yield grows faster than ROW corn yield, then we will underestimate the net change in cropland due to the increase in ethanol production.*
- *If US corn yield grows slower than ROW yield, then we will overestimate the net change in cropland due to increase in ethanol production.*

Given the difficulty of forecasting global yield growth, we believe that the balanced growth assumption is a reasonable compromise. Of course we would prefer to have a fully accurate, global baseline – or better yet – completely up to date global yield data by AEZ. However, neither of those is currently available. Therefore, we prefer a simple, plausible and transparent assumption.

This Page Intentionally Left Blank

Appendix C11

Co-product Credit Analysis when Using Distiller's Grains Derived from Corn Ethanol Production

The carbon intensity values assigned to the fuels regulated under the Low Carbon Fuel Standard (LCFS) are established through 'lifecycle analysis'—a method for calculating the total GHG emissions from fuel production, transport, storage and use. In some cases, fuel production generates marketable products in addition to the primary fuel product. These additional products are referred to as 'co-products.' Corn ethanol production, for example, yields a co-product known as distiller's grains, which can be used as livestock feed. To the extent that distillers grains displace more traditional feeds (corn and soybean meal), they do away with the GHGs generated during the production, transport, storage, and use of those products. This GHG reduction becomes a life-cycle carbon intensity credit for corn ethanol.

A recent report by Michael Wang et al.(7) of Argonne National Laboratory arrived at a distiller's grain co-product value that is higher than the value used in the LCFS life cycle emissions model. As the following discussion shows, however, ARB staff has concluded that sufficient justification for adopting the Wang et al. value doesn't currently exist.

The dry milling process to produce ethanol from corn involves several steps:

- a) clean and grind the grain into coarse flour
- b) Water and enzymes are added to convert starch into sugar
- c) The mixture is cooked and sterilized
- d) Upon cooling the mixture, yeast is added to begin fermentation
- e) The products of fermentation include ethanol, carbon dioxide and residue (termed mash(8))
- f) Distillation of the mixture allows for separation of ethanol

The residue from the fermentation process contains liquid and solid fractions. When removed, the liquid is called *thin stillage*. This can be sold directly as animal feed or dehydrated to produce condensed distiller's solubles (CDS). The solid fraction is called Wet Distiller's Grains (WDG). When dried, WDG becomes Dry Distiller's Grains (DGS). When solubles are combined with WDG, distiller's grain plus solubles (WDGS) is the result; combining DGS with solubles yields Dry Distiller's Grains with Solubles (DDGS).

DDGS (or WDGS) can be used as a substitute feed for various types of livestock. The Wang et al.(7) study used data from a few studies to analyze the suitability of DDGS as replacement feed for beef cattle, dairy cattle and hogs. The conclusion was that each pound of DDGS could potentially replace approximately 1.27 lbs of animal feed (a combination of feed corn, soybean meal and urea). This value has subsequently been used in the Argonne GREET model's well-to-wheels life-cycle analysis of corn ethanol.

In an effort to determine whether Argonne's 1:1.27 DDGS-to-feed ratio should be adopted for use in the California LCFS, ARB staff conducted an extensive review of the literature. More specifically, staff sought to determine the likelihood that significant quantities of traditional feed will be replaced by DDGS as the latter becomes more available due to the projected expansion of ethanol production through 2012. Generally, the following three factors need to be considered when determining the feasibility of displacing traditional feeds with DDGS(9):

- Variability of nutrient content and availability (between plants and between batches from the same plant) and resulting impacts on nutrient management and animal performance;
- Handling, storage and transportation of DDGS; and
- Education of livestock producers and managers.

Variability of nutrient content and availability

Nutrient concentrations in DDGS vary considerably, due at least in part to variations in the nutrient content of feedstock corn, differences in yeast types, fermentation and distillation process parameters and efficiencies, drying process variability, and soluble—solid fraction blending ratios. Variation has been observed between batches from the same plant, and between batches from different plants. Table C11-1 compares corn and DDGS nutrient values and provides typical ranges for all nutrients.

**Table C11-1
Compositional Values for Corn and DDGS**

Nutrient/Component*	Corn	DDGS		
	(%)	Range (%)	Digestibility (%)	Availability %
Crude Protein	8.5-9.9	28-32	60-90	16.8-28.8
Crude fiber, %	1.5 – 3.3	5-14		5-14
Phosphorus, %	0.28 - 0.34	0.7 - 1.3	80-90	0.56-1.17
Fat, %	3.5 – 4.7	3 - 12	85 - 90	3 - 12
Sodium, %	0.00 - 0.02	0.05 - 0.17	100	0.05-0.17
Sulfur	0.12	0.4-0.8	100	0.4-0.8

* reported as a percentage of dry matter

Values include variation between animal species.

Since a significant portion of the carbohydrate is removed during fermentation, the protein fraction in DDGS is proportionately larger, as shown in Table C11-1. A critical process parameter affecting protein availability is heat exposure during fermentation. Prolonged exposure can subject large portions of proteins and sugars to a “browning reaction” which leaves some of the carbohydrate and protein content unavailable to the animal(8). The browning reaction is thought to account for the reduced protein utilization observed in animals that were fed DDGS.(10-14) Akayezu et al. reported similar results. Although DDGS contains more protein than corn (28-32 percent versus

corn's 8.5-9.9 percent), less of the protein in DDGS is nutritionally available to the animal: livestock are only able to digest and metabolize 16.8-28.8 percent of the DDGS protein fraction. The protein content of the feed, therefore, is not the same as protein availability to the animal. In addition, lysine, an essential amino acid, is deficient in DDGS. Cattle fed DDGS must therefore receive appropriate quantities of supplemental lysine.

The increased sulfur content of DDGS is also likely to limit the blending of DDGS into animal feeds, particularly in areas with high sulfur content in feed water. Certain neurological problems in cattle have been attributed to high sulfur levels in feed³. High phosphorus levels in DDGS also lead to increased excretory phosphorus, a likely manure management issue for the livestock farmer. Diets containing high levels of phosphorus should include a supplemental calcium source such as limestone to prevent urinary calculi, particularly in hogs^{Error! Bookmark not defined.} (The recommended calcium-to-phosphorus ratio in backgrounding and feedlot diets is a minimum of 2:1). The high crude fiber levels in DDGS is a potential problem for hogs, since monogastric animals cannot utilize fiber as do ruminants. The fat content in DDGS is a likely issue for dairy cattle: diets high in fats can lead to milk with unacceptably high fat content. In newer plants, the corn is finely ground to yield more product per bushel. The small particle sizes can predispose hogs to gastric ulcers when DGS is used in the feed.

In addition to the nutrient-related issue summarized above, one study(15) which investigated the partial replacement of steam-flaked corn with 25 percent DDGS concluded that the DDGS content reduced ruminal pH, which, in turn, suppressed the growth of ruminal bacteria responsible for fermentation. The resulting reductions in ruminal digestion decreased overall digestion and absorption of most nutrients. (note that steam-flaking of grain is the most prevalent grain processing method for feedlot grain, followed by high-moisture corn and dry-rolled corn(16)). The authors recommend that livestock managers increase ruminal pH in animals consuming a DDGS-flaked corn blend. They also recommend additional supplements to ensure appropriate nitrogen availability for the bacteria responsible for digestion of dietary organic content.

Handling, storage and transportation of DDGS

DDGS transport includes the cost of transporting the water content in the feed. As a result, transport distance beyond a 50-60 mile radius from the ethanol plant may not be cost-effective. The shelf-life of the wet product, which is highly dependent upon temperature, is about 3-7 days. The size of a farm may also limit use of DGS. The smallest shipment size available from an ethanol plant is a truckload and small farms may have insufficient animals to consume a truckload before spoilage occurs(17). Infrastructure and handling issues may also limit use on small farms^{Error! Bookmark not defined.}. Mycotoxins may accumulate during storage, of wet DGS(18).

The fine particles in dry DDGS tend to settle and cake during transport(19). Because the caked layers can adhere to the sides and bottoms of rail cars, the cars must be

hammered to free up the caked product. This has led to severe rail car damage and replacement costs are becoming prohibitively expensive. Large railroads including BNSF and UP have prohibited DDGS shipments on their own cars (ethanol companies must either own or lease their own rail cars).

Education of livestock industry

Livestock managers generally lack the information they need on the potential advantages of DDGS when utilized in conjunction with nutrient efficiency management practices. The industry faces challenges due to reports of neurological or digestive problems in animals which are likely to cause managers to be wary of including DDGS in diets. International marketing efforts currently underway by the U. S. Grains Council is boosting exports(20) but it remains to be seen if this can be enhanced given the large quantities of distiller's grains being produced by the rapid expansion of corn ethanol production.

Staff Recommendation

From the analysis presented above, it is evident that significant barriers to the widespread adoption of DDGS as livestock feed exist. The observed variability in DDGS properties will make it difficult for the livestock manager to ensure consistency in feed formulation. Transport and handling issues are likely to lead to inefficiencies in making DDGS available to the end user. One factor not discussed to this point is the price of DDGS. With rising corn prices from increased demand for ethanol, prices are likely to rise for DDGS. Higher prices render DDGS less cost-effective as a replacement feed, particularly where soybean meal is to be replaced.

Clearly, studies such as those cited by Michael Wang and others support the suitability of DDGS as replacement for both corn feed and soybean meal. Although Dr. Wang's analysis was based on a limited data set, the results were generalized to the entire livestock industry. For the reasons presented in this document, staff believes that it may not yet be appropriate to generalize from Dr. Wang's limited findings. In fact, DDGS appears to face significant barriers to widespread adoption as a replacement for corn and soybean meal. For this reason, staff feels that providing a co-product credit equating 1lb of DDGS to 1lb of feed corn is generous. As for the issue of reduced enteric fermentation resulting from shorter times in feedlots, there is no clear evidence that DDGS will be used in a manner detailed in the Dr. Wang article^{Error! Bookmark not defined.}. Given the limited information available on the optimal use of DDGS from a nutritional perspective and the logistical issues related to transporting and storing DDGS, staff is of the opinion that any claims of reduced enteric emissions are not clearly established by the limited research in this area. When the actual impact of the significant quantities of DDGS resulting from the production of 15 billion gallons of corn ethanol have been assessed, staff will re-visit this issue and make updates to the co-product credit, as appropriate.

Appendix C12 Greenhouse Gas Emissions from the Recovery of Various Crudes Used in California

Crude oil used in California refineries is derived from various sources: crude produced in California, imported from Alaska, and from overseas sources that is shipped via oil tankers from various countries of the world. Figure C12-1 shows the make-up of crude used by California refineries over the period 1982-2007(21). Data show the gradual decline in use of crude oil produced in California or imported from Alaska with the reductions being off-set by increased imports from overseas sources.

**Figure C12-1
Crude Make-up in CA from 1982-2007**

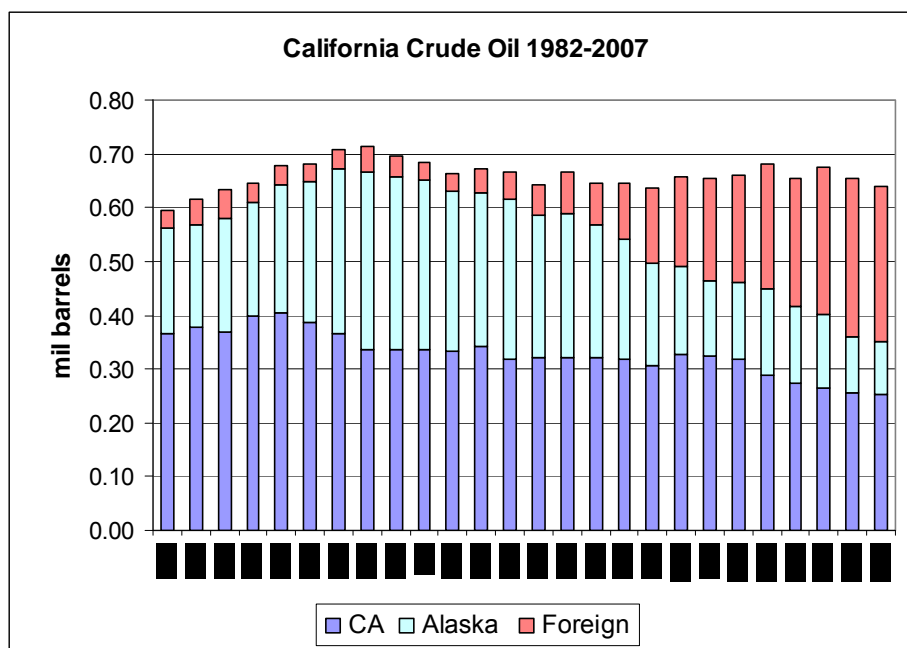


Table C12-1 shows the make-up of various crudes produced in California and those imported from outside California for 2006. For 2006, California produced 38.7% of its crude oil consumption internally and imported 61.2%. Of these imports, Alaska supplied 16.1% and overseas suppliers provided 45.1%. The table also shows detailed breakdown of the various types of feedstock recovered in California based on recovery technique. They include primary, gas injected, water flooding and thermal enhanced oil recovery (TEOR) methods. Table C12-2 shows details of imported crude from overseas locations into California in 2006.

**Table C12-1
Breakdown of Crude Supplied to California Refineries**

Source of Crude	Grade of Crude	Crude Recovery Method	% of CA Crude	CA Total %
CA	Heavy	TEOR	14.80%	38.7%
	Light to Medium	Water Flood	6.10%	
	Medium	Gas Injection	1.30%	
	Light	Primary	16.50%	
Imported	Alaska Light	Primary	16.10%	61.2%
	Venezuela Heavy	TEOR like	0.63%	
	Other Imported Light	Primary	44.44%	

**Table C12-2
Imported Crude into California in 2006 by Country(21)**

	Barrels	% of total imports	% of total CA crude
SAUDI ARABIA	86,976,000	29.45%	13.27%
ECUADOR	71,174,000	24.10%	10.86%
IRAQ	56,163,000	19.02%	8.57%
BRAZIL	17,938,000	6.07%	2.74%
MEXICO	15,473,000	5.24%	2.36%
ANGOLA	14,979,000	5.07%	2.29%
COLOMBIA	9,362,000	3.17%	1.43%
OMAN	6,326,000	2.14%	0.97%
VENEZUELA	4,120,000	1.40%	0.63%
ARGENTINA	3,484,000	1.18%	0.53%
Others:	9,311,000	3.15%	1.42%
Total Foreign Sources	295,306,000	100%	45.1%

The analysis presented here calculates the carbon intensity of crude recovery for the various crudes used in California. It then calculates a weighted average carbon

intensity from these individual crudes. The CA-GREET model was used to calculate the carbon intensity for all the crudes processed by California refineries.

Crude recovery is modeled in the original Argonne GREET model(22) based on an efficiency of recovery. A value of 98% recovery efficiency used by the GREET model does not distinguish between the various grades of crude used by U. S. Refineries. However, for the LCFS, staff with assistance from Life Cycle Associates disaggregated the various crudes processed by California refineries. Energy use for crude recovery was broken down by the different sources of crude supplied to California:

- Crude imported from Alaska;
- Crude imported from overseas countries; and
- California produced crude

Crude imported from Alaska was assumed to have the same recovery efficiency (98%) as the original Argonne GREET model default. For imported crude, this 98% recovery efficiency was assumed, except for Venezuelan crude (0.63% of California mix). Due to lack of available data for Venezuelan crude, extraction and processing emissions were assumed to be similar to heavy oil recovery and processing in GREET. The GHG emissions associated with heavy oil recovery were based on the GREET calculations for oil sands assuming that the fuel source was bitumen. Processing energy use was assumed to be equivalent to hydrogen production in GREET for heavy oil processing.

Crude produced in California was disaggregated based on recovery techniques and is classified as:

- Primary;
- Gas-injected;
- Water injected; and
- Thermal Enhanced Oil Recovery (with and without co-generation).

The energy inputs for gas injection are based on data presented in the EPRI study of California oil production options (23). The electricity input corresponds to a 93.5% production efficiency. The energy efficiency for water flooding was assumed to be 97% compared with the baseline value of 98% for conventional crude oil. This assumption is based on the estimate (by Life Cycle Associates) that pumping energy is 1% of total crude extraction energy requirement and that water flooding would double this energy requirement.

Thermal enhanced oil recovery (TEOR) processes include the injection of steam into the oil reservoir. The analysis presented here aggregates all the TEOR produced to be representative from three major fields in California: Midway-Sunset, Kern River, and South Belridge and data used was from the Department of Oil, Gas and Geothermal Resources(24). Together they account for more than 80% of the total crude produced using steam in California. The Kern River represents a high efficiency, low SOR

(Steam-Oil-Ratio⁴) case and the Midway-Sunset / South Belridge cases represent a lower efficiency, higher-SOR case. The two cases used were weighted as follows: because the Kern River field alone represents 1/3 of California TEOR production, we assume that the Kern River case represents 40% of production (i.e., Kern River plus other high efficiency/low SOR fields represent together 40% of total TEOR production). The Midway-Sunset /South Belridge case is assigned to represent the other 60% of California TEOR production.

The inputs to these two cases and the weighted outputs are presented in Table C12-3. The resulting GREET inputs are shown in Table C12-4.

Table C12-3
Parameters Used and Resulting Specific Energies

Parameter	OTSG		Cogeneration	
	Kern River	MS/SB	Kern River	MS/SB
Steam generation eff. (η_{steam})	85.0%	82.5%	34.0%	39.2%
Power generation eff (η_{elect})	NA	NA	30.2%	26.9%
Cogeneration efficiency	NA	NA	64.2%	66.1%
Steam oil ratio (SOR)	3.08	5.13	3.08	5.13
Energy content of steam (η_{steam})	0.30	0.320	0.30	0.32
Fuel energy (mmBtu/bbl inc. oil)	1.09	1.99	2.72	4.19
Electricity co-produced (mmBtu/bbl inc. oil)	0.0	0.0	0.82	1.13
SE Natural gas (J/J oil)	0.187	0.341	0.444	0.682
SE Coal (J/J oil)	0.0	0.0	0.023	0.036
SE Electricity (J/J oil)	0.012	0.012	0.012	0.012
SE Net electric output (J/J oil)	0.0	0.0	0.129	0.182

Table C12-4
CA-GREET Inputs From Two Cases and Weighted Total

Specific energy inputs ^a	OTSG			Cogeneration		
	Kern	MW/SB	Weighted total	Kern	MW/SB	Weighted total
Crude oil extraction efficiency (η_{oil})	83.5%	73.9%	77.7%	67.6%	57.8%	61.7%
Fuel share NG	94.1%	96.7%	95.6%	92.7%	93.5%	93.2%
Fuel share Coal	0.0%	0.0%	0.0%	4.9%	4.9%	4.9%
Fuel share Electricity	5.9%	3.3%	4.4%	2.4%	1.6%	1.9%

The specific energy inputs for cogeneration systems are higher, resulting in smaller overall efficiencies of oil extraction. This increased energy intensity (higher GHG emissions) is offset by credits for the co-produced electric power (GHG emission credits).

⁴ The SOR is the steam volume (in barrels of water equivalent) required to induce production of a barrel of incremental oil.

Calculation of GHG emissions using CA-GREET:

The fuel share by fuel type and overall efficiency η_{oil} calculated above in Table C12-4 is used to generate the GHG impacts of TEOR production using CA-GREET. These emissions are then included in the statewide overall fuel mix using the 40% cogeneration, 60% OTSG weighting described above. The electricity co-produced is given a credit based on marginal California natural-gas-based power production. The detailed GHG emissions are shown in Table C12-5.

Table C12-5
CA-GREET Emissions Outputs

	Unit	OTSG	Cogen
Total GHGs	g-CO ₂ e/mmBtu	19,634	39,573
Total GHGs	g-CO ₂ e/MJ	18.61	37.51
Electricity Credit	g-CO ₂ e/MJ	0.00	-18.51
Extraction emissions	g-CO ₂ e/MJ	18.74	19.13

In summary, weighted emissions from TEOR-based oil production are calculated from CA-GREET to be 18.74 and 19.13 gCO₂-eq./MJ. When weighted with 60% OTSG and 40% Co-gen, the total TEOR related GHG emissions are 18.89 gCO₂e/MJ.

This is then combined with the other crudes produced in California and imported crude. Table C12-6 below provides details on the individual contributions and the total carbon intensity of average crude used by California refineries.

Table C12-6
Detailed Breakdown of GHG Emissions from Recovery of Crudes
used in California in 2006 (gCO₂e/MJ)

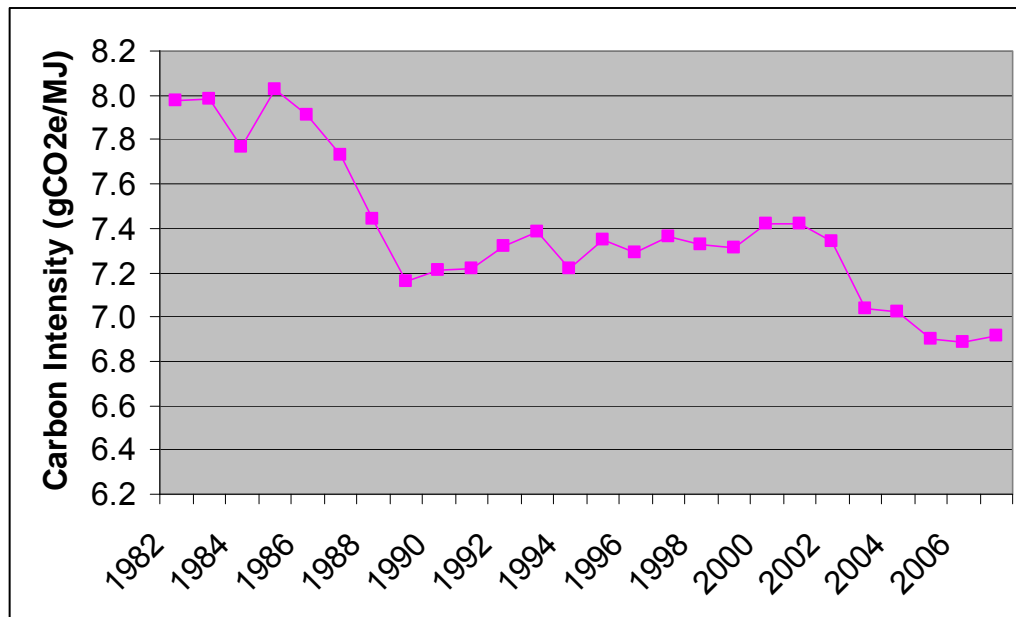
	California Crude						Imported			
	OTSG	Co-gen	Total TEOR	Water Flood	Gas Inject	Primary	Alaska	Other Imported	Venezuela	Average Carbon Intensity
Crude Transport to CA Refineries	0.13	0.13		0.11	0.11	0.11	0.65	1.29	0.97	
Crude Recovery	18.61	37.51		5.57	12.75	4.20	3.71	3.36	20.98	
C-Gen Electricity Credit		-18.51								
Net Carbon Intensity	18.74	19.13	18.89	5.68	12.86	4.31	4.36	4.65	21.95	6.93

Note: Both OTSG and Co-Gen refer to Thermal Enhanced Oil Recovery methods used in California. For California TEOR recovered crude, 60% was from OTSG and 40% from Co-gen. OTSG refers to once-through steam generator with no co-generation employed at the site.

Using this analysis, staff calculated the change in average carbon intensity for crudes used in California between 1982-2006. Details of crude supplies are from the Energy Almanac(21). Figure C12-2 below shows the plot for average crude recovery carbon

intensity used in California for this period. The plot shows that carbon intensity has been declining over this time period generally as a result of lower production of heavier crudes in California and increasing imports of lighter crudes from overseas sources.

Figure C12-2
Carbon Intensity for Crude Recovery for Average Crude used in California



(note: % breakdown of California crudes is assumed to be the same for all years as shown in Table 2. Energy inputs for steam generation for thermally enhanced oil recovery is assumed to be constant over time.)

References:

1. TIAX (2007). Full Fuel Cycle Assessment Well to Tank Energy Inputs, Emissions, and Water Impacts. California Energy Commission.
2. Michael O'Hare and et al. (2009). Proper accounting for time increases crop-based biofuels' GHG deficit versus petroleum. UC Berkeley.
3. S. Solomon and et al. (2007). Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change. Intergovernmental Panel on Climate Change.
4. NASS (2009). Agricultural Prices. US Department of Agriculture.
5. R. Keeney and T. W. Hertel (2008). Indirect Land Use Impacts of US Biofuels Policies: The Importance of Acreage, Yield and Bilateral Trade Responses. GTAP Working Paper 52. Purdue University.
6. USDA (2009). Agricultural Outlook: Statistical Indicators. US Department of Agriculture.
7. Salil Arora, May Wu, and Michael Wang (2008). Update of Distillers Grains Displacement Ratios for Corn Ethanol Life-Cycle Analysis. Argonne National Laboratory.
8. Kent Tjardes and Cody Wright (2002). Feeding Corn Distiller's Co-Products to Beef Cattle. San Diego State University.
9. R. Lemenager and et al. (2006). The Value of Distillers' Grains as a Livestock Feed. Purdue University.
10. T. J. Klopfenstein (1991). "Efficiency of escape protein utilization." *Proc. Distillers Feed Res. Council* 46: 77-82.
11. G. L. Cromwell, K. L. Herkelman, and T. S. Stahly (1993). "Physical, chemical, and nutritional characteristics of distillers dried grains with solubles for chicks and pigs." *J. Anim. Sci* 71: 679-686.
12. F. M. Dong, B. A. Rasco, and S. S. Gazzaz (1987). "A protein quality assessment of wheat and corn distillers dried grains with solubles." *Cereal Chemistry* 64: 327-332.
13. A. S. Chaudhry and A. J. F. Webster (1993). "The true digestibility and biological value for rats of undegraded dietary nitrogen in feeds for ruminants." 42: 209-221.
14. T. Nakamura, et al. (1994). "Growth efficiency and digestibility of heated protein fed to growing ruminants." *J. Anim. Sci.* 72: 774-782.
15. S. Uwituze (2008). The effects of feeding dry distiller's grains with solubles on ruminal metabolism, growth performance, and carcass traits of feedlot cattle. Kansas State University.
16. T. J. Vasconcelos and M. L. Galyean (2007). "Nutritional recommendations of feedlot consulting nutritionists: The Texas Tech University survey." 85: 2772-2781.
17. F. J. Dooley (2008). Market analysis for dried distillers grains in Indiana. Purdue University.

18. Michael R. Lehman and Kurt A. Rosentrater (2007). "Microbial development in distillers wet grains produced during fuel ethanol production from corn (*Zea mays*)." *Can J. Microbiology* 53: 1046-1052.
19. Kurt A. Rosentrater Ethanol Processing Co-Products: Economics, Impacts, Sustainability. US Department of Agriculture.
20. Mike Deering and Marri Carrow. (2009). "Global Update: February 19, 2009." Retrieved, from <http://www.grains.org/global-update/1375-global-update-february-19-2009>.
21. CEC. (2008). "Energy Almanac." Retrieved, from <http://energyalmanac.ca.gov/>.
22. Argonne (2008). The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) Model. Argonne National Laboratory.
23. EPRI (1999). Enhanced Oil Recovery Scoping Study. Electric Power Research Institute.
24. DOC. (2009). "Oil, Gas & Geothermal - DOGGR Home Page." Retrieved, from <http://www.conservation.ca.gov/dog/Pages/Index.aspx>.

Appendix D
LCFS Credit Calculations

THIS PAGE IS INTENTIONALLY LEFT BLANK

This appendix provides sample calculations of LCFS credits, deficits and credit balance. Subsection A. lists illustrative examples of credits and deficits generated by fuels and blendstocks provided by a regulated party. Examples of credit balance calculations are listed in subsection B. All credits and deficits are denominated in units of metric tons of carbon dioxide equivalent (“MT”).

Note: All data and scenarios in the examples are hypothetical presented for illustrative purposes only.

The Tables 1, 2, 4, and 5, below are from the proposed LCFS regulation and provide inputs for the calculations below. The table numbering from the regulation has been preserved for ease of cross-referencing. Tables unique to this appendix are numbered with appendix number (D) followed by the table number (starting with 1).

**Table 1 [from Section 95482(b)]
LCFS Compliance Schedule for 2011 to 2020 for Gasoline and
Fuels Used as a Substitute for Gasoline.**

Year	Average Carbon Intensity (gCO₂e/MJ)	% Reduction
2010	Reporting Only	
2011	95.61	0.25%
2012	95.37	0.5%
2013	94.89	1.0%
2014	94.41	1.5%
2015	93.45	2.5%
2016	92.50	3.5%
2017	91.06	5.0%
2018	89.62	6.5%
2019	88.18	8.0%
2020	86.27	10.0%

**Table 2 [from Section 95482(c)]
LCFS Compliance Schedule for 2011 to 2020 for Gasoline and
Fuels Used as a Substitute for Gasoline.**

Year	Average Carbon Intensity (gCO₂e/MJ)	% Reduction
2010	Reporting Only	
2011	94.47	0.25%
2012	94.24	0.5%
2013	93.76	1.0%
2014	93.29	1.5%
2015	92.34	2.5%
2016	91.40	3.5%
2017	89.97	5.0%
2018	88.55	6.5%
2019	87.13	8.0%
2020	85.24	10.0%

**Table 4 [from section 95485(a)]
Energy Densities of LCFS Fuels and Blendstocks.**

Fuel (units)	Energy Density
CARBOB (gal)	119.53 (MJ/gal)
CaRFG (gal)	115.63 (MJ/gal)
Diesel fuel (gal)	134.47 (MJ/gal)
CNG (scf)	0.98 (MJ/scf)
LNG (gal)	78.83 (MJ/gal)
Electricity (KWh)	3.60 (MJ/KWh)
Hydrogen (kg)	120.00 (MJ/kg)
Neat denatured Ethanol (gal)	80.53 (MJ/gal)
Neat Biomass-based diesel (gal)	126.13 (MJ/gal)

**Table 5 [from section 95485(a)]
EER Values for Fuels Used in
Light- and Medium-Duty, and Heavy-Duty Applications**

Light/Medium-Duty Applications (Fuels used as gasoline replacement)		Heavy-Duty/Off-Road Applications (Fuels used as diesel replacement)	
Fuel/Vehicle Combination	EER Values Relative to Gasoline	Fuel/Vehicle Combination	EER Values Relative to Diesel
Gasoline (incl. E6 and E10) or E85 (and other ethanol blends)	 1.0	Diesel fuel or Biomass-based diesel blends	 1.0
CNG / ICEV	1.0	CNG or LNG	0.9
Electricity / BEV, or PHEV	3.0	Electricity / BEV, or PHEV	2.7
H2 / FCV	2.3	H2 / FCV	1.9

(BEV = battery electric vehicle, PHEV=plug-in hybrid electric vehicle, FCV = fuel cell vehicle, ICEV = internal combustion engine vehicle)

A. Sample Calculations for Credits and Deficits Generated

Example D1. Electricity General

In 2011, an electricity Load Servicing Entity (LSE) provided 10,000 KWh of electricity for transportation use. All of this electricity is used in heavy-duty applications (and hence, displaces diesel fuel).

A comparison of an electric vehicle to a conventional diesel vehicle shows an EER of 2.7 (see section 95485(a) Table 5).

The average carbon intensity requirement for diesel fuel in 2011 is 94.47gCO₂e/MJ (see section 95482 (c) Table 2). The GREET carbon intensity value for electricity provided is 124.10 gCO₂e/MJ. The energy density for electricity is 3.60 MJ/KWh (see section 95485 Table 4). Calculate the credit awarded to the LSE for providing the fuel electricity.

Step 1:

$$(Credits\ or\ Deficits)^{XD} = (CI_{standard}^{XD} - CI_{reported}^{XD}) \times E_{displaced}^{XD} \times C$$

[from section 95485(a)(3)(A) of proposed regulation]

$$CI_{reported}^{XD} = \frac{CI_i}{EER_i^{XD}} \text{ [from section 95485(a)(3)(B) of proposed regulation]}$$

$$E_{displaced}^{XD} = E_i \times EER_i^{XD} \text{ [from section 95485(a)(3)(C) of proposed regulation]}$$

The known values are:

$$CI_{standard}^{Diesel} = 94.47 \text{ gCO}_2\text{e/MJ}$$

$$CI_{Electricity} = 124.10 \text{ gCO}_2\text{e/MJ}$$

$$EER_{Electricity}^{Diesel} = 2.7$$

$$C = 1.0 \times 10^{-6} \frac{(MT)}{(gCO_2e)}$$

$$\text{Energy Density of Electricity} = 3.60 \text{ MJ/KWh}$$

Step 2:

Estimate adjusted carbon intensity, $CI_{reported}^{Gasoline}$, and diesel fuel energy displaced, $E_{displaced}^{Gasoline}$ using the EER value of 2.7.

The adjusted carbon intensity value for electricity provided, in gCO₂e/MJ, is

$$CI_{reported}^{Diesel} = \frac{CI_{Electricity}}{EER_{Electricity}^{Diesel}} = (124.10 \text{ gCO}_2\text{e/MJ}) / 2.7 = 45.96 \text{ gCO}_2\text{e/MJ}$$

The amount of electricity provided as a diesel fuel replacement, in MJ, is

$$E_{displaced}^{Diesel} = E_{Electricity} \times EER_{Electricity}^{Diesel} = (10,000 \text{ KWh} * 3.6 \text{ MJ/KWh}) \times 2.7 = 97,200 \text{ MJ}$$

Step 3:

Since the adjusted carbon intensity of electricity is lower than the diesel carbon intensity standard, the electricity fuel will generate credits.

$$\boxed{Credits_{Electricity}^{Diesel} = (CI_{standard}^{Diesel} - CI_{reported}^{Diesel}) \times E_{displaced}^{Diesel} \times C}$$

Numerically,

$$Credits_{Electricity}^{Diesel} = [(94.47 - 45.96) \times (9.72 \times 10^4) \times (1.0 \times 10^{-6})] = 5 \text{ MT}$$

Notice that the credits are reported to the nearest whole metric ton of CO₂e.

Step 4:

Since the LSE is only supplying electricity as a diesel fuel substitute, total credits generated by this regulated party in 2011 are:

$$Credits^{GEN} = Credits^{Diesel} = 5 \text{ MT}$$

Example D2. Electricity Plug-in Hybrid Electric Vehicle

In 2020, an electricity LSE is providing 10 million KWh of electricity for transportation use. All of this electricity is used in light-duty applications (and hence, displaces gasoline).

Use the following values:

$$CI_{standard}^{Gasoline} = 86.27 \text{ gCO}_2\text{e/MJ};$$

$$CI_{Electricity} = 124.10 \text{ gCO}_2\text{e/MJ};$$

$$EER_{Electricity}^{Gasoline} = 3.0;$$

$$C = 1.0 \times 10^{-6} \frac{(MT)}{(gCO_2e)}; \text{ and}$$

$$Energy \text{ Density of Electricity} = 3.60 \text{ MJ/KWh}$$

In this case, all electricity is provided as a gasoline substitute, thus the LSE will use gasoline standard.

Step 1:

Estimate adjusted carbon intensity, $CI_{reported}^{Gasoline}$, and diesel fuel energy displaced, $E_{displaced}^{Gasoline}$ using the EER value of 3.0.

The amount of electricity provided as a gasoline fuel replacement, in MJ, is

$$E_{displaced}^{Gasoline} = E_{Electricity} \times EER_{Electricity}^{Gasoline} = (1 \times 10^7 \text{ KWh} \times 3.6 \text{ MJ/KWh}) \times 3.0 = 1.08 \times 10^8 \text{ MJ}$$

The adjusted carbon intensity value for electricity provided, in gCO₂e/MJ, is

$$CI_{reported}^{Gasoline} = \frac{CI_{Electricity}}{EER_{Electricity}^{Gasoline}} = 124.10 / 3.0 = 41.37 \text{ gCO}_2\text{e/MJ}$$

Step 2:

Since the adjusted carbon intensity of electricity is lower than the gasoline carbon intensity standard, the electricity fuel will generate credits.

$$Credits_{Electricity}^{Gasoline} = (CI_{standard}^{Gasoline} - CI_{reported}^{Gasoline}) \times E_{displaced}^{Gasoline} \times C$$

Numerically,

$$Credits_{Electricity}^{Gasoline} = [(86.27 - 41.37) \times (1.08 \times 10^8) \times (1.0 \times 10^{-6})] = 4,849 \text{ MT}$$

Step 3:

Since the LSE is only supplying one fuel i.e. electricity, total credits generated by this regulated party in 2020 are:

$$Credits^{GEN} = Credits^{Gasoline} = 4,849 \text{ MT}$$

Example D3. California Reformulated Gasoline (CaRFG)

In 2015, a regulated party produces 80 million barrels of CARBOB in a quarter. The regulated party blends 5 million barrels of corn ethanol and 4 million barrels of cellulosic ethanol with the CARBOB to produce E10.

Use the following values:

Average carbon intensity requirement for gasoline fuel in 2015 from Table 1 section 95482(a):

$$CI_{standard}^{Gasoline} = 93.45 \text{ gCO}_2\text{e/MJ}$$

Energy densities from Table 4 section 95485(a):

CARBOB: 119.53 MJ/gal

Ethanol: 80.53 MJ/gal

Carbon intensity values from Table ES-6:

$$CI_{CARBOB} : 95.86 \text{ gCO}_2\text{e/MJ}$$

$$CI_{CornEthanol} \text{ (California; Dry Mill, Wet DGS; NG): } 80.70 \text{ gCO}_2\text{e /MJ}$$

$$CI_{SugarcaneEthanol} \text{ (Brazilian Sugarcane): } 73.40 \text{ gCO}_2\text{e /MJ}$$

Unit conversions:
 $C = 1 \times 10^{-6} \text{ MT/gCO}_2\text{e}$
 42 gal/barrel

The EER for gasoline (E_{10}) = 1.0 (from section 95485(a) Table 5)

Step 1:

Convert all volumes to energy units (E_i)

$$E_{CARBOB} : \left(80 \times 10^6 \text{ barrels} \right) \left(42 \frac{\text{gal}}{\text{barrel}} \right) \left(119.53 \frac{\text{MJ}}{\text{gal}} \right) = 4.02 \times 10^{11} \text{ MJ}$$

$$E_{\text{CornEthanol}} : \left(5 \times 10^6 \text{ barrels} \right) \left(42 \frac{\text{gal}}{\text{barrel}} \right) \left(80.53 \frac{\text{MJ}}{\text{gal}} \right) = 1.69 \times 10^{10} \text{ MJ}$$

$$E_{\text{SugarcaneEthanol}} : \left(4 \times 10^6 \text{ barrels} \right) \left(42 \frac{\text{gal}}{\text{barrel}} \right) \left(80.53 \frac{\text{MJ}}{\text{gal}} \right) = 1.35 \times 10^{10} \text{ MJ}$$

Step 2:

Since EER value for E10 is 1.0, the amount of each blendstock provided as gasoline replacement ($E_{displaced}^{Gasoline}$) is same as the amount calculated in energy units, MJ, above.

$$E_{displaced}^{Gasoline} = E_i \times EER_i^{Gasoline} = E_i \times 1.0 = E_i$$

Since the EER for E10 is 1.0, the adjusted carbon intensity for each blendstock is same as carbon intensity values provided above.

$$CI_{reported}^{Gasoline} = \frac{CI_i}{EER_i^{Gasoline}} = \frac{CI_i}{1.0} = CI_i$$

Step 3:

Since the gasoline standard for 2015 is 93.45 gCO₂e/MJ, the credits/deficits generated according to Eqn. V.5 are:

CARBOB:

Since carbon intensity of CARBOB is higher than the gasoline standard, deficits are generated

$$\boxed{\text{Deficits}_{CARBOB}^{Gasoline} = \left(CI_{standard}^{Gasoline} - CI_{reported}^{Gasoline} \right) \times E_{displaced}^{Gasoline} \times C}$$

$$= [(93.45-95.86) \times (4.02 \times 10^{11}) \times (1.0 \times 10^{-6})] = -968,820 \text{ MT}$$

Corn Ethanol:

Since carbon intensity of corn ethanol is lower than the gasoline standard, credits are generated

$$\boxed{Credits_{CornEthanol}^{Gasoline} = (CI_{standard}^{Gasoline} - CI_{reported}^{Gasoline}) \times E_{displaced}^{Gasoline} \times C}$$

$$= [(93.45-80.70) \times (1.69 \times 10^{10}) \times (1.0 \times 10^{-6})] = 215,475 \text{ MT}$$

Sugarcane Ethanol:

Since carbon intensity of sugarcane ethanol is lower than the gasoline standard, credits are generated.

$$\boxed{Credits_{CornEthanol}^{Gasoline} = (CI_{standard}^{Gasoline} - CI_{reported}^{Gasoline}) \times E_{displaced}^{Gasoline} \times C}$$

$$= [(93.45-73.4) \times (1.35 \times 10^{10}) \times (1.0 \times 10^{-6})] = 270,675 \text{ MT}$$

Step 4:

For this gasoline provider, the total credits and deficits generated in this quarter are the same as credits and deficits generated under the gasoline standard by all blendstocks.

$$Credits^{Gen}(MT) = Credits_{CornEthanol}^{Gasoline} + Credits_{SugarcaneEthanol}^{Gasoline} = 486,150 \text{ MT}$$

$$Deficits^{Gen}(MT) = Deficits_{CARBOB}^{Gasoline} = -968,820 \text{ MT}$$

Example D4. Provider of Multiple Fuels

A regulated party is providing E10 (CaRFG), CNG, hydrogen and E85 in the year 2015. All fuels are assumed to be gasoline replacements only. The carbon intensities and quantities of the fuels and blendstocks provided on an annual basis are shown in Table D-1. All fuel quantities are assumed to have been converted to energy using appropriate energy densities provided in section 95485(a) Table 4 of the proposed regulation.

Refer to section 95485(a) Table 5 of the proposed regulation for EER value of each fuel relative to gasoline.

Using average carbon intensity requirement of 93.45 gCO₂e/MJ calculate total credits and deficits generated by the regulated party for the supply of all fuels collectively.

Step 1:

Calculate adjusted carbon intensity, $CI_{reported}^{Gasoline}$, and gasoline energy displaced, $E_{displaced}^{Gasoline}$, for each fuel and blendstock as shown in Table D-1 below.

Table D-1
Data and Formulas Used in Example D4.

				$CI_{reported}^{Gasoline} =$	$E_{displaced}^{Gasoline} =$
	E_i (MJ)	CI_i (g/MJ)	$EER_i^{Gasoline}$	$CI_i / EER_i^{Gasoline}$ (g/MJ)	$E_i \times EER_i^{Gasoline}$ (MJ)
E10 and E85*					
CARBOB	1,021,000,000	95.86	1.0	95.86	1,021,000,000
Ethanol (Corn)	122,000,000	80.70	1.0	80.70	122,000,000
Ethanol (Sugarcane)	32,000,000	73.40	1.0	73.40	32,000,000
CNG					
CA Average	70,000,000	67.70	1.0	67.70	70,000,000
North American CNG	30,000,000	68.00	1.0	68.00	30,000,000
Hydrogen					
Compressed H2 from on-site reforming of NG	50,000,000	98.30	2.3	42.74	115,000,000

* Note. For gasoline (E10) and E85, since both the EER values are 1.0, the CARBOB and ethanols used to produce both fuels do not have to be separated. E_i values shown are total values used to produce both E10 and E85.

Step 2:

Since the gasoline standard for 2015 is 93.45 gCO₂e/MJ, the credits/deficits generated according to Eqn. V.5 are:

CARBOB: $Deficits_{CARBOB}^{Gasoline} = - 2,461 \text{ MT}$

Corn Ethanol: $Credits_{CornEthand}^{Gasoline} = 1,556 \text{ MT}$

Sugarcane Ethanol: $Credits_{CornEthand}^{Gasoline} = 642 \text{ MT}$

California CNG: $Credits_{CornEthand}^{Gasoline} = 1,803 \text{ MT}$

North American CNG: $Credits_{CornEthand}^{Gasoline} = 764 \text{ MT}$

Hydrogen: $Credits_{CornEthand}^{Gasoline} = 5,832 \text{ MT}$

Step 3:

For this gasoline provider, the total credits and deficits generated are the same as credits and deficits generated under the gasoline standard by all blendstocks. According to Eqns. V.3 and V.4:

$$Credits^{Gen}(MT) = \sum_i^n Credits_i^{gasoline} = 10,597 \text{ MT}$$

$$Deficits^{Gen}(MT) = \sum_i^n Deficit_i^{gasoline} = -2,491 \text{ MT}$$

B. Calculating Credit Balance

Example D5:

A regulated party purchases sugarcane ethanol with a carbon intensity value of 73.40 gCO₂e/MJ and blends it with CARBOB with carbon intensity of 95.86 gCO₂e/MJ to produce gasoline and E85. The carbon intensity standards for gasoline and the volumes of CARBOB and ethanol between 2011 and 2020 are shown in Table D-2. The regulated party chooses to bank all credits generated and does not elect to acquire, sell, export, or retire any credits.

Determine:

1. The amount of total credits/deficits generated each year pursuant to section 95485(a) of the proposed regulation (Appendix A) in units of metric ton CO₂ equivalent (MT). In which year a net deficit is generated by the supply of gasoline the first time?
 2. The credit balance for each year. In which year the credit balance is negative the first time?
-

Step 1:

The credits and deficits generated each year are calculated as per Eqn. V-5 using the methodology illustrated in Examples D1 through D4 above.

Since carbon intensity of CARBOB is higher than the gasoline standard for all years, CARBOB generates deficits each year. Sugarcane ethanol on the other hand generates credits each year.

Table D-2 shows credits and deficits generated by the regulated party each year. Refer to 'Net Credit/Deficit Generated' column in Table D-1. The regulated party generates a net credit each year until the year 2014. A net deficit is incurred in 2015 the first time. This happens because the deficits generated by CARBOB exceed the credits generated by sugarcane ethanol in 2015. Each year thereafter the regulated party incurs a net deficit as the gasoline standard becomes more and more stringent.

Table D-2
Total LCFS Credits and Deficits Generated Between 2011 and 2020.

Year	Gasoline Standard CI (gCO ₂ e/MJ)	Total CARBOB (Mgal)	Total Ethanol (Mgal)	Deficits CARBOB (MT)	Credits Ethanol (MT)	Net Credit/Deficit Generated (MT)
2011	95.61	138.82	14.43	-4148	25809	21661
2012	95.37	138.64	14.42	-8120	25512	17392
2013	94.89	137.71	14.31	-15967	24765	8798
2014	94.41	136.92	14.20	-23731	24025	294
2015	93.45	136.22	14.70	-39241	23735	-15506
2016	92.50	133.42	16.42	-53584	25256	-28328
2017	91.06	130.91	18.42	-75109	26196	-48913
2018	89.62	126.33	22.20	-94225	28998	-65227
2019	88.18	121.94	26.24	-111940	31232	-80708
2020	86.27	117.13	30.81	-134265	31932	-102333

Step 2:

To determine whether the regulated party is in violation of the proposed LCFS regulation, a total credit balance that takes into consideration the total amounts of credits acquired, carried over, sold, exported, or retired must be evaluated.

Pursuant to section 95484(b)(2) of the proposed regulation,

$$\begin{aligned} \text{CreditBalance} = & \text{Credits}^{\text{Gen}} + \text{Credits}^{\text{CarriedOver}} + \text{Credits}^{\text{Acquired}} \\ & + \text{Deficits}^{\text{Gen}} - \text{Credits}^{\text{Sold}} - \text{Credits}^{\text{Exported}} - \text{Credits}^{\text{Retired}} \end{aligned}$$

Table D-3 lists the credit balance of the regulated party each year.

Table D-3
Credit Balance Between 2011 and 2020 for Example D5.

Year	Credits Generated (MT)	Credits CarriedOver (MT)	Credits Acquired (MT)	Deficits Generated (MT)	Credits Sold (MT)	Credits Exported (MT)	Credits Retired (MT)	Credit Balance (MT)
	A	B	C	D	E	F	G	A+B+C+D-E-F-G
2011	25809	0	0	-4148	0	0	0	21661
2012	25512	21661	0	-8120	0	0	0	39053
2013	24765	39053	0	-15967	0	0	0	47851
2014	24025	47851	0	-23731	0	0	0	48145
2015	23735	48145	0	-39241	0	0	0	32639
2016	25256	32639	0	-53584	0	0	0	4311
2017	26196	4311	0	-75109	0	0	0	-44602
2018	28998	-44602	0	-94225	0	0	0	-109829
2019	31232	-109829	0	-111940	0	0	0	-190537
2020	31932	-190537	0	-134265	0	0	0	-292870

Table D-3 shows that the credit balance of the regulated party is positive each year until 2016. 2017 is the first year with a negative credit balance. Each year thereafter the credit balance is negative.

Data in Tables D-2 and D-3 shows that although a net deficit was generated by the supply of gasoline in 2015 and 2016, the regulated party is able to maintain a positive credit balance in these two years by simply using banked credits from earlier years. In 2017 the banked credits are not able to compensate for the deficit generated resulting in a negative credit balance for that year.

Example D6.

The same regulated party above has decided to export all net credits generated in the first 3 years to another GHG program.

Using the same data as the Example D5, determine:

1. Will there be enough credits to maintain a positive credit balance in 2015 when the first net deficit is generated?
2. Does the regulated party incur a penalty in 2015?

Step 1:

Since all volumes, blendstock carbon intensities values, and required carbon intensities values are the same as in Example D5, the credits/deficits calculated for sugarcane ethanol and CARBOB, and the net credit/deficit generated each year are the same as in Table D-2. However, since the regulated party elected to export net credits generated within the first 3 years, the credit balance for each year is different.

Table D-4 shows the credit balance for each year between 2011 and 2020. The credit balance is zero for the first three years since the regulated party exported all net credits.

In 2015, the regulated party generates a deficit of -15,506 MT (Table D-2) but only has 294 MT of carried over credits from the previous year. This creates an overall negative credit balance of -15,212 MT (Table D-4).

Table D-4
Credit Balance Between 2011 and 2020 for Example D6.

Year	Credits Generated (MT)	Credits CarriedOver (MT)	Credits Acquired (MT)	Deficits Generated (MT)	Credits Sold (MT)	Credits Exported (MT)	Credits Retired (MT)	Credit Balance (MT)
	A	B	C	D	E	F	G	A+B+C+D-E-F-G
2011	25809	0	0	-4148	0	21661	0	0
2012	25512	0	0	-8120	0	17392	0	0
2013	24765	0	0	-15967	0	8798	0	0
2014	24025	0	0	-23731	0	0	0	294
2015	23735	294	0	-39241	0	0	0	-15212
2016	25256	-15212	0	-53584	0	0	0	-43540
2017	26196	-43540	0	-75109	0	0	0	-92453
2018	28998	-92453	0	-94225	0	0	0	-157680
2019	31232	-157680	0	-111940	0	0	0	-238388
2020	31932	-238388	0	-134265	0	0	0	-340721

Step 2:

Since the regulated party has a negative credit balance in 2015, a compliance determination using credit-deficit ratio is triggered. The credit-to-deficit ratio is computed as follows:

$$\text{Credit-to-deficit Ratio} = \text{abs}[(23735+294)/(-39241)] * 100\% = 61\%$$

Pursuant to section 95484 (b)(4) of the proposed regulation, the regulated party is in violation and incurs a penalty since the credit-to-deficit ratio is less than

90%. In addition, the regulated party must clear the deficit of 2015 by end of next year.

Example D7.

The same regulated party above decided to purchase 12,000 MT credits in 2015. Using the same data as the Example D6, determine:

1. Did the regulated party meet the LCFS credit obligations in 2015?
2. What are the obligations in 2016?

The new credit balance is shown in Table D-5 below.

Table D-5
Credit Balance Between 2011 and 2020 for Example D7.

Year	Credits Generated (MT)	Credits CarriedOver (MT)	Credits Acquired (MT)	Deficits Generated (MT)	Credits Sold (MT)	Credits Exported (MT)	Credits Retired (MT)	Credit Balance (MT)
	A	B	C	D	E	F	G	A+B+C+D-E-F-G
2011	25809	0	0	-4148	0	21661	0	0
2012	25512	0	0	-8120	0	17392	0	0
2013	24765	0	0	-15967	0	8798	0	0
2014	24025	0	0	-23731	0	0	0	294
2015	23735	294	12000	-39241	0	0	0	-3212
2016	25256	-3212	0	-53584	0	0	0	-31540
2017	26196	-31540	0	-75109	0	0	0	-80453
2018	28998	-80453	0	-94225	0	0	0	-145680
2019	31232	-145680	0	-111940	0	0	0	-226388
2020	31932	-226388	0	-134265	0	0	0	-328721

Step 1:

As shown above the 12,000 MT credits acquired by the regulated party fell short of bridging the credit gap for that year. Thus, the regulated party has a negative credit balance in 2015 triggering a credit-to-deficit ratio computation.

The credit-to-deficit ratio is:

$$\text{Credit-to-deficit Ratio} = \text{abs}[(23735+294+12000)/(-39241)] * 100\% = 92\%$$

Pursuant to section 95484 (b)(4) of the proposed regulation, since the regulated party did not incur a deficit in the previous year (+ 294 MT in 2014), and the credit-to-deficit ratio in 2015 is >90%, the regulated party is in deficit with the LCFS I 2015 but does not have to pay penalty. The regulated party may carry

over the deficit of -3,212 MT in 2015 to 2016 without penalty. However, this deficit must be cleared in 2016.

Step 2:

In the year 2016, by supplying gasoline the regulated party generates a net deficit of -28,328 MT (Table D-2). Combining the previous year's carried over deficit of -3,212 MT, the regulated party now has a credit balance of -31,540 MT. A negative credit balance for two or more consecutive years constitute a violation of the LCFS. The regulated party must clear the violation by acquiring an additional minimum -31,540 MT credits, and paying a penalty.

This page intentionally left blank

Appendix E

Supporting Documentation for the Compliance Scenarios

This Page Left Intentionally Blank

Appendix E

Supporting Documentation for the Compliance Scenarios

This appendix presents the year-by-year results for the seven compliance scenarios: four for gasoline and fuels substituting for gasoline and three for diesel and fuels substituting for diesel fuel. In addition, this appendix provides background information on the calculation of the benefits of the federal RFS program.

A. Year-By-Year Results

In summary, the seven scenarios are listed below.

Gasoline and Fuels that Substitute for Gasoline

Scenario 1: Increasing volumes of Federal New Renewable Biofuels (ethanol)¹ through 2015, then gradual decline of higher CI crop-based biofuels through 2020 as advanced renewable ethanol fuels become available. Conventional corn ethanol gradually decreases to zero in 2017, but lower intensity corn ethanol remains. There would be gradual increases in the number of FFVs using E85. The number of advanced technology vehicles (BEV, PHEV, FCVs) using electricity or hydrogen as a fuel increases to about 560,000 by 2020. This number is consistent with the penetration schedule in the 2008 ARB ZEV regulation.

Scenario 2: Similar to Scenario 1 except that a wider mix for cellulosic ethanol, advanced renewable ethanol, and sugarcane ethanol is used.

Scenario 3: Similar to Scenario 2 except that the number of advanced vehicles is increased from 560,000 vehicles to 1 million vehicles in 2020. In turn, the number of FFVs using E85 in 2020 and the amount of cellulosic ethanol, advanced renewable ethanol, and sugarcane ethanol are reduced.

Scenario 4: Similar to Scenario 3 except the number of advanced vehicles is increased to 2 million vehicles in 2020.

¹ The Federal Renewable Fuels Standard (RFS2), which is discussed in Chapter II of this report) specifies that ethanol derived from corn starch produced at new facilities that commence construction after the date the act was signed, must achieve at least a 20 percent reduction in lifecycle greenhouse gas emissions compared to baseline lifecycle greenhouse gas emissions. The baseline is defined as the average 2005 lifecycle GHG emissions for gasoline.

Diesel Fuel and Fuels that Substitute for Diesel Fuel

Scenario 1: The first scenario is based on a diversification of the liquid fuel pool using available low-carbon-intensity fuels.

Scenario 2: The second scenario includes not only a variety of liquid fuels, but also CNG vehicles penetrating the fleet.

Scenario 3: Diesel Compliance Scenario 3 increases the compliance options by expanding Diesel Scenario 2 to include Heavy Duty PHEVs (HD PHEVs).

Tables E-1a through E-7a present the year-by-year results. Tables E-1b through E-7b show how each fuel generates debits and credits in the year 2020.

Table E-1a
Year-by-Year Analysis of Compliance Scenarios
for Gasoline and Fuels that Substitute for Gasoline
Scenario 1

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
% Reduction in AFCl and Emissions	0	0.25	0.5	1.0	1.5	2.5	3.5	5.0	6.5	8.0	10.0
FFVs (millions)	0	0	0	0	0	0.1	0.4	0.8	1.5	2.1	3.0
PHEVs (millions)	0.0005	0.0005	0.02	0.045	0.07	0.11	0.15	0.20	0.27	0.34	0.4
BEVs (millions)	0.002	0.003	0.005	0.007	0.009	0.02	0.03	0.04	0.045	0.07	0.09
FCVs (millions)	0.0005	0.0009	0.002	0.003	0.004	0.01	0.015	0.02	0.037	0.055	0.07
MW Avg. Corn EtOH (Bgal)	1.15	0.92	0.82	0.65	0.52	0.31	0.21	0	0	0	0
CA Low-Cl Corn EtOH (Bgal)	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Cell. EtOH (Bgal)	0	0	0.03	0.09	0.15	0.28	0.42	0.62	0.82	1.02	1.29
Adv. Renew.(Bgal)	0	0	0.03	0.09	0.15	0.28	0.42	0.62	0.82	1.02	1.29
Fed. New Renew. Biofuels (Bgal)	0	0.22	0.25	0.30	0.30	0.30	0.30	0.30	0.24	0.12	0
Total EtOH (Bgal)	1.45	1.44	1.43	1.43	1.42	1.47	1.65	1.84	2.18	2.46	2.88
Total CARBOB (Bgal)	13.97	13.88	13.86	13.77	13.69	13.62	13.34	13.09	12.67	12.30	11.84
E85 % of Gasoline	0	0	0	0	0	0.5	1.9	3.8	7.0	9.6	13.5
vol % EtOH	9.4	9.4	9.4	9.4	9.4	9.8	11.0	12.3	14.7	16.7	19.6

Table E-1b
Emission Credits and Deficits for Each Fuel in 2020
(MMT/yr CO₂)

	CARBOB	Electricity	CA Low-Cl Corn EtOH	Cellulosic EtOH	Advanced Renew. EtOH	Sugar Cane	H ₂
Credits/Deficit	-15.1	1.4	0.1	6.7	6.5	0	0.2

Note: The numbers in Table E-1b are not the emission reduction benefits achieved by each fuel type. They are the amount of emissions that are either above or below the required carbon intensity.

Table E-2a
Scenario 2: ZEVs per 2008 ARB Regulation
(400,000 PHEVs, 90,000 BEVs, 70,000 FCVs in 2020)

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
% Reduction in AFCl and Emissions	0	0.25	0.5	1.0	1.5	2.5	3.5	5.0	6.5	8.0	10.0
FFVs (millions)	0	0	0	0	0	0.1	0.4	0.8	1.6	2.4	3.4
PHEVs (millions)	0.0005	0.0005	0.02	0.045	0.07	0.11	0.15	0.20	0.27	0.34	0.40
BEVs (millions)	0.002	0.003	0.005	0.007	0.009	0.02	0.03	0.04	0.045	0.07	0.09
FCVs (millions)	0.0005	0.0009	0.002	0.003	0.004	0.01	0.015	0.02	0.037	0.055	0.07
MW Avg. Corn EtOH (Bgal)	1.15	0.95	0.83	0.67	0.52	0.31	0.20	0	0	0	0
CA Low-Cl Corn EtOH (Bgal)	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Cell. EtOH (Bgal)	0	0	0.02	0.08	0.15	0.28	0.42	0.62	0.81	1.01	1.24
Adv. Renew.(Bgal)	0	0	0.02	0.08	0.15	0.28	0.42	0.62	0.81	1.01	1.24
Sugar Cane EtOH (Bgal)	0	0.19	0.27	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Total EtOH (Bgal)	1.45	1.44	1.44	1.43	1.42	1.47	1.64	1.84	2.22	2.62	3.08
Total CARBOB (Bgal)	13.97	13.88	13.86	13.77	13.69	13.62	13.34	13.09	12.63	12.19	11.71
E85 % of Gasoline	0	0	0	0	0	0.5	1.9	3.8	7.5	11.0	15.2
vol % EtOH	9.4	9.4	9.4	9.4	9.4	9.8	10.9	12.3	15.0	17.7	20.8

Table E-2b
Emission Credits and Deficits in Scenario 2 for Each Fuel in 2020
(MMT/yr CO2)

	CARBOB	Electricity	CA Low-Cl Corn EtOH	Cellulosic EtOH	Advanced Renew. EtOH	Sugar Cane	H2
Credit/Deficit	-14.9	1.4	0.1	6.5	6.3	0.3	0.2

Note: The numbers in Table E-2b are not the emission reduction benefits achieved by each fuel type. They are the amount of emissions that are either above or below the required carbon intensity.

Table E-3a
Scenario 3: ZEVs Penetration Increased Due to
Expansion of the ARB ZEV Regulation
(670,000 PHEVs, 220,000 BEVs, 110,000 FCVs in 2020)

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
% Reduction in AFCl and Emissions	0	0	0.25	0.5	1.0	1.5	2.5	3.5	5.0	6.5	8.0
FFVs (millions)	0	0	0	0	0.2	0.4	0.6	0.9	1.3	2.0	2.9
PHEVs (millions)	0.0005	0.004	0.023	0.045	0.07	0.15	0.22	0.3	0.38	0.52	0.67
BEVs (millions)	0.002	0.003	0.005	0.007	0.011	0.031	0.056	0.085	0.12	0.16	0.22
FCVs (millions)	0.0005	0.001	0.002	0.003	0.0025	0.0125	0.025	0.04	0.058	0.078	0.11
MW Avg. Corn EtOH (Bgal)	1.15	0.95	0.83	0.65	0.64	0.51	0.37	0.17	0	0	0
CA Low CI Corn EtOH (Bgal)	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Cell. EtOH (Bgal)	0	0	0.02	0.09	0.15	0.27	0.38	0.55	0.73	0.90	1.10
Adv.. Renew. (Bgal)	0	0	0.02	0.09	0.15	0.27	0.38	0.55	0.73	0.90	1.10
Sugar Cane (Bgal)	0	0.19	0.27	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Total EtOH (Bgal)	1.45	1.44	1.44	1.43	1.54	1.65	1.73	1.87	2.06	2.40	2.80
Total CARBOB (Bgal)	13.97	13.88	13.86	13.77	13.61	13.32	13.22	12.98	12.65	12.23	11.70
E85 % of Gasoline	0	0	0	0	1.0	2.0	2.9	4.3	6.1	9.3	13.2
vol % EtOH	9.4	9.4	9.4	9.4	10.1	11.0	11.6	12.6	14.0	16.4	19.3

Table E-3b
Credits and Deficits for Each Fuel in 2020
(MMT/yr CO₂)

	CARBOB	Electricity	CA Low-CI Corn EtOH	Cell. EtOH	Adv. Renew.	Sugar Cane	H2
Credit/Deficit	-14.9	2.7	0.1	5.8	5.6	0.3	0.4

Note: The numbers in Table E-3b are not the emission reduction benefits achieved by each fuel type. They are the amount of emissions that are either above or below the required carbon intensity.

Table E-4a
Scenario 4: Highest Level of ZEV Penetration
(1,340,000 PHEVs, 440,000 BEVs, and 220,000 FCVs in 2020)

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
% Reduction in AFCI and Emissions	0	0.25	0.5	1.0	1.5	2.5	3.5	5.0	6.5	8.0	10.0
FFVs (millions)	0	0	0	0	0	0	0	0.1	0.6	1.1	1.8
PHEVs (millions)	0.0005	0.008	0.037	0.07	0.14	0.30	0.44	0.60	0.76	1.06	1.34
BEVs (millions)	0.002	0.006	0.008	0.012	0.022	0.062	0.112	0.17	0.24	0.34	0.44
FCVs (millions)	0.0005	0.001	0.0016	0.003	0.005	0.025	0.05	0.08	0.116	0.165	0.22
MW Avg. Corn EtOH (Bgal)	1.15	0.97	0.81	0.68	0.59	0.42	0.26	0	0	0	0
CA Low CI Corn EtOH (Bgal)	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Cell. EtOH (Bgal)	0	0	0.01	0.07	0.11	0.19	0.26	0.41	0.53	0.62	0.79
Adv. Renew. (Bgal)	0	0	0.01	0.07	0.11	0.19	0.26	0.41	0.53	0.62	0.79
Sugar Cane (Bgal)	0	0.17	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Total EtOH (Bgal)	1.45	1.44	1.43	1.42	1.41	1.40	1.38	1.42	1.66	1.84	2.18
Total CARBOB (Bgal)	13.97	13.88	13.85	13.75	13.65	13.55	13.31	13.09	12.67	12.20	11.68
E85 % of Gasoline	0	0	0	0	0	0	0	0.5	2.9	5.3	8.6
vol % EtOH	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.8	11.6	13.1	15.7

Table E-4b
Credits and Deficits for Each Fuel in 2020
(MMT/yr CO₂)

	CARBOB	Electricity	CA Low-CI Corn EtOH	Cell. EtOH	Adv. Renew.	Sugar Cane	H ₂
Credit/Deficit	-14.6	5.3	0.1	4.1	4.0	0.3	0.8

Note: The numbers in Table E-4b are not the emission reduction benefits achieved by each fuel type. They are the amount of emissions that are either above or below the required carbon intensity.

Table E-5a
Scenario 1H: Similar Vehicle Mix as Scenario 3, CI for biofuels Modified to
Exclude Land Use Change Effects
(670,000 PHEVs, 220,000 BEVs, 110,000 FCVs in 2020)
(No Land Use Effects)

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
% Reduction in AFCI and Emissions	0	0	0	0	0.12	0.35	0.6	0.94	1.35	1.95	2.73
FFVs (millions)	0	0	0	0	0.12	0.35	0.6	0.94	1.35	1.95	2.73
PHEVs (millions)	0.0005	0.004	0.023	0.045	0.07	0.15	0.22	0.30	0.38	0.52	0.67
BEVs (millions)	0.002	0.003	0.005	0.007	0.011	0.031	0.056	0.085	0.12	0.16	0.22
FCVs (millions)	0.0005	0.001	0.002	0.003	0.0025	0.0125	0.025	0.04	0.058	0.078	0.11
MW Avg. Corn EtOH (Bgal)	1.15	1.03	0.89	0.69	0.62	0.50	0.37	0.17	0	0	0
CA Low CI Corn EtOH (Bgal)	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Cell. EtOH (Bgal)	0	0	0	0.07	0.14	0.26	0.38	0.56	0.74	0.88	1.06
Adv. Renew. (Bgal)	0	0	0	0.07	0.14	0.26	0.38	0.56	0.74	0.88	1.06
Sugar Cane (Bgal)	0	0.11	0.24	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Total EtOH (Bgal)	1.45	1.44	1.43	1.43	1.50	1.62	1.73	1.89	2.08	2.36	2.72
Total CARBOB (Bgal)	13.97	13.88	13.86	13.77	13.64	13.50	13.22	12.96	12.64	12.23	11.76
E85 % of Gasoline	0	0	0	0	0.6	1.7	2.9	4.5	6.4	9.0	12.5
vol % EtOH	9.4	9.4	9.4	9.4	9.8	10.7	11.6	12.8	14.2	16.2	18.8

Table E-5b
Credits and Deficits for Each Fuel in 2020
(MMT/yr CO₂)

	CARBOB	Electricity	CA Low-CI Corn EtOH	Cell. EtOH	Adv. Renew.	Sugar Cane	H ₂
Credit/Deficit	-17.3	2.6	0.8	6.9	5.2	1.4	0.4

Note: The numbers in Table E-5b are not the emission reduction benefits achieved by each fuel type. They are the amount of emissions that are either above or below the required carbon intensity.

Table E-6a
Year-by-Year Analysis of Compliance Scenarios
for Diesel Fuels and Fuels that Substitute for Diesel Fuel
Scenario 5 – Use Liquid Fuels Only

Year	% Reduc.	HD CNG (Veh. and %)	HD PHEVs (Veh. and %)	Conv. Biodiesel (M gal/yr)	Adv. Renew. Diesel (Mgal/yr) ¹	Total Diesel (M gal/yr)	Bio. and Renew. % of Diesel
2011	0.25	0	0	6	11	4484	0.4
2012	0.5	0	0	12	23	4577	0.8
2013	1.0	0	0	25	47	4672	1.5
2014	1.5	0	0	36	72	4768	2.3
2015	2.5	0	0	64	126	4866	3.9
2016	3.5	0	0	90	177	4977	5.4
2017	5.0	0	0	133	262	5091	7.8
2018	6.5	0	0	175	344	5207	10.0
2019	8.0	0	0	218	433	5325	12.2
2020	10.0	0	0	281	557	5445	15.4

Table E-6b
Year 2020 Credits and Deficits for Each Fuel
Scenario 5

	Conven. Diesel	CNG	Electricity	Biodiesel- Soybeans	Renewable Diesel
Credit/Deficit	-5.1	0	0	0.5	4.6

Note: The numbers in Table E-6b are not the emission reduction benefits achieved by each fuel type. They are the amount of emissions that are either above or below the required carbon intensity.

Table E-7a
Year-by-Year Analysis of Compliance Scenarios
for Diesel Fuels and Fuels that Substitute for Diesel Fuel
Scenario 6 – Some CNG Used by HDVs

Year	% Reduc.	HD CNG (Veh. and %)	HD PHEVs (Veh. and %)	Conv. Biodiesel (M gal/yr)	Adv. Renew. Diesel (M gal/yr)	Total Diesel (M gal/yr)	Bio. and Renew. % of Diesel
2011	0.25	413 (0.06%)	0	6	11	4482	0.4
2012	0.5	844 (0.13%)	0	12	23	4573	0.8
2013	1.0	1,724 (0.30%)	0	24	47	4664	1.5
2014	1.5	2,643 (0.4%)	0	36	72	4756	2.3
2015	2.5	4,502 (0.6%)	0	61	122	4846	3.8
2016	3.5	6,519 (0.8%)	0	88	174	4948	5.3
2017	5.0	9,406 (1.2%)	0	131	257	5049	7.7
2018	6.5	12,817 (1.6%)	0	173	338	5149	9.9
2019	8.0	16,373 (2.0%)	0	216	426	5252	12.2
2020	10.0	20,917 (2.5%)	0	276	546	5352	15.4

Table E-7b
Year 2020 Credits and Deficits for Each Fuel
Scenario 6

	Conven. Diesel	CNG	Electricity	Biodiesel-Soybeans	Renewable Diesel
Credits/Deficits	-5.8	0	0	0.6	5.2

Note: The numbers in Table E-7b are not the emission reduction benefits achieved by each fuel type. They are the amount of emissions that are either above or below the required carbon intensity.

Table E-8a
Year-by-Year Analysis of Compliance Scenarios
for Diesel Fuels and Fuels that Substitute for Diesel Fuel
Scenario 7 – HD CNG and PHEVs in Use

Year	% Reduc.	HD CNG (Veh. and %) ¹	HD PHEVs (Veh. and %) ¹	Conv. Biodiesel (M gal/yr)	Adv. Renew. Diesel (Mgal/yr) ²	Total Diesel (Mgal/yr)	Bio. and Renew. % of Diesel
2011	0.25	516 (0.1%)	103 (0.01%)	6	11	4482	0.4
2012	0.5	1,054 (0.2%)	351 (0.05%)	12	23	4571	0.8
2013	1.0	2,155 (0.3%)	718 (0.1%)	23	45	4660	1.5
2014	1.5	3,304 (0.5%)	1,101 (0.14%)	35	69	4749	2.2
2015	2.5	5,628 (0.8%)	1,876 (0.2%)	60	117	4834	3.7
2016	3.5	7,823 (1.1%)	2,684 (0.3%)	86	168	4933	5.1
2017	5.0	11,757 (1.7%)	3,919 (0.5%)	126	247	5025	7.4
2018	6.5	16,021 (2.0%)	5,207 (0.6%)	164	327	5118	9.6
2019	8.0	19,648 (2.4%)	6,549 (0.8%)	231	404	5215	12.2
2020	10.0	25,100 (3.0%)	8,367 (1.0%)	264	524	5305	14.9

Table E-8b
Year 2020 Credits and Deficits for Each Fuel
Scenario 7

	Conven. Diesel	CNG	Electricity	Biodiesel-Soybeans	Renewable Diesel	Conven. Diesel
Credit/Deficit	-5.7	0	0	0.6	5.1	-5.7

Note: The numbers in Table E-8b are not the emission reduction benefits achieved by each fuel type. They are the amount of emissions that are either above or below the required carbon intensity.

B. California Reformulated Gasoline, the Federal Renewable Fuels Standard 2 and Ethanol in Gasoline

Calculated Volumes of Renewable Fuels Based on RFS2

The Federal Renewable Fuels Standard 2 (RFS2) requires fuel producers to use progressively increasing amounts of biofuel, culminating in at least 36 billion gallons of biofuel by 2022. The RFS2 volume requirements are listed in Chapter II, Table II-3 of the Staff Report.

The Federal Renewable Fuels Standard 2 does not list required volumes of conventional biofuel (corn-based ethanol). However, ARB staff have estimated the volumes of conventional biofuel based on the Federal Renewable Fuels Standard 2 required volumes. Whatever portion of the total renewable fuel (a listed volume) is not advanced biofuel (a listed volume), is assumed to be conventional biofuel (a calculated volume).

In 2008, for example, 9.0 billion gallons of total renewable fuel are required. None of that renewable fuel in 2008 was required to be advanced biofuel – it was, rather, conventional biofuel (ie, corn ethanol). Likewise, in 2022 a total of 36 billion gallons of renewable fuel is required, and of that, 21 billion gallons must be advanced biofuels. The remainder – 15 billion gallons – would presumably be conventional biofuel from sources such as corn. The calculated volumes of conventional biofuel are shown in Table E2-1 below.

Also shown in Table E-9 are ARB staff estimates of the volumes of other advanced biofuel – the amounts needed to make up total advanced biofuel. Other advanced biofuel could be, for example, renewable hydrocarbons from algae or other sources. The calculated volumes are ARB staff estimates and may not be the volumes eventually produced. For example, volumes of other advanced biofuel could vary if more biodiesel is produced after 2012, or if U.S. EPA adjusts volume of cellulosic biofuel required.

Table E-9
Federal Renewable Fuels Standard 2 Volume Requirements,
and Calculated (highlighted) Volumes

Year	Advanced Biofuel				Conventional Biofuel (c)	Total Renewable Fuel
	Cellulosic Biofuel	Biomass Based Biodiesel (a)	Other Advanced Biofuel (b)	Total		
2008					9.0	9.0
2009		0.5	0	0.6	10.35	11.1
2010	0.1	0.65	0	0.95	11.875	12.95
2011	0.25	0.8	0	1.35	12.5	13.95
2012	0.5	1.0	0	2.0	13.2	15.2
2013	1.0	1.0 ^(a)	0.25 ^(b)	2.75	13.8	16.55
2014	1.75	1.0 ^(a)	0.5 ^(b)	3.75	14.4	18.15
2015	3.0	1.0 ^(a)	1.0 ^(b)	5.5	15.0	20.5
2016	4.25	1.0 ^(a)	1.5 ^(b)	7.25	15.0	22.25
2017	5.5	1.0 ^(a)	2.0 ^(b)	9.0	15.0	24.0
2018	7.0	1.0 ^(a)	2.5 ^(b)	11.0	15.0	26.0
2019	8.5	1.0 ^(a)	3.0 ^(b)	13.0	15.0	28.0
2020	10.5	1.0 ^(a)	3.0 ^(b)	15.0	15.0	30.0
2021	13.5	1.0 ^(a)	3.0 ^(b)	18.0	15.0	33.0
2022	16.0	1.0 ^(a)	3.5 ^(b)	21.0	15.0	36.0

(a) Per EISA 2007 requirement, the applicable biomass-based biodiesel volume would be determined by the US EPA administrator, and should not be less than the volume listed for 2012. For illustrative purposes, ARB staff have assumed that the volume for 2013 through 2022 remains at the 2012 level.

(b) Other advanced biofuel is not an RFS2 requirement, but is calculated by:

$$V_{\text{Other Adv Bio}} = V_{\text{Total Adv Bio}} - 1.5V_{\text{biodiesel}} - V_{\text{cellulosic}}$$

where: $V_{\text{Total Adv Bio}}$ is the applicable volume of total advanced biofuel for the corresponding calendar year, and V_{cell} is the applicable volume of cellulosic biofuel for corresponding calendar year. Biodiesel is assumed to have a 1.5 multiplier towards total advanced biofuel, to account for the volumetric energy content. Note that the volume of other advanced biofuel is assumed to be zero for 2011 and 2012, as the cellulosic biofuel plus 1.5 times the biodiesel accounts for total advanced biofuel.

(c) Conventional biofuel is not an RFS2 requirement, but is calculated by:

$$V_{\text{Conventional}} = V_{\text{Total Renewable}} - V_{\text{Total Advanced biofuel}}$$

GHG Reduction Requirements and “California Share” of RFS2 Volumes

In addition to the volume requirements, RFS2 also requires that the biofuels have a reduction in carbon intensity compared to the baseline fuel they are displacing. The baseline is defined as the average 2005 lifecycle GHG emissions for gasoline or diesel (whichever is being replaced). Per RFS2, advanced biofuel (renewable fuel, other than ethanol derived from corn starch) must have lifecycle greenhouse gas emissions that are at least 50 percent less than baseline lifecycle greenhouse gas emissions. Cellulosic biofuels must have greenhouse gas lifecycle emissions at least 60 percent less than baseline. Biomass-based biodiesel must also have lifecycle greenhouse gas emissions at least 50 percent less than baseline.

Finally, for other renewable fuels (including ethanol derived from corn starch) produced at new facilities that commence construction after the date the act was signed, must achieve at least a 20 percent reduction in lifecycle greenhouse gas emissions compared to baseline lifecycle greenhouse gas emissions. On a nationwide basis it is estimated that facilities which existed or were under construction at the time the act was signed accounted for 13 billion gallons of the total 2020 capacity of 15 billion gallons of conventional biofuels.(1)

A California proportional share of 11.3 percent of the RFS2 volumes was assumed for purposes of this analysis. Tables E-10 and E-11 show the California volumes assumed for advanced and non-advanced biofuels.

Table E-10
California Volumes of RFS2 Advanced Biofuels
(for estimating benefits of RFS2 in California)

Billion Gallons	Renewable Volume Requirements	Advanced Biofuel (-50%)	Cellulosic Biofuel (-60%)	Biomass-Based Diesel (-50%)	Other Advanced Biofuel (-50%)
2010	1.46	0.11	0.01	0.07	0.00
2011	1.58	0.15	0.03	0.09	0.00
2012	1.72	0.23	0.06	0.11	0.00
2013	1.87	0.31	0.11	0.11	0.03
2014	2.05	0.42	0.20	0.11	0.06
2015	2.32	0.62	0.34	0.11	0.11
2016	2.51	0.82	0.48	0.11	0.17
2017	2.71	1.02	0.62	0.11	0.23
2018	2.94	1.24	0.79	0.11	0.28
2019	3.16	1.47	0.96	0.11	0.34
2020	3.39	1.70	1.19	0.11	0.34

Table E-11
California Volumes of RFS2 Non-Advanced Biofuels
(for estimating benefits of RFS2 in California)

Other Advanced Biofuel (-50%)	Total Non-Adv Biofuel (Corn etOH)	Grandfathered US Corn Ethanol (0%)	Non-Grandfathered US Corn EtOH (-20%)	CA Dry Mill Wet DGS Corn EtOH
0.00	1.34	0.86	0.18	0.30
0.00	1.41	0.92	0.19	0.30
0.00	1.49	0.99	0.20	0.30
0.03	1.56	1.05	0.21	0.30
0.06	1.63	1.11	0.22	0.30
0.11	1.70	1.17	0.23	0.30
0.17	1.70	1.17	0.23	0.30
0.23	1.70	1.17	0.23	0.30
0.28	1.70	1.17	0.23	0.30
0.34	1.70	1.17	0.23	0.30
0.34	1.70	1.17	0.23	0.30

Carbon Intensity Values Used for California RFS 2 Scenario

ARB staff used our gasoline and diesel carbon intensity (CI) values, and the RFS2 percent reduction in greenhouse gases to calculate the carbon intensity for the RFS2 fuels.

Gasoline

Gasoline baseline CI = 95.7

- 1.13 bgal of conventional MW corn ethanol with CI = 95.7 (this is a 0% reduction from our gasoline baseline and our fair share of the grandfathered corn ethanol)
- 0.300 bgal of CA Dry Mill Wet DGS Corn EtOH with CI = 80.7 (this is our value for CI and this is based on the capacity of ethanol plants within CA currently)
- 0.220 bgal of conventional MW corn ethanol with CI = 76.56 (this is a 20% reduction from our gasoline baseline and our fair share of the non-grandfathered corn ethanol)
- 0.33 bgal of other advanced renewable ethanol with CI = 47.85 (this is a 50% reduction from our gasoline baseline and our fair share of the total advanced biofuel minus the biomass-based biodiesel minus the cellulosic biofuel volumes)

- 1.16 bgal of cellulosic ethanol with CI = 38.28 (this is a 60% reduction from our gasoline baseline and our fair share of the cellulosic biofuel)

This represents a total of 3.14 bgal of ethanol in 2020.

Diesel

- 0.11 bgal of biomass-based diesel with CI = 47.355 (this is a 50% reduction from our diesel baseline and our fair share of the biomass-based diesel)

We assume 50 percent from the diesel baseline because of the RFS2 definition of how they determine the baseline carbon intensity.

GHG Benefits of RFS2 vs. LCFS

ARB staff estimated the greenhouse gas benefits of the federal RFS 2 program, compared to the benefits of the low carbon fuel standard. Using the RFS2 greenhouse gas reductions, and the California share RFS2 volumes, the GHG benefits of RFS2 only (no LCFS) in California were estimated. For gasoline, ARB staff estimated that RFS2 would yield a reduction in GHG emissions and carbon intensity of about 4 percent. For diesel, ARB staff estimated that RFS2 would yield a reduction in GHG emissions of about 1.1 percent. For gasoline and diesel combined, therefore, RFS 2 would yield about a 3 percent reduction in greenhouse gases, compared to an LCFS reduction of 10 percent overall.

Appendix E References:

1. Susanne Retka Schill (2008). "U.S. ethanol production." Ethanol producer magazine (October).

APPENDIX F

Supporting Documentation for Environmental Analysis

This Page Intentionally Left Blank

Appendix F
Supporting Documentation for Environmental Analysis

Table of Contents

- F1. Supporting Documentation for the GHG Emission Benefits
- F2. Location and Emissions of Facilities Producing Transportation Fuel
- F3. Permitting and Mitigation Requirements for Facilities in California
- F4. Emissions from Biomass and Biofuel Transportation and Distribution
- F5. Emissions from Potential Biorefineries
- F6. Motor Vehicle Emissions – E85 vs. Gasoline
- F7. Motor Vehicle Emissions – Biodiesel vs. Diesel
- F8. Motor Vehicle Emissions – Electricity and Hydrogen vs. Gasoline and Diesel
- F9. Motor Vehicle Emissions – CNG vs. Diesel
- F10. Cancer Health Risk Assessment for Individual and Multiple Co-located Biorefinery Facilities
- F11. Health Impacts Associated with Emissions from Potential Biorefineries
- F12. Impacts on Water Quality and Water Consumption
- F13. Impacts on Hazardous Waste
- F14. Impacts on Waste

This Page Intentionally Left Blank

Appendix F1

Supporting Documentation for GHG Emission Benefits

A. Introduction

In this analysis, we evaluated the benefits of the LCFS in two ways. In the first analysis, staff evaluated the fuel energy required to meet the LCFS standard in each year using only the “tank-to-wheel” carbon intensity. This analysis reasonably represents the emissions that would occur in California and is similar to the analysis used in the Scoping Plan. In addition, these reductions are the estimates of targeted emissions that would be compared to the targeted emissions in the Scoping Plan. In the second analysis, staff used the full lifecycle carbon intensity to estimate the overall CO₂ emission reductions associated with the LCFS.

In general, the energy requirements necessary to meet the LCFS are a function of the estimates of fuel use required each year for transportation fuels. These estimates are projected from 2010 to 2020 using a business as usual scenario for both gasoline and diesel fuel. The fuel use is expressed as an energy value to account for the different types of fuel used (gasoline, diesel, CNG, electricity, hydrogen, etc.) In addition, the estimates are then adjusted by the recommended actions presented in the Scoping Plan. Chapter VI discusses these adjustments in more detail and presents a baseline case. The emissions estimates for each year are then projected by multiplying the respective baseline carbon intensities for gasoline and diesel fuel by the total energy required each year.

Table F1-1 presents the energy requirements and projected emission estimates for each year and each fuel based only on the carbon intensity values for the combustion of the fuel (“tank-to-wheel”). Table F1-2 presents similar information for the full lifecycle analysis. Note that the only difference is the use of the carbon intensity value used. With this baseline, estimates of “tank-to-wheel” and full lifecycle benefits associated with the LCFS can be calculated.

Table F1-1
Baseline Emission Estimates for Transportation
“Tank-to-Wheel” Basis

Year	Gasoline		Diesel	
	Energy Requirements (Megajoules)	Baseline GHG Emissions (MMT CO ₂)	Energy Requirements (Megajoules)	Baseline GHG Emissions (MMT CO ₂)
2010	1786	130	578	43
2011	1775	129	603	45
2012	1772	129	616	46
2013	1761	128	628	47
2014	1751	127	641	48
2015	1748	127	654	49
2016	1727	126	669	50
2017	1715	125	685	51
2018	1694	123	700	52
2019	1673	122	716	54
2020	1653	120	732	55

Table F1-2
Baseline Emission Estimates for Transportation
Full Lifecycle Basis

Year	Gasoline		Diesel	
	Energy Requirements (Megajoules)	Baseline GHG Emissions (MMT CO ₂ e)	Energy Requirements (Megajoules)	Baseline GHG Emissions (MMT CO ₂ e)
2010	1786	171	578	55
2011	1775	170	603	57
2012	1772	170	616	58
2013	1761	169	628	59
2014	1751	168	641	61
2015	1748	168	654	62
2016	1727	165	669	63
2017	1715	164	685	65
2018	1694	162	700	66
2019	1673	160	716	68
2020	1653	158	732	69

B. “Tank-to-Wheel” GHG Emission Reductions

Using the baseline information presented above, the “Tank-to-Wheel” emissions with the LCFS can be determined. This is done by assuming that there is a 10% reduction in the “tank-to-wheel” carbon intensity factor for each year. Table F1-3 presents the estimates of GHG emissions for each year. As the table shows, the emissions decrease each each year. Using the information from Tables F1-1 and F1-3, the emissions benefits for each year can be calculated. These results are presented in Table F1-4.

Table F1-3
GHG Emissions with the LCFS
“Tank-to-Wheel” Estimates

Year	Gasoline		Diesel	
	Energy Requirements (Megajoules)	Baseline GHG Emissions (MMT CO ₂)	Energy Requirements (Megajoules)	Baseline GHG Emissions (MMT CO ₂)
2010	1786	130	578	43
2011	1775	129	603	45
2012	1772	128	616	46
2013	1761	127	628	47
2014	1751	125	641	47
2015	1745	124	654	48
2016	1722	121	669	48
2017	1707	119	684	49
2018	1684	115	700	49
2019	1660	112	715	49
2020	1635	108	732	49

Table F1-4
GHG Emission Benefits of the LCFS
“Tank-to-Wheel” Basis

Year	GHG Emission Reductions (MMT CO ₂ e)		
	Gasoline	Diesel	Total
2010	---	---	---
2011	0.3	0.1	0.4
2012	0.7	0.2	0.9
2013	1.3	0.5	1.8
2014	1.9	0.7	2.6
2015	3.2	1.3	4.5
2016	4.4	1.7	6.1
2017	6.3	2.5	8.8
2018	8.1	3.4	11.5
2019	9.7	4.3	14.0
2020	12.1	5.5	17.6*

*Please note that this does not include a 1.8 reduction to eliminate the double counting of the ZEV mandate. If this is included, the estimated total “tank-to-wheel” GHG benefits would be 15.8 MMT CO₂e in 2020.

C. Full Lifecycle Analysis GHG Emission Reductions

Using the baseline information presented above, the full lifecycle emissions with the LCFS can be determined. This is done by assuming that there is a 10% reduction in the full lifecycle carbon intensity factor for each year. Table F1-5 presents the estimates of GHG emissions for each year. As the table shows, the emissions decrease each year. Using the information from Tables F1-2 and F1-5, the emissions benefits for each year can be calculated. These results are presented in Table F1-6.

Table F1-5
GHG Emissions with the LCFS
Full Lifecycle Estimates

Year	Gasoline		Diesel	
	Energy Requirements (Megajoules)	Baseline GHG Emissions (MMT CO ₂)	Energy Requirements (Megajoules)	Baseline GHG Emissions (MMT CO ₂)
2010	1786	171	578	55
2011	1775	170	603	57
2012	1772	169	616	58
2013	1761	167	628	59
2014	1751	165	641	60
2015	1745	163	654	60
2016	1722	160	669	61
2017	1707	156	684	62
2018	1684	152	700	62
2019	1660	147	715	62
2020	1635	143	732	62

Table F1-6
GHG Emission Benefits of the LCFS
Full Lifecycle Basis

Year	GHG Emission Reductions (MMT CO ₂ e)		
	Gasoline	Diesel	Total
2010	---	---	---
2011	0.4	0.1	0.5
2012	0.9	0.3	1.2
2013	1.7	0.6	2.3
2014	2.5	0.9	3.4
2015	4.2	1.6	5.8
2016	5.8	2.2	8.0
2017	8.3	3.2	11.5
2018	10.6	4.3	14.9
2019	12.8	5.4	18.2
2020	15.9	7.0	22.9

Appendix F2
Location and Emissions of Facilities Producing Transportation Fuel

A. Petroleum Refineries

According to the CEIDARS database, there are currently 25 facilities that fall under the category of petroleum refining in California. However, of those 25 facilities, only 15 of them produce transportation fuel according to the CEC(1). Five of those facilities reside in the Bay Area Air Quality Management District, seven reside in the South Coast Air Quality Management District, and three reside in the San Joaquin Valley Unified Air Pollution Control District. A list of the 15 refineries is presented in Table F2-1, and they are included on the map in Figure F2-1. The list has been updated from the CEC list to reflect the current refinery owners.

Table F2-1
Currently Operating Petroleum Refineries in California

Facility Name	Location
BP West Coast Products LLC	Carson
Chevron U.S.A. Inc.	El Segundo
Chevron U.S.A. Inc.	Richmond
Tesoro Refining & Marketing Company	Avon
Shell Oil Products	Martinez
ExxonMobil Refining & Supply	Torrance
Valero Benicia Refinery	Benicia
ConocoPhillips	Wilmington
Tesoro Refining & Marketing Company	Wilmington
Valero (Ultramar)	Wilmington
ConocoPhillips	Rodeo
Big West of California LLC	Bakersfield
Alon USA Energy, Inc.	Paramount
Kern Oil and Refining Company	Bakersfield
San Joaquin Refining Co. Inc.	Bakersfield

Figure F2-1
Location of Existing Petroleum Refineries



ARB's Planning and Technical Support Division compiles each of the local districts' estimates for emissions for stationary sources within its jurisdiction. The emission data are available at <http://www.arb.ca.gov/app/emsmv/emssumcat.php>. There are six subcategories that have been used to estimate emissions associated with petroleum refining in each district. These subcategories are: oil and gas production (combustion), petroleum refining (combustion), oil and gas production, petroleum refining, petroleum marketing, other (petroleum production and marketing). The following tables show the estimated emissions from petroleum refining for 2006 (Table F2-2) and the projected emissions from petroleum refining for 2010 (Table F2-3) and 2020 (Table F2-4). The projected emissions are based on the 2002 base year inventory and the growth and control data maintained by the ARB and Districts. Control reflects only adopted rules.

**Table F2-2
2006 California Petroleum Refining Emissions (tons/day)**

Air District	TOG	ROG	CO	NOX	SOX	PM	PM10	PM2.5
Bay Area AQMD	90.18	25.6	7.52	16.66	35.61	3.05	2.48	2.38
Santa Barbara County APCD	13.12	4.3	1.88	2.42	0.32	0.12	0.12	0.12
San Joaquin Valley Unified APCD	91.37	39.01	13.03	12.86	1.68	1.71	1.66	1.65
San Luis Obispo County APCD	1.7	1.01	0.33	0.65	9.77	0.39	0.24	0.19
South Coast AQMD	38.35	33.05	18.26	13.31	12.62	3.89	3.07	2.8
Total	234.7	103	41.02	45.9	60	9.16	7.57	7.14

**Table F2-3
2010 California Petroleum Refining Emissions (tons/day)**

Air District	TOG	ROG	CO	NOX	SOX	PM	PM10	PM2.5
Bay Area AQMD	94.9	25.62	7.86	17.38	37.5	3.19	2.6	2.49
Santa Barbara County APCD	12.47	4.03	1.8	2.35	0.32	0.11	0.11	0.11
San Joaquin Valley Unified APCD	88.08	37.85	12.44	11.43	1.62	1.64	1.59	1.59
San Luis Obispo County APCD	1.64	0.99	0.33	0.66	10.56	0.41	0.24	0.2
South Coast AQMD	37.86	32.66	18.26	11.03	9.88	3.5	2.83	2.58
Total	234.95	101.15	40.69	42.85	59.88	8.85	7.37	6.97

**Table F2-4
2020 California Petroleum Refining Emissions (tons/day)**

Air District	TOG	ROG	CO	NOX	SOX	PM	PM10	PM2.5
Bay Area AQMD	110.85	28.33	8.78	19.27	42.67	3.6	2.92	2.8
Santa Barbara County APCD	12.11	3.69	1.63	2.14	0.29	0.11	0.11	0.11
San Joaquin Valley Unified	86.97	36.41	12.38	11.17	1.73	1.75	1.67	1.68
San Luis Obispo County	1.67	1.04	0.26	0.65	12.25	0.49	0.28	0.23
South Coast AQMD	40.18	35.03	16.94	10.7	9.08	3.45	2.8	2.55
Total	251.78	104.5	39.99	43.93	66.02	9.4	7.78	7.37

For comparison, the statewide stationary source emissions are provided in Table F2-5.

**Table F2-5
California Statewide Stationary Source Emissions (tons/day)**

Year	TOG	ROG	CO	NOX	SOX	PM	PM10	PM2.5
2006	2117.14	381.55	346.55	380.26	113.64	209.78	135.23	83.02
2010	2200.81	388.65	353.92	381.25	117.7	221.02	142.11	86.7
2020	2460.88	428.55	378.65	403.81	131.1	251.3	160.71	97.51

B. Ethanol Facilities

In addition to petroleum refineries, there are presently ten permitted ethanol facilities in California (Table F2-6). Currently the production capacity of commercial-size ethanol facilities ranges from approximately 35 MMgal/yr. to 60 MMgal/yr.

**Table F2-6
Currently Permitted Ethanol Facilities in California^a**

Facility Name	Feedstock	Location	Capacity (MMgpy)	Current Status ^b
Calgren	Corn	Pixley	52.5	Operating
Cilion, Inc.	Corn	Keyes	55	Operating
Pacific Ethanol	Corn	Stockton	60	Idle
Great Valley Ethanol	Corn	Hanford	60	Permitted
Cilion, Inc.	Corn	Famoso	55	Permitted
Pacific Ethanol	Corn	Brawley	60	Permitted
Pacific Ethanol	Corn	Madera	40	Idle
Altra, Inc. (Phoenix)	Corn	Goshen	35	Idle
Parallel Products	Corn	Rancho Cucamonga	5	Operating
Blue Fire Ethanol	Cellulosic	Lancaster	3.1	Permitted, demonstration facility
Total Potential Capacity			425.6	

^aCalifornia Energy Commission, San Joaquin Valley Air Pollution Control District

^bCurrent status as of February 2009

ARB staff has also compiled data from permits and engineering evaluations for existing in-state corn ethanol and cellulosic ethanol production facilities. ARB staff looked at oxides of nitrogen (NO_x), particulate matter 10 microns in diameter and smaller (PM₁₀), and volatile organic compound (VOC) emissions from each facility. The data collected are summarized in the Tables F2-7 and F2-8.

**Table F2-7
Emissions from Permitted Corn Ethanol Facilities**

Facility Name	Air Basin	Production Rate (MMgal/yr)	VOC (lb/yr)	NOx (lb/yr)	PM10 (lb/yr)
Calgren ¹	SJVAB	55	13,263	2,737	4,699
Pacific Ethanol, Stockton ²	SJVAB	60	39,279	15,803	17,164
Pacific Ethanol, Madera ³	SJVAB	40	35,828	15,237	18,182
Pacific Ethanol, Brawley ⁴	SSAB	60	35,800	22,600	33,200
Great Valley Ethanol ⁵	SJVAB	60	38,327	19,055	16,103
Altra Inc. ⁶	SJVAB	35	18,569	6,406	5,037
TOTAL		310	181,066	81,838	94,385

**Table F2-8
Emissions from Permitted Cellulosic Ethanol Facilities**

Facility Name	Process	Production Rate (MMgal/yr)	VOC (lbs/yr)	NOx (lb/yr)	PM10 (lb/yr)
BlueFire ⁷	Concentrated Acid Hydrolysis	3.1	46,376	46,314	15,496

Note that the emissions from the BlueFire facility are larger than the other corn ethanol facilities. There are two reasons for the higher numbers. First, the facility is a small scale production facility and does not have the same level of emissions control that a commercial scale facility would incorporate. Second, the energy requirements for the cellulosic facilities are substantially greater than that required for corn ethanol facilities.

C. Biodiesel Facilities

California biodiesel facilities currently in operation use the fatty-acid methyl ester (FAME) transesterification process. The capacity of FAME biodiesel facilities is

¹ San Joaquin Valley Unified Air Pollution Control District. 2005. ATC application review and associated permits. Calgren Renewable Fuels, LLC. Permit Nos. S4214-1 through S2414-15, and S2414-19 through S2414-24.

² San Joaquin Valley Unified Air Pollution Control District. 2006. ATC application review and associated permits. Pacific Ethanol, Stockton. Permit Nos. N-7365-1 through N-7365-28.

³ San Joaquin Valley Unified Air Pollution Control District. 2006. ATC application review and associated permits. Pacific Ethanol, Madera. Permit Nos. C-4261-1 through C-4261-26.

⁴ Imperial County Air Pollution Control District. 2007. ATC application review and associated permits. Pacific Ethanol, Brawley, LLC. Permit No. 3495

⁵ San Joaquin Valley Unified Air Pollution Control District. 2006. ATC application review and associated permits. Great Valley Ethanol, LLC. Permit Nos. C-7335-1 through C-7335-23.

⁶ San Joaquin Valley Unified Air Pollution Control District. 2007. ATC application review and associated permits. Phoenix Biofuels (Altra, Inc.) Permit Nos. S-4272-1 through S-4272-21.

⁷ Antelope Valley Air Quality Management District. 2008. Engineering Evaluation and associated permits. Bluefire Ethanol Lancaster, LLC. Permit Nos. B010425, B010433, B-10437 through B010440, C010426 through C010428, C010430, C010432, C010434 through C010436, C010441, C010442, C010446, E010447, T010429, T010431, T010448 through T010452.

generally less than 10 MMgpy. There are presently nine operating biodiesel facilities in California, although the following table (F2-9) includes only those facilities that could be verified.

**Table F2-9
Currently Permitted Biodiesel Facilities in California^a**

Facility Name	Location	Capacity (MMgal/yr)	Current Status
Renewable Energy Products, LLC	Santa Fe Springs	10	Operational
Sirona Fuels (Blue Sky)	Oakland	10	Operational
Whole Energy Fuels	Richmond	---	Operational
Wright Biofuels	San Jacinto		Operational
Darling International, Inc.	San Francisco	10	Operational
Imperial Western Products	Coachella	6	Operational
Crimson Renewable Energy LP	Bakersfield	30	Operational
Simple Fuels Biodiesel	Chilhoot	---	Under Construction

^aCorrespondence with facility personnel.

Emissions from available permits for the biodiesel facilities currently permitted in California are shown in Table F2-10.

**Table F2-10
Emissions from Permitted Biodiesel Facilities**

Facility Name	Air Basin	Production Rate (MMgal/yr)	VOC (lbs/yr)	NOx (lb/yr)	PM10 (lb/yr)
American Biodiesel ⁸	SJVAB	6.1	11,602	1,407	979
Crimson Renewable Energy, LP ⁹	SJVAB	30	10,967	3,175	1,538
Lakeland Development Company ¹⁰	SCAB	11	No Info in Permit	No Info in Permit	No Info in Permit
Noil Energy Group ¹¹	SCAB	5	No Info in Permit	No Info in Permit	No Info in Permit
Blue Sky Bio-Fuel, Inc. ¹²	SFBAB	1	460	0	0
Golden Gate Petroleum Company ¹³	AFBAB	10	1,000	0	0
Total Capacity		63			

A map of currently permitted ethanol and biodiesel facilities is shown in Figure F2-2.

⁸San Joaquin Valley Unified Air Pollution Control District. 2007. ATC application review and associated permits. American Biodiesel, Inc. DBA Comm. Fuels. Permit Nos. N-7480-1-0 through N-7480-3-0.

⁹San Joaquin Valley Unified Air Pollution Control District. 2008. ATC application review and associated permits. Crimson Renewable Energy, LP. Permit Nos. S-6971-1-1, S-6971-2-0, S-6971-5-0, S-6971-6-0, and S-6971-7-0.

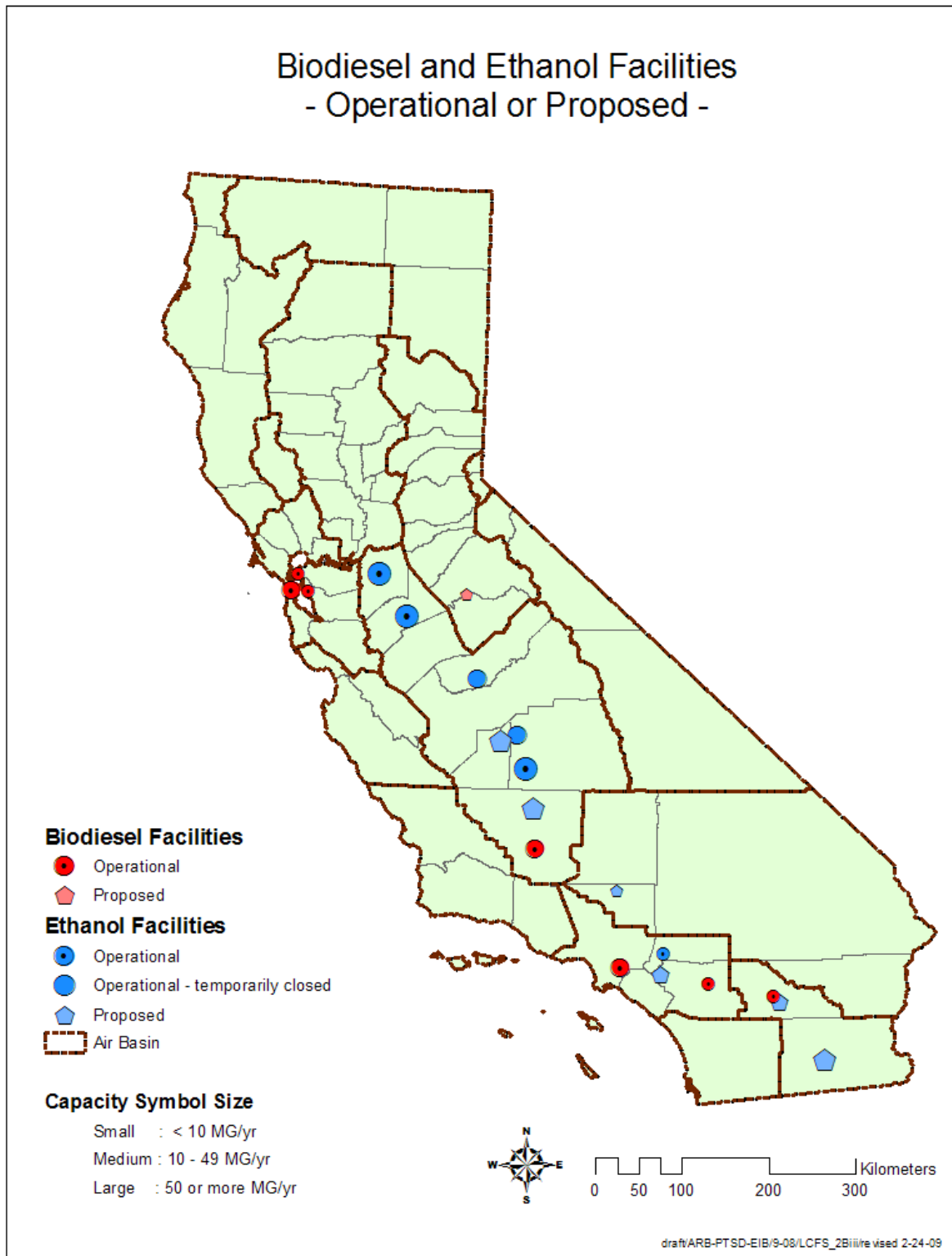
¹⁰South Coast Air Quality Management District. 2007. Permit to Construct. Lakeland Development Company. Application Nos. 406603 through 406605, 406608, 467784, 467786, 467788, 467789, 467791, 471735, and 471736.

¹¹South Coast Air Quality Management District. 2007. Permit to Construct. Noil Energy Group. Application Nos. 464569, 475885, 464570, and 469131.

¹²Bay Area Air Quality Management District. 2008. Permit to Operate. Blue Sky Bio-Fuel, Inc. Application Nos. 14953.

¹³Bay Area Air Quality Management District. 2008. Permit to Operate. Golden Gate Petroleum Co. Application Nos. 15965.

Figure F2-2
Location of Current and Proposed
Biorefineries



Appendix F3

Permitting and Mitigation Requirements for Facilities in California

A. Regulatory Structure

Large industrial sources such as biorefineries are known as “stationary sources.” “Mobile sources” include both on- and off-road sources such as passenger cars, trucks, heavy-duty construction equipment, marine vessels, and lawn and garden equipment. The regulation of stationary sources is conducted at three levels of government in California: federal, State, and local. 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 health-based pollutant thresholds called national ambient air quality standards. 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, the U.S. Environmental Protection Agency (U.S. EPA) is responsible for implementation of the federal Clean Air Act. Some portions of the Act are implemented directly by the 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 the Air Resources Board (ARB or Board) and the 35 independent local air pollution control and air quality management districts (districts). The ARB and districts follow the laws 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.

Both State and federal law address pollutants for which there are ambient air quality standards as criteria pollutants. These criteria pollutants include oxides of nitrogen (NO_x); carbon monoxide (CO); ozone, inhalable and fine particulate matter (PM₁₀, PM_{2.5}); and sulfur oxides (SO_x). There are no ambient air quality standards for volatile organic compounds (VOC), but they contribute to ozone formation and are considered criteria air pollutants.

State law gives the ARB direct authority to regulate pollution from mobile sources, fuels, and consumer products. Primary responsibility for controlling pollution from stationary sources lies with the districts. The districts responsibility for stationary sources includes developing region-specific rules, permitting, enforcing the local rules, collecting data associated with emissions inventory, and the preparing local air quality plans. The districts may obtain authority from the 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 Signification Deterioration (PSD) program.

B. Stationary Source Permitting Requirements

This section summarizes the primary legal requirements for permitting stationary sources of air pollution in California. Each district has adopted rules as part of the SIP to meet State and federal ambient air quality standards. District rules define the procedure and criteria districts use in permitting stationary sources. Although specific rules vary in scope and level of stringency by district depending on the region's air quality status, the general procedure for permitting new and expanding sources is the same throughout the State. Pollutant-emitting sources must first obtain an authority to construct 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 stationary source program requirements.

The requirement to get a district permit is equipment specific and may vary among districts. In some cases, a source may require a permit but individual pieces of equipment may be exempt from permit. For example, in many districts, reciprocating engines rated at less than 50 brake horsepower (bhp) and small natural gas-fired boilers do not require a district permit. Based on the projected emissions from potential biorefinery projects in California, ARB staff expects that all projects will require district permits regardless of location.

District requirements for stationary sources generally fit into two categories. The first category of rules applies to the construction and operation of new and modified (or expanding) stationary sources. These rules are referred to as the New Source Review (NSR) program.

The California NSR program is the foundation of stationary source emission control and allows industrial growth to continue in polluted areas while not undermining progress toward meeting clean air standards. The NSR permit program is derived from the California Clean Air Act and is codified in the [California Health and Safety Code](#) at Division 26. 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 clean technology; and (2) result in a net reduction in emissions. This is accomplished through two major requirements in each district NSR rule: best available control technology (BACT)¹⁴ and offsets.

¹⁴ In California, BACT is synonymous with the federal term Lowest Achievable Emission Rate (LAER) for nonattainment area permit requirements.

1. Best Available Control Technology

Depending on the quantity of emissions 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 emissions unit basis (generally an individual piece of equipment or an integrated process consisting of several pieces of equipment). The BACT emission trigger levels for the districts where ARB staff expects biorefinery projects to be sited are given in Table F3-1 below. There may be some cases where the equipment requires a permit but BACT is not triggered.

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. 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. District staff does not consider cost for technologies or strategies that are already deemed achieved in practice.

Table F3-1
BACT Emission Levels by District

District	NOx	PM10	CO	SOx	VOC
Bay Area AQMD	≥10.0 lbs/day	≥10.0 lbs/day	≥10.0 lbs/day	≥10.0 lbs/day	≥10.0 lbs/day
North Coast Unified AQMD	>50 lbs/day	>80 lbs/day	>137 lbs/day in nonattainment area; >500 lbs/day in attainment area	>80 lbs/day	>50 lbs/day
San Joaquin Valley APCD ⁽¹⁾	>2.0 lbs/day	>2.0 lbs/day	≥200,000 lbs/yr	>2.0 lbs/day	>2.0 lbs/day
South Coast AQMD ⁽²⁾	Any increase	Any increase	Any increase	Any increase	Any increase

(1) SJVAPCD has recently adopted a more stringent NSR rule, but this rule will not be effective until U.S. EPA approves it into the State Implementation Plan.

(2) Due to a recent lawsuit, SCAQMD cannot not supply offsets for any sources; hence all emission increases must be offset by the applicant.

The largest pollutant-emitting equipment at a biorefinery includes fossil fuel and/or biomass-fueled boilers; biofuel processing and storage equipment; and grain receiving, handling, and grinding operations. While BACT will be determined at the time of permitting, ARB staff expects typical BACT requirements to include one or more of the following control technologies: low-NOx burners, flue gas recirculation, selective non-

catalytic reduction, selective catalytic reduction, VOC collection and reduction systems, baghouses, and electrostatic precipitators.

2. 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 and/or cleaning up the existing facility (or a source owned by another company) beyond what is required by law.

The amount of offsets required depends on the distance between the source of offsets and the new or modified source. Offsets are generally required at a greater than 1-to-1 ratio so that when the new or modified facility begins operation, more emissions are reduced than are increased. 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 benefit. Some districts have pre-established ratios for interpollutant offsets in their rules. The offset trigger levels for the air districts where ARB staff expects biorefinery projects might be sited are given in Table F3-2 below. While BACT is triggered on an emissions unit basis, offsets are triggered on a project basis.

**Table F3-2
Offset Emission Levels by District**

District	NOx	PM10	CO	SOx	VOC
Bay Area AQMD	>10 TPY; >35 TPY the applicant is responsible to supply the offsets	Increase >1 TPY for major sources since 1991	≥100/250 TPY ⁽¹⁾ must model emissions to show no interference with attainment status	Increase >1 TPY for major sources since 1991	>10 TPY; >35 TPY the applicant is responsible to supply the offsets
North Coast Unified AQMD	≥25 TPY	≥25 TPY	Must model emissions to show no interference with attainment status	≥25 TPY	≥25 TPY
San Joaquin Valley APCD	≥20,000 lbs/yr	≥29,200 lbs/yr	≥30,000 lbs/yr in nonattainment area; 200,000 lbs/yr in attainment area or modeling	≥54,750 lbs/yr	≥20,000 lbs/yr
South Coast AQMD	≥4 TPY	≥4 TPY	≥29 TPY must model emissions to show no interference with attainment status	≥4 TPY	≥4 TPY

(1) The 100 TPY trigger level applies if the facility is one of the 28 PSD source categories listed in Section 169(1) of the federal Clean Air Act.

C. Stationary Source Prohibitory Rules

A second category of requirements is rules which every source, or every source in a certain category of sources, must meet. These are often referred to as prohibitory rules. They apply whether or not a source is new or existing.

Each district has prohibitory 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 NOx) at any facility, or they may address specific equipment, such as a turbine, a boiler, or a reciprocating internal combustion engine. Sources are also subject to a general nuisance rule which provides authority to the district to control the discharge of any air contaminants, including odor, 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 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.

D. Toxic Air Contaminant Requirements

Most districts include toxic air contaminant (TAC) review during the permitting process. Sources emitting TACs must comply with district requirements regarding risk assessment and risk management of TAC emissions. Screening analyses and health risk assessments may be performed as part of the permitting process, or as part of the State AB2588 Hot Spots Program. In the case of unacceptable health risks, districts may require mitigation to reduce the risk. In addition, a new or expanding source, as well as existing sources, may be subject to either a federal NESHAP or a State-mandated airborne toxic control measure promulgated by the ARB, or both.

E. Ambient Air Quality Impact Analysis

In California, most district permitting rules require evaluation of the air quality impact of a project to be based on the proposed emissions of the project. This is typically done with air quality modeling. Usually, air quality impact analyses using air quality models are only required when emission offsets are not provided. In most cases, only NSR requirements are imposed by California districts since PSD requirements are mostly enforced by the U.S. EPA. As a result, air quality modeling is mostly 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 or, in some cases, PSD increments, the project may not be approved, unless acceptable mitigation measures are provided. The project is assumed to meet the net air quality benefit requirement if it complies with all district emission offset requirements. As discussed above, the emission threshold level at which offsets are required varies by district and is in accordance with minimum requirements of the California Clean Air Act.

F. Federal Program Requirements

In addition to the district rules, there are also federal rules which govern the permitting of new or modified stationary sources. These requirements are federal NSR and prevention of significant deterioration (PSD). The purpose of federal NSR is to ensure that air quality does not deteriorate any further 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. The PSD program requires that sources apply emissions controls that are cost

effective and demonstrate that the new or modified source will not cause a violation of the federal ambient air quality standards.

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 rules that limit hazardous (toxic) air pollutants are known as Maximum Achievable Control Technologies (MACT).

The overall impact of the federal permitting regulations on the required emission standards for stationary sources in California is minimal due to our more stringent requirements, stemming from the California Clean Air Act and the more stringent California ambient air quality standards.

G. 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 the California Environmental Quality Act (CEQA) codified in the State Public Resources Code. 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 a project's environmental impacts and alternatives are disclosed to governmental decision-makers and the public, and that any 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. 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, districts can also have this responsibility.

1. The CEQA Process

If a project is not exempt from CEQA review, it is evaluated to determine if there is the possibility of a significant effect on the environment¹⁵. 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 impacts, 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

¹⁵ A significant effect on the environment is defined as a substantial adverse change in the physical conditions which exist in the area affected by the proposed project.

notice of preparation (NOP) of an environmental impact report (EIR). 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. ARB staff expects that any large biorefinery project proposed for California will require the full EIR process including the full mitigation of emissions.

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 significance 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 of federal standards; (4) expose sensitive receptors to substantial pollutant concentrations; or (5) create objectionable odors affecting a substantial number of people.

Where applicable, the emission thresholds established by the district may be relied upon to make the CEQA determinations of significance. However, unlike district rules, CEQA analyses must also consider: impacts of facility construction; indirect emissions from increased mobile source activity; and the cumulative impacts of 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.

Standard mitigation measures for construction equipment have typically included equipment maintenance requirements; use of CARB-certified diesel for all off-road and portable diesel-powered equipment; and use of newer, cleaner engines or retrofit of existing engines with diesel oxidation catalysts, catalyzed diesel particulate filters, or other district-approved retrofit devices on diesel-powered equipment. Standard mitigation measures for fugitive PM10 control for construction activities have typically included paving, watering, or applying non-toxic soil stabilizers on all unpaved access roads, parking areas, and staging areas; watering dirt stock-piles; and sweeping streets at the end of each day if visible soil material is carried onto streets, or wash off trucks and equipment leaving the site.

Cumulative effects means the individual effects from the project are considered 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 evaluated against growth projections of emission forecasts in the SIP. If there is a significant impact, the lead agency will evaluate the need for mitigation measures identified in the EIR, such as providing offsets, before approving the project.

This Page Intentionally Left Blank

Appendix F4

Emissions from Biomass and Biofuel Transportation and Distribution

A. Cellulosic Biofuel Facilities

1. Feedstock Delivery

The Western Governors' Association (WGA) report prepared by researchers at the University of California at Davis estimates the volume of a variety of dry feedstocks that would be necessary for California cellulosic ethanol biofacilities to produce biofuels in the future.(2) The feedstock sources are based on the location in California and include municipal solid waste, orchard and vineyard waste, forest waste, stover and straw.

To calculate the number of feedstock delivery truck trips for a typical cellulosic biofacility in 2020, the volume of feedstock at each facility was assumed to be delivered by a 25 ton capacity truck. The volume of each dry feedstock was adjusted for moisture content according to the values in Table F4-1.

Table F4-1
Moisture Content of Cellulosic Feedstocks

Feedstock	Moisture Content (%)
Municipal Solid Waste	
Paper	10
Wood	50
Yard	50
Orchard and Vineyard Waste	35
Forest	50
Stover	15
Straw	15

After moisture content correction, the number of feedstock truck trips was calculated for each facility projected in the WGA report. The average number of feedstock truck trips for a 50 MMgpy cellulosic ethanol facility is estimated to be 110 per day.

The number of miles feedstock trucks traveled was assumed to be 50 miles round trip. Emission calculations used emission factors for the 2020 fleet. Emission factors are shown in Table F4-2.

**Table F4-2
Emission Factors for 2020 Diesel Trucks(3)**

Pollutant	Emission factor (g/mi/truck)
ROG	0.52
CO	3.32
NOx	7.86
CO2	2.14
SOx	0.18
PM10	0.24
PM2.5	0.22 (calculated as 92% of PM10)

2. Ethanol Delivery

In California, there are approximately 45 terminals blending CARBOB and ethanol. It is likely that ethanol biorefineries in 2020 will be located in close proximity to a blending terminal. To calculate the number of finished ethanol truck trips and the emissions from the trucks, finished ethanol was assumed to be delivered from each facility to a blending terminal. Each truck was assumed to travel 20 miles round trip. Finished fuel will be delivered in 7,500 gallon capacity diesel trucks. For each 50 MMgpy facility, approximately 20 trucks per day would be necessary to deliver ethanol from the facility to the blending terminal. Emissions were estimated using the 2020 fleet emissions factors, shown in Table F4-2.

B. Corn Ethanol Biorefineries

Currently permitted capacity of corn ethanol facilities in California is expected to be sufficient to meet anticipated corn ethanol usage in 2020. Therefore, emissions for the transportation and distribution of corn ethanol have been accounted for in the LCFS baseline, and there are no additional emissions expected due to increases production.

C. Biodiesel Facilities

1. Feedstock Delivery

Currently there are approximately nine operating biodiesel facilities in California utilizing Fatty-Acid Methyl Ester (FAME) technology to produce approximately 63 MMgpy. While these facilities may continue to produce limited quantities of biodiesel in the future, facilities using other technologies are expected to contribute larger quantities of biodiesel to the California market.

Based on the results of the WGA report, Fischer-Tropsch (FT) facilities using municipal solid waste as feedstock and hydrotreatment technology using waste grease and tallow are expected to be utilized to produce biodiesel in California in 2020. Five FT facilities and one hydrotreatment facility of 50 MMgpy capacity each would provide a total of 300,000 MMgpy biodiesel.

FT facilities are typically located at municipal waste sites to take advantage of minimal cost in acquiring feedstock. Trucks used for feedstock collection were assumed to travel 20 miles roundtrip.

Hydrotreatment facilities in California in 2020 would collect waste grease and tallow via diesel trucks traveling 200 miles round trip. Emission calculations used emission factors for the 2020 fleet. Emission factors are shown in Table F4-2.

2. Biodiesel Delivery

There are approximately 45 blending terminals located throughout California. It is likely that biodiesel facilities in 2020 will be located in close proximity to a blending terminal. Finished biodiesel was assumed to be delivered from each facility to a blending terminal. Round trip miles traveled were assumed to be 20 for each truck trip. Finished fuel will be delivered in 3,000 gallon capacity diesel trucks. For each 50 MMgpy facility, approximately 46 trucks per day would be necessary to deliver ethanol from the facility to the blending terminal. Emissions were estimated using the emission factors in Table F4-2.

D. Imported Ethanol and Biodiesel

Imported biofuels (approximately 1.0 billion gallons ethanol and 470 million gallons biodiesel in 2020) are assumed to travel by unit train from the Midwest into California via three locations: Needles, Yuma, or Reno. All unit trains deliver to Carson or Selby. Ethanol is assumed to then travel by 7,500 gallon tanker truck to blending terminals. Average distance traveled is assumed to be 20 miles roundtrip.

Imported biodiesel is assumed to travel by unit train from the Midwest into California via one location: Reno. All biodiesel unit trains deliver to the Selby refinery. Biodiesel is assumed to travel in 3,000 gallon diesel trucks to blending terminals. Average roundtrip distance traveled is assumed to be 20 miles.

Ethanol was assumed to be transported by unit trains from the Midwest to California; however, emissions are based on estimated locomotive activity inside California. Formula F4-1 generally describes the emissions from ethanol unit trains.

Formula F4-1

$$\text{Emissions (g)} = \text{Emission Factor (g/gal)} \times \text{Fuel Consumption (gal)}$$

Specific route information with regard to locomotive fleet composition and activity was not available. Therefore, staff based estimates on national locomotive fleet information, information from existing federal regulations, and various agreements between the Railroads and ARB. Based on this information, staff estimates that, in 2020, the

average locomotive operating in California would meet U.S. EPA Tier 2 emission standards.

The emission factors used to calculate locomotive emissions are derived from the U.S. EPA test method 40 CFR Part 92, used to determine if a locomotive is compliant with the applicable federal certification standards. Locomotives have eight discrete power settings with different power outputs, fuel consumption, and emission rates. While locomotive emission factors are weighted over the entire line-haul duty cycle, they are generally representative of line haul operations.

Fuel consumption is a function of weight, distance, and fuel efficiency. Distances were estimated from the California border and appropriate conversions were made so that all commodities were compared by weight. Fuel efficiency is based on the amount of work a gallon of fuel produces. Work is measured by the distance a given weight is pulled (ton-mile). For example, if a train hauls 100 tons 100 miles then it has performed 10,000 ton-miles worth of work.

Formula F4-2

$$\text{Work} = \text{Weight (tons)} \times \text{Distance (miles)}$$

Railroads report their ton-miles, fuel consumption, and fuel efficiency on a yearly basis in their annual reports. Using the reported fuel efficiency we can estimate the amount of fuel consumed in a given scenario. Estimated fuel consumption for a given scenario can be calculated by dividing the calculated ton-miles (work) by the reported fuel efficiency.

Formula F4-3

$$\text{Fuel Consumption (gal)} = \text{Work (ton-miles)} \div \text{Fuel Efficiency (ton-mile/gal)}$$

Using formula F4-1, we can use the estimated fuel consumption and emission factor to estimate the emissions associated with the delivery of corn to corn ethanol biofacilities in California.

Table F4-3 shows the feedstock and feedstock volumes for potential biorefineries based on their location.

Table F4-3
Estimate of Potential 2020 Biorefinery Feedstock Volumes(2)

Facility Location	# of Facilities	Facility Type	Feedstock	Feedstock Volume (tons)	Feedstock Truck Delivery Miles (50 miles Round Trip)
Los Angeles	1	cellulosic	msw wood	210,821	1,686,568
			msw yard	449,179	3,593,432
Mecca	1	cellulosic	msw wood	210,821	1,686,568
			msw yard	449,179	3,593,432
Oceanside	1	cellulosic	msw paper	54,653	121,451
			msw wood	179,196	716,782
			msw yard	423,554	1,694,214
			forest	303	1,210
			ovw	1,054	3,243
			straw	1,242	2,922
San Diego	2	cellulosic	msw paper	378,071	1,680,315
			msw wood	77,798	622,384
			msw yard	183,886	1,471,084
			ovw	18,133	111,585
			stover	1,498	7,049
			straw	615	2,895
Oxnard	2	cellulosic	msw paper	365,181	1,623,024
			msw wood	62,499	499,992
			msw yard	196,850	1,574,796
			forest	444	3,548
			ovw	34,791	214,098
			stover	126	593
			straw	110	520
San Francisco	1	cellulosic	msw paper	188,167	418,149
			msw wood	97,023	388,092
			msw yard	229,328	917,312
			forest	53,131	212,524
			ovw	38,649	118,918
			stover	6,181	14,544
			straw	1,115	2,625
San Jose	1	cellulosic	msw paper	156,139	346,976
			msw wood	80,509	322,034
			msw yard	190,295	761,178
			forest	142,189	568,756
			ovw	32,832	101,020
			stover	496	1,166
			straw	1,007	2,369

Table F4-3
2020 Estimate of Potential Biorefinery Feedstock Volumes (continued)

Facility Location	# of Facilities	Facility Type	Feedstock	Feedstock Volume (tons)	Feedstock Truck Delivery Miles (50 miles Round Trip)
Bakersfield	1	cellulosic	msw paper	278,142	618,093
			msw wood	24,523	98,092
			msw yard	57,964	231,856
			forest	9,814	39,256
			ovw	267,179	822,088
			stover	1,928	4,536
			straw	20,450	48,119
Sacramento	1	cellulosic	msw paper	57,917	128,703
			msw wood	29,863	119,452
			msw yard	70,586	282,342
			forest	220,968	883,870
			ovw	121,235	373,031
			stover	103,564	243,679
			straw	49,384	116,197
Stockton	1	cellulosic	msw paper	42,649	94,776
			msw wood	21,991	87,964
			msw yard	51,979	207,914
			forest	78,302	313,208
			ovw	220,789	679,351
			stover	96,178	226,301
			straw	20,453	48,124
Fresno	2	cellulosic	msw yard	51,381	411,048
			forest	142,189	1,137,512
			ovw	390,905	2,405,572
			stover	37,935	178,515
			straw	60,777	286,008
Eureka	1	cellulosic	forest	545,015	2,180,058
			ovw	38	116
			stover	93	218
Redding	1	cellulosic	forest	377,870	1,511,480
			ovw	376	1,155
			straw	6,044	14,221
Fort Bragg	1	cellulosic	forest	283,959	1,135,834
			ovw	12,062	37,112

Table F4-3
2020 Estimate of Potential Biorefinery Feedstock Volumes (continued)

Facility Location	# of Facilities	Facility Type	Feedstock	Feedstock Volume (tons)	Feedstock Truck Delivery Miles (50 miles Round Trip)
Colusa	1	cellulosic	forest	303,423	1,213,692
			ovw	84,400	259,692
			stover	32,406	76,249
			straw	19,806	46,603
Los Angeles	1	hydro	grease	56,856	
		biodiesel	tallow	35,515	

Criteria pollutant emissions for the transportation and distribution of ethanol and biodiesel in 2020 excluding baseline emissions are shown in Table F4-4. Tables F4-5 and F4-6 show the totals for feedstock transportation and distribution and finished fuel distribution, respectively.

Table F4-4
Transportation and Distribution Emissions for 2020 Biofacilities

Air Basin	2020 Emissions (tons/day)						
	ROG	CO	NOx	CO2	SOx	PM10	PM2.5
North Coast	0.006	0.036	0.086	0.023	0.002	0.003	0.002
Sacramento Valley	0.009	0.057	0.749	0.037	0.003	0.015	0.014
San Francisco Bay	0.018	0.117	0.454	0.075	0.006	0.012	0.011
San Joaquin Valley	0.018	0.113	0.266	0.073	0.006	0.008	0.007
South Central Coast	0.007	0.042	0.099	0.027	0.002	0.003	0.003
South Coast	0.012	0.078	0.731	0.050	0.004	0.016	0.015
San Diego	0.013	0.082	0.467	0.053	0.004	0.011	0.010
Mountain Counties			0.969			0.017	0.016
Mojave Desert			0.824			0.015	0.014
Salton Sea			0.545			0.010	0.010
Total	0.083	0.525	5.19	0.338	0.027	0.110	0.102

Table F4-5
Projected 2020 Criteria Pollutant Emissions from Feedstock Production, Transportation, and Distribution above the Baseline

Feedstock	2020 Emissions Changes (tons/day)					
	VOC	CO	NO _x	SO _x	PM ₁₀	PM _{2.5}
Crude Oil	--	--	--	--	--	--
Electricity	--	--	--	--	--	--
Natural Gas	--	--	--	--	--	--
Corn Ethanol ^a	--	--	--	--	--	--
Cellulosic Waste Feedstock ^b	0.02	0.33	0.80	0.02	0.02	0.02
Biodiesel Feedstock ^c	0.01	0.09	0.20	0.005	0.006	0.006

^a No emissions are attributed to corn ethanol as no new facilities are expected to be built.

^b Forest waste, orchard and vineyard waste, corn stover, straw, and/or municipal landfill waste.

^c Beef tallow, pork lard and/or municipal landfill waste.

Table F4-6
Projected 2020 Criteria Pollutant Emission Changes from Fuel Transportation and Distribution

Fuel	2020 Emissions Changes (tons/day)					
	VOC	CO	NO _x	SO _x	PM ₁₀	PM _{2.5}
Finished Petroleum Products ⁶	--	--	--	--	--	--
Electricity ⁶	--	--	--	--	--	--
Compressed Natural Gas						
Corn Ethanol	--	--	--	--	--	--
Cellulosic Ethanol ^a	0.04	0.05	3.58	0.001	0.069	0.063
Biodiesel ^a	0.011	0.047	0.61	0.002	0.004	0.003
Hydrogen						

⁶ Based on hypothetical optimized locations for cellulosic ethanol and biodiesel facilities.

^a These transportation emissions include the rail emissions from imported cellulosic ethanol and biodiesel once they enter the state.

Appendix F5

Emissions from Potential Biorefineries

A. Introduction

Criteria pollutants were calculated for cellulosic ethanol and fatty-acid methyl ester (FAME) biodiesel production facilities as shown in Table F5-1 below. These estimates reflect 1) the most recent data gathered from permits and engineering evaluations for existing in-state facilities, 2) use of the cleanest energy conversion technologies and air pollution control technologies available, 3) emissions from stationary sources that do not require a permit, and 4) emissions from electrical back-up generators. ARB staff looked at oxides of nitrogen (NO_x), particulate matter 10 microns in diameter and smaller (PM₁₀), and volatile organic compound (VOC) emissions from each facility. Additional data from out-of-state facilities was used for comparison purposes. Permitted emissions can be found in Table F5-2.

Emissions are based on data gathered from permits and engineering evaluations for the following existing facilities:

- Western Biomass Energy¹⁶ is a cellulosic ethanol production plant with an annual capacity of 1.58 million gallons. The ethanol is produced from green waste, wood waste, and other cellulosic urban wastes.
- American Biodiesel¹⁷ is a FAME biodiesel facility producing 6.1 MMgal/yr of biodiesel from waste grease.

Table F5-1
Emissions per Million Gallons of Fuel Produced

Fuel Type	NO_x (LB/MMGAL)	PM₁₀ (LB/MMGAL)	VOC (LB/MMGAL)
Cellulosic Ethanol	3,840	3,919	10,053
Biodiesel	106	51	366

1. Adjustment of Criteria Emissions Associated with Scale-up of Western Biomass Energy

Staff used the Western Biomass Energy emissions profile as an estimate of future emissions associated with cellulosic ethanol facilities. There are several variables that, if incorporated into a scaled up version of the Western Biomass Energy facility, would decrease the criteria emissions impact (on a ton per million gallon ethanol produced):

¹⁶Wyoming Department of Environmental Quality. 2006. Air Quality Permit and permit application. Western Biomass Energy. Permit No. CT-4486.

¹⁷San Joaquin Valley Unified Air Pollution Control District. 2007. ATC application review and associated permits. American Biodiesel, Inc. DBA Comm. Fuels. Permit Nos. N-7480-1-0 through N-7480-3-0.

1. The use of SCR will reduce boiler NO_x emissions by 90%.
2. The use of an oxidation catalyst will reduce boiler CO emission by 80%.
3. The use of an oxidation catalyst will reduce boiler VOC emissions by 50%.
4. The use of an ESP will reduce PM₁₀ by 98%.
5. An inspection and maintenance program will reduce fugitive VOC emissions by 80%.
6. The use of a CO₂ scrubber and an oxidation catalyst will reduce VOC emissions by 99.95%.
7. The use of vapor recovery at the ethanol truck load out will reduce VOC emissions by control of 90%.
8. The size fractionation of the particulate matter for the cooling tower was determined to be 85% PM₁₀ and 15% PM_{2.5}.

**Table F5-2
Emissions from Permits**

Facility Name		Cellulosic process	Fuel Production Rate (MMgal/yr)	VOC (lbs/yr)	NOx (lbs/yr)	PM10 (lbs/yr)
In State	BlueFire ¹⁸	Concentrated Acid Hydrolysis	3.1	46,376	46,314	15,496
Out of State	Western Biomass Energy (Wyoming) ¹⁹	Weak Acid Hydrolysis	1.58	34,800	11,200	5,200
	Range Fuels Biofuels (Georgia) ²⁰	Gasification Catalytic	100	52,400	191,000	186,200
	Verenium Biofuels (Louisiana) ²¹	Weak Acid Hydrolysis	2.1	35,600	33,120	9,580
At 50 Million Gallons/Year						
Out of State	Western Biomass Energy (Wyoming)	Weak Acid Hydrolysis	50	502,649	192,019	195,994

¹⁸ Antelope Valley Air Quality Management District. 2008. Engineering Evaluation and associated permits. Bluefire Ethanol Lancaster, LLC. Permit Nos. B010425, B010433, B-10437 through B010440, C010426 through C010428, C010430, C010432, C010434 through C010436, C010441, C010442, C010446, E010447, T010429, T010431, T010448 through T010452.

¹⁹ Wyoming Department of Environmental Quality. 2006. Air Quality Permit and permit application. Western Biomass Energy. Permit No. CT-4486.

²⁰ Georgia Department of Natural Resources. 2007. Air Quality Permit. Range Fuels Biofuels. Permit No. 2869-283-0005-S-01-0.

²¹ Louisiana Department of Environmental Quality. 2008. Air Emission Permit. Verenium Biofuels Louisiana, LLC. Permit No. 1360-00071-01.

This Page Intentionally Left Blank

Appendix F6

Motor Vehicle Emissions – E85 vs. Gasoline

One potential avenue to reduced greenhouse gas emissions is expanded use of E85 in place of gasoline. E85, however, cannot be used in conventional gasoline vehicles, flexible fuel vehicles (FFVs) are necessary. Upgrades to the fuel distribution system are also required. This section examines the potential impacts to emissions of criteria pollutants and toxic air contaminants from switching from gasoline to E85. Given that both conventional gasoline and flexible fuel vehicles must meet the same emissions standards, it is reasonable to expect that the emissions levels will be similar. The following discussion presents aspects which are essential to examine E85's feasibility and environmental impact.

- FFV and total gasoline light duty vehicle populations
- Vehicles currently certified by ARB to use E85 and projected sales for the 2008 model year
- Estimates of refueling emissions
- Summary of vehicle standards
- Comparison of 2008 FFV certification data between E85 and gasoline
- E85 and other ethanol blends fuel efficiency and emissions studies
- E85 vehicle technology

The number of vehicles and the emissions per vehicle on each fuel can be used to determine the change in emissions in switching from gasoline to E85.

A. Vehicle Populations

Estimated FFV and total gasoline light duty vehicle populations are shown in Table F6-1. It can be seen from these data that the FFV portion of the gasoline LDV fleet was about 1.2 percent in 2005. The FFV population estimates were made in 2005, before the LCSF concept was conceived.

Table F6-1
Estimated FFV and Total Gasoline Light Duty Vehicle Populations

Year	FFV Population(4) (thousands)	EMFAC2007 Total Gasoline Light Duty Vehicle¹ Population (thousands)
2005	251	20,850
2006	265	20,679
2007	290	20,680
2008	315	21,047
2009	338	21,481
2010	359	21,927
2015	400	23,954
2020	500	25,726

¹ passenger cars and light duty trucks

Source: ARB, Planning and Technical Support Division, 2008

Vehicles currently certified by ARB to use E85 are shown in Table F6-2.

Table F6-2
E85 Vehicles Currently ARB Certified
Projected Model Year 2008 Sales(5)

Manufacturer	Vehicle Class	Models	Test Group ID	Evaporative Family
GM	T2L2	Chevy Uplander FWD, Pontiac Montana SV6 FWD, Buick Terraza FWD, Chevy Uplander FWD 3.9L, Montana SV6 FWD	8GMXT03.9140	8GMXR0170956
				8GMXR0203958
GM	PC	Chevy Impala 3.5L, Chevy Impala 3.9L	8GMXV03.9052	8GMXR0133810
GM	T3L2	Chevy Express 2WD, Chevy Van 2WD, Chevy Express AWD, Chevy Van AWD Conv., Chevy Van AWD, Savana 2WD Cargo Conv., Savana Cargo 2WD, Savana Passenger 2WD, Savana AWD Cargo Conv., Savana Passenger Van AWD, Savana Cargo AWD, Chevy G15/25 Van 2WD	8GMXT05.3373	8GMXR0223840
GM	T4L2	C1500 Tahoe 2WD 5.3L, K1500 Tahoe 4WD 5.3L, C15 Silverado 2WD 5.3L, K15 Silverado 5.3L, C1500 Yukon 2WD 5.3L, K1500 Yukon 4WD 5.3L, C15 Sierra 2WD 5.3L, K15 Sierra 4WD 5.3L, K1500 Avalanche 4WD 5.3L, K1500 Suburban 4WD 5.3L, C1500 Avalanche 2WD 5.3L, C1500 Suburban 2WD 5.3L, Chevy Silverado 2WD 5.3L, Chevy Silverado 4WD 5.3L, K1500 Yukon XL 4WD 5.3L, C1500 Yukon XL 2WD 5.3L, GMC Sierra 2WD 5.3L, GMC Sierra 4WD 5.3L	8GMXT05.3381	8GMXR0176820
				8GMXR0223840
Ford	PC	Grand Marquis FFV, Crown Victoria FFV, Crown Victoria Police	8FMXV04.6VEF	8FMXR0115GAK
Ford	T4L2	F-150 Pickup 4WD FFV	8FMXT05.44E2	8FMXR0240NBR
Ford	M4L2	E-150 Club Wagon FFV, E-150 Econoline 2WD FFV, E-250 Econoline 2WD FFV	8FMXT04.65E9	8FMXR0265GAS
Chrysler	T2L2	Carv 2WD, T&C 2WD	8CRXT03.3NEP	8CRXR0150XHA
DaimlerChrysler	PC	C300	8MBXV03.0U2A	8MBXR0155LNF

¹ARB, Mobile Source Operations Division, 2008

It is possible to make an updated projection of the 2020 FFV population with the following assumptions:

- A FFV population of 251,000 in 2005;
- ARB staff assumed the addition of about 68,000 FFVs per year based on recent manufacturer projected sales; therefore
- Based on those assumptions, staff project there would be just under one million FFVs in 2020.

The staff has developed five hypothetical compliance scenarios for compliance with the gasoline LCFS. For each of these five scenarios the staff has estimated the amounts of low-carbon intensity corn ethanol, cellulosic ethanol, sugar cane ethanol, and advanced renewable blendstocks that would be needed to meet the required 10 percent reduction in greenhouse gas emissions. The staff has also estimated the number of flex fuel vehicles using E85 that would be required to burn the estimated amounts of low-carbon intensity ethanol that would be used. The staff's estimate of the required number of FFVs in 2020 ranges from 1.8 million to 3.4 million, assuming that the FFVs burn E85 100 percent of the time. If the FFVs burn E85 less than 100 percent of the time, the required number of FFVs would be higher.

Clearly production levels of FFVs would need to be increased over current levels to lead to a sufficient population in 2020 to enable the levels of ethanol consumption envisioned by the LCFS.

A recent estimate made by California Energy Commission staff (Gary Yowell 2009) projected a population of 4.2 million FFVs in 2020. This value is sufficient to enable the levels of ethanol consumption envisioned by the LCFS.

B. Refueling Emissions Estimates

An estimated maximum increase of 84 ton/year NMOG evaporative emissions from refueling results in switching to scenario 2 volumes of E10 and E85 in 2020, as opposed to not switching from an energy equivalent volume of 2010 baseline CaRFG3 fuel (E10). The other scenarios offer somewhat smaller increases. See Table F6-3.

Table F6-3
Estimates of Refueling Emissions in 2020(6)¹

Scenario	NMOG Emissions (ton/year)			
	E10 + E85		E10 only	(E10 + E85) – E10 only
	E10	E85		
1	3,070	430	3,426	74
2	3,024	489	3,428	84
3	3,034	417	3,379	72
4	3,058	258	3,272	45
5	3,056	391	3,379	68

¹Source: ARB, Stationary Source Division, 2009 analysis based on data contained in December 2008: California-GREET model version 1.8b and Full Fuel Cycle Assessment Well to Tank Energy Inputs(7), Emissions, and Water Impacts(8)

The values in Table F6-3 were calculated based upon estimates of the volume of E10 and E85 used in 2020, emission factors and control efficiencies published in the CEC report, and heating values from the California-GREET model. The E85 emission factor is 7.3 lb NMOG per 1000 gallons, and the E10 emission factor is 8.1 lb NMOG per 1000 gallons. Those NMOG emissions would be largely controlled by on-board vapor recovery, at 95% control on 90% of the fleet. The E10 is assumed to be 9.38% ethanol by volume, and the E85 is assumed to be 85% ethanol by volume. The higher volume of E85 than E10 is offset by the lower emission factor, but the net effect is an increase in emissions in 2020.

C. Summary of Vehicle Standards

Regulations for vehicles which use E85 are the same as for vehicles which use gasoline. Alcohol-fueled and flexible-fuel vehicle regulations can be found as shown below. Except for 13 CCR 1961.1 which deals with greenhouse gas exhaust emission standards and test procedures, the regulations do not refer to E85, they refer to alcohol-fueled and flexible-fuel vehicles.

- California Evaporative Emission Standards and Test Procedures for 2001 and Subsequent Model Motor Vehicles”, adopted August 5, 1999, last amended October 17, 2007. These adopt the provisions of 40 CFR 86, subparts A and B as adopted or amended as of July 1, 1989, and subpart S as adopted or amended on May 4, 1999, with specific exceptions and additions (for details see 40 CFR 86). They apply to gasoline, LPG and alcohol fueled vehicles.(9)
- Sections 1976 and 1978, title 13, California Code of Regulations, as effective January 4, 2008, can be found by referring to the table of contents within "The California Low-Emission Vehicle Regulations". (10)There are several references to alcohol fuels, which include:
 - 1956.8. Exhaust Emission Standards and Test Procedures - 1985 and Subsequent Model Heavy-Duty Engines and Vehicles. (LEV I) Applicable

to petroleum, alcohol, LPG, and natural gas fueled vehicles for 2005 and subsequent model heavy-duty Otto-cycle engines.

- 1960.1. Exhaust Emission Standards and Test Procedures - 1981 through 2006 Model Passenger Cars, Light-Duty Trucks, and Medium-Duty Vehicles. (LEV I) These SFTP standards do not apply to vehicles certified on fuels other than gasoline and diesel fuel, but the standards do apply to the gasoline and diesel fuel operation of flexible-fuel vehicles and dual-fuel vehicles.
- 1961. Exhaust Emission Standards and Test Procedures - 2004 and Subsequent Model Passenger Cars, Light-Duty Trucks, and Medium-Duty Vehicles. (LEV II) Applicable to flex fuel vehicles on both alcohol fuels and gasoline.
- 1976. Standards and Test Procedures for Motor Vehicle Fuel Evaporative Emissions. Applicable to 1978 and subsequent model gasoline-fueled, 1983 and subsequent model LPG-fueled, and 1993 and subsequent model alcohol-fueled motor vehicles and hybrid electric vehicles subject to exhaust emission standards under this article, except petroleum-fueled diesel vehicles, CNG-fueled vehicles, hybrid electric vehicles that have sealed fuel systems which can be demonstrated to have no evaporative emissions, and motorcycles.
- 1978. Standards and Test Procedures for Vehicle Refueling Emissions. Applicable to 1998 and subsequent model gasoline, alcohol, diesel, LPG, fuel-flexible, and hybrid electric passenger cars, light-duty trucks, and medium-duty vehicles with a gross vehicle weight rating less than 8,501 pounds. Applies equally to certification and in-use vehicles.

D. Comparison of 2008 FFV California Certification Data between E85 and Gasoline

Average 2008 FFV California certification values and standards are shown in Table F6-4.

Table F6-4
Average 2008 FFV Certification Values and Standards, g/mi(11)

Vehicle	NMOG		CO		NOx		HCHO		Hwy NOx	
	Cert	Std	Cert	Std	Cert	Std	Cert	Std	Cert	Std
E85	0.049	0.089	1.1	3.7	0.03	0.07	1.3	16	0.02	0.08
Gasoline	0.044	0.095	1.3	3.7	0.04	0.07	0.4	16	0.02	0.08

A cursory review of California certification data for 2008 model year flexible fuel vehicles yields the following observations:

- All of the FFVs are compliant on both E85 and gasoline for all pollutants.

- Certification values in grams/mile for non-methane organic gases (NMOG) on E85 are mostly greater than on gasoline, more so at 50,000 miles than at useful life.
- Certification values in grams/mile for carbon monoxide (CO) on E85 are mostly less than on gasoline, both at 50,000 miles and useful life.
- Certification values in grams/mile for oxides of nitrogen (NOx) on E85 are about the same as on gasoline, both at 50,000 miles and useful life.
- Certification values in grams/mile for formaldehyde on E85 are greater than on gasoline, both at 50,000 miles and useful life (note however there was only one pair of values for each).
- While the differences were slight, emissions of CO and NOx tended to be less on E85 than on gasoline, while emissions of NMOG tended to be greater on E85 than on gasoline. Emissions of formaldehyde (HCHO) were also greater on E85 than on gasoline, showing a much larger difference, although there was only one pair of test values (DaimlerChrysler).
- Summarizing all of the differences in certification values by manufacturer, it can be seen that GM and DaimlerChrysler tend to have higher NMOG emissions on E85 than gasoline, while Ford tends to have less. CO is the opposite: GM and DaimlerChrysler tend to have lower emissions on E85 than gasoline, while Ford shows no difference. GM also tends to have higher NOx emissions on E85 than gasoline, while Ford and DaimlerChrysler tend to have less. GM has nearly double the projected 2008 sales of FFVs than that of Ford and DaimlerChrysler combined.

In summary, while differences were slight, emissions of CO and NOx tended to be less on E85 than on gasoline, while emissions of NMOG tended to be greater on E85 than on gasoline. Emissions of formaldehyde (HCHO) were also greater on E85 than on gasoline, showing a much larger difference, although there was only one pair of test values (DaimlerChrysler).

The comparable data for 2009 model year FFVs are substantially similar to 2008, the notable exception being that Ford also tends to have higher NMOG emissions on E85 than gasoline.

E. E85 and Other Ethanol Blends Fuel Efficiency and Emissions Studies

A literature search was conducted for E85 and FFV emissions. Results turned up mostly dated (1990s) publications and low-to-intermediate ethanol concentration fuels. Since that time, reformulated gasoline has emerged and vehicle technologies have changed considerably. Fewer recent publications are available. Emissions studies yielded mixed results; there does not appear to be a clear consensus as to whether E85 or gasoline has greater emissions.

A good introductory summary can be found at the US Department of Energy Alternative Fuels & Advanced Vehicles Data Center website, see http://www.afdc.energy.gov/afdc/vehicles/emissions_e85.html

Recently published reports include:

- Fuel Permeation from Automotive Systems: E0, E6, E10, E20 and E85, Final Report CRC E-65-3, December 2006
- CRC CM-138-08: Cold Start and Warm-up E85 and E15/E20 Driveability Program, 26 vehicles, using 8 fuels (E85, E20, E15, and E0). Field work was completed Jan/Feb 2008. See 2007 2008CRC E85 Volatility Program2.doc for a program description. The final report was completed October 2008. Results showed that for the test program conditions, driveability of the FFVs improved with increasing vapor pressure of E85 fuels, whereas the vapor pressure of gasoline had no effect. There is no statistically significant effect of temperature on driveability with either E85 blends or gasolines for the temperature range tested in the program.
- Regulated and Non-regulated Emissions from Euro 4 Alternative Fuel Vehicles, June 2008, SAE document no. 2008-01-1770. A copy of the paper has been obtained. Note this document is copyrighted. This study concludes that the use of E85 as compared to gasoline results in reductions in NO_x, 1,3-butadiene, benzene, toluene and PN (particle number), and increases in aldehyde emissions in temperate climates, and increases in aldehyde, CO, HC, PM and PN emissions in cold climates.
- Emissions from light duty gasoline vehicles operating on low blend ethanol gasoline and E85.(12) This study concludes that the use of E85 as compared to gasoline results in statistically significant decreases in emissions of NO_x (-45%), non-methane hydrocarbons (NMHC) (-48%), 1,3-butadiene (-77%), and benzene (-76%); statistically significant increases in emissions of formaldehyde (73%) and acetaldehyde (2540%), and no statistically significant change in CO, CO₂, and non-methane organic gases (NMOG) emissions.
- Regulatory Impact Analysis: Renewable Fuel Standard Program, Chapter 3 Impacts on Emissions from Vehicles, Nonroad Equipment, and Fuel Production Facilities.

ARB staff is continuing to examine California certification data of 2008 and 2009 flexible fuel vehicles to see if there are significant differences in emissions between gasoline and E85. The results of this review will be included in an addendum to the LCSF staff report.

ARB staff is currently analyzing fueling data collected during the E85 demonstration program on a fleet of 50 flexible fuel vehicles (FFV) (Chevrolet Impalas and Silverados) over the course of the last year using mostly E85, also some California reformulated gasoline (E6).

ARB is doing some in-house emissions testing on ethanol blends. Two vehicles from Caltrans fleet of FFVs used in the E85 demonstration program will be tested for exhaust emissions on E6, E85, and a 50/50 blend of the two fuels, in addition to other vehicles. The data are undergoing QA/QC review now and are expected to be validated by the

end of 2008. A final report is expected early 2009.

At least two other vehicle studies are in the works:

1. CRC E-80: ARB is co-funding this study. The co-chairs are Michael Ingham (Chevron) and Cynthia Williams (Ford). The study consists of testing of 7 vehicles for exhaust emissions and 4 vehicles for evaporative emissions, using 4 fuels (E6, E85 and 2 intermediate blends). Coordinating Research Council permission is required to release the test plan and interim reports. Emissions testing is presently underway, a final report is expected in 2009.
2. US EPA Contract EP-C-07-018 to Southwest Research Institute: Comprehensive Gasoline Light Duty Exhaust Fuel Effects Test Program to Cover Multiple Fuel Properties and Two Ambient Test Temperatures. Testing of 19 vehicles, 31 fuels (E0, E10, E15, and E20). This work is focusing on speciation of volatile organic compounds and particulate matter emissions. Phase 1 of this study is complete, phase 2 is expected to wrap up around the end of January 2009. Phase 3 is expected to take place February through December 2009. For more information, contact US Environmental Protection Agency (EPA) National Vehicle Fuel and Emissions Laboratory staff Tony Fernandez at fernandez.antonio@epa.gov, 734 214-4431 or Rafal Sobotowski at sobotowski.rafal@epa.gov, 734 214-4228.

ARB staff is aware of several other studies of off-road vehicles and equipment involving a variety of gasoline formulations including low-to-intermediate ethanol concentration fuels, but not E85.

F. E85 Vehicle Technology

Spark-ignition engines can be designed to run on one or more fuels. Although gasoline engines are most common, engines designed to run on alternative fuels like ethanol have been around since the days of the Model T. Flexible fuel vehicles (FFVs) in their present incarnation arose out of efforts to develop dedicated alcohol (methanol) fuel vehicles in the 1980s, and are now designed to operate on either gasoline (E10 or less) or E85. The technology to run on these two fuels is not fundamentally different, the differences include some or all of the following:

- upgrade aluminum/brass parts in contact with fuel to stainless steel to minimize effect of alcohol's higher corrosion potential, and upgrade some plastic/rubber parts in contact with fuel to minimize swelling/shrinkage/disintegration leading to increased permeation emissions/possible leakage: inc. fuel tank, fuel pump, fuel lines, injection pump, injectors, etc.
- change type of fuel pump if susceptible to increased wear
- change type of fuel gauge indicator sending unit if capacitance type due to alcohol's increased electrical conductivity
- increase capacity of fuel tank, fuel pump, fuel lines, injection pump, injectors, etc. to account for alcohol's lower energy density

- increase amount of fuel injected by modifying engine map/injection pulse width (duration) to account for alcohol's lower energy density
- update engine calibration to optimize combustion to maximize power and fuel economy, enable cold start, minimize emissions (e.g., spark advance)
- upgrade material used in piston rings, cylinder head, valve seats and valves to minimize wear (alcohol can wash lubrication from parts)
- install anti-siphon fuel filler neck (gasoline and methanol are both toxic – gasoline will induce vomiting upon ingestion while methanol won't) and spark arrestor to handle alcohol's greater flammability range
- add heat shielding to ORVR canister and fuel lines to minimize evaporative emissions
- redesign combustion chamber to increase compression ratio to take advantage of alcohol's higher octane number
- add fuel sensor to measure fuel composition (optional – can be done with ECU software)
- install an auxiliary cold-start system that injects gasoline from a small tank in the engine compartment to help starting when cold, especially with neat alcohol
- switch to an engine oil with a different additives package to absorb acidic by-products, especially with methanol
- upgrade wiring insulation to handle alcohol's increased conductivity and corrosiveness
- install colder spark plugs suitable for dissipating heat due to alcohol's higher flame temperatures (before modern engines, hotter plugs for city driving [a better insulator using less substantial ceramic insulators to retain heat] and colder plugs for sustained highway driving [a better conductor using more substantial ceramic insulators to dissipate heat] were sometimes used – racing engines still benefit from picking the right heat range plugs); a plug has to be hot enough to prevent fouling but cold enough to prevent knocking.

From a technical standpoint, there is no reason why all gasoline engines could not be designed to run on E85. Proven technology has existed for many years. The marginal cost of producing a FFV is on the order of \$200 over that of a comparable gasoline powered vehicle. It would be quite simple to legislate that an increasing percentage of the vehicle fleet, if not all vehicles, be FFVs. The biggest challenge would be the time needed to increase the production capacity of suppliers of FFV specific parts to the auto manufacturers. Another challenge is upgrading bulk fuel terminals to handle ethanol. There is also the perceived “chicken or egg” problem – vehicle manufacturers don't want to produce FFVs without an established E85 distribution network in place, and fuel marketers don't want to make capital investments in equipment for a fuel without an established demand.

Appendix F7

Motor Vehicle Emissions – Biodiesel vs. Diesel

The LCFS will be fully implemented in 2020. Under this regulation, 15% of petroleum diesel will be displaced by renewable alternative diesel fuels (biodiesel 5% and renewable diesel 10%). In addition to climate gas reductions, renewable alternative diesel fuels have the potential to change regulated emission rates. To estimate changes in emission rates in 2020, a number of factors need to be taken into consideration and a number of assumptions made.

The main factors that will affect changes in emission rates are feedstock composition, changes in engine technologies, and regulatory action. Feedstocks can have a significant effect on emissions of ROG, PM, and NOx. NOx is of particular interest because biodiesel has been reported to increase NOx emissions. Knowledge of feedstocks used in 2020 is of major importance since biodiesel emissions are highly dependent on the type of feedstocks in use. One problem is that feedstocks used in 2020 are likely to be significantly different than those in current use and little emission impact data is available for these feedstocks.

The second factor is lack of data on how biodiesel will effect emissions from 2010 engines. The 2010 engine technologies are significantly different from current engines since they control both NOx and PM and emit lower emissions than uncontrolled engines. Another factor, is that the on-road and off-road diesel regulations will make almost all diesel engines controlled by 2020 and almost all on-road engine technologies will be 2010 or equivalent.

Renewable diesel is probably not significantly affected by feedstock since the renewable diesel feedstocks are blended with petroleum diesel feedstocks to make compliant diesel fuels. Although feedstocks will not affect renewable diesel emissions, engine technology and implementation of regulations are factors that will need to be considered in estimating emission changes for renewable diesel. Neste 100% renewable diesel fuel has been reported to decrease NOx, PM, and THC by 15%, 25%, and 20% respectively(13). Again, as with biodiesel, the issue is whether these emission changes apply to 2007 and 2010 engines.

To account for the uncertainty in the current data base, three scenarios are presented to cover the range of possible emission changes that can be expected from the 2020 fleet. The first and most likely scenario is that the 2010 engine controls will likely result in no emissions differences between CARB diesel and renewable alternative diesel fuels. Since almost all engines will meet this criterion the assumption is that there will be no net impact to the 2020 fleet. The second scenario is that the percent change in emissions for new technology is the same as for pre-2007 engines. Williams et al(14) reported that biodiesel use of a diesel particulate trap showed lower emissions for hydrocarbons, carbon monoxide, and particulate and higher emissions for oxides of nitrogen as compared to petroleum diesel, which is directionally similar to uncontrolled engines. Therefore, this scenario assumes that 2010 technology is also directionally

similar to pre-2007 engines and that the pre-2007 emission factors apply to the entire 2020 fleet. The third scenario is to assume that retrofitted engines do not achieve any emission changes on 2010 engines and that the pre-2007 emission factors will be applied to pre 2010 engines. Based on EMFAC approximately 53% of the on-road fleet will be pre-2010. The pre-2007 emission factors will be applied to this portion of the fleet. The emission factors for biodiesel(15) were based on data comparing clean diesel fuels to biodiesel and from ARB current emissions study(16). Table F7-1 shows the expected emission changes (tons/day) for ROG, NOx, and PM based on the scenarios discussed.

**Table F7-1
Emissions Changes**

Baseline	ROG	NOX	PM2.5
	tons/day	tons/day	tons/day
on-road	32.6	435	14.2
off-road			
	Change in Emissions	Change in Emissions	Change in Emissions
Scenario one	BD/RD tons/day	BD/RD tons/day	BD/RD tons/day
on-road	0/0	0/0	0/0
off-road	0/0	0/0	0/0
Scenario two			
on-road	-.35/-.20	1.1/-2.3	-.22/-.12
off-road	-.70/-.41	1.0/-2.0	-.24/-.13
Scenario three			
on-road	-1.1/-.66	3.3/-6.6	-.68/-.36
off-road	-1.4/-.82	2.0/-4.1	-.49/.26

Scenario one: Assumes alternative diesel fuels have no net impact on emission rates for the entire 2020 fleet

Scenario two: Use pre-2007 emission factors only for retrofitted vehicles and no net impact on emission rates for 2010 vehicles. Use the pre-2007 emission factors for 50% of the 2020 off-road fleet

Scenario three: Apply pre-2007 emission factors to the entire 2020 fleet

Appendix F8 Motor Vehicle Emissions- Electricity and Hydrogen vs. Gasoline and Diesel

A. Impact on On-Road Motor Vehicles (LDV, HDV)

1. Light Duty Vehicles (LDV)

The proposed rulemaking allows for hydrogen or electricity used in a fuel cell, battery or plug-in hybrid electric vehicle to receive low carbon fuel credits. While the current Zero Emission Vehicle (ZEV) regulation sets requirements for manufacturers to produce and deploy vehicles using these fuels. The low carbon fuel standard has the potential to increase emissions benefits beyond those achieved by the ZEV regulation due to an increase in clean fuel use.

An analysis of three different deployment scenario groupings for these vehicles was performed to determine possible emissions from various populations. Scenario's one and two vehicle distribution is based on more conservative auto manufacturer's public announcements and current ZEV regulation compliance. Scenarios three and five are based on more aggressive auto manufacturer public announcements and a significantly more stringent ZEV regulation. Scenario four assumes that California vehicle consumers and manufacturers shift to the purchase and production of ZEV technologies due to increased fuel prices, competitive vehicle pricing, and a strong commitment to California's greenhouse gas reduction goals. The five scenarios are combined into three groups due to the number of vehicles being the same for scenarios one and two and also three and five. The three groups and their respective vehicle populations are presented in Table F8-1 analysis was performed for years 2010, 2015 and 2020 and by technology type.

**Table F8-1
Potential Vehicle Rollout Scenarios**

Year	Scenario 1&2 (millions)			Scenario 3&5 (millions)			Scenario 4 (millions)		
	BEV	PHEV	FCV	BEV	PHEV	FCV	BEV	PHEV	FCV
2010	0.002	0.001	0.0005	0.002	0.001	0.0003	0.002	0.002	0.0006
2015	0.020	0.110	0.0100	0.031	0.150	0.0125	0.06	0.3	0.025
2020	0.090	0.400	0.0700	0.220	0.670	0.1100	0.44	1.34	0.22
Scenario 1&2: Current ZEV regulation Scenario 3&5: Potential revised ZEV regulation Scenario 4: Enhanced market penetration Battery Electric Vehicle (BEV), Plug-in Hybrid Electric Vehicle (PHEV), Fuel Cell Vehicle (FCV)									

Incorporating ZEV fuels into the low carbon fuel standard would decrease emissions for all criteria pollutants in each scenario. Scenario four would provide the largest reduction in criteria pollutant emissions in the year 2020 compared to the other scenarios.

Scenario four assumes a large market penetration of electric drive vehicles: up to 2 million hydrogen, plug-in and electric vehicles in the year 2020 providing 5400 tons of reduction in NO_x emissions and 500 tons of reduction in PM₁₀ emissions per year. All ZEV's were assumed to replace vehicles meeting the ultra low emission vehicle (ULEV) standard, if the ZEVs technologies replace vehicles that emit more than ULEVs then the emissions reductions will be even greater. Emissions values displayed in table F8-2 as tons per year reduced were derived from the LCFS California GREET model version 1.8b. Table F8-3 displays the emissions reduction in tons per day for the combined scenarios.

Table F8-2
Scenario Emissions Reductions
WTW GHG & Criteria Pollutant reductions (tons/year)

	Scenario 1&2			Scenario 3&5			Scenario 4		
	2010	2015	2020	2010	2015	2020	2010	2015	2020
VOC	-6	-210	-910	-6	-300	-1,500	-	-570	-2,900
CO	-60	-2,000	-8,500	-60	-2,900	-14,000	-	-5,200	-26,000
NOx	-5	-350	-1,500	-6	-500	-2,200	-	-1,000	-5,400
PM10	-1	-40	-160	-1	-60	-260	-	-100	-500
PM2.5	-1	-20	-90	-1	-30	-150	-	-50	-300
Sox	-2	-60	-270	-2	-90	-440	-	-170	-900
Emissions values rounded to two significant digits. ZEV vehicles are assumed to replace ULEV gasoline vehicles. Actual values derived from individual vehicle emissions.									

Table F8-3
Scenario Emissions Reductions
WTW GHG & Criteria Pollutant reductions (tons/day)

	Scenario 1&2			Scenario 3&5			Scenario 4		
	2010	2015	2020	2010	2015	2020	2010	2015	2020
VOC	0	-1	-2	0	-1	-4	-	-2	-8
CO	0	-5	-23	0	-8	-38	-	-14	-71
NOx	0	-1	-4	0	-1	-6	-	-3	-15
PM10	0	0	0	0	0	-1	-	0	-1
PM2.5	0	0	0	0	0	0	-	0	-1
Sox	0	0	-1	0	0	-1	-	0	-2
Emissions values rounded to two significant digits. ZEV vehicles are assumed to replace ULEV gasoline vehicles. Actual values derived from individual vehicle emissions.									

2. Heavy Duty Vehicles (HDV)

Currently a limited number of Zero emission hydrogen fuel cell buses (ZBus) are being used by transit fleets in demonstration projects. The number of vehicles is limited and expected to increase as the technology is validated and regulations facilitate the adoption of cleaner fleets. Future heavy duty vehicle populations have the potential to reach over 7300 units in 2020 due to emission reduction requirements placed on transit agencies. Therefore an emissions comparison between 7300 Ultra low sulfur diesel buses and 7300 ZBuses in the year 2020 is provided in table F8-4. The table demonstrates the potential for emissions of GHGs to be reduced by 16,200 tons/year and criteria pollutants by 1000 tons/year.

Table F8-4
Projected Emissions Reductions in 2020 Replacing Heavy Duty Diesel Buses with Zero Emission Hydrogen Fuel Cell Buses

	Reduction (tons/year)
VOC: Total	-23
CO: Total	-231
NOx: Total	-512
PM10: Total	-312
Benzene	-0.8
1-3 Butadiene	-0.3
Formaldehyde	+0.4
Acetaldehyde	-0.2
Diesel PM	-523

AB1007 WTW FFCA

B. Impact on Off-Road Motor Vehicles and Off-Road Equipment

LCFS will continue to monitor the application of off-road vehicles and equipment, however at this time it is not policy to implement requirements under this regulation. Current programs help facilitate the incorporation of clean alternative off-road electric equipment and vehicles such as the Carl Moyer program for forklifts.

1. Hydrogen

a. Off-Road Motor Vehicle

As stated above LCFS will continue to monitor the application of off-road hydrogen vehicles however at this time it is not policy to implement requirements under this regulation. Currently there is no significant population of Off-road motor vehicles using hydrogen however studies are being performed with utility, maintenance and all terrain vehicles.

b. Off-Road Equipment

As above LCFS will continue to monitor the application of off-road hydrogen equipment however at this time it is not policy to implement requirements under this regulation. Off-road equipment using hydrogen can include forklifts, cargo handling, lawn care, farm, tractor and industrial equipment. Currently the large numbers of off-road hydrogen forklifts are in the research and demonstration phase although some companies have begun a transition to the commercial phase. Hydrogen forklifts have been shown to increase productivity and decrease fuel cost for specific indoor applications and therefore have potential to displace large amounts of battery electric forklifts. A large portion of the outdoor forklift market uses gasoline, diesel or propane as a fuel, if these have the potential to be replaced with hydrogen forklifts then significant emissions reductions can be achieved.

2. Electricity

a. Off-Road Motor Vehicle

The electric off-road motor vehicle market includes such vehicles as small all terrain utility vehicles providing mobility to specific users (e.g. ranch, sport, and maintenance) and combined off/on-road city vehicles such as the Global Electric Motorcars (GEM) vehicle. These vehicles have the potential to replace a segment of the populations transportation needs, such as limited distance travel or private property use (e.g. city vehicle, resorts, universities).

b. Off-Road Equipment

The electric off-road equipment market includes electric forklifts, electric refrigeration units, and truck stop electrification for heat and power and marine power auxiliary uses. Electric forklifts have been used for a number of years due to their zero emissions and economics. Electric refrigeration units and truck stop electrification can provide reduced diesel truck emissions from idling and auxiliary generator units. Although marine power units are not currently planned to be regulated under the LCFS they do have the potential to reduce emissions significantly with the use of electrical sources.

C. Impact on the State Implementation Plan

1. Hydrogen

Impacts to the State implementation plan (SIP) on local governments, local air districts and the air resources board from hydrogen fuel use and production will result in reductions of emissions compared to current technology. Direct hydrogen fuel cell vehicle use results in zero tailpipe emissions and should be considered within any transportation portion of SIPs that foresee future FCV use.

The exact emissions effects from hydrogen production on the SIP are difficult to determine since there are multiple pathways for producing hydrogen with varying emissions. Therefore the affect on the SIP is dependent on the specific location and method of hydrogen production. Local air districts will need to account for any future construction or import of hydrogen and new hydrogen production facilities will be need to obtain the required operational permits. A vehicles size will not make a difference on the SIP since the vehicles themselves produce zero emissions and will at worst affect traffic and at best improve the emissions profile for all transportation in that air district.

2. Electricity

The impacts to the SIP from electric vehicle use will affect transportation plans and emissions estimates by creating reductions. On the fueling side the power generation can be an emissions source depending on electrical production method and will be incorporated into any local air districts emissions program.

A detailed review of the electricity sector in California was performed on the average and marginal production pathways. This pathway includes energy production from residual oil, coal, natural gas, biomass and nuclear. However the carbon intensity value used to determine the LCFS carbon credit will be based on the marginal electricity generation which is composed of generating electricity in Natural Gas Combined Cycle Combustion Turbines (NG CCCTs) and the upstream emissions associated with producing and transporting natural gas to the power plant. The emissions for N₂O, CO₂ and CH₄ for the different methods for electric generation are listed below and are in units of grams per million British thermal units of fuel produced.

The total net savings in gCO₂ from electricity use will vary depending on the exact electrical production method. A potential scenario for electric vehicles produced in the year 2020 would include electricity that is produced meeting future renewable and emissions requirements. This scenario assumes the marginal electricity pathway provides a large percentage of the electricity available. Using the year 2020 and scenario four vehicle rollout the GHG reductions would be 2,460,000 tons of CO₂ compared to California reformulated gasoline and conventional vehicles²².

A battery electric vehicle (EV) uses electrical energy for motive power and produces zero black carbon vehicle emissions. However plug in hybrid electric vehicles use a combination of electrical and combustion energy to propel the vehicle and may produce some black carbon vehicle emissions.

Black carbon emissions are produced during the production of electricity and the amount of emissions vary depending on production method. These production methods include combustion of residual oil, natural gas, biomass and coal. Because the black carbon emission levels vary between combustion processes, the LCFS uses an assumption that all vehicles will use the marginal power produced within the state and

²² Assumptions 11,486 VMT, EV 1.08 MJ/mi.

this includes emissions from natural gas combustion as well as some biomass combustion.

D. Mineral Resources, Soil, Noise

1. Electric Vehicle Noise

Vehicles and traffic create various levels of noise both on the interior and exterior of the vehicle. Government agencies try to reduce the amount of noise that the public must endure due to traffic congestion and high volume traffic by using solutions such as sound barriers or freeway walls. At the same time automobile manufacturers are constantly trying to improve the interior vehicle noise to make the customers driving experience more enjoyable. One of the main sources of noise from today's vehicles comes from the tires rolling on the road surface(17). Other sources include braking, engine, traffic, and road material noise. Because electric vehicles either run partially or always in all electric mode, the vehicle's engine and braking noise is significantly reduced compared to gasoline and diesel vehicles. This is due to the lack of mechanical noise from combustion engine operation, driveline and transmission noise. Electric vehicles have electric motors which are the source of mechanical propulsion and generally contain only one moving part.

The road noise from rolling tire contact is not a component of the vehicle drivetrain and for all vehicles will vary depending on vehicle weight, tire pressures and road surface. The lack of noise for electric vehicles can be beneficial in an urban environment where communities wish to reduce the amount of background noise and make for a more pleasant living experience. However the reduced vehicle noise in an urban environment creates a danger for people with partial or full impairment of vision, the danger is created at street or parking locations where there are no controls. Automobile manufacturers are aware of this safety issue and are exploring audible devices which would create acoustic sounds duplicating standard vehicle noises at low to moderate speeds.

2. Demand for Lithium

Automotive manufacturers' public announcements have stated their plans for future PHEVs, BEVs and FCVs vehicles to incorporate Lithium Ion battery technology. There are numerous battery chemistries that can be used for certain electric vehicle applications such as Nickel metal Hydride and lead acid. However it is strongly believed by industry that some variation of Lithium Ion batteries will be the dominant battery chemistry used in future vehicles. Lithium is an alkali metal element found in compounds due to its high reactivity. Sources of lithium for batteries come from brines and clays containing lithium carbonate (Li_2CO_3). The lithium content required for future vehicles is projected to be approximately 0.3 kilograms per kilowatt-hour (0.66 pounds per kilowatt-hour). ZEV battery capacities may range from a few kilowatt-hours to more than fifty, this translates from a few to over thirty pounds of lithium per vehicle.(18)

The amount of lithium reserves²³ in the United States is estimated to be approximately 38,000 metric tons or just less than 84 million pounds. These reserves do not include the reserve base which is estimated at 410,000 tons for the United States, these are lithium supplies which are currently uneconomical sources yet meet the USGS physical requirements for lithium. These reserves have the potential to provide between 2.8 to 16.8 million vehicles depending on amount of onboard energy storage. World reserves of lithium are estimated at 4.1 million metric tons or 9 billion pounds, if all vehicles were full function BEVs then these reserves would supply enough lithium for approximately 273 million vehicles. However, lithium is also required for other industries such as small rechargeable batteries, ceramics, pharmaceuticals, aluminum, polymers and others.(19)

As demands for lithium supplies increase the cost is also expected to increase along with it, creating competition among different markets. Scenario three estimates 2 million PHEVs in 2020 and assuming that these vehicles require 10 kwhr of energy storage total lithium use would be 6 million pounds or 7% of the US reserves. Another factor affecting lithium supplies is the pace at which production can keep up with varying vehicle use scenarios. Estimates for the supply and demand have stated that the year 2020 may be the point at which lithium supplies are overtaken by demand and production may not keep pace.

3. Multimedia Impacts From Electric Vehicles

Significant reductions are achieved in multimedia emissions from electric vehicles versus the current petroleum infrastructure. These reductions are due to the lack of fluids in the vehicle and also in the fuel transport vehicles. Since electricity is transported from power plants through the electric grid the transportation emissions are zero. Results from the state alternative fuels plan conclude that there is a 90% reduction in multimedia impacts due to the reduced hydrocarbon spills. It states there are no spills from electric operation, any engine oils to spill and or smaller engines with less fuel and oil to spill such as PHEVs.

E. Waste Management - Disposal of Batteries

The end of life goal for these batteries is desired to match or exceed the life of the vehicle; some estimates place this at 10 years (20). It has been suggested that once the batteries complete service in the vehicle they will be further placed in service as stationary back up power or auxiliary power applications. If this occurs the final point of disposal for the batteries will be many years beyond the vehicles life and at this point the batteries can be recycled. Lithium is not considered a hazardous waste by the US EPA. Lithium ion batteries can currently be recycled and lithium carbonate can be obtained from the process along with any other metals that may be in the batteries. It is not expected that the large lithium automotive batteries will be disposed of in landfills due to the economics of the materials and California regulations. Even current

²³ "Reserves. That part of the reserve base which could be economically extracted or produced at the time of determination. The term reserves need not signify that extraction facilities are in place and operative. Reserves only include recoverable materials."

regulations in California make it illegal to dispose of cell phones in landfills²⁴. If the batteries are not removed from the vehicle and placed in service for other energy storage then they will likely be removed and recycled during disposal of the vehicle. Currently, over 95% of vehicles in the United States are recycled at no cost to the consumer or taxpayer; over 84% of materials by weight are recycled from these vehicles.(20) Currently, Toyota offers a monetary reward for used hybrid vehicle batteries to ensure they are recycled and Honda offers free shipment for hybrid batteries so that it is not disposed of improperly.

²⁴ <http://www.ciwmb.ca.gov/WPW/Power/RechBattInfo.htm#Other%20Types>

Appendix F9 Motor Vehicle Emissions – CNG vs. HD Diesel

When considering the impacts of changing a fuel for the purpose of compliance with AB 32, every effort must be made to ensure that there are not significant increases in TACs due to the switch. An analysis was made of switching a number of diesel fueled HHDD trucks to CNG fuel to compare the change in PM and NOx emissions. This analysis was performed for 4,600 conversions by 2015 and 23,300 conversions by 2020. The results are shown in the Table F9-1.

**Table F9-1
Changes to Criteria Pollutants from Fleet Conversion to CNG(21, 22)**

Fuel	2015		2020	
	PM (TPD)	NOx (TPD)	PM (TPD)	NOx (TPD)
Diesel	0.08	2.6	0.44	14.2
CNG	0.07	1.5	0.40	7.8
Δ	-0.01	-1.2	-0.04	-6.4

This analysis shows that switching from diesel fuel to CNG would result in a slight decrease in PM emissions, as well as a slight decrease in NOx emissions. Staff did not estimate any change in emissions of CO and NMHC.

Table F9-2 shows the emission factors used in the analysis for each fuel. The CNG emission factors are directly from 2008 certification data. The diesel emission factors are modified from the certification data based on staff's estimate of compliance with the 2010 standards.

**Table F9-2
Emissions Factors²⁵**

Fuel	PM EF (g/bhp-hr)	NOx EF (g/bhp-hr)
Diesel	0.01	0.20
CNG	0.009	0.11

2008 model year certification data used in the analysis is shown in the Table F9-3. Note that the CNG truck is already in compliance with the 2010 PM standard but the diesel truck is still complying with 2007 standards. The following data are from a 2008 MY Cummins MHD diesel fueled engine, and 2008 MY Cummins MHD CNG fueled engine. All of the data are according to the engine Federal Test Procedure. The items in parentheses are the certification standards.

²⁵ Staff estimates based on Certification levels

**Table F9-3
HD-CNG Engine Comparison**

Vehicle Class	CO (g/bhp-hr)	NMHC (g/bhp-hr)	PM (g/bhp-hr)	NOx (g/bhp-hr)
Cummins 8.9 L Diesel	0.9 (15.5)	0.034 (0.14)	0.002 (0.01)	1.02 (1.14)
Cummins 8.8 L CNG	1.2 (15.5)	0.13 (0.14)	0.009 (0.01)	0.11 (0.20)

The diesel engine is comparable to other recently certified heavy duty engines within about +/- 50% in emissions. No similar comparison could be made with the CNG as it was the only heavy duty diesel cycle CNG fueled engine family certified in 2008.

Appendix F10

Cancer Health Risk Assessment for Individual and Multiple Co-located Biorefinery Facilities

ARB staff conducted a health risk assessment (HRA) study to evaluate the health impacts associated with toxic air contaminants emitted from typical biorefinery facilities within the state of California. The HRA focused on the potential cancer risk associated with diesel particulate matter (diesel PM) emissions caused by the biorefinery facilities.

A. What is Health Risk Assessment?

A health risk assessment uses mathematical models to evaluate the health impacts from exposure to certain chemical or toxic air contaminants released from a facility or found in the air. HRAs provide information to estimate potential life-time (i.e., 70 years) cancer and non-cancer health risks. HRAs do not gather information or health data on specific individuals, but are estimates for the potential health impacts on a population at large.

An HRA consists of three major components: the air pollution emission inventory, the air dispersion modeling, and an assessment of associated health risks. The air pollution emission inventory provides an understanding of how the air toxics are generated and emitted. The air dispersion modeling takes the emission inventory and meteorology data such as temperature and wind speed/direction as its inputs, then uses a computer model to predict the distributions of air toxics in the air. Based on this information, an assessment of the potential health risks of the air toxics to an exposed population is performed.

The most frequently used expression of estimated adverse health impacts is potential cancer health effects, which is usually presented as the number of chances in a population of a million people exposed. The number may be stated as “10 in a million” or “10 chances per million”. The methodology used to estimate the potential cancer risks is consistent with the Tier-1 analysis of *Air Toxics Hot Spots Program Risk Assessment Guidelines* (23). A Tier-1 analysis assumes that an individual is exposed to an annual average concentration of a given pollutant continuously for 70 years. The length of time that an individual is exposed to a given air concentration is proportional to the risk.

The potential cancer risk from a given carcinogen estimated from the health risk assessment is expressed as the incremental number of potential cancer cases that could be developed per million people, assuming population is exposed to the carcinogen at a constant annual average concentration over a presumed 70-year lifetime. For example, if the cancer risk were estimated to be 100 chances per million, the probability of an individual developing cancer would be expected to not exceed 100 chances in a million. If a population (e.g., one million people) were exposed to the same potential cancer risk (e.g., 100 chances per million), then statistics would predict

that no more than 100 of those million people exposed are likely to develop cancer from a lifetime of exposure (i.e., 70 years) due to diesel PM emissions from a facility.

B. Why did the HRA focus on Diesel PM?

In 1998, ARB identified particulate matter from diesel exhaust (diesel PM) as a toxic air contaminant based on its potential to cause cancer and other adverse health problems, including respiratory illnesses, and increased risk of heart disease(24). Subsequent research has shown that diesel PM contributes to premature death²⁶(25). Exposure to diesel PM is a health hazard, particularly to children whose lungs are still developing and the elderly who may have other serious health problems. In addition, the diesel PM particles are very small. By mass, approximately 94% of these particles are less than 2.5 microns in diameter (PM_{2.5}). Because of their tiny size, diesel PM is readily respirable and can penetrate deep into the lung and enter the bloodstream, carrying with them an array of toxins. Population-based studies in hundreds of cities in the U.S. and around the world demonstrate a strong link between elevated PM levels and premature deaths(26), increased hospitalizations for respiratory and cardiovascular causes, asthma and other lower respiratory symptoms, acute bronchitis, work loss days, and minor restricted activity days(27) .

Diesel PM emissions are the dominant toxic air contaminant (TAC) in and around a biorefinery facility. Diesel PM typically accounts for about 70% of the State's estimated potential ambient air toxic cancer risks. This estimate is based on data from ARB's ambient monitoring network in 2000(28). These findings are consistent with that of the study conducted by South Coast Air Quality Management District: *Multiple Air Toxics Exposure Study in the South Coast Air Basin*(29). Based on these scientific research findings, the health impacts in this study primarily focus on the risks from the diesel PM emissions.

C. Prototype Biorefinery Facilities

According to AB 32 Scoping Plan, there may be 30 biorefinery facilities with an average production capacity of 50 million gallon per year established in the state of California by 2020. In order to estimate the potential cancer risk associated with a newly established biorefinery facility, ARB staff developed a prototype biorefinery facility for a case study of HRA. In the study, staff intended to emphasize the health impact of the facility related activities by eliminating other possible impact factors of health risks, such as local topographic and emission source geometric conditions.

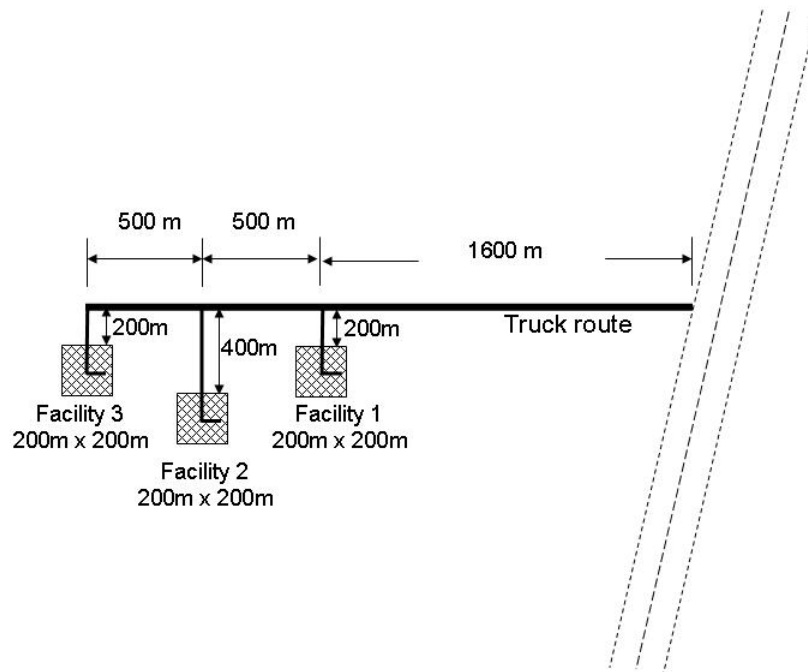
²⁶ Premature Death: as defined by U.S. Centers for Disease Control and Prevention's Years of Potential Life Lost, any life ended before age 75 is considered premature death.

Based on the size of some in state biorefineries, staff assumes the prototype facility located in a 200 meters by 200 meters square fence line (depicted in the Figure F10-1). The selection of square shape facility is to avoid the influence of complexity of sources geometry on the estimated potential health effects. The emission sources from the facility include natural gas or biomass boilers and turbines. Diesel PM emissions are generally generated by the heavy duty trucks that are used to transport feedstocks and finished biofuel. As indicated in Figure F10-1, staff assumes an “L” shape truck routes within the facility, with a longer edge starting from the north side of the fenceline to the center of the facility (100 meter in length), and a shorter edge extending toward the east side of the fenceline (80 meters in length).

There are three major types of biorefineries: corn ethanol, cellulosic ethanol, and biodiesel. Among them, a cellulosic ethanol facility requires the most amount of feedstock. Using farm tree as an example, staff estimates that over 500,000 tons of feedstocks are required to support a 50 million gallon per year of production capacity. Assuming one heavy duty truck can load 25 tons of farm tree and up to 7,500 gallons of ethanol, staff estimates an average of about 110 daily truck trips would be made to transport feedstock in and finished fuel out for a 50 million gallon per year facility. Based on above the assumptions explained above for truck routes, each truck round trip within the facility boundary is 360 meters. Staff also assumes each truck to be idling at the loading and unloading area located in the center of the facility for five minutes.

For the most conservative analysis, staff assumes that one main truck route connects a major freeway and three prototype biorefinery facilities, as indicated in Figure F10-1. The truck route from the freeway to Facility 1 is about 1 mile (1600 meters). Facility 1, 2 and 3 are 500 meters apart from each other. The individual truck routes which connect Facilities 1, 2, and 3 to the main route are 200, 400, and 200 meters, respectively.

Figure F10-1
Three Prototype Biorefinery Facilities



Based on the EMFAC emission factors for model year 2010 and newer, the total diesel PM emissions from three facilities, including truck movements and idling, are about 0.0036 tons per year. Staff defines this portion of emissions as “onsite”. The diesel PM emissions from the main and three individual truck routes are also directly caused by the bio-refineries, although these routes are outside of the facility boundaries. The total diesel PM emissions from these routes are about 0.12 tons per year. Staff defines this portion of emissions as “offsite”. Staff considers the diurnal variation of the emissions by assuming the truck activities occur between 8 am and 6 pm.

It should be noted that three biorefinery facilities are not likely to be placed as closely together as the prototype. In fact, it does not make economical sense. The purpose of this analysis is to demonstrate the worst case scenario of biorefinery lay-out for the most conservative estimate.

D. Air Dispersion Modeling

Air dispersion models are often used to simulate atmospheric processes for applications in which the spatial scale is in the tens of meters to tens of kilometers. Selection of air dispersion models depends on many factors, such as characteristics of emission

sources (point, area, volume, or line), the type of terrain (flat or complex) at the emission source locations, and source-receptor relationships. For these prototype biorefinery facilities, ARB staff selected the U.S. EPA's newly approved air dispersion model AERMOD to estimate the impacts associated with diesel PM emissions. AERMOD stands for American Meteorological Society / Environmental Protection Agency Regulatory Model Improvement Committee (**AERMIC**) **MODEL**. It is a state-of-science air dispersion model and is a replacement for its predecessor, the U.S. EPA Industrial Sources Complex (ISC) air dispersion model.

E. Emission Source Characterization and Parameters

When a mobile source, such as a heavy heavy duty truck, is moving, the emissions are simulated as a series of volume sources to represent the initial lateral dispersion of emissions by the exhaust stack's movement through the air. Key model parameters for volume sources include emission rate (strength), source release height, and initial lateral and vertical dimensions of volumes. Diesel exhaust emissions from heavy heavy duty truck activity in a biorefinery are considered as a major diesel PM source in the facility. For modeling simulations, staff assumes the initial lateral and vertical dimensions of the volume to be 10 meters and 4.15 meters, respectively.

F. Meteorological Data

In order to run AERMOD, the following hourly surface meteorological data are required: wind speed, wind direction, ambient temperature, and opaque cloud cover. In addition, the daily upper air sounding data need to be provided(30). These meteorological variables are important to describe the air dispersion in the atmosphere. The wind speed determines how rapidly the pollutant emissions are diluted and influences the rise of emission plume in the air, thus affecting downwind concentrations of pollutants. Wind direction determines where pollutants will be transported. The difference between ambient temperature and the emission releasing temperature from sources determines the initial buoyancy of emissions. In general, the greater the temperature difference, the higher the plume rise. The opaque cloud cover and upper air sounding data are used in calculations to determine other important dispersion parameters. These include atmospheric stability (a measure of turbulence and the rate at which pollutants disperse laterally and vertically) and mixing height (the vertical depth of the atmosphere within which dispersion occurs). The greater the mixing height is, the larger the volume of atmosphere is available to dilute the pollutant concentration.

The meteorological data used in the model are selected on the basis of representativeness. Representativeness is determined primarily by whether the wind speed/direction distributions and atmospheric stability estimates generated through the use of a particular meteorological station (or set of stations) are expected to mimic those actually occurring at the facility where such data are not available. Typically, the key factors for determining representativeness are proximity to the meteorological station and the presence or absence of nearby terrain features that might alter airflow patterns.

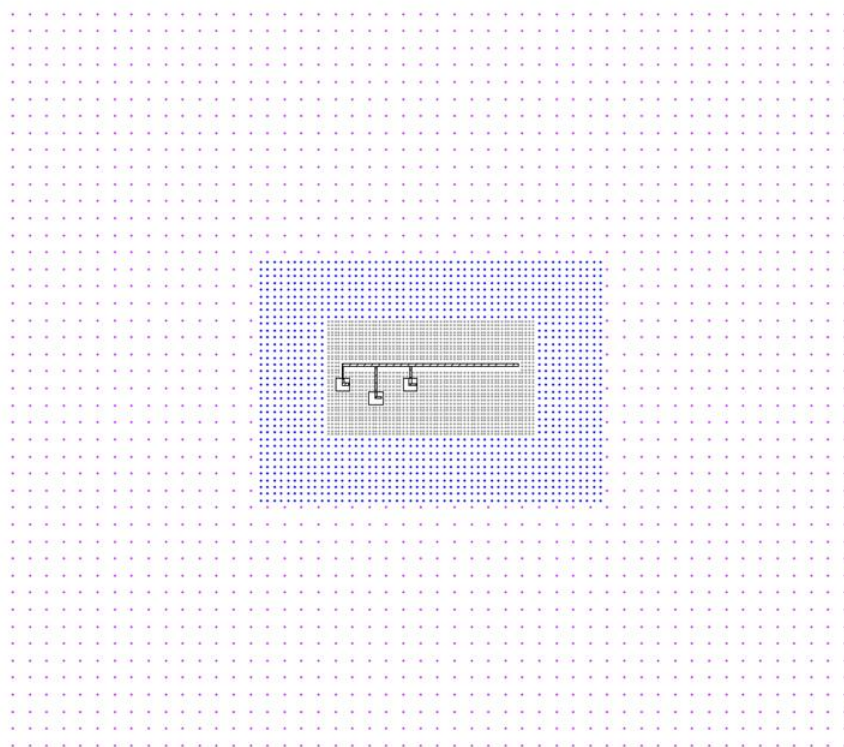
In this study, staff conducted an HRA analysis of prototype biorefineries that is independent of geographic location. Based on the estimates of potential biorefinery locations, two sets of meteorological data were selected as candidate model inputs, one from the South Coast Air Basin (Lynwood and Los Angeles downtown USC station), and the other from San Joaquin Valley Air Basin (Stockton station). Further data analysis indicated that the average wind speed in the Stockton station is about twice that of the Lynwood station. As explained above, the higher the wind speed used in the model, the lower the estimated air toxic concentrations would be as a result of dilution. Therefore, in order to securely estimate the health impact, the more conservative meteorological data from South Coast Air Basin was selected. The hourly wind speed and direction data from the Lynwood station and temperature and cloud cover data from the Los Angeles downtown USC station were used in the AERMOD. The upper air sounding data were chosen from the San Diego-Miramar NAS stations(31).

G. Model Receptors

Model receptors are the locations where the model provides concentrations. A Cartesian grid receptor network is used in this study where an array of points are identified by their x (east-west) and y (north-south) coordinates. The modeling domain is defined as an 18 x 18 km (km: kilometers) region, which covers the biorefinery facilities in the center of the domain. To better capture the different concentration gradients surrounding the facilities, 3 receptor grid networks were used. A fine grid of 50 m x 50 m (m: meter) surrounding the biorefinery facilities and the truck routes was used for modeling within 0.5 mile of the fence line and truck routes, a medium grid of 250 m x 250 m was used for modeling the domain from 0.5 mile to 1 mile of the facility fence lines and truck routes, and a coarse receptor grid of 500 m x 500 m was used throughout the rest of the modeling domain.

Figure F10-2 illustrates the grid receptor networks and model domain used in air dispersion modeling for the biorefinery facilities.

Figure F10-2
Air Dispersion Modeling Grid Receptor Network and
Domain Used for the Biorefinery Facilities



H. Health Risk Assessment

The HRA follows *The Air Toxics Hot Spots Program Risk Assessment Guidelines*(23) published by the California Office of Environmental Health Hazard Assessment (OEHHA). The HRA is based on the facility specific emission inventory and air dispersion modeling predictions.

Exposure assessment is a comprehensive process that integrates and evaluates many variables. Three process components have been identified to have significant impacts on the results of a health risk assessment – emissions, meteorological conditions, and exposure duration of nearby residents. The emissions have a linear effect on the risk levels, given meteorological conditions and defined exposure duration. Meteorological conditions can also have a critical impact on the resultant ambient concentration of a toxic pollutant, with higher concentrations found along the predominant wind direction and under calm wind conditions. An individual's proximity to the emission plume, how long he or she breathes the emissions (exposure duration), and the individual's breathing rate play key roles in determining potential risk. In general, the longer the exposure time for an individual, the greater the estimated potential risk for the individual.

The risk assessment adopted in this study generally assumes that the receptors will be exposed to the same toxic levels for 24 hours per day for 70 years. If a receptor is exposed for a shorter period of time to a given pollutant concentration of diesel PM, the cancer risk will proportionately decrease. Children have a greater risk than adults because they have greater exposure on a per unit body weight basis and also because of other factors.

Risk characterization is defined as the process of obtaining a quantitative estimate of risk. The risk characterization process integrates the results of air dispersion modeling and relevant toxicity data (e.g., diesel PM cancer potential factor) to estimate potential cancer or non-cancer health effects associated with air contaminant exposure.

Exposures to pollutants that were originally emitted into the air can also occur in different pathways as a result of breathing, dermal contact, ingestion of contaminated produce, and ingestion of fish that have taken up contaminants from water bodies. These exposures can all contribute to an individual's health risk. However, diesel PM risk is evaluated by the inhalation pathway only in this study because the risk contributions by other pathways of exposure are insignificant relative to the inhalation pathway. It should be noted that the background or ambient diesel PM concentrations are not incorporated into the risk quantification in this study. Therefore, the estimated potential health risk in the study should be viewed as risk level above those due to the background impacts.

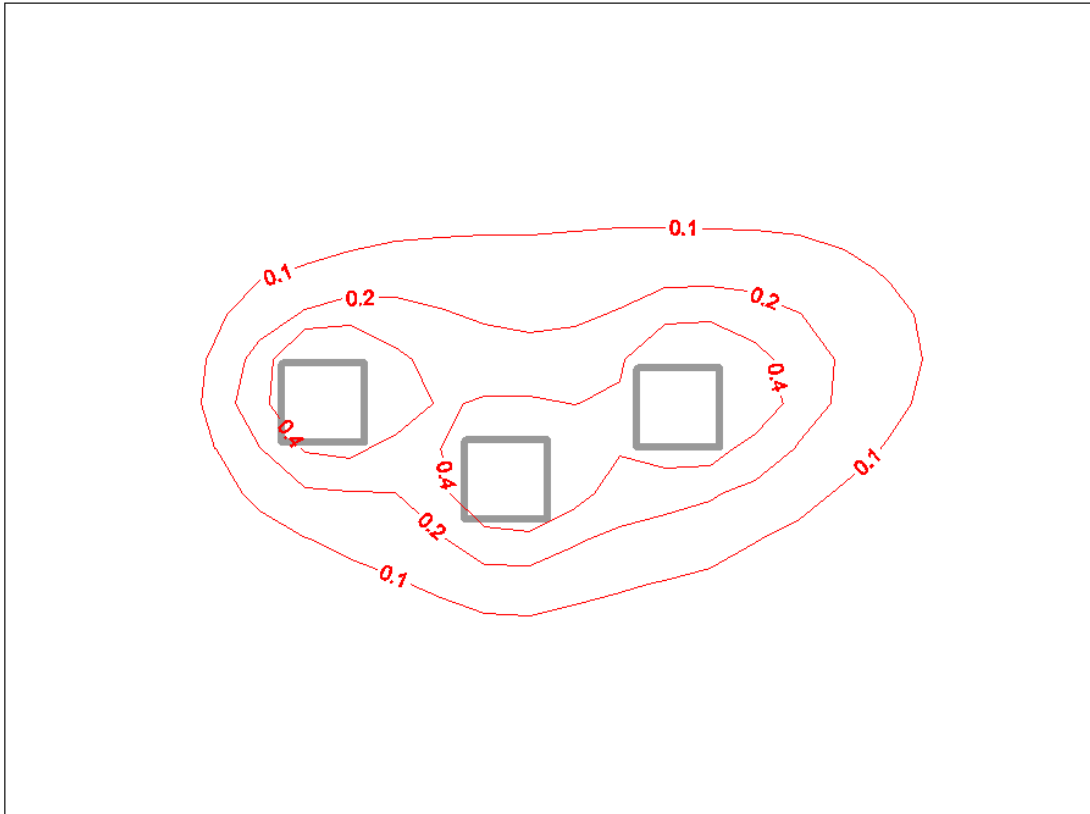
I. Risk Characterization Associated with Onsite Emissions of the Three Prototype Biorefinery Facilities

The potential cancer risks levels associated with the onsite diesel PM emissions from the three prototype biorefinery facilities are displayed by using isopleths, based on the 80th percentile breathing rate and 70 year exposure duration for residents. An isopleth is a line drawn on a map through all points of equal value of some measurable quantity; in this case, cancer risk. Figure F10-3 presents the isopleths of estimated potential cancer risks caused by the onsite diesel PM emissions from three prototype biorefinery facilities.

As indicated by Figure F10-3, the area with the greatest impact has an estimated potential cancer risk of over 0.4 chances in a million, surrounding the facility fence lines. At about 200 yards from the facility boundaries, the estimated cancer risks decrease to about 0.2 chances per million. The estimated potential cancer risks further decrease to about 0.1 chances per million at about 400 yards from the facility boundaries.

It is important to understand that these risk levels represent the predicted risks (due to the biorefinery facility diesel PM emissions) above the existing background risk levels. For the broader San Joaquin Valley Air Basin, for instance, the estimated regional background risk level is estimated to be about 390 in a million caused by diesel PM and about 590 in a million caused by all toxic air pollutants in 2000(32).

Figure F10-3
Estimated Life-time Cancer Risks (chances per million people) Associated with the Onsite Diesel PM Emissions from the Three Prototype Biorefinery Facilities

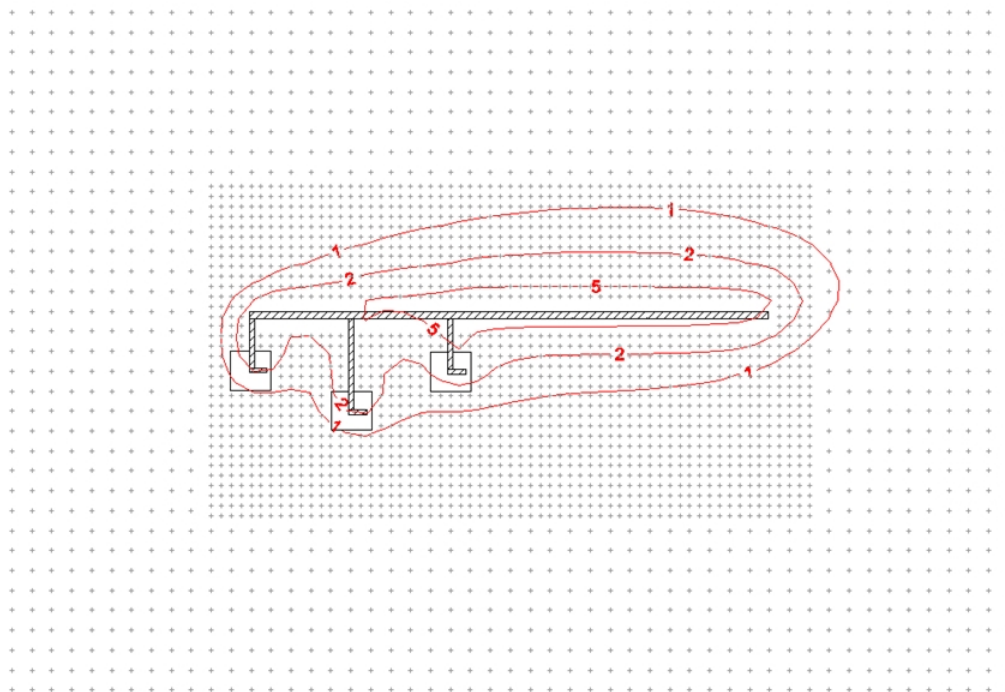


J. Risk Characterization Associated with Combined Onsite and Offsite Emissions of the Three Prototype Bio-Refinery Facilities

Staff also estimated the health impact associated with the combined onsite and offsite emissions of the three prototype bio-refinery facilities. Figure F10-4 presents the isopleths of estimated potential cancer risks caused by the combined onsite and offsite emissions.

As indicated by Figure F10-4, the area with the greatest impact has an estimated potential cancer risk of over 5 chances in a million, mostly occurring along the main truck route that connects the Facility 2 and the major freeway. This risk level extends for about 150 yards from the north side of the roadway. The estimated cancer risk is about 2 chances per million surrounding the individual truck routes. This risk level extends for about 300 yards from the main truck route. At about 500 yards from the truck routes, the estimated cancer risks decrease to about 1 chance per million.

Figure F10-4
Estimated Life-time Cancer Risks (chances per million people) Associated with
the Combined Onsite and Offsite Diesel PM Emissions from three Prototype
Bio-Refinery Facilities



Staff would like to point out that the three collocated biorefinery facilities lay-out is the worst case assumption. It does not make economical sense and is not likely to happen. The UC Davis biofuel supply modeling work assumes the facilities to be at least 50 miles apart, because each facility would need biomass feedstock supply from that area. According to this modeling work, the economically optimal capacity of a biorefinery is 100 million gallons per year. In this analysis, staff estimated the health impact of individual biorefinery with capacity of 50 million gallons per year, which is consistent with the AB 32 Scoping Plan. In addition, staff estimated cumulative health impacts from three collocated biorefinery facilities with a total capacity of 150 million gallon per year, as the most conservative health risk analysis.

K. Uncertainties in Health Risk Assessment

The HRA is a complex process that is based on current knowledge and a number of assumptions. However, there is a certain extent of uncertainty associated with the process of risk assessment. The uncertainty arises from lack of data in many areas necessitating the use of assumptions. The assumptions used in the assessments are

often designed to be conservative on the side of health protection in order to avoid underestimation of risk to the public. As indicated by the OEHHA Guidelines, the Tier-1 evaluation is useful in comparing risks among a number of facilities and similar sources. Thus, the risk estimates should not be interpreted as a literal prediction of disease incidence in the affected communities but more as a tool for comparison of the relative risk between one facility and another. In addition, the HRA results are best used to compare potential risks to target levels to determine the level of mitigation needed. They are also an effective tool for determining the impact a particular control strategy will have on reducing risks.

THIS PAGE IS INTENTIONALLY LEFT BLANK

Appendix F11

Health Impacts Associated with Emissions from Potential Biorefineries

A. Health Impacts Assessment

A substantial number of epidemiologic studies have found a strong association between exposure to ambient PM_{2.5} and a number of adverse health effects (33). For this report, ARB staff quantified seven non-cancer health impacts associated with the change in exposure to PM_{2.5} emissions. This analysis shows that the statewide health impacts of the emissions associated with this regulation in year 2020 are approximately:

- 24 premature deaths (7 – 43, 95% CI)
- 3 hospital admissions due to respiratory causes (1 – 4, 95% CI)
- 5 hospital admissions due to cardiovascular causes (3 – 7, 95%CI)
- 340 cases of asthma-related and other lower respiratory symptoms (130 – 530, 95% CI)
- 27 cases of acute bronchitis (0 – 57, 95% CI)
- 2,200 work loss days (1,900 – 2,600, 95% CI)
- 13,000 minor restricted activity days (11,000 – 15,000, 95% CI)

Table F11-1 lists the impacts associated with primary PM and secondary PM emissions separately. The methodology for estimating these health impacts is described below, and details can be found in Appendix A of the Emission Reduction Plan for Ports and Goods Movement in California (34).

Table F11-1
Total Health Impacts Associated with Emissions Related to
Potential Biorefineries in Year 2020*

Endpoint	Pollutant	# of Cases 95% C.I. (Lower Bound)	# of Cases (Mean)	# of Cases 95% C.I. (Upper Bound)
Premature Death	PM	1	4	6
	NOx	6	21	37
	<i>Total</i>	7	24	43
Hospital admissions (Respiratory)	PM	0	0	1
	NOx	1	2	4
	<i>Total</i>	1	3	4
Hospital admissions (Cardiovascular)	PM	0	1	1
	NOx	3	4	6
	<i>Total</i>	3	5	7
Asthma & Lower Respiratory Symptoms	PM	20	51	82
	NOx	120	290	450
	<i>Total</i>	130	340	530
Acute Bronchitis	PM	0	4	9
	NOx	0	23	48
	<i>Total</i>	0	27	57
Work Loss Days	PM	280	330	380
	NOx	1,600	1,900	2,200
	<i>Total</i>	1,900	2,200	2,600
Minor Restricted Activity Days	PM	1,600	1,900	2,300
	NOx	9,100	11,000	13,000
	<i>Total</i>	11,000	13,000	15,000

* Health effects from primary and secondary PM are labeled PM and NOx, respectively. The sum of PM and NOx impacts may not equal the total given due to rounding.

1. Primary Diesel PM

The estimation of premature death and other health impacts from PM exposure used by CARB staff is based on a peer-reviewed methodology developed by the U.S. EPA for their risk assessments (35-37). This methodology is regularly updated by CARB staff as new epidemiological studies and other related studies are published that are relevant to California's health impacts analysis. The methodology uses concentration-response functions which describe the relation between ambient PM_{2.5} concentration and premature death and illness. The selection of the concentration-response functions was based on the latest epidemiologic literature, as described in Emission Reduction Plan

for Ports and Goods Movement in California (34) and Methodology for Estimating the Premature Deaths Associated with Long-term Exposure to Fine Airborne Particulate Matter in California (38). The central estimate of the relative risk of premature death used in this assessment is 10% increase risk per 10 $\mu\text{g}/\text{m}^3$ increase in PM_{2.5} exposure, with a confidence interval of 3% - 20% (38).

This analysis used a “tons per incident” approach to estimate the health impacts associated with emissions from possible biorefineries. These tons-per-incident factors were developed for estimating health impacts associated with changes in diesel PM exposures. The following is an example of how the approach was used to estimate the effect of PM_{2.5} on mortality. Using estimated diesel PM concentration for year 2005 (1.6 $\mu\text{g}/\text{m}^3$) and the concentration-response function for mortality (38), we estimate that primary diesel PM exposure can be associated with a mean estimate of 3,500 premature deaths in year 2005 in California. The diesel PM_{2.5} emissions for year 2005 were 37,800 tons. Using this information, we estimate that for a reduction of 10.8 tons diesel PM_{2.5} emissions per year, one fewer premature death would result. This factor is derived by dividing 37,800 tons of diesel PM by 3,500 deaths.

Staff developed air basin-specific factors to estimate health impacts, such as hospitalizations and asthma symptoms, from PM_{2.5} exposure. These basin-specific factors were developed using basin-specific diesel PM concentrations and emissions for the year 2005 and the relevant health studies. The basin-specific factors were applied to each air basin to estimate health impacts. Estimates of health impacts, such as hospitalizations and asthma symptoms, were calculated using basin-specific factors developed from relevant health studies. Details on the methodology used to calculate these estimates can be found in Appendix A of the Emission Reduction Plan for Ports and Goods Movement in California (34).

2. Secondary Diesel PM

In addition to directly emitted PM, emissions associated with possible biorefineries contain NO_x, which is a precursor to nitrates, a secondary diesel-related PM formed in the atmosphere that can lead to additional health impacts beyond those associated with directly emitted PM_{2.5}. To quantify such impacts, staff developed population-weighted nitrate concentrations for each air basin using data not only from the statewide routine monitoring network, which was used in Lloyd and Cackette (39), but also from special monitoring programs such as IMPROVE and Children’s Health Study (CHS) in years 2004, 2005 and 2006. The IMPROVE network provided additional information in the rural areas, while the CHS added more data to southern California. Staff calculated the health impacts resulting from the three-year average exposure to these concentrations of nitrate PM_{2.5} and then associated the impacts with the basin-specific NO_x emissions from diesel sources to develop basin-specific factors (tons per incident). The basin-specific factors and emissions were applied to each air basin to estimate health impacts. Using an approach similar to that used for primary diesel PM and adjusting for population changes between 2020 and 2005, staff estimates that the 2,000 tons of NO_x emissions related to possible biorefineries in year 2020 are associated with an

estimated 21 premature deaths (6 – 37, 95% CI). Other health effects were also estimated as outlined above.

3. Assumptions and Limitations of Health Impacts Assessment

There are a number of uncertainties involved in quantitatively estimating the health impacts associated with exposure to outdoor air pollution. They include the selection and applicability of the concentration-response (C-R) functions, the exposure assessment, and the baseline incidence rates. These are briefly described below.

- A primary uncertainty is the choice of the specific studies and the associated C-R functions used for quantification. Epidemiological studies used in this report have undergone extensive peer review and include sophisticated statistical models that account for the confounding effects of other pollutants, meteorology, and individual level risk factors. While there may be questions on whether C-R functions from the epidemiological studies are applicable to California, studies have shown that the mortality effects of PM in California are fairly consistent with those found in other locations in the United States (40-43). The C-R function for PM_{2.5}-related mortality used in this report was based on a review of all relevant scientific literature and a thorough consideration of each study's strengths and limitations. In addition, it was approved by our advisors and independent peer reviewers (38).
- Only emissions from truck and rail transport of feedstock and biofuel were included in the health impact calculation. There are significant emissions from the biorefineries themselves. Biorefinery emissions were not included in the health impact calculation because increased local emissions from biorefineries are expected be offset by decreased emissions within the air basin.
- In this analysis, CARB staff assumed diesel PM is as toxic as ambient PM_{2.5}. This assumption is reasonable since the “tons per case” factors were then applied to estimate the health benefits associated with reducing PM_{2.5} emissions.
- This report estimated health impacts due to emissions associated with possible biorefineries. The methodology applies a “tons per incident” factor to estimate the number of health effects avoided due to reductions in PM_{2.5} and assumes the emissions are evenly distributed within the air basin.
- CARB staff assumed the baseline incidence rate for each health endpoint was uniform across each county. This assumption is consistent with methods used by the U.S. EPA for its regulatory impact assessment, and the incidence rates match those used by U.S. EPA.
- Although the analysis illustrates that PM_{2.5} exposure would result in health impacts to people living in California, we did not provide estimates for all

endpoints for which there are C-R functions available. Health effects such as myocardial infarction (heart attack), chronic bronchitis, and onset of asthma were not quantified due to the potential overlap with the quantified effects such as lower respiratory symptoms and hospitalizations. In addition, estimates of the effects of PM_{2.5} on low birth weight and reduced lung function growth in children are not presented. While these endpoints are significant in an assessment of the public health impacts of diesel exhaust emissions, there are currently few published investigations on these topics, and the results of the available studies are not entirely consistent (34). In summary, because only a subset of the total number of health outcomes is considered here, the estimates may be an underestimate of the total public health impact of PM exposure.

B. Economic Valuation of Health Effects

This section describes the methodology for monetizing the value of avoiding adverse health impacts.

The U.S. EPA has established \$4.8 million in 1990 dollars at the 1990 income level as the mean value of avoiding one premature death (36). This value is the mean estimate from five contingent valuation studies and 17 wage-risk studies. Contingent valuation and wage-risk studies examine the willingness to pay (or accept payment) for a minor decrease (or increase) in the risk of premature death. For example, if individuals are willing to pay \$800 to reduce their risk of mortality by 1/10,000, then collectively they are willing to pay \$8 million to avoid one death. This is also known as the “value of a statistical life” or VSL.²⁷

As real income increases, people are willing to pay more to prevent premature death. U.S. EPA adjusts the 1990 value of avoiding a premature death by a factor of 1.201²⁸ to account for real income growth from 1990 through 2020(35). We also updated the value to 2008 dollars. After these adjustments, the value of avoiding one premature death is \$9.3 million in 2009, and \$10 million in 2020, all expressed in 2008 dollars.

The U.S. EPA also uses the willingness-to-pay (WTP) methodology for some non-fatal health endpoints, including lower respiratory symptoms, acute bronchitis and minor restricted activity days. WTP values for these minor illnesses are also adjusted for anticipated income growth through 2020, although at a lower rate (about 0.2% per year in lieu of 0.6% per year).

²⁷ Some recent U.S. EPA regulatory impact analyses, (U.S. EPA 2004, 2005), apply a different VSL estimate (\$5.5 million in 1999 dollars, with a 95 percent confidence interval between \$1 million and \$10 million). This alternative value has not been endorsed by the Environmental Economics Advisory Committee (EEAC) of U.S. EPA’s Science Advisory Board (SAB). Until U.S. EPA’s SAB endorses another estimate, CARB staff continues to use the last VSL estimate endorsed by the SAB, i.e., \$4.8 million in 1990 dollars.

²⁸ U.S. EPA’s real income growth adjustment factor for premature death incorporates an elasticity estimate of 0.4. CARB applies an elasticity estimate of 0.5 because both U.S. EPA, (U.S. EPA 2004), and a review of published estimates (Viscusi and Aldy, 2004) indicate that a value of 0.4 underestimates elasticity.

For work-loss days, the U.S. EPA uses an estimate of an individual's lost wages, (U.S. EPA, 2004), which CARB adjusts for projected real income growth, at a rate of approximately 1.5% per year.

"The Economic Value of Respiratory and Cardiovascular Hospitalizations," calculated the cost of both respiratory and cardiovascular hospital admissions in California as the cost of illness (COI) plus associated costs such as loss of time for work, recreation and household production (44). When adjusting these COI values for inflation, CARB uses the Consumer Price Index (CPI) for medical care rather than the CPI for all items.

Table F11-2 lists the valuation of avoiding various health effects, compiled from CARB and U.S. EPA publications, updated to 2008 dollars. The valuations based on WTP, as well as those based on wages, are adjusted for anticipated growth in real income.

ARB staff estimates the statewide health impacts of the emissions associated with this regulation in year 2020 are approximately \$180 million using a 3% discount rate or \$120 million using a 7% discount rate²⁹. A large proportion of the monetized benefits results from avoiding premature death. The estimated benefits from avoided morbidity are approximately \$1.3 million with a 3% discount rate and nearly \$860 thousand with a 7% discount rate. Approximately 85% of the benefits are associated with reduced PM from NOx emissions, and the remaining 15% from direct PM emissions.

²⁹ CARB follows U.S. EPA practice in reporting results using both 3% and 7% discount rates.

Table F11-2
Undiscounted Unit Values for Health Effects
(at various income levels in 2008 dollars)¹

Health Endpoint	2009	2010	2020	References
Mortality				
Premature death (\$ million)	9.3	9.4	10	(35, 36, 45)
Hospital Admissions				
Cardiovascular (\$ thousands)	46	46	52	(44)
Respiratory (\$ thousands)	38	38	43	(44)
Minor Illnesses				
Acute Bronchitis	453	454	467	(35)
Lower Respiratory Symptoms	20	20	21	(35)
Work loss day	64	64	66	
Minor restricted activity day (MRAD)	194	198	240	(35)

¹The value for premature death is adjusted for projected real income growth, net of 0.5 elasticity. Wage-based values (Work Loss Days) are adjusted for projected real income growth, as are WTP-derived values (Lower Respiratory Symptoms, Acute Bronchitis, and MRADs). Health endpoint values based on cost-of-illness (Cardiovascular and Respiratory Hospitalizations) are adjusted for the amount by which projected CPI for Medical Care (hospitalization) exceeds all-item CPI.

C. Conclusion

For this report, ARB staff quantified seven non-cancer health impacts associated with the change in exposure to PM_{2.5} emissions. This analysis shows that the statewide health impacts of the emissions associated with this regulation in year 2020 are approximately 24 premature deaths, 3 hospital admissions due to respiratory causes, 5 hospital admissions due to cardiovascular causes, 340 cases of asthma-related and other lower respiratory symptoms, 27 cases of acute bronchitis, 2,200 work loss days, and 13,000 minor restricted activity days. The uncertainty behind each estimated benefit ranges from about 15% to 75% for most endpoints. The estimated statewide impacts in year 2020 associated with health effects is 120 million using a 7% discount rate or \$180 million using a 3% discount rate.

This Page Intentionally Left Blank

Appendix F12

Impacts on Water Quality and Water Consumption

This section briefly describes the water quality issues, water use impacts, and current regulatory requirements for the production and use of various low carbon “fuel” candidates. Eight candidate “fuels” were evaluated based on feedstocks, conversion technology and scale of conversion, resulting in a combination of seventeen scenarios without regard to the extent to which any of those fuels would be a part of a LCFS mix.

A. Water Quality

Water quality issues include spills in transport, unauthorized releases during production or storage, unlawful disposal to storm sewers or even to WWTP. Releases of ethanol, biodiesel, and butanol blends to groundwater potentially contaminate drinking water with highly toxic petrochemicals (alkanes, BTEX and aliphatic compounds). Ethanol and biodiesel blends released to surface water may increase the likelihood and degree of fish kills compared to CARB gasoline and petroleum diesel because they deplete oxygen more rapidly.

Wastewater discharge volume from the production facilities range from none to high as described below, but regardless of the discharge volume these facilities will need permits. With the exception of wastewater from pyrolysis operations that may be highly toxic, most wastewater discharges from the proposed LCFS facilities are not expected to be “toxic” per se, but may be high in salinity and BOD and therefore prohibited from discharge to land or water. In some cases the limitations on water discharge from production facilities may limit the development of the LCFS options in California.

B. Water Use

Water supply and consumption is a major issue in California and the State Water Board is responsible for surface water rights adjudications and the protection of their “beneficial uses”. Ownership of virtually every drop of surface water in California has been established. Surface water is neither free nor easily available. Even when water supplies can be acquired, the Water Boards may limit use if the removal of fresh water from a watershed basin adversely impacts the environment, ecology, or other beneficial uses.(46)

Groundwater is not adjudicated statewide, but is limited in some areas. The Water Boards instead encourage the use of treated wastewater to produce fuels and irrigate feedstock crops where possible.

The production of fuels that consume very large quantities of water may be limited by available local supply and impacts on beneficial uses, and further limited to specific supplies such as Waste Water Treatment Plant (WWTP) ocean discharges(47).

Table F12-I below estimates the worse case water consumption scenario of the LCFS mix.

Table F12-1
Worse Case Water Use to Meet Proposed LCFS Goals

Fuel	# plants	unit output (MMgal)	total fuel output (MMgal)	gallons of water /gallon of fuel	total water consumed to meet LCFS goals (MMgal)
EtOH cellulosic biochemical	9	50	450	6 (48)	2,700
EtOH cellulosic thermo chemical	9	50	450	1.5 ³⁰	675
EtOH corn fermentation (irrigated)	6	50	300	785 (48)	235,500
Biodiesel	6	50	300	0.5 ³¹	150
					239,025

Note: the EtOH corn option includes irrigation water requirements. Production plant water consumption is estimated at 3.5 gallons of water per gallon of EtOH.(48)

The total annual volume of water used in this LCFS scenario equals 70% of the maximum volume of Folsom Lake(49). Finding new available surface water for this volume of water in the California Central Valley may be extremely difficult, especially if corn crops grown for fuel require irrigation. Proponents of ethanol production facilities should consult with the Region Water Boards and the State Water Board, Division of Water Rights prior to committing to a location in order to confirm that sufficient water is available and that the state and regional boards have no objections to the use of that water.

Groundwater supply is not adjudicated or regulated by the State Water Board per se, but there are often competing local demands for groundwater.

Although recycled wastewater from a local wastewater treatment plant (WWTP) may be available for irrigation and process water, proponents of ethanol plants in the California Central Valley and other water scarce areas are advised to confirm the availability of such water especially during periods of low surface water flow.

Ocean discharge from coastal WWTPs is a more reliable source of process water than WWTP discharge to land and the available volume easily exceeds the water supply requirements of the entire LCFS scenario above by several orders of magnitude. In fact, WWTP discharge to the ocean in California could supply enough water to support a 100% hydrogen economy. The available annual ocean discharge from WWTP can

³⁰ Personal experience manufacturing and testing low-Btu gasification and reforming technology.

³¹ Personal site surveys of California biodiesel plants.

supply sufficient water ‘feedstock’ to produce enough hydrogen to supply over 1000% of California’s 2007 gasoline consumption on a Btu basis.³²

Thus the proposed LCFS candidate fluid fuel production schemes should not create a water use problem if sited near large coastal WWTP and utilize ocean discharge water. Sites located inland may face difficulty finding water supplies.

C. Regulatory Requirements

The Water Boards regulate water discharges from any fuel production facility including electric power plants, as well as, the storage of any fuel in underground storage tanks UST. The Water Boards also protect and regulate the “beneficial use” of California’s water including the impact on beneficial uses posed by water consumption in the production of energy.

Water related environmental and regulatory issues which fall entirely or in part within the authority of the State Water Board include water use, wastewater discharge from production facilities, toxicity of wastewater discharges, water quality related to ecology and other beneficial uses, permits required for production and storage of these fuels, and other regulatory limits on storage of fuels which do not necessarily require a permit.

D. Permits Required

An NPDES permit is required if there is a wastewater discharge from the production facility. Owners of these facilities will need to obtain an NPDES permit from the Regional Board with jurisdiction.

A discharge permit from a local wastewater treatment plant is required if the production facility’s effluent is to be discharged to the local sewer. The WWTP managers do not have to accept any discharge. Because they also have NPDES permits with discharge requirements, they can and will refuse to accept wastewater that may cause them to violate the terms of their NPDES permit. Small scale biodiesel producers technically need a permit to discharge wash water or bad batches into the sewer regardless of volume because the permit is based on both flow and concentration of constituents.

All retail or fleet storage of fuels in UST requires a Permit to Operate from the local authority (CUPA) and are required to notify the local CUPA before changing fuels stored i.e., switching from ULSD to a biodiesel blend for example.

There are no special permit requirements or regulations for any specific alternative fuel. All fuels are subject to the same HSC requirements.

³² Personal calculation based on California’s ocean outfall volume (MGD), an assumed limit on the volume of that ocean discharge water available for conversion to hydrogen, and the hydrogen content of that volume of water

E. Regulatory Limitations on Storage of Fuel that Do Not Require a “Permit”

Any U.S. EPA listed fuel may be stored in above ground tanks (AST), if allowed by the local agency with jurisdiction (CUPA) and fire marshal, but no fuels containing petroleum may be stored in underground storage tanks (UST) without Underwriter's Laboratory (UL) approval of the UST system for the blend stored.

UL has certified some UST, pipe, and dispensers to store any ethanol blend including E85. The State Water Board is currently reviewing the UL certification and is expected to agree with the UL determination.

However, there are no UST systems with UL approval to store B100 or any blend of biodiesel or Butanol at this time. The storage of biodiesel has become a major regulatory problem. The Water Board is working closely with UL and UST system manufacturers to resolve.

Table F12-2
Water Quality, Water Use, and Related Regulatory Requirements
for Low Carbon Fuel Candidates

Fuel	Production Water Use (1)	Production Wastewater Volume	Production Wastewater Toxicity	Water Quality Issues
Ethanol from corn including irrigation	Extremely High	moderate to none	can be high in salinity and BOD	Salinity, BOD, in wastewater. Spills in transport or unauthorized releases of toxic petrochemicals (BTEX) and prolongs bioremediation of groundwater.
Ethanol via biological conversion of cellulose feedstocks	High	moderate	may be highly toxic	"" ""
Ethanol via thermochemical conversion of cellulose feedstocks	low	low	may be highly toxic and carcinogenic.	Wastewater likely contains hazardous substance. Spills in transport or unauthorized releases of toxic petrochemicals (BTEX) and prolongs bioremediation of groundwater.
Large scale biodiesel from oil bearing crops	Low to none	Low to none.	none anticipated if methanol recovered	unauthorized releases of D975 diesel via spills or from USTs
Large scale Biodiesel from waste FOG	Low to none	Low to none	none anticipated if methanol recovered	"" ""
Small Scale biodiesel regardless of feedstocks	Low	undocumented	undocumented, but potential for illegal disposal of toxic and high BOD wastewater	No practical method exists at this time to locate and regulate unauthorized releases of wash water or disposal of bad batches by small producers.
Renewable diesel from reduction of cellulose feedstock	Low	Low	potentially highly carcinogenic and toxic hydrocarbons	Wastewater likely contains hazardous substance. Spills in transport or unauthorized releases of toxic petrochemicals and prolongs bioremediation of groundwater.
Renewable diesel from reforming FOG	Low	Unknown, or not documented	Unknown, or not well documented	unauthorized releases of D975 diesel via spills or from USTs
Butanol from cellulose	High	similar to ethanol from cellulose	highly toxic to carcinogenic	Wastewater likely contains hazardous substance. Spills in transport or unauthorized releases of toxic petrochemicals and prolongs bioremediation of groundwater.
Butanol from fossil fuel	Low	Low, similar to gasoline	similar to gasoline	unauthorized releases of BTEX from spills and UST
Electricity via combustion of hydrocarbons	Relatively Moderate	Power plant cooling water	high salinity	salinity; leachate from landfill disposal from large scale battery use and disposal
Electricity via hydroelectric, photovoltaic, wind	Low to none	algae reactor water treatment discharge	high salinity	disposal of saline water
Hydrogen by electrolysis of water	Very high.	High to moderate	salinity and other feed water concentrates	Disposal of highly concentrated saline and/or toxic slurry from an RO or other feedstock purification process.
Hydrogen via reduction of hydrocarbons	High to moderate	High to moderate	Hydrocarbon waste stream constituents are likely to be toxic.	"" ""
Hydrogen from algae	Very high, highest water consumption	Very high.	salinity and solids	Disposal of highly concentrated saline and/or toxic slurry from a water purification process.
CNG	None	None	None	None
LNG	None	None	None	None
(1) Water Use is expressed in relative terms of volume of water consumed per volume of fuel produced. "Water Use" includes water consumption, which is the physical destruction of water or a change of phase of water such that the result is a decrease in the volume of liquid water.				

This Page Intentionally Left Blank

Appendix F13

Impacts on Hazardous Waste

Operators of facilities designed to produce fuels for the LCFS will be required to comply with federal, state, and local safety and environmental regulations. Compliance with existing regulations must be considered adequate to minimize significant worker exposure and potential environmental hazards. Many of the potential hazard and hazardous materials impacts can be reduced to less than significant levels. Facilities producing biofuels will involve the use and on-site storage of hazardous materials including gasoline, diesel fuel, ethanol, urea, hydrochloric acid along with any hazardous waste from production processes. There is a potential for release of these materials either through human error, equipment malfunction or other causes including a seismic event. During construction of a biofuels facility a Spill Contingency Plan is required as part of the Storm Water Pollution Prevention Plan. This plan is required to include provisions for cleanup, spill containment, notifications and storage of hazardous and toxic materials.

Chemicals for routine maintenance and operation of the facilities would be used intermittently and stored on-site in limited amounts. Some of the materials used in the production of biofuels will be considered to be hazardous for health and/or fire safety reasons. The facilities are required to be designed so that potential hazardous materials are handled and contained with the required technology to minimize the chances of a release. Ethanol and gasoline would probably be stored in carbon steel tanks. Aqueous ammonia, enzymes, sulfuric acid, and urea would be stored in stainless steel tanks. All tanks would be required to be surrounded by spill containment structures and equipped with vapor control features. All process operations that require periodic maintenance and regular wash downs would be placed within a building or curbed area. To minimize the escape of grain dust, grain conveyor unloading and milling operations would have dust collection systems to capture fugitive dust emissions, which could be reused as additional feedstock. Wastewater discharges, fire, explosions, spills during the processing, storage and transportation during operations are some of the many potential loss incidents associated with biofuels production.

Facility operators prepare a site specific Spill Prevention Control and Counter Measure Plan (SPCC) and Emergency Response, and site specific Hazardous Materials Business Management Plan once the site is in operation. The project proponent is required to prepare and comply with a Risk Management Plan (RMP) if stored quantities of certain hazardous materials exceed state and federal limits. The proposed projects are subject to Federal Process Safety Management (PSM) requirements and compile a plan. Hazardous Operations (HAZOP) studies are conducted as part of the startup operation.

Of potential concern would be radiant heat from a fire occurring within the containment structures. This worst case scenario assumes that a tank would rupture and be ignited. Typically, modeling is done prior to facility construction to determine the best placement of containment structures to reduce the impacts from a fire. A Hazardous Materials

Management Plan and Business Plan are prepared for each project which will provide measures for the control, notification and clean up of any accidental spills, fire prevention procedures and safeguards for employees. These plans will provide any emergency evacuation plans and other notifications plans if required. Prior to construction, facilities are required to prepare a Risk Management Plan (RMP) under the California Accidental Release Prevention Program to prevent the accidental releases of regulated (hazardous) substances and to reduce the consequences in the event a release occurs. This program requires businesses that handle more than a threshold quantity of a regulated substance to develop a RMP. The main components of a RMP are: hazard assessment, prevention, and emergency response.

Hazardous materials will be stored and used in and around the biofuels facilities. The ethanol distillation process utilizes hazardous materials such as Ammonium Hydroxide, Sodium hydroxide, Sulfuric Acid, and Anhydrous Ammonia to produce ethanol. Wastewater discharges, fire, explosions, spills during the processing, storage and transportation during operations are some of the many potential loss incidents associated with ethanol production. The impacts associated with routine transport, disposal, and use of hazardous materials on-site are considered potentially significant.

A. Spill Prevention Control and Countermeasures Plan

Facilities that store oil or petroleum in excess of 1320 gallons are required to prepare a Spill Prevention Control and Countermeasures (SPCC) plan. The SPCC plan considers a release analysis, operating procedures to prevent spills; control measures to prevent spills from entering surface water; countermeasures such as secondary containment for spills and bulk storage compliance, an inspection schedule, security and training. The Plan includes the requirement that the facility provide a stock pile of containment materials and equipment on site to assist the Fire Department Hazardous Materials Units to control or stop a spill or a leak at the facility and provide hazardous materials equipment for the response to any roadway incidents involving trucking of hazardous materials to and from site. The plan must be certified by a licensed professional engineer. Appropriate technology and best management practices during construction would mitigate potential impacts.

B. Transportation of Hazardous Materials

Biofuel facilities will involve the routine transportation of hazardous materials that could result in the accidental spills into the environment. These facilities will place additional vehicles on the roadway in California transporting hazardous materials. This could result in a significant hazard to the public or the environment through a reasonably foreseeable upset and accident conditions involving the release of hazardous materials into the environment. Although most transport of hazardous or toxic materials will be by independent contractors, the facility operators are expected to establish and implement Department of Transportation standards for trucks hauling these materials. This includes inspection of trucks to assure that they meet safety requirements for hauling hazardous materials and the drivers are properly licensed and trained. An off-site risk

analysis analyzing the potential impact of release of gasoline, ethanol or aqueous ammonia is generally conducted in the event of a spill or other accidental release of this material.

Implementation of the proposed project would require the transport of various substances, some of which are flammable. The biofuels facilities would involve the routine transport of raw product (corn, grain), processed ethanol (alcohol), and wet-distiller grain by-product or municipal solid waste and yellow grease. Other substances involved in the operational practices of the facility include enzymes, water, natural gas, yeast, and hydrocarbon denaturant. Of these substances, ethanol, biodiesel, natural gas, and denaturant would be considered flammable and represent a potentially significant hazardous condition when used or transported to and from the facility. This could pose a significant hazard should an accident involving the substances occur.

Biofuel facilities would involve the limited use of hazardous materials associated with operation of the project and limited use of hazardous materials associated with the transporting of biofuels. The project would be required to comply with all federal, state and local regulations regarding the handling of such materials. The biofuels facilities are not anticipated to contribute significantly to cumulative impacts to hazardous materials/risk of upset. The impacts associated with routine transport, disposal, and use of hazardous materials on-site are considered potentially significant. There are a number of important regulations associated with biofuels production and are intended to ensure the safe transport, disposal and use of hazardous materials. Facility operators will need to comply with the regulations promulgated by various State Agencies.

C. California Environmental Protection Agency

The California Environmental Protection Agency (Cal-EPA) and the State Water Resources Control Board establishes rules governing the use of hazardous materials and the management of hazardous waste. Applicable state and local laws include the following:

- Public Safety/Fire Regulations/Building Codes
- Hazardous Waste Control Law
- Hazardous Substances Information and Training Act
- Air Toxics Hot Spots and Emissions Inventory Law
- Underground Storage of Hazardous Substances Act
- Porter-Cologne Water Quality Control Act

Within Cal-EPA, the Department of Toxic Substance Control (DTSC) has primary regulatory responsibility, with delegation of enforcement to local jurisdictions that enter into agreements with the state agency, for the management of hazardous materials and the generation, transport and disposal of hazardous waste under the authority of the Hazardous Waste Control Law (HWCL).

California's Secretary for Environmental Protection (CalEPA) has established a

unified hazardous waste and hazardous materials management regulatory program (Unified Program) as required by statute (Health and Safety Code Chapter 6.11). The Unified Program consolidates, coordinates, and makes consistent portions of the following six existing programs:

- Hazardous Waste Generators and Hazardous Waste Onsite Treatment
- Underground Storage Tanks
- Hazardous Material Release Response Plans and Inventories
- California Accidental Release Prevention Program
- Aboveground Storage Tanks (spill control and countermeasure plan only)
- Uniform Fire Code Hazardous Material Management Plans and Inventories

D. Process Safety Management (PSM) of Highly Hazardous Chemicals

The U.S. Department of Labor's OSHA passed a rule in May 1992 that addresses the prevention of catastrophic accidents. This rule, known as Process Safety Management of Highly Hazardous Chemicals (29 CFR § 1910.119), requires companies handling hazardous substances in excess of specific threshold amounts to develop and implement process safety management (PSM) systems. The rule emphasizes the management of hazards associated with highly hazardous chemicals and establishes a comprehensive management program that integrates technologies, procedures, and management practices. The PSM rule is directed primarily at protecting workers within a facility that handles hazardous materials. The major objective of process safety management of highly hazardous chemicals is to prevent unwanted releases of hazardous chemicals, especially into locations that could expose employees and others to serious hazards. This rule contains requirements for preventing or minimizing the consequences of catastrophic releases of toxic, reactive, flammable, or explosive chemicals.

E. California Accidental Release Prevention Program (CalARP)

The operators of proposed biofuels facilities would be required to comply with all federal, state, and local regulations regarding the storage and use of any hazardous materials onsite. In addition, as a requirement of California Accidental Release Prevention (CalARP) Program, an Emergency Action Plan would be prepared. The California Code of Regulations (Title 19, Division 2, Chapter 4.5), the CalARP, requires any facility handling more than a threshold quantity of acutely hazardous materials to establish an RMP for the facility. The purpose of the program is to prevent accidental release of regulated substance. CalARP includes the federal Chemical Accident Prevention Provisions, with certain additions specific to the state pursuant to Article 2, Chapter 6.95, of the Health and Safety Code. The CalARP program defines three program levels with different requirements depending upon the complexity, accident history, and potential impact of release of regulated substances. Such requirements may include the following: develop and implement a management system to oversee the implementation of the risk management program elements, conduct a hazard assessment, implement the prevention program, develop and implement an

emergency response program, and submit data on prevention program elements. CalARP also requires a Pre-Startup Review of the processes prior to those processes being brought on line.

F. Process Safety Management of Hazardous Materials (PSM)

The California State equivalent of the federal PSM regulations is found in 8 CCR § 5189, Process Safety\Management of Acutely Hazardous Materials. The regulations set forth the requirements for preventing or minimizing the consequences of catastrophic releases of highly hazardous toxic, reactive, flammable, or explosive chemicals. Key to these regulations is the establishment of a comprehensive process safety management program that integrates technologies, procedures, and management practices intended to eliminate to a substantial degree the risks to which employees in petroleum refineries, chemical plants, and other facilities are exposed.

G. Hazardous Waste Generator Requirements

Pursuant to the California Health and Safety Code and Title 22, California Code of Regulations (CCR), requirements were set in place for Hazardous Waste Generators.

The following requirements apply to generators of hazardous waste except for generators that generate no more than 100 kg exclusively of silver-only hazardous waste:

1. Hazardous Waste Determination: Determine if the waste is hazardous by identifying it as either a toxic, reactive, ignitable or corrosive. Determine if the waste listed as a hazardous waste is in Appendix X of chapter 11 of division 4.5 of Title 22 CCR.
2. Identification Number: This number identifies each handler on hazardous waste manifests and other paperwork. The identification number enables regulators to track the waste from original to final disposal ("cradle to grave"). These numbers are site-specific and there must be only one number at a single address. All hazardous waste transporters and permitted treatment, storage and disposal facilities (TSDFs) must have an identification number.
3. Accumulation: Hazardous waste may be accumulated onsite in generator accumulation units (containers, tanks, drip pads, or containment buildings) only in compliance with the applicable time limits specified in the Health and Safety Code section 25123.3.
4. Labeling/Marking: The date upon which each period of accumulation begins must be clearly marked and visible for inspection on each accumulation unit. While being accumulated on site, each generator tank or container must be labeled or clearly marked with the words, "Hazardous Waste." Each container and portable tank in which hazardous waste is accumulated must be labeled with the following information:
 - a. Composition and physical state of the waste;

- b. Statement(s) that call attention to the particular hazardous properties of the waste (e.g. flammable, reactive); and
- c. Name and address of the generator.

Containers and tanks used by the generator to collect or consolidate wastes initially accumulated in other containers or tanks are subject to the same labeling requirements.

5. Emergency Procedures/Contingency Plans: All generators must comply with the following requirements regarding preparedness and prevention:
- a. All operations must minimize the possibility of a fire, explosion or any unplanned release of hazardous waste or hazardous waste constituents to air, soil, or surface water that could threaten human health or the environment.
 - b. A generator's site must be equipped with the following, unless it can be demonstrated to DTSC that none of the hazards posed by waste could require a particular kind of equipment.
 - c. All communications and alarm systems, fire protection equipment, spill control equipment and decontamination equipment, where required, must be tested and maintained as necessary to ensure its proper operation in time of emergency.
 - d. Wherever hazardous waste is being handled, all personnel involved in the operation must have immediate access to an internal alarm or emergency communication device, either directly or through visual or voice contact with another employee, unless DTSC has determined that such a device is not required.
 - e. If only one employee is on the premises while the facility is operating, he/she must have immediate access to a device, such as a telephone (immediately available at the scene of operation) or a hand-held two-way radio, capable of summoning external emergency assistance, unless DTSC has determined that such a device is not required.
 - f. The generator must maintain aisle space to allow the unobstructed movement of personnel, fire protection equipment, spill control equipment and decontamination equipment to any area of operation in an emergency, unless it can be demonstrated to DTSC that aisle space is not needed for any of these purposes.
 - g. The generator must attempt to make the following arrangements, as appropriate, for the types of waste handled at the site and the potential need for the services of these organizations:
 - i. Arrangements to familiarize police and fire departments, emergency response teams and the local Office of Emergency Services with the layout of the facility, properties of the hazardous waste, associated hazards, places where personnel would normally be working, entrances to roads inside the facility and possible evacuation routes;
 - ii. Where more than one police and fire department might respond to an emergency, agreements designated primary emergency authority to a specific police and a specific fire department, and

- agreements with any others to provide support to the primary emergency authority;
- iii. Agreements with State emergency response teams, emergency response contractors and equipments suppliers;
- iv. Arrangements to familiarize local hospitals with the properties of hazardous waste handled and the types of injuries or illnesses that could result from fires, explosions or releases at the facilities; and
- v. Where State or local authorities decline to enter into such arrangements, the generator must document the refusal in the operating record.

Generators that generate less than 1000 kg per month of hazardous waste must comply with the following requirements:

- a. At all times there must be at least one employee either on the premises or on call with the responsibility for coordinating all emergency response measures. This employee is the emergency coordinator.
- b. Post the following information next to the telephone:
 - i. The name and telephone number of the emergency coordinator;
 - ii. The location of fire extinguishers and spill control material, and fire alarm; and
 - iii. The telephone number of the fire department, unless the facility has a direct alarm.
- c. The emergency coordinator or his/her designee must respond to any emergencies that arise.

Each generator that generates 1000 kg per month or more hazardous waste per month must comply with the requirements of Title 22, CCR division 4.5, chapter 15, article 4.

- 6. Training: Generators that generates less than 1000 kg per month of hazardous waste must ensure that all employees are thoroughly familiar with proper waste handling and emergency procedures, relevant to their responsibilities during normal facility operations and emergencies. Generators that generate 1000 kg or more per month of hazardous waste must comply with the requirements of section 66265.16.
- 7. Shipment: When shipping hazardous waste totaling more than 50 pounds per 5 gallons off the premises a generator must do the following:
 - a. Use only transporters, and transfer, treatment, storage and disposal facilities that are registered or permitted by DTSC and have obtained an ID number;
 - b. Comply with the Department of Transportation (DOT) requirements for packing, labeling and marking and ensure that the transport vehicle is correctly placarded;
 - c. Use a California Hazardous Waste Manifest, DTSC Form 80221, unless the receiving state requires otherwise.
 - d. Complete the generator and waste sections and sign the manifest certification according to the instructions included in the Appendix to Chapter 12 of Division 4.5, Title 22, CCR;

- e. Obtain the handwritten signature of the initial transporter and date of acceptance on the manifest;
 - f. Retain two copies of the manifest, in accordance with Section 66262.40 (a);
 - g. Keep the generator copy of each manifest for three years or until the signed copy is returned by the designated facility. This signed copy must be retained for at least three years from the date the waste was accepted by the initial transporter;
 - h. Ensure that if shipping hazardous waste to an out of state non-permitted TSD, that the TSD signs and returns the final copy of the manifest to the generator, who is then responsible for sending the signed copy to DTSC.
 - i. Submit the appropriate copy of each manifest to DTSC, within thirty days of each shipment;
 - j. If a manifest from another state is used to ship hazardous waste to that state, then submit a legible copy of the manifest used to DTSC within thirty days of each shipment;
 - k. Ship waste only to facilities authorized to accept the waste type;
 - l. Contact the transporter and/or the owner or operator of the designated facility to determine the status of the hazardous waste if the generator has not received a copy of the manifest signed by the operator of the designated facility within 35 days of the date the waste was accepted by the initial transporter; and
 - m. File an Exception Report with DTSC if a copy of the manifest signed by the facility operator is not received within 45 days of the date the waste was accepted by the initial transporter. The time to file an exception report is 60 days for generators of less than 1000 kg per month and who meet other specified requirements.
8. Biennial Report: Submitting a biennial report is required for a generator who ships any hazardous waste to a transfer, treatment, storage or disposal facility within the United States. The report is due by March 1 of each even-numbered year and covers the previous year of hazardous waste activity. Copies must be retained for three years.

Generators that generate no more than 100 kg exclusively of silver-only hazardous waste must comply with the federal Conditionally Exempt Small Quantity Generator (CESQG) requirements in 40 C.F.R section 261.5, instead of the CCR, Title 22 requirements. They only need to:

- 1. Determine if their waste is hazardous;
- 2. Accumulate no more than 100 kg of hazardous waste at any one time; and
- 3. Ensure that the disposal or recycling of the hazardous waste is done at an authorized facility.

These silver-only generators do not need to obtain an identification number and they do not have to use a hazardous waste manifest or registered hazardous waste transporter when shipping their hazardous waste.

Management of Waste Gasoline and Diesel Fuel Filters

Assembly Bill (AB) 2254, was signed into law on August 23, 2004, and became effective on January 1, 2005. Generally, this new law allows waste filters that contain residues of gasoline or diesel fuel (waste fuel filters) to be managed according to Department of Toxic Substances Control (DTSC) regulations for the management of used oil filters. AB 2254 imposes several specific requirements on the accumulation of waste fuel filters containing gasoline residues and commingled used oil/waste fuel filters containing gasoline residues.

Properly drained waste fuel filters can now be accumulated and stored with used oil filters to be recycled for scrap metal content.

Anyone involved in the management of used oil and waste fuel filters is potentially affected by AB 2254. Affected parties include: household generators, small quantity generators (SQG), businesses that generate waste fuel filters, household hazardous waste collection centers, used oil collection centers, used oil recyclers, and any other entity that generates, transports, recycles or manages waste fuel filters and used oil filters commingled with waste fuel filters.

AB 2254 has made the following changes:

Waste fuel filters may now be accumulated in the same containers with the used oil filters and handled in the same manner as used oil filters. This provision only applies to used oil and/or waste fuel filters that have been drained of all free flowing liquid and are destined for recycling as scrap metal.

When the accumulated filters contain residues of gasoline, additional requirements apply. Such filters:

- Must be stored in containers designed to prevent the ignition of gasoline, and must be labeled "Used Oil and Gasoline Filters."
- Must be properly packaged and labeled before transporting, as required by U.S. Department of Transportation.
- Must be stored and managed in accordance with state and local fire code requirements.
- Any residues containing gasoline that accumulate in filter storage containers, and any non-filter material removed from filter housing must be evaluated for hazardous waste characteristics under Section 66262.11 of title 22 of the California Code of Regulations, and managed according to the waste's classification.

This Page Intentionally Left Blank

Appendix F14

Impacts on Waste

California has diverse, widespread and substantial biomass resources, which include residues from municipal solid wastes (MSW) in addition to forestry and agriculture sources. Materials in the waste stream can be used as resources to produce alternative renewable energy and biofuels, thereby increasing diversion, developing new markets, and helping to mitigate climate change.

A. Policy Actions

The California Integrated Waste Management Board (CIWMB) is the state agency tasked with overseeing and managing the 90 million tons of waste generated each year, and its activities have resulted in large gains with respect to waste reduction and diversion. In 1989, California was recycling only 10% of its waste. California has achieved a 57% diversion rate, yet the state still landfilled approximately 42 million tons of MSW and used 3 million tons of green waste as alternative daily cover (ADC) in 2005. The organic fraction of the disposed MSW is estimated at roughly 70%, and according to studies conducted by the California Biomass Collaborative, the potential to produce ethanol and other liquid fuels from this landfilled material is estimated to be equivalent to about 300 million gallons of gasoline.

CIWMB's Strategic Directives provide direction for waste diversion efforts. Strategic Directive 6.1 focuses on organic materials and calls for a reduction of the amount of organics in the waste stream of 50% by 2020. Meeting Strategic Directive 6.1 will require development of perhaps 50-100 new facilities (or equivalent expansion of existing facilities) that produce compost, biofuels, and/or bioenergy; increased development of product standards and increased procurement by private and public entities; and resolution of cross-agency regulatory issues.

The importance of producing renewable energy and biofuels from waste is further reflected in the Board's Strategic Directive 9.2, which encourages the development of alternative energy and biofuels, and Strategic Directive 9.3, under which CIWMB plays an active role in the Bioenergy Inter-Agency Working Group. The Bioenergy Inter-Agency Working Group's objectives include maximizing the contributions of bioenergy toward achieving the state's petroleum reduction, climate change, renewable energy, and environmental goals in addition to facilitating market entry for new applications of bioenergy including electricity, biogas, and biofuels.

CIWMB is moving forward with objectives described in the Bioenergy Action Plan by establishing goals for 2010 and beyond for the use of landfill-bound residuals to be used for bioenergy and biofuels production. CIWMB is particularly interested in demonstration of bioenergy and biofuel technologies in California.

These directives and objectives correlate with the goals of the LCFS. Biofuels and bioenergy derived from MSW sources may have a lower carbon intensity when

compared to petroleum-derived fuels and minimal indirect effects. These effects are further reduced by feedstock proximity to biofuel production facilities and by the existing waste handling infrastructure, including collection and processing capabilities already in place.

B. AB 32 Scoping Plan

Per the Statewide GHG emissions inventory, the largest emissions from the Recycling and Waste Management sector come from landfills and are in the form of methane, which is produced when materials placed in landfills decompose over time. Often, decades elapse and methane is still produced from this decomposition. Although methane is captured currently at many large landfill sites, there are still active landfill operations and closed landfill sites that continue to emit methane that could be captured. ARB staff worked with the Recycling and Waste Management Subgroup of the Climate Action Team to develop measures to reduce landfill methane emissions.

ARB identified improved capture of landfill methane as a Discrete Early Action Measure. Methane that is currently emitted can be captured and further controlled, and can, in some cases, be used as a fuel to replace conventional fossil fuels. In addition, methane capture can also reduce air quality impacts by capturing and destroying volatile organic compounds and other landfill gases that are emitted during the decomposition process. ARB staff is working closely with CIWMB to develop this measure.

CIWMB also identified technologies and outreach that would improve emission reduction through voluntary strategies. One method involves increasing the use of anaerobic digestion (AD), a type of controlled, in-vessel decomposition of the organic fraction of the waste stream that allows for renewable energy production and avoidance of landfill methane emissions. The development of new AD facilities that utilize foodwaste as their primary feedstock (with biosolids and manure as secondary feedstocks) to generate biogas; or use existing AD facilities and source foodwaste for biogas production. In either case, there is a focus on pre-processing of waste to maximize biogas yields and collection/delivery systems for sourcing consistent volumes and pricing of foodwaste. In addition, co-location consideration of new AD facilities at landfills, agricultural processing industries, where siting, feedstock delivery and cost synergies exist.

C. Negative Effects

Potential adverse waste impacts are not expected to be significant. The proposed measures are not anticipated to result in a substantial increase in the generation of solid waste or require that any permitted facility to expand its capacity to accommodate increased quantities of waste.

Appendix F References

1. CEC. (2009). "California's Oil Refineries " Retrieved, from <http://energyalmanac.ca.gov/petroleum/refineries.html>.
2. UC Davis (2008). Strategic Development of Bioenergy in the Western States. Western Governors' Association.
3. ARB (2007). Emfac 2007. Air Resources Board.
4. ARB (2009). Emfac Screenshot Table F6-1. California Air Resources Board.
5. ARB (2009). Emfac Screenshot Table F6-2. California Air Resources Board.
6. ARB (2009). GREET Analysis Table F6-3. California Air Resources Board.
7. ARB (2008). California-GREET Model version 1.8b. Air Resources Board. <http://www.arb.ca.gov/fuels/lcfs/lcfs.htm>.
8. TIAX (2007). Full Fuel Cycle Assessment Well to Tank Energy Inputs, Emissions, and Water Impacts. California Energy Commission.
9. ARB (2007). CALIFORNIA EVAPORATIVE EMISSION STANDARDS AND TEST PROCEDURES FOR 2001 AND SUBSEQUENT MODEL MOTOR VEHICLES. California Air Resources Board.
10. ARB (2008). The California Low-Emission Vehicle Regulations. California Air Resources Board.
11. MSCD (2008). E85 Spreadsheet F6-4. California Air Resources Board.
12. Lisa A. Graham, Sheri L. Belisle, and Cara-Lynn Baas (2008). "Emissions from Light Duty Gasoline Vehicles Operating on Low Blend Ethanol Gasoline and E85." Atmospheric Environment 42: 4498-4516.
13. Renewable Technology (2005). Renewable Diesel Subcommittee of the WSDA Technical Work Group. WSDA.
14. Aaron Williams, et al. (2006). Effect of Biodiesel Blends on Diesel Particulate Filter Performance. SAE.
15. EPA (2002). A Comprehensive Analysis of Biodiesel Impacts on Exhaust Emissions. US Environmental Protection Agency.
16. Thomas D. Durbin, J. Wayne Miller, Kent Johnson (2009). For the CeCERT Engine Testing portion for the CARB Assessment of the Emissions from the Use of Biodiesel as a Motor Vehicle Fuel in California "Biodiesel Characterization Study" Testing on 2006 Cummins ISM. California Air Resources Board.
17. SAE (2004). Automotive Handbook. Society of Automotive Engineers.
18. William Tahil (2007). The Trouble with Lithium. Meridian International Research.
19. Joyce A. Ober (2008). Lithium. US Geological Survey.
20. USCAR. (2007). "What's recycled more than any other item in the U.S.? Here's a hint -- USCAR's VRP IS involved." Retrieved, from http://www.uscar.org/commands/files_download.php?files_id=125.
21. Annette Hebert (2008) A-021-0479 Cummins
22. Annette Hebert (2008) A-021-0458-1 Cummins
23. OEHHA (2003). Air Toxics Hot Spots Program Risk Assessment Guidelines. California Office of Environmental Health Hazard Assessment.
24. ARB (1998). PROPOSED IDENTIFICATION OF DIESEL EXHAUST AS A TOXIC AIR CONTAMINANT. California Air Resources Board.

25. ARB (2002). Public Hearing to Consider Amendments to the Ambient Air Quality Standards for Particulate Matter and Sulfates. California Air Resources Board.
26. ARB (2007). Health Risk Assessment for the Union Pacific Railroad Commerce Railyard. California Air Resources Board.
27. ARB (2006). Emission Reduction Plan for Ports and Goods Movement in California. California Air Resources Board.
28. ARB (2000). Risk Reduction Plan to Reduce Particulate Matter Emissions from Diesel-Fueled Engines and Vehicles. California Air Resources Board.
29. SCAQMD (2000). MULTIPLE AIR TOXICS EXPOSURE STUDY. South Coast Air Quality Management District.
30. EPA (2004). USER'S GUIDE FOR THE AMS/EPA REGULATORY MODEL - AERMOD. US Environmental Protection Agency.
31. ARB (2007). Health Risk Assessment for the Union Pacific Railroad Commerce Railyard Stationary Source Division. California Air Resources Board.
32. ARB (2006). ARB Almanac 2006. California Air Resources Board.
33. ARB and OEHHA (2002). Public Hearing to Consider Amendments to the Ambient Air Quality Standards for Particulate Matter and Sulfates. California Air Resources Board.
34. ARB (2006). Emission Reduction Plan for Ports and Goods Movement. California Air Resources Board.
35. EPA (2004). Final Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines. US Environmental Protection Agency.
36. EPA (1999). The Benefits and Costs of the Clean Air Act 1990 to 2010. US Environmental Protection Agency.
37. EPA (2005). Regulatory Impact Analysis for the Final Clean Air Interstate Rule. US Environmental Protection Agency.
38. ARB (2008). Methodology for Estimating the Premature Deaths Associated with Long-term Exposures to Fine Airborne Particulate Matter in California. California Air Resources Board.
39. Alan C. Lloyd and Thomas A. Cackette (2001). "Diesel Engines: Environmental Impact and Control." *Journal of the Air & Waste Management Association* 51: 809-847.
40. F Diminici and et al. (2005). "Revised Analyses of the National Morbidity, Mortality, and Air Pollution Study: Mortality Among Residents Of 90 Cities." *Journal of Toxicology & Environmental Health: Part A* 68(13/14): 1071-1092.
41. MEREDITH FRANKLIN, ARIANA ZEKA, and JOEL SCHWARTZ (2007). "Association between PM_{2.5} and all-cause and specific-cause mortality in 27 US communities." *Journal of Exposure Science and Environmental Epidemiology* 17(3): 279-287.
42. Michael Jerrett and et al. (2005). "Spatial Analysis of Air Pollution and Mortality in Los Angeles." *Epidemiology* 16(6): 727-736.
43. C. Arden Pope III, et al. (2002). "Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution." *Journal of the American Medical Association* 287(9): 1132-1141.
44. Mark A. Thayer (2003). The Economic Value of Respiratory and Cardiovascular Hospitalizations. UC San Diego.

45. EPA (2000). Guidelines for Preparing Economic Analyses. US Environmental Protection Agency.
46. Katherine Mrowka (2008). Division of Water Rights, State Water Resources Control Board.
47. Bart Christensen PE (2008). Division of Water Quality, State Water Resources Control Board.
48. Andy Aden (2007). Water Usage for Current and Future Ethanol Production. National Renewable Energy Laboratory.
49. Bureau of Reclamation. (2009). "Central Valley Project - Folsom and Sly Park." Retrieved, from <http://www.usbr.gov/dataweb/html/folsom.html>.

This page intentionally left blank

APPENDIX G

Supporting Documentation for Economic Analysis

THIS PAGE INTENTIONALLY LEFT BLANK

The purpose of this appendix is to provide additional information to support the data and discussion in Chapter VIII. This appendix is organized as follows:

- Gasoline Gallon Equivalent (gge) and Diesel Gallon Equivalent (dge) Calculations
- Example of an Estimated Alternative-Fuel Cost on a Per-GGE Basis
- Economic Analysis Spreadsheets for Diesel and Gasoline Scenarios
 - All eight diesel and gasoline scenarios
 - Three pages per scenario
- Estimated Impacts to Federal, State, and Local Governments

THIS PAGE INTENTIONALLY LEFT BLANK

Gasoline Gallon Equivalent and Diesel Gallon Equivalent Calculations

GGE Conversion

To calculate the gasoline gallon equivalent (gge) or the diesel gallon equivalent (dge) for the alternative fuels, one needs to compare the energy content per unit of each fuel and then calculate the ratios.

Staff used the following information to calculate the gge for ethanol, hydrogen, and electricity:

Fuel Type	Unit of Measure	BTUs/Unit
CARBOB	Gallon	113,300
Ethanol	Gallon	76,330
Electricity	kW-Hr	3,413
Hydrogen	Kilogram	134,000

The calculation for ethanol, electricity, and hydrogen is as follows:

GGE for ethanol = BTU of one gallon CARBOB/BTU of one gallon ethanol

$$= 113,300/76,330 = 1.48$$

1.48 gallons of ethanol = 1 gge

GGE for electricity = BTU of one gallon CARBOB/BTU of kW-Hr of electricity

$$= 113,300/3,413 = 33.2$$

33.2 kW-Hr of electricity = 1 gge

GGE for hydrogen = BTU of one gallon CARBOB/BTU of a kg of hydrogen

$$= 113,300/134,000 = 0.85$$

0.85 kg of hydrogen = 1 gge

DGE Conversion

Similarly, staff used the following information to calculate dge for CNG and electricity:

Fuel Type	Unit of Measure	BTUs/Unit
Diesel	Gallon	127,500
CNG	Cubic foot	930
Electricity	kW-Hr	3,413

The calculation for electricity and CNG is as follows:

DGE for CNG = Btu of one gallon diesel/Btu of one cubic foot CNG

$$= 127,500/930 = 137$$

137 cubic foot CNG = 1 dge

DGE for electricity = BTU of one gallon diesel/BTU of kW-Hr of electricity

$$= 127,500/3,413 = 37$$

37 KW-Hr of electricity = 1 dge

THIS PAGE INTENTIONALLY LEFT BLANK

Example of Cost Estimate on a Per-GGE Basis for an Alternative fuel

Example of Cost Estimate on a Per-GGE Basis of an Alternative Fuel

Corn (dry mill)

Capital Cost: \$71 million for a 50 MGY plant – using an 8% real interest rate for 10 years

$$\$71 \times 0.1490 = \$10.58 \text{ million}$$

$$\text{For 50 MGY} = \$0.21/\text{gal} \times 1.48 = \$0.31/\text{gge}$$

Production Cost: \$27.4 million

$$\text{For 50 MGY} = \$0.55/\text{gal} \times 1.48 = \$0.81/\text{gge}$$

Feedstock Cost: \$3.77/bushel – using an ethanol conversion rate of 2.72 gallons of ethanol per bushel

$$3.77/2.72 = \$1.39/\text{gal} \times 1.48 = \$2.05/\text{gge}$$

By-Product Credit: Staff estimated approximately 30% of feedstock cost

$$\$2.05 \times -0.30 = -\$0.61/\text{gge}$$

State-by-State Freight Cost: Staff used RFS freight cost - \$0.21/gal

$$\$0.21 \times 1.48 = \$0.31/\text{gge}$$

Storage and Distribution Cost: Staff estimated storage and distribution cost from RFS - \$0.02/gal

$$\$0.02 \times 1.48 = \$0.03/\text{gge}$$

Total Cost: $0.31 + 0.81 + 2.05 + (0.61) + 0.31 + 0.03 = \$2.90/\text{gge}$

Economic Analysis Spreadsheets for Diesel and Gasoline Scenarios

LCFS Compliance Diesel Scenario #1								
DEMAND (Fuel Volume, million gallons/yr)								
Year	Conv. Renewable Biodiesel	Adv. Renewable Biodiesel	Total Diesel (only Liquid fuels)	Bio. and Renew. % of Diesel	CNG	Electricity	Total Biodiesel	Total Conv. Diesel (petroleum)
2010	0	0	4393	0	0	0	0	4,393
2011	6	11	4484	0.4	0	0	17	4,467
2012	12	23	4577	0.8	0	0	35	4,542
2013	25	47	4672	1.5	0	0	72	4,600
2014	36	72	4768	2.3	0	0	108	4,660
2015	64	126	4866	3.9	0	0	190	4,676
2016	90	177	4977	5.4	0	0	267	4,710
2017	133	262	5091	7.8	0	0	395	4,696
2018	175	344	5207	10	0	0	519	4,688
2019	218	433	5325	12.2	0	0	651	4,674
2020	281	557	5445	15.4	0	0	838	4,607

LCFS Compliance Diesel Scenario #1							Base Case (No LCFS)				
Fuel Costs (million dollars)							Volume		Costs		
Conv. Renew. Biodiesel	Adv. Renew. Biodiesel	Total Biodiesel	CNG	Electricity	Total Conv. Diesel	Total Cost of Fuel (Million \$)	Total Biodiesel (Mil gal)	Total Conv. Diesel (Mil gal)	Total Biodiese l (Mil \$)	Total Conv. Diesel (Million \$)	Total Cost of Fuel (Million \$)
\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$10,890	\$10,890	0	4,393	\$0	\$10,890	\$10,890
\$13.1	\$26.7	\$39.8	\$0.0	\$0.0	\$11,279	\$11,319	0	4,484	\$0	\$11,322	\$11,322
\$26.5	\$56.2	\$82.7	\$0.0	\$0.0	\$11,682	\$11,765	0	4,577	\$0	\$11,772	\$11,772
\$56.1	\$115.9	\$171.9	\$0.0	\$0.0	\$12,112	\$12,284	0	4,672	\$0	\$12,301	\$12,301
\$82.3	\$179.2	\$261.5	\$0.0	\$0.0	\$12,629	\$12,890	0	4,768	\$0	\$12,921	\$12,921
\$148.3	\$315.7	\$464.0	\$0.0	\$0.0	\$12,929	\$13,393	0	4,866	\$0	\$13,454	\$13,454
\$211.1	\$446.2	\$657.3	\$0.0	\$0.0	\$13,282	\$13,940	0	4,977	\$0	\$14,035	\$14,035
\$314.9	\$663.5	\$978.4	\$0.0	\$0.0	\$13,440	\$14,418	0	5,091	\$0	\$14,570	\$14,570
\$418.0	\$875.1	\$1,293.1	\$0.0	\$0.0	\$13,614	\$14,907	0	5,207	\$0	\$15,121	\$15,121
\$525.2	\$1,106.4	\$1,631.6	\$0.0	\$0.0	\$13,770	\$15,401	0	5,325	\$0	\$15,687	\$15,687
\$682.6	\$1,429.3	\$2,111.9	\$0.0	\$0.0	\$13,761	\$15,873	0	5,445	\$0	\$16,264	\$16,264

	Diesel Scenario #1	Emissions (MMT per yr)		
Year	Total Cost or Saving (million \$)	GHG Baseline (No LCFS)	GHG Reductions (with LCFS)	GHG resulted from LCFS Compliance
2010	\$0.0	56.00	0.00	56.00
2011	(\$3.1)	57.10	0.14	56.96
2012	(\$7.3)	58.30	0.29	58.01
2013	(\$17.6)	59.50	0.60	58.91
2014	(\$31.1)	60.70	0.91	59.79
2015	(\$61.4)	62.00	1.55	60.45
2016	(\$95.6)	63.40	2.22	61.18
2017	(\$152.1)	64.80	3.24	61.56
2018	(\$214.1)	66.30	4.31	61.99
2019	(\$286.2)	67.80	5.42	62.38
2020	(\$391.2)	69.40	6.94	62.46
Total	(\$1,259.8)		25.62	
Cumulative Avg. Savings (\$/MMT)	(\$49.17)			

LCFS Compliance Diesel Scenario #2								
DEMAND (Fuel Volume, million gallons/yr)								
Year	Conv. Renewable Biodiesel	Adv. Renewable Biodiesel	Total Diesel (only Liquid fuels)	Bio. and Renew. % of Diesel	CNG	Electricity	Total Biodiesel	Total Conv. Diesel (petroleum)
2010	0	0	4393	0	0	0	0	4,393
2011	6	11	4482	0.4	2	0	17	4,465
2012	12	23	4573	0.8	4	0	35	4,538
2013	24	47	4664	1.5	9	0	71	4,593
2014	36	72	4756	2.3	13	0	108	4,648
2015	61	122	4846	3.8	22	0	183	4,663
2016	88	174	4948	5.3	32	0	262	4,686
2017	131	257	5049	7.7	47	0	388	4,661
2018	173	338	5149	9.9	64	0	511	4,638
2019	216	426	5252	12.2	81	0	642	4,610
2020	276	546	5352	15.4	104	0	822	4,530

LCFS Compliance Diesel Scenario #2							Base Case (No LCFS)				
Fuel Costs (million dollars)							Volume		Costs		
Conv. Renew. Biodiesel	Adv. Renew. Biodiesel	Total Biodiesel	CNG	Electricity	Total Conv. Diesel	Total Cost of Fuel (Million \$)	Total Biodiesel (Mil gal)	Total Conv. Diesel (Mil gal)	Total Biodiese l (Mil \$)	Total Conv. Diesel (Million \$)	Total Cost of Fuel (Million \$)
\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$10,890	\$10,890	0	4,393	\$0	\$10,890	\$10,890
\$13.1	\$26.7	\$39.8	\$3.7	\$0.0	\$11,274	\$11,318	0	4,484	\$0	\$11,322	\$11,322
\$26.5	\$56.2	\$82.7	\$7.5	\$0.0	\$11,672	\$11,762	0	4,577	\$0	\$11,772	\$11,772
\$53.8	\$115.9	\$169.7	\$15.2	\$0.0	\$12,093	\$12,278	0	4,672	\$0	\$12,301	\$12,301
\$82.3	\$179.2	\$261.5	\$23.2	\$0.0	\$12,596	\$12,881	0	4,768	\$0	\$12,921	\$12,921
\$141.4	\$305.6	\$447.0	\$39.1	\$0.0	\$12,893	\$13,379	0	4,866	\$0	\$13,454	\$13,454
\$206.5	\$438.6	\$645.1	\$56.7	\$0.0	\$13,215	\$13,916	0	4,977	\$0	\$14,035	\$14,035
\$310.1	\$650.8	\$961.0	\$81.6	\$0.0	\$13,340	\$14,382	0	5,091	\$0	\$14,570	\$14,570
\$413.2	\$859.8	\$1,273.1	\$110.9	\$0.0	\$13,469	\$14,853	0	5,207	\$0	\$15,121	\$15,121
\$520.4	\$1,088.5	\$1,608.9	\$142.5	\$0.0	\$13,581	\$15,332	0	5,325	\$0	\$15,687	\$15,687
\$670.5	\$1,401.0	\$2,071.5	\$182.1	\$0.0	\$13,531	\$15,785	0	5,445	\$0	\$16,264	\$16,264

	Diesel Scenario #2	Emissions (MMT per yr)		
Year	Total Cost or Saving (million \$)	GHG Baseline (No LCFS)	GHG Reductions (with LCFS)	GHG resulted from LCFS Compliance
2010	\$0.0	56.00	0.00	56.00
2011	(\$4.4)	57.10	0.14	56.96
2012	(\$10.0)	58.30	0.29	58.01
2013	(\$23.1)	59.50	0.60	58.91
2014	(\$40.5)	60.70	0.91	59.79
2015	(\$75.2)	62.00	1.55	60.45
2016	(\$118.8)	63.40	2.22	61.18
2017	(\$188.1)	64.80	3.24	61.56
2018	(\$268.4)	66.30	4.31	61.99
2019	(\$355.0)	67.80	5.42	62.38
2020	(\$479.5)	69.40	6.94	62.46
Total	(\$1,563.1)		25.62	
Cumulative Avg. Savings (\$/MMT)	(\$61.00)			

LCFS Compliance Diesel Scenario #3								
DEMAND (Fuel Volume, million gallons/yr)								
Year	Conv. Renewable Biodiesel	Adv. Renewable Biodiesel	Total Diesel (only Liquid fuels)	Bio. and Renew. % of Diesel	CNG	Electricity	Total Biodiesel	Total Conv. Diesel (petroleum)
2010	0	0	4393	0	0	0	0	4,393
2011	6	11	4482	0.4	3	0	17	4,465
2012	12	23	4571	0.8	5	0	35	4,536
2013	23	45	4660	1.5	11	1	68	4,592
2014	35	69	4749	2.2	16	1	104	4,645
2015	60	117	4834	3.7	28	2	177	4,657
2016	86	168	4933	5.1	39	3	254	4,679
2017	126	247	5025	7.4	58	5	373	4,652
2018	164	327	5118	9.6	79	6	491	4,627
2019	231	404	5215	12.2	97	8	635	4,580
2020	264	524	5305	14.9	124	10	788	4,517

LCFS Compliance Diesel Scenario #3							Base Case (No LCFS)				
Fuel Costs (million dollars)							Volume		Costs		
Conv. Renew. Biodiesel	Adv. Renew. Biodiesel	Total Biodiesel	CNG	Electricity	Total Conv. Diesel	Total Cost of Fuel (Million \$)	Total Biodiesel (Mil gal)	Total Conv. Diesel (Mil gal)	Total Biodiese l (Mil \$)	Total Conv. Diesel (Million \$)	Total Cost of Fuel (Million \$)
\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$10,890	\$10,890	0	4,393	\$0	\$10,890	\$10,890
\$13.1	\$26.7	\$39.8	\$4.7	\$0.6	\$11,274	\$11,319	0	4,484	\$0	\$11,322	\$11,322
\$26.5	\$56.2	\$82.7	\$9.4	\$2.0	\$11,667	\$11,761	0	4,577	\$0	\$11,772	\$11,772
\$51.6	\$110.9	\$162.5	\$19.0	\$4.2	\$12,091	\$12,276	0	4,672	\$0	\$12,301	\$12,301
\$80.1	\$171.7	\$251.8	\$29.0	\$6.4	\$12,588	\$12,875	0	4,768	\$0	\$12,921	\$12,921
\$139.0	\$293.1	\$432.2	\$48.9	\$10.8	\$12,877	\$13,368	0	4,866	\$0	\$13,454	\$13,454
\$201.8	\$423.5	\$625.3	\$68.1	\$15.5	\$13,195	\$13,904	0	4,977	\$0	\$14,035	\$14,035
\$298.3	\$625.5	\$923.8	\$102.0	\$22.6	\$13,314	\$14,362	0	5,091	\$0	\$14,570	\$14,570
\$391.7	\$831.8	\$1,223.6	\$138.7	\$30.0	\$13,437	\$14,829	0	5,207	\$0	\$15,121	\$15,121
\$556.6	\$1,032.3	\$1,588.8	\$170.9	\$37.8	\$13,493	\$15,290	0	5,325	\$0	\$15,687	\$15,687
\$641.3	\$1,344.6	\$1,985.9	\$218.5	\$48.2	\$13,492	\$15,745	0	5,445	\$0	\$16,264	\$16,264

	Diesel Scenario #3	Emissions (MMT per yr)		
Year	Total Cost or Saving (million \$)	GHG Baseline (No LCFS)	GHG Reductions (with LCFS)	GHG resulted from LCFS Compliance
2010	\$0.0	56.00	0.00	56.00
2011	(\$2.9)	57.10	0.14	56.96
2012	(\$11.3)	58.30	0.29	58.01
2013	(\$24.9)	59.50	0.60	58.91
2014	(\$46.2)	60.70	0.91	59.79
2015	(\$86.0)	62.00	1.55	60.45
2016	(\$131.6)	63.40	2.22	61.18
2017	(\$208.1)	64.80	3.24	61.56
2018	(\$292.1)	66.30	4.31	61.99
2019	(\$397.2)	67.80	5.42	62.38
2020	(\$519.3)	69.40	6.94	62.46
Total	(\$1,719.5)		25.62	
Cumulative Avg. Savings (\$/MMT)	(\$67.11)			

LCFS Compliance Gasoline Scenario #1

DEMAND (Fuel Volume, billion gallons)

Year	Conv. MW Corn EtOH (Bgal)	CA Dry Mill Corn EtOH (Bgal)	Fed. New Renew. Biofuels (Bgal)	Cell. EtOH (Bgal)	Adv. Renew. EtOH (Bgal)	Sugar Cane EtOH (Bgal)	Total EtOH (Bgal)	Total CARB OB (Bgal)	%E85	Vol % EtOH	Dry Corn ETOH (Bgal)	Wet Corn EtOH (Bgal)
2010	1.15	0.3	0	0	0		1.45	13.97	0	9.4	0.98	0.17
2011	0.92	0.3	0.22	0	0		1.44	13.88	0	9.4	0.78	0.14
2012	0.82	0.3	0.25	0.03	0.03		1.43	13.86	0	9.4	0.70	0.12
2013	0.65	0.3	0.3	0.09	0.09		1.43	13.77	0	9.4	0.55	0.10
2014	0.52	0.3	0.3	0.15	0.15		1.42	13.69	0	9.4	0.44	0.08
2015	0.31	0.3	0.3	0.28	0.28		1.47	13.62	0.5	9.8	0.26	0.05
2016	0.21	0.3	0.3	0.42	0.42		1.65	13.34	1.9	11	0.18	0.03
2017	0	0.3	0.3	0.62	0.62		1.84	13.09	3.8	12.3	0.00	0.00
2018	0	0.3	0.24	0.82	0.82		2.18	12.67	7	14.7	0.00	0.00
2019	0	0.3	0.12	1.02	1.02		2.46	12.3	9.6	16.7	0.00	0.00
2020	0	0.3	0	1.29	1.29		2.88	11.84	13.5	19.6	0.00	0.00

LCFS Compliance Gasoline Scenario #1

Fuel Costs (billion dollars)

Year	Electricity	Hydrogen	MW Dry Corn ETOH	MW Wet Corn EtOH	CA Dry Mill Corn EtOH	Fed. New Renew. Biofuels (Bgal)	Cell. EtOH	Adv. Renew. EtOH	Sugar Cane EtOH	Total ETOH Costs	Total CARBOB Costs	Total Cost of Fuel (Bil \$)
2010	\$0.0008	\$0.0006	\$1.46	\$0.26	\$0.50	\$0.00	\$0.00	\$0.00	\$0.00	\$2.21	\$33.74	\$35.95
2011	\$0.0010	\$0.0011	\$1.18	\$0.21	\$0.50	\$0.33	\$0.00	\$0.00	\$0.00	\$2.22	\$34.16	\$36.38
2012	\$0.0067	\$0.0022	\$1.06	\$0.19	\$0.50	\$0.38	\$0.02	\$0.02	\$0.00	\$2.17	\$34.76	\$36.94
2013	\$0.0122	\$0.0034	\$0.85	\$0.15	\$0.50	\$0.46	\$0.06	\$0.06	\$0.00	\$2.10	\$35.38	\$37.49
2014	\$0.0176	\$0.0039	\$0.69	\$0.12	\$0.50	\$0.47	\$0.11	\$0.11	\$0.00	\$2.01	\$36.22	\$38.25
2015	\$0.0304	\$0.0107	\$0.42	\$0.07	\$0.50	\$0.48	\$0.20	\$0.20	\$0.00	\$1.89	\$36.79	\$38.71
2016	\$0.0423	\$0.0157	\$0.29	\$0.05	\$0.50	\$0.48	\$0.30	\$0.30	\$0.00	\$1.96	\$36.77	\$38.79
2017	\$0.0542	\$0.0208	\$0.00	\$0.00	\$0.50	\$0.49	\$0.45	\$0.45	\$0.00	\$1.94	\$36.63	\$38.65
2018	\$0.0711	\$0.0382	\$0.00	\$0.00	\$0.50	\$0.39	\$0.60	\$0.60	\$0.00	\$2.18	\$35.98	\$38.27
2019	\$0.0952	\$0.0540	\$0.00	\$0.00	\$0.50	\$0.20	\$0.75	\$0.75	\$0.00	\$2.29	\$35.45	\$37.89
2020	\$0.1129	\$0.0708	\$0.00	\$0.00	\$0.50	\$0.00	\$0.95	\$0.95	\$0.00	\$2.52	\$34.61	\$37.31

Base Case (No LCFS)						Cost of Gasoline Scenario #1	Emissions (MMT per yr)		
Year	Volume (billion gallons)		Costs (billion \$)				Total Cost or Saving (mil \$)	GHG Baseline (No LCFS)	GHG Reductions (with LCFS)
	Conv. ETOH (Bgal)	Total CARBOB (Bgal)	Total ETOH Costs	Total CARBOB Costs	Total Cost of Fuel				
2010	1.45	13.97	\$2.16	\$33.74	\$35.90	48.0	171.2	0.00	171.2
2011	1.44	13.88	\$2.17	\$34.16	\$36.33	48.0	170.1	0.43	169.7
2012	1.43	13.82	\$2.18	\$34.66	\$36.85	93.8	169.9	0.85	169.1
2013	1.43	13.77	\$2.21	\$35.38	\$37.60	(113.0)	168.8	1.69	167.1
2014	1.42	13.69	\$2.23	\$36.22	\$38.48	(226.0)	167.8	2.52	165.3
2015	1.41	13.66	\$2.24	\$36.90	\$39.18	(466.1)	167.6	4.19	163.4
2016	1.40	13.49	\$2.25	\$37.18	\$39.49	(701.7)	165.6	5.80	159.8
2017	1.39	13.39	\$2.25	\$37.47	\$39.79	(1,148.3)	164.4	8.22	156.2
2018	1.37	13.22	\$2.24	\$37.54	\$39.89	(1,623.8)	162.4	10.56	151.8
2019	1.35	13.04	\$2.22	\$37.58	\$39.95	(2,062.4)	160.4	12.83	147.6
2020	1.33	12.89	\$2.21	\$37.68	\$40.07	(2,758.4)	158.6	15.86	142.7
Total						(\$8,909.9)		62.93	
Cumulative Avg. Savings (\$/MMT)						(\$141.58)			

LCFS Compliance Gasoline Scenario #2

DEMAND (Fuel Volume, billion gallons)

Year	Conv. MW Corn EtOH (Bgal)	CA Dry Mill Corn EtOH (Bgal)	Fed. New Renew. Biofuels (Bgal)	Cell. EtOH (Bgal)	Adv. Renew. EtOH (Bgal)	Sugar Cane EtOH (Bgal)	Total EtOH (Bgal)	Total CARB OB (Bgal)	%E85	Vol % EtOH	Dry Corn ETOH (Bgal)	Wet Corn EtOH (Bgal)
2010	1.15	0.3	0	0	0	0	1.45	13.97	0	9.4	0.98	0.17
2011	0.95	0.3	0	0	0	0.19	1.44	13.88	0	9.4	0.81	0.14
2012	0.82	0.3	0	0.02	0.02	0.27	1.43	13.86	0	9.4	0.70	0.12
2013	0.67	0.3	0	0.08	0.08	0.3	1.43	13.77	0	9.4	0.57	0.10
2014	0.52	0.3	0	0.15	0.15	0.3	1.42	13.69	0	9.4	0.44	0.08
2015	0.31	0.3	0	0.28	0.28	0.3	1.47	13.62	0.5	9.8	0.26	0.05
2016	0.2	0.3	0	0.42	0.42	0.3	1.64	13.34	1.9	10.9	0.17	0.03
2017	0	0.3	0	0.62	0.62	0.3	1.84	13.09	3.8	12.3	0.00	0.00
2018	0	0.3	0	0.81	0.81	0.3	2.22	12.63	7.5	15	0.00	0.00
2019	0	0.3	0	1.01	1.01	0.3	2.62	12.19	11	17.7	0.00	0.00
2020	0	0.3	0	1.24	1.24	0.3	3.08	11.71	15.2	20.8	0.00	0.00

LCFS Compliance Gasoline Scenario #2

Fuel Costs (billion dollars)

Year	Electricity	Hydrogen	MW Dry Corn EtOH	MW Wet Corn EtOH	CA Dry Mill Corn EtOH	Fed. New Renew. Biofuels (Bgal)	Cell. EtOH	Adv. Renew. EtOH	Sugar Cane EtOH	Total EtOH Costs	Total CARBOB Costs	Total Cost of Fuel (Bil \$)
2010	\$0.0008	\$0.0006	\$1.46	\$0.26	\$0.50	\$0.00	\$0.00	\$0.00	\$0.00	\$2.21	\$33.74	\$35.95
2011	\$0.0010	\$0.0011	\$1.22	\$0.21	\$0.50	\$0.00	\$0.00	\$0.00	\$0.38	\$2.31	\$34.16	\$36.48
2012	\$0.0067	\$0.0022	\$1.06	\$0.19	\$0.50	\$0.00	\$0.01	\$0.01	\$0.54	\$2.32	\$34.76	\$37.09
2013	\$0.0122	\$0.0034	\$0.88	\$0.16	\$0.50	\$0.00	\$0.06	\$0.06	\$0.61	\$2.26	\$35.38	\$37.65
2014	\$0.0176	\$0.0039	\$0.69	\$0.12	\$0.50	\$0.00	\$0.11	\$0.11	\$0.61	\$2.15	\$36.22	\$38.39
2015	\$0.0304	\$0.0107	\$0.42	\$0.07	\$0.50	\$0.00	\$0.20	\$0.20	\$0.61	\$2.02	\$36.79	\$38.85
2016	\$0.0423	\$0.0157	\$0.27	\$0.05	\$0.50	\$0.00	\$0.30	\$0.30	\$0.61	\$2.08	\$36.77	\$38.90
2017	\$0.0542	\$0.0208	\$0.00	\$0.00	\$0.50	\$0.00	\$0.45	\$0.45	\$0.62	\$2.07	\$36.63	\$38.78
2018	\$0.0711	\$0.0382	\$0.00	\$0.00	\$0.50	\$0.00	\$0.59	\$0.59	\$0.62	\$2.39	\$35.87	\$38.37
2019	\$0.0952	\$0.0540	\$0.00	\$0.00	\$0.50	\$0.00	\$0.74	\$0.74	\$0.62	\$2.71	\$35.13	\$37.99
2020	\$0.1129	\$0.0708	\$0.00	\$0.00	\$0.50	\$0.00	\$0.92	\$0.92	\$0.62	\$3.08	\$34.23	\$37.49

Base Case (No LCFS)						Cost of Gasoline Scenario #2	Emissions (MMT per yr)		
Year	Volume (billion gallons)		Costs (billion \$)				Total Cost or Saving (mil \$)	GHG Baseline (No LCFS)	GHG Reductions (with LCFS)
	Conv. ETOH (Bgal)	Total CARBOB (Bgal)	Total ETOH Costs	Total CARBOB Costs	Total Cost of Fuel				
2010	1.45	13.97	\$2.16	\$33.74	\$35.90	\$48.0	1.45	13.97	\$2.16
2011	1.44	13.88	\$2.17	\$34.16	\$36.33	\$144.0	1.44	13.88	\$2.17
2012	1.43	13.82	\$2.18	\$34.66	\$36.85	\$243.7	1.43	13.82	\$2.18
2013	1.43	13.77	\$2.21	\$35.38	\$37.60	\$47.8	1.43	13.77	\$2.21
2014	1.42	13.69	\$2.23	\$36.22	\$38.48	(\$87.1)	1.42	13.69	\$2.23
2015	1.41	13.66	\$2.24	\$36.90	\$39.18	(\$330.7)	1.41	13.66	\$2.24
2016	1.40	13.49	\$2.25	\$37.18	\$39.49	(\$585.8)	1.40	13.49	\$2.25
2017	1.39	13.39	\$2.25	\$37.47	\$39.79	(\$1,018.8)	1.39	13.39	\$2.25
2018	1.37	13.22	\$2.24	\$37.54	\$39.89	(\$1,520.9)	1.37	13.22	\$2.24
2019	1.35	13.04	\$2.22	\$37.58	\$39.95	(\$1,958.8)	1.35	13.04	\$2.22
2020	1.33	12.89	\$2.21	\$37.68	\$40.07	(\$2,577.8)	1.33	12.89	\$2.21
Total						(\$7,596.5)		62.93	
Cumulative Avg. Savings (\$/MMT)						(\$120.71)			

LCFS Compliance Gasoline Scenario #3

DEMAND (Fuel Volume, billion gallons)

Year	Conv. MW Corn EtOH (Bgal)	CA Dry Mill Corn EtOH (Bgal)	Fed. New Renew. Biofuels (Bgal)	Cell. EtOH (Bgal)	Adv. Renew. EtOH (Bgal)	Sugar Cane EtOH (Bgal)	Total EtOH (Bgal)	Total CARB OB (Bgal)	%E85	Vol % EtOH	Dry Corn ETOH (Bgal)	Wet Corn EtOH (Bgal)
2010	1.15	0.3	0	0	0	0	1.45	13.97	0	9.4	0.98	0.17
2011	0.95	0.3	0	0	0	0.19	1.44	13.88	0	9.4	0.81	0.14
2012	0.82	0.3	0	0.02	0.02	0.27	1.43	13.86	0	9.4	0.70	0.12
2013	0.65	0.3	0	0.09	0.09	0.3	1.43	13.77	0	9.4	0.55	0.10
2014	0.64	0.3	0	0.15	0.15	0.3	1.54	13.61	1	10.1	0.54	0.10
2015	0.51	0.3	0	0.27	0.27	0.3	1.65	13.32	2	11	0.43	0.08
2016	0.37	0.3	0	0.38	0.38	0.3	1.73	13.22	2.9	11.6	0.31	0.06
2017	0.17	0.3	0	0.55	0.55	0.3	1.87	12.98	4.3	12.6	0.14	0.03
2018	0	0.3	0	0.73	0.73	0.3	2.06	12.65	6.1	14	0.00	0.00
2019	0	0.3	0	0.9	0.9	0.3	2.4	12.23	9.3	16.4	0.00	0.00
2020	0	0.3	0	1.1	1.1	0.3	2.8	11.7	13.2	19.3	0.00	0.00

LCFS Compliance Gasoline Scenario #3

Fuel Costs (billion dollars)

Year	Electricity	Hydrogen	MW Dry Corn ETOH	MW Wet Corn EtOH	CA Dry Mill Corn EtOH	Fed. New Renew. Biofuels (Bgal)	Cell. EtOH	Adv. Renew. EtOH	Sugar Cane EtOH	Total ETOH Costs	Total CARBOB Costs	Total Cost of Fuel (Bil \$)
2010	\$0.0008	\$0.0006	\$1.46	\$0.26	\$0.50	\$0.00	\$0.00	\$0.00	\$0.00	\$2.21	\$33.74	\$35.95
2011	\$0.0018	\$0.0011	\$1.22	\$0.21	\$0.50	\$0.00	\$0.00	\$0.00	\$0.38	\$2.31	\$34.16	\$36.48
2012	\$0.0067	\$0.0022	\$1.06	\$0.19	\$0.50	\$0.00	\$0.01	\$0.01	\$0.54	\$2.32	\$34.76	\$37.09
2013	\$0.0122	\$0.0034	\$0.85	\$0.15	\$0.50	\$0.00	\$0.06	\$0.06	\$0.61	\$2.24	\$35.38	\$37.63
2014	\$0.0189	\$0.0039	\$0.86	\$0.15	\$0.50	\$0.00	\$0.11	\$0.11	\$0.61	\$2.36	\$36.01	\$38.39
2015	\$0.0428	\$0.0129	\$0.69	\$0.12	\$0.50	\$0.00	\$0.19	\$0.19	\$0.61	\$2.35	\$35.98	\$38.38
2016	\$0.0654	\$0.0259	\$0.51	\$0.09	\$0.50	\$0.00	\$0.28	\$0.28	\$0.61	\$2.31	\$36.43	\$38.83
2017	\$0.0913	\$0.0416	\$0.23	\$0.04	\$0.50	\$0.00	\$0.40	\$0.40	\$0.62	\$2.25	\$36.32	\$38.70
2018	\$0.1186	\$0.0596	\$0.00	\$0.00	\$0.50	\$0.00	\$0.53	\$0.53	\$0.62	\$2.26	\$35.93	\$38.36
2019	\$0.1601	\$0.0798	\$0.00	\$0.00	\$0.50	\$0.00	\$0.66	\$0.66	\$0.62	\$2.53	\$35.25	\$38.02
2020	\$0.2089	\$0.1113	\$0.00	\$0.00	\$0.50	\$0.00	\$0.81	\$0.81	\$0.62	\$2.85	\$34.20	\$37.37

Base Case (No LCFS)						Cost of Gasoline Scenario #3	Emissions (MMT per yr)		
Year	Volume (billion gallons)		Costs (billion \$)				Total Cost or Saving (mil \$)	GHG Baseline (No LCFS)	GHG Reductions (with LCFS)
	Conv. ETOH (Bgal)	Total CARBOB (Bgal)	Total ETOH Costs	Total CARBOB Costs	Total Cost of Fuel				
2010	1.45	13.97	\$2.16	\$33.74	\$35.90	\$48.0	171.20	0.00	171.2
2011	1.44	13.88	\$2.17	\$34.16	\$36.33	\$144.7	170.10	0.43	169.7
2012	1.43	13.82	\$2.18	\$34.66	\$36.85	\$243.7	169.90	0.85	169.1
2013	1.43	13.77	\$2.21	\$35.38	\$37.60	\$31.0	168.80	1.69	167.1
2014	1.42	13.69	\$2.23	\$36.22	\$38.48	(\$87.1)	167.80	2.52	165.3
2015	1.41	13.66	\$2.24	\$36.90	\$39.18	(\$796.5)	167.60	4.19	163.4
2016	1.40	13.49	\$2.25	\$37.18	\$39.49	(\$655.8)	165.60	5.80	159.8
2017	1.39	13.39	\$2.25	\$37.47	\$39.79	(\$1,092.9)	164.40	8.22	156.2
2018	1.37	13.22	\$2.24	\$37.54	\$39.89	(\$1,533.6)	162.40	10.56	151.8
2019	1.35	13.04	\$2.22	\$37.58	\$39.95	(\$1,934.2)	160.40	12.83	147.6
2020	1.33	12.89	\$2.21	\$37.68	\$40.07	(\$2,694.1)	158.60	15.86	142.7
Total						(\$8,326.7)		62.93	
Cumulative Avg. Savings (\$/MMT)						(\$132.31)			

LCFS Compliance Gasoline Scenario #4

DEMAND (Fuel Volume, billion gallons)

Year	Conv. MW Corn EtOH (Bgal)	CA Dry Mill Corn EtOH (Bgal)	Fed. New Renew. Biofuels (Bgal)	Cell. EtOH (Bgal)	Adv. Renew. EtOH (Bgal)	Sugar Cane EtOH (Bgal)	Total EtOH (Bgal)	Total CARB OB (Bgal)	%E85	Vol % EtOH	Dry Corn ETOH (Bgal)	Wet Corn EtOH (Bgal)
2010	1.15	0.3	0	0	0	0	1.45	13.97	0	9.4	0.98	0.17
2011	0.97	0.3	0	0	0	0.17	1.44	13.88	0	9.4	0.82	0.15
2012	0.81	0.3	0	0.01	0.01	0.3	1.43	13.85	0	9.4	0.69	0.12
2013	0.69	0.3	0	0.07	0.07	0.3	1.43	13.75	0	9.4	0.59	0.10
2014	0.6	0.3	0	0.11	0.11	0.3	1.42	13.65	0	9.4	0.51	0.09
2015	0.43	0.3	0	0.19	0.19	0.3	1.41	13.55	0	9.4	0.37	0.06
2016	0.28	0.3	0	0.26	0.26	0.3	1.4	13.31	0	9.4	0.24	0.04
2017	0	0.3	0	0.41	0.41	0.3	1.42	13.09	0.5	9.8	0.00	0.00
2018	0	0.3	0	0.53	0.53	0.3	1.66	12.67	2.9	11.6	0.00	0.00
2019	0	0.3	0	0.62	0.62	0.3	1.84	12.2	5.3	13.1	0.00	0.00
2020	0	0.3	0	0.79	0.79	0.3	2.18	11.68	8.6	15.7	0.00	0.00

LCFS Compliance Gasoline Scenario #4

Fuel Costs (billion dollars)

Year	Electricity	Hydrogen	MW Dry Corn EtOH	MW Wet Corn EtOH	CA Dry Mill Corn EtOH	Fed. New Renew. Biofuels (Bgal)	Cell. EtOH	Adv. Renew. EtOH	Sugar Cane EtOH	Total EtOH Costs	Total CARBOB Costs	Total Cost of Fuel (Bil \$)
2010	\$0.0008	\$0.0006	\$1.46	\$0.26	\$0.50	\$0.00	\$0.00	\$0.00	\$0.00	\$2.21	\$33.74	\$35.95
2011	\$0.0036	\$0.0011	\$1.24	\$0.22	\$0.50	\$0.00	\$0.00	\$0.00	\$0.34	\$2.30	\$34.16	\$36.47
2012	\$0.0106	\$0.0022	\$1.05	\$0.19	\$0.50	\$0.00	\$0.01	\$0.01	\$0.61	\$2.35	\$34.74	\$37.10
2013	\$0.0192	\$0.0034	\$0.91	\$0.16	\$0.50	\$0.00	\$0.05	\$0.05	\$0.61	\$2.28	\$35.32	\$37.62
2014	\$0.0379	\$0.0051	\$0.80	\$0.14	\$0.50	\$0.00	\$0.08	\$0.08	\$0.61	\$2.21	\$36.12	\$38.38
2015	\$0.09	\$0.03	\$0.58	\$0.10	\$0.50	\$0.00	\$0.14	\$0.14	\$0.61	\$2.07	\$36.60	\$38.78
2016	\$0.13	\$0.05	\$0.38	\$0.07	\$0.50	\$0.00	\$0.19	\$0.19	\$0.61	\$1.94	\$36.68	\$38.81
2017	\$0.18	\$0.08	\$0.00	\$0.00	\$0.50	\$0.00	\$0.30	\$0.30	\$0.62	\$1.72	\$36.63	\$38.61
2018	\$0.24	\$0.12	\$0.00	\$0.00	\$0.50	\$0.00	\$0.39	\$0.39	\$0.62	\$1.94	\$35.98	\$38.28
2019	\$0.33	\$0.17	\$0.00	\$0.00	\$0.50	\$0.00	\$0.46	\$0.46	\$0.62	\$2.10	\$35.16	\$37.76
2020	\$0.42	\$0.22	\$0.00	\$0.00	\$0.50	\$0.00	\$0.58	\$0.58	\$0.62	\$2.38	\$34.14	\$37.16

Base Case (No LCFS)						Cost of Gasoline Scenario #4	Emissions (MMT per yr)		
Year	Volume (billion gallons)		Costs (billion \$)				Total Cost or Saving (mil \$)	GHG Baseline (No LCFS)	GHG Reductions (with LCFS)
	Conv. ETOH (Bgal)	Total CARBOB (Bgal)	Total ETOH Costs	Total CARBOB Costs	Total Cost of Fuel				
2010	1.45	13.97	\$2.16	\$33.74	\$35.90	\$48.0	171.20	0.00	171.2
2011	1.44	13.88	\$2.17	\$34.16	\$36.33	\$136.5	170.10	0.43	169.7
2012	1.43	13.82	\$2.18	\$34.66	\$36.85	\$253.7	169.90	0.85	169.1
2013	1.43	13.77	\$2.21	\$35.38	\$37.60	\$20.1	168.80	1.69	167.1
2014	1.42	13.69	\$2.23	\$36.22	\$38.48	(\$103.1)	167.80	2.52	165.3
2015	1.41	13.66	\$2.24	\$36.90	\$39.18	(\$398.4)	167.60	4.19	163.4
2016	1.40	13.49	\$2.25	\$37.18	\$39.49	(\$681.1)	165.60	5.80	159.8
2017	1.39	13.39	\$2.25	\$37.47	\$39.79	(\$1,180.4)	164.40	8.22	156.2
2018	1.37	13.22	\$2.24	\$37.54	\$39.89	(\$1,612.8)	162.40	10.56	151.8
2019	1.35	13.04	\$2.22	\$37.58	\$39.95	(\$2,192.5)	160.40	12.83	147.6
2020	1.33	12.89	\$2.21	\$37.68	\$40.07	(\$2,903.1)	158.60	15.86	142.7
Total						(\$8,613.2)		62.93	
Cumulative Avg. Savings (\$/MMT)						(\$136.86)			

LCFS Compliance Gasoline Scenario #5

DEMAND (Fuel Volume, billion gallons)

Year	Conv. MW Corn EtOH (Bgal)	CA Dry Mill Corn EtOH (Bgal)	Fed. New Renew. Biofuels (Bgal)	Cell. EtOH (Bgal)	Adv. Renew. EtOH (Bgal)	Sugar Cane EtOH (Bgal)	Total EtOH (Bgal)	Total CARB OB (Bgal)	%E85	Vol % EtOH	Dry Corn ETOH (Bgal)	Wet Corn EtOH (Bgal)
2010	1.15	0.3		0	0	0	1.45	13.97	0	9.4	0.98	0.17
2011	1.03	0.3		0	0	0.11	1.44	13.88	0	9.4	0.88	0.15
2012	0.89	0.3		0	0	0.24	1.43	13.86	0	9.4	0.76	0.13
2013	0.69	0.3		0.07	0.07	0.3	1.43	13.77	0	9.4	0.59	0.10
2014	0.62	0.3		0.14	0.14	0.3	1.5	13.64	0.6	9.8	0.53	0.09
2015	0.5	0.3		0.26	0.26	0.3	1.62	13.5	1.7	10.7	0.43	0.08
2016	0.37	0.3		0.38	0.38	0.3	1.73	13.22	2.9	11.6	0.31	0.06
2017	0.17	0.3		0.56	0.56	0.3	1.89	12.96	4.5	12.8	0.14	0.03
2018	0	0.3		0.74	0.74	0.3	2.08	12.64	6.4	14.2	0.00	0.00
2019	0	0.3		0.88	0.88	0.3	2.36	12.23	9	16.2	0.00	0.00
2020	0	0.3		1.06	1.06	0.3	2.72	11.76	12.5	18.8	0.00	0.00

LCFS Compliance Gasoline Scenario #5

Fuel Costs (billion dollars)

Year	Electricity	Hydrogen	MW Dry Corn EtOH	MW Wet Corn EtOH	CA Dry Mill Corn EtOH	Fed. New Renew. Biofuels (Bgal)	Cell. EtOH	Adv. Renew. EtOH	Sugar Cane EtOH	Total EtOH Costs	Total CARBOB Costs	Total Cost of Fuel (Bil \$)
2010	\$0.0008	\$0.0006	\$1.46	\$0.26	\$0.50	\$0.00	\$0.00	\$0.00	\$0.00	\$2.21	\$33.74	\$35.95
2011	\$0.002	\$0.0011	\$1.32	\$0.23	\$0.50	\$0.00	\$0.00	\$0.00	\$0.22	\$2.27	\$34.16	\$36.44
2012	\$0.007	\$0.002	\$1.15	\$0.20	\$0.50	\$0.00	\$0.00	\$0.00	\$0.48	\$2.34	\$34.76	\$37.11
2013	\$0.012	\$0.003	\$0.91	\$0.16	\$0.50	\$0.00	\$0.05	\$0.05	\$0.61	\$2.28	\$35.38	\$37.67
2014	\$0.019	\$0.004	\$0.83	\$0.15	\$0.50	\$0.00	\$0.10	\$0.10	\$0.61	\$2.30	\$36.09	\$38.42
2015	\$0.04	\$0.013	\$0.68	\$0.12	\$0.50	\$0.00	\$0.19	\$0.19	\$0.61	\$2.32	\$36.46	\$38.83
2016	\$0.07	\$0.03	\$0.51	\$0.09	\$0.50	\$0.00	\$0.28	\$0.28	\$0.61	\$2.31	\$36.43	\$38.83
2017	\$0.09	\$0.04	\$0.23	\$0.04	\$0.50	\$0.00	\$0.41	\$0.41	\$0.62	\$2.27	\$36.26	\$38.66
2018	\$0.12	\$0.06	\$0.00	\$0.00	\$0.50	\$0.00	\$0.54	\$0.54	\$0.62	\$2.27	\$35.90	\$38.35
2019	\$0.16	\$0.08	\$0.00	\$0.00	\$0.50	\$0.00	\$0.65	\$0.65	\$0.62	\$2.50	\$35.25	\$37.99
2020	\$0.21	\$0.11	\$0.00	\$0.00	\$0.50	\$0.00	\$0.78	\$0.78	\$0.62	\$2.79	\$34.37	\$37.48

Base Case (No LCFS)						Cost of Gasoline Scenario #5	Emissions (MMT per yr)		
Year	Volume (billion gallons)		Costs (billion \$)				Total Cost or Saving (mil \$)	GHG Baseline (No LCFS)	GHG Reductions (with LCFS)
	Conv. ETOH (Bgal)	Total CARBOB (Bgal)	Total ETOH Costs	Total CARBOB Costs	Total Cost of Fuel				
2010	1.45	13.97	\$2.16	\$33.74	\$35.90	\$48.0	171.2	0.00	171.2
2011	1.44	13.88	\$2.17	\$34.16	\$36.33	\$103.6	170.1	0.43	169.7
2012	1.43	13.82	\$2.18	\$34.66	\$36.85	\$261.6	169.9	0.85	169.1
2013	1.43	13.77	\$2.21	\$35.38	\$37.60	\$64.5	168.8	1.69	167.1
2014	1.42	13.69	\$2.23	\$36.22	\$38.48	(\$63.5)	167.8	2.52	165.3
2015	1.41	13.66	\$2.24	\$36.90	\$39.19	(\$360.5)	167.6	4.19	163.4
2016	1.40	13.49	\$2.25	\$37.18	\$39.52	(\$689.0)	165.6	5.80	159.8
2017	1.39	13.39	\$2.25	\$37.47	\$39.85	(\$1,189.5)	164.4	8.22	156.2
2018	1.37	13.22	\$2.24	\$37.54	\$39.96	(\$1,612.7)	162.4	10.56	151.8
2019	1.35	13.04	\$2.22	\$37.58	\$40.04	(\$2,057.5)	160.4	12.83	147.6
2020	1.33	12.89	\$2.21	\$37.68	\$40.20	(\$2,720.3)	158.6	15.86	142.7
Total						(\$8,215.3)		62.93	
Cumulative Avg. Savings (\$/MMT)						(\$130.54)			

THIS PAGE INTENTIONALLY LEFT BLANK

Estimated Impacts to Federal, State, and Local Governments

Impact of LCFS Scenarios on Government Agencies

Year	Diesel #1			Diesel #2			Diesel #3		
	Impact on Fed Govt (including tax credit) (Mil \$)	Impact on State (Excise & Sales Taxes) (Mil \$)	Impact on Local Govt (Mil \$)	Impact on Fed Govt (including tax credit) (Mil \$)	Impact on State (Excise & Sales Taxes) (Mil \$)	Impact on Local Govt (Mil \$)	Impact on Fed Govt (including tax credit) (Mil \$)	Impact on State (Excise & Sales Taxes) (Mil \$)	Impact on Local Govt (Mil \$)
2010	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
2011	(\$17)	\$0	\$0	(\$18)	(\$1)	(\$0)	(\$18)	(\$1)	(\$0)
2012	(\$35)	\$0	\$0	(\$37)	(\$1)	(\$0)	(\$38)	(\$2)	(\$0)
2013	(\$72)	\$0	\$0	(\$76)	(\$2)	(\$0)	(\$75)	(\$4)	(\$1)
2014	(\$108)	\$0	\$0	(\$116)	(\$4)	(\$1)	(\$115)	(\$6)	(\$1)
2015	(\$190)	\$0	\$0	(\$196)	(\$6)	(\$1)	(\$195)	(\$10)	(\$2)
2016	(\$267)	\$0	\$0	(\$281)	(\$9)	(\$2)	(\$279)	(\$14)	(\$3)
2017	(\$395)	\$0	\$0	(\$415)	(\$13)	(\$3)	(\$410)	(\$22)	(\$4)
2018	(\$519)	\$0	\$0	(\$548)	(\$18)	(\$4)	(\$541)	(\$30)	(\$6)
2019	(\$651)	\$0	\$0	(\$689)	(\$23)	(\$5)	(\$697)	(\$37)	(\$7)
2020	(\$838)	\$0	\$0	(\$882)	(\$30)	(\$6)	(\$867)	(\$47)	(\$9)

Year	Gasoline #1			Gasoline #2			Gasoline #3		
	Impact on Fed Govt (including tax credit) (Mil \$)	Impact on State (Excise & Sales Taxes) (Mil \$)	Impact on Local Govt (Mil \$)	Impact on Fed Govt (including tax credit) (Mil \$)	Impact on State (Excise & Sales Taxes) (Mil \$)	Impact on Local Govt (Mil \$)	Impact on Fed Govt (including tax credit) (Mil \$)	Impact on State (Excise & Sales Taxes) (Mil \$)	Impact on Local Govt (Mil \$)
2010	\$0	\$0	\$0.0	\$0	\$0	\$0.0	\$0	\$0	\$0.0
2011	\$0	\$0	\$0.0	\$0	\$0	\$0.0	\$0	\$0	\$0.0
2012	\$6	\$16	\$2.3	\$6	\$16	\$2.3	\$6	\$16	\$2.3
2013	\$0	\$0	\$0.0	\$0	\$0	\$0.0	\$0	\$0	\$0.0
2014	\$0	\$0	\$0.0	\$0	\$0	\$0.0	(\$46)	(\$5)	\$0.1
2015	(\$23)	(\$3)	\$0.1	(\$23)	(\$3)	\$0.1	(\$116)	(\$84)	(\$10.5)
2016	(\$83)	\$0	\$1.8	(\$84)	(\$4)	\$1.2	(\$139)	(\$38)	(\$3.0)
2017	(\$172)	(\$20)	\$0.5	(\$172)	(\$20)	\$0.5	(\$207)	(\$64)	(\$5.5)
2018	(\$317)	(\$43)	\$0.0	(\$343)	(\$54)	(\$1.2)	(\$288)	(\$81)	(\$6.5)
2019	(\$430)	(\$52)	\$1.0	(\$495)	(\$62)	\$0.8	(\$429)	(\$99)	(\$6.4)
2020	(\$606)	(\$81)	\$0.2	(\$685)	(\$90)	\$0.5	(\$612)	(\$164)	(\$12.8)

Year	Gasoline #4			Gasoline #5		
	Impact on Fed Govt (including tax credit) (Mil \$)	Impact on State (Excise & Sales Taxes) (Mil \$)	Impact on Local Govt (Mil \$)	Impact on Fed Govt (including tax credit) (Mil \$)	Impact on State (Excise & Sales Taxes) (Mil \$)	Impact on Local Govt (Mil \$)
2010	\$0	\$0	\$0.0	\$0	\$0	\$0.0
2011	\$0	\$0	\$0.0	\$0	\$0	\$0.0
2012	\$4	\$12	\$1.7	\$6	\$16	\$2.3
2013	(\$3)	(\$8)	(\$1.2)	\$0	\$0	\$0.0
2014	(\$6)	(\$16)	(\$2.4)	(\$27)	(\$1)	\$0.4
2015	(\$16)	(\$45)	(\$6.6)	(\$80)	(\$16)	(\$0.9)
2016	(\$25)	(\$74)	(\$11.0)	(\$139)	(\$38)	(\$3.0)
2017	(\$63)	(\$123)	(\$17.8)	(\$218)	(\$68)	(\$6.0)
2018	(\$178)	(\$169)	(\$22.8)	(\$302)	(\$83)	(\$6.6)
2019	(\$304)	(\$256)	(\$34.0)	(\$419)	(\$108)	(\$8.1)
2020	(\$458)	(\$328)	(\$42.3)	(\$579)	(\$157)	(\$12.4)

Reference List for Appendices B – G

Appendix B References:

1. California Board of Equalization. (2008). "Fuel tax rates." Retrieved, from <http://www.boe.ca.gov/sptaxprog/spftrpts.htm>.
2. EIA. (2007). "U.S. Product Supplied for Crude Oil and Petroleum Products." Retrieved, from http://tonto.eia.doe.gov/dnav/pet/pet_cons_psup_dc_nus_mbbl_a.htm.
3. CEC. (2009). "California's Oil Refineries " Retrieved, from <http://energyalmanac.ca.gov/petroleum/refineries.html>.
4. ARB (2007). Emfac 2007. Air Resources Board.
5. Alexander E Farrell, Daniel Sperling, and et al. (2007). A Low-Carbon Fuel Standard for California Part 1: Technical Analysis
6. Antares Group (2008). Strategic Assessment of Bioenergy Development in the West.
7. US EPA (2007). Regulatory Impact Analysis: Renewable Fuel Standard Program. O.o.T.a.A. Quality. 116-170.
8. RFA (2009). Renewable Fuels Association Biorefineries Locations. Renewable Fuels Association.
9. Renewable Fuels Association. (2007). "Renewable Fuels Association Ethanol Industry Statistics." Retrieved, from <http://www.ethanolrfa.org/industry/statistics/#E>.
10. (2007). Congressional Research Service Report for Congress; Agriculture Based Renewable Energy Production.
11. (2008). Attachment E for Landfill Methane as a Biomass Renewable Energy Source.
12. ARB (1998). Noncombustion Landfill Gas Control Technologies. California Air Resources Board.
13. GTI and Prometheus Energy Company (2007). GTI and Prometheus Energy Company Grant Application Package. California Air Resources Board.
14. Oregon. (2007). "Biomass Energy Homepage." Retrieved, from [http://www.oregon.gov/ENERGY/RENEW/Biomass/biogas.shtml#Anaerobic Digestion](http://www.oregon.gov/ENERGY/RENEW/Biomass/biogas.shtml#Anaerobic_Digestion).
15. CEC. (2008). "Biomass - Anaerobic Digestion." Retrieved, from www.energy.ca.gov/research/renewable/biomass/anaerobic_digestion/index.html.
16. Hilarides (2007). Hilarides Dairy Grant Application Package. California Air Resources Board.
17. NGSA (2004). Overview of Natural Gas. Natural Gas Supply Association.
18. Michelle Fost (2007). Introduction to LNG. UT Austin.
19. CEC (2009). Significant Events in the History of LNG. California Energy Commission.
20. EIA. (2009). "Natural Gas Plant Processing." Retrieved, from http://tonto.eia.doe.gov/dnav/ng/ng_prod_pp_dcu_nus_a.htm.
21. EIA. (2009). "U.S. Natural Gas Imports by Country " Retrieved, from http://tonto.eia.doe.gov/dnav/ng/ng_move_imp_s1_a.htm.

22. CLNG. (2008). "Bringing LNG to the United States." Retrieved, from <http://www.lngfacts.org/LNG-Today/Bringing-LNG.asp>.
23. Fritz R. Kalhammer, Bruce M Kopf, and et al. (2007). Report of the ARB Independent Expert Panel. Air Resources Board.
24. CEC (2008). 2007 Net System Power Report. California Energy Commission.
25. CEC (2007). Transportation Energy Forecasts for the 2007 Integrated Energy Policy Report. California Energy Commission.
26. CEC. (2007). "Total Electricity System Power." Retrieved, from http://energyalmanac.ca.gov/electricity/total_system_power.html.
27. CEC. (2008). "Proposed Generation Within the Western Electricity Coordinating Council " Retrieved, from http://energyalmanac.ca.gov/electricity/wecc_proposed_generation.html.
28. Michael Kintner-Meyer, Kevin Schneider, and Robert Pratt (2007). Impacts Assessment of Plug-in Hybrid Vehicles on Electric Utilities and Regional U.S. Power Grids Part 1: Technical Analysis. Pacific Northwest National Laboratory.
29. Lucy Sanna (2005). "Driving the Solution: The Plug-In Hybrid Vehicle." EPRI Journal.
30. Rolf Schreiber. (2008). "Vehicle to grid (V2G) overview." Retrieved, from <http://rechargeit.blogspot.com/2008/09/vehicle-to-grid-v2g-overview.html>.
31. NAP. (2008). "Transitions to Alternative Transportation Technologies: A Focus on Hydrogen." Retrieved, from http://www.nap.edu/catalog.php?record_id=12222.
32. Carlo N Hamelinck and et al. (2005). "Ethanol from Lignocellulosic Biomass: Techno-Economic performance in Short-, Middle- and Long-Term." Biomass and Bioenergy 28(4): 384-410.
33. S. Phillips, et al. (2007). Thermochemical Ethanol via Indirect Gasification and Mixed Alcohol Sythesis of Lignocellulosic biomass. National Renewable Energy Laboratory.
34. Craig W Rismiller and Wallace E Tyner (2008). Biofuels Comparison Model: Model description and Economic Analysis of Base Case. Department of Agricultural Economics, Purdue University.
35. Renewable Fuels Association. (2008). "U.S. Cellulosic Ethanol Projects under Development and Construction." Retrieved, from <http://www.ethanolrfa.org/resource/cellulosic/documents/RFACellulosicPlantHandout.pdf>.
36. Sasol Chevron (2008). The Greenhouse Gas Impact of Gas to Liquids (GTL), An Industry Perspective. Chevron.
37. Anders S Carlsson, et al. (2007). Micro- and Macro-Algae: Utility for Industrial Applications. Outputs from the EPOBIO Project.
38. A.B.M. Sharif Hossain, et al. (2008). "Biodiesel Fuel Production from Algae as Renewable Energy." American Journal of Biochemistry and Biotechnology 4(3): 250-254.
39. Jessica M Adams and et al. (2008). "Fermentation Study on Saccharina latissima for Bioethanol." Journal of Applied Phycology.
40. John R Benemann (2008). Microalgae Biofuels: A Brief Introduction.
41. NREL (2008). Photobiological Water Splitting. National Renewable Energy Laboratory.

42. Green Car Congress. (2008). "Sapphire Energy Introduces Algae-Derived Bio-Gasoline." Retrieved, from <http://www.greencarcongress.com/2008/05/sapphire-energy.html>.
43. CSR Wire. (2006). "Arizona Public Service and GreenFuel Technologies Corp. Successfully Recycle Power Plant Flue Gases into Transportation-Grade Biodiesel and Ethanol." Retrieved, from <http://www.csrwire.com/News/6959.html>.
44. Robert Buderl. (2007). "Metcalf Takes Reins at GreenFuel After Key Setbacks; Company Lays Off Half its Staff, Seeks to Raise Cash." Retrieved, from <http://www.xconomy.com/boston/2007/07/01/metcalf-takes-reins-at-greenfuel-after-key-setbacks-company-lays-off-half-its-staff-and-seeks-to-raise-cash/>.
45. DOE. (2009). "Alternative and Advanced Fuels, Butanol as an Alternative Fuel." Retrieved, from http://www.afdc.energy.gov/afdc/fuels/emerging_biobutanol_what_is.html.
46. Eric J Steen and et al. (2008). "Metabolic engineering of *Saccharomyces cerevisiae* for the production of n-butanol." *Microbial Cell Factories* 7(36).
47. David; Yang Ramey, Shang-Tian (2004). Work performed under contract number: DE-F-G02-00ER86106 for U.S. Department of Energy. US Department of Energy.
48. Jiri van Straelen (2008). CO2 Capture for refineries, a practical approach. ScienceDirect.com.
49. CEC (2007). WEST COAST REGIONAL CARBON SEQUESTRATION PARTNERSHIP: SOURCE-SINK CHARACTERIZATION AND GEOGRAPHIC INFORMATION SYSTEM-BASED MATCHING. California Energy Commission.

Appendix C References:

1. TIAX (2007). Full Fuel Cycle Assessment Well to Tank Energy Inputs, Emissions, and Water Impacts. California Energy Commission.
2. Michael O'Hare and et al. (2009). Proper accounting for time increases crop-based biofuels' GHG deficit versus petroleum. UC Berkeley.
3. S. Solomon and et al. (2007). Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change. Intergovernmental Panel on Climate Change.
4. NASS (2009). Agricultural Prices. US Department of Agriculture.
5. R. Keeney and T. W. Hertel (2008). Indirect Land Use Impacts of US Biofuels Policies: The Importance of Acreage, Yield and Bilateral Trade Responses. GTAP Working Paper 52. Purdue University.
6. USDA (2009). Agricultural Outlook: Statistical Indicators. US Department of Agriculture.
7. Salil Arora, May Wu, and Michael Wang (2008). Update of Distillers Grains Displacement Ratios for Corn Ethanol Life-Cycle Analysis. Argonne National Laboratory.
8. Kent Tjardes and Cody Wright (2002). Feeding Corn Distiller's Co-Products to Beef Cattle. San Diego State University.
9. R. Lemenager and et al. (2006). The Value of Distillers' Grains as a Livestock Feed. Purdue University.
10. T. J. Klopfenstein (1991). "Efficiency of escape protein utilization." *Proc. Distillers Feed Res. Council* 46: 77-82.
11. G. L. Cromwell, K. L. Herkelman, and T. S. Stahly (1993). "Physical, chemical, and nutritional characteristics of distillers dried grains with solubles for chicks and pigs." *J. Anim. Sci* 71: 679-686.
12. F. M. Dong, B. A. Rasco, and S. S. Gazzaz (1987). "A protein quality assessment of wheat and corn distillers dried grains with solubles." *Cereal Chemistry* 64: 327-332.
13. A. S. Chaudhry and A. J. F. Webster (1993). "The true digestibility and biological value for rats of undegraded dietary nitrogen in feeds for ruminants." 42: 209-221.
14. T. Nakamura, et al. (1994). "Growth efficiency and digestibility of heated protein fed to growing ruminants." *J. Anim. Sci.* 72: 774-782.
15. S. Uwituze (2008). The effects of feeding dry distiller's grains with solubles on ruminal metabolism, growth performance, and carcass traits of feedlot cattle. Kansas State University.
16. T. J. Vasconcelos and M. L. Galyean (2007). "Nutritional recommendations of feedlot consulting nutritionists: The Texas Tech University survey." 85: 2772-2781.
17. F. J. Dooley (2008). Market analysis for dried distillers grains in Indiana. Purdue University.

18. Michael R. Lehman and Kurt A. Rosentrater (2007). "Microbial development in distillers wet grains produced during fuel ethanol production from corn (*Zea mays*)." *Can J. Microbiology* 53: 1046-1052.
19. Kurt A. Rosentrater Ethanol Processing Co-Products: Economics, Impacts, Sustainability. US Department of Agriculture.
20. Mike Deering and Marri Carrow. (2009). "Global Update: February 19, 2009." Retrieved, from <http://www.grains.org/global-update/1375-global-update-february-19-2009>.
21. CEC. (2008). "Energy Almanac." Retrieved, from <http://energyalmanac.ca.gov/>.
22. Argonne (2008). The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) Model. Argonne National Laboratory.
23. EPRI (1999). Enhanced Oil Recovery Scoping Study. Electric Power Research Institute.
24. DOC. (2009). "Oil, Gas & Geothermal - DOGGR Home Page." Retrieved, from <http://www.conservation.ca.gov/dog/Pages/Index.aspx>.

Appendix E References:

1. Susanne Retka Schill (2008). "U.S. ethanol production." Ethanol producer magazine (October).

Appendix F References

1. CEC. (2009). "California's Oil Refineries " Retrieved, from <http://energyalmanac.ca.gov/petroleum/refineries.html>.
2. UC Davis (2008). Strategic Development of Bioenergy in the Western States. Western Governors' Association.
3. ARB (2007). Emfac 2007. Air Resources Board.
4. ARB (2009). Emfac Screenshot Table F6-1. California Air Resources Board.
5. ARB (2009). Emfac Screenshot Table F6-2. California Air Resources Board.
6. ARB (2009). GREET Analysis Table F6-3. California Air Resources Board.
7. ARB (2008). California-GREET Model version 1.8b. Air Resources Board. <http://www.arb.ca.gov/fuels/lcfs/lcfs.htm>.
8. TIAX (2007). Full Fuel Cycle Assessment Well to Tank Energy Inputs, Emissions, and Water Impacts. California Energy Commission.
9. ARB (2007). CALIFORNIA EVAPORATIVE EMISSION STANDARDS AND TEST PROCEDURES FOR 2001 AND SUBSEQUENT MODEL MOTOR VEHICLES. California Air Resources Board.
10. ARB (2008). The California Low-Emission Vehicle Regulations. California Air Resources Board.
11. MSCD (2008). E85 Spreadsheet F6-4. California Air Resources Board.
12. Lisa A. Graham, Sheri L. Belisle, and Cara-Lynn Baas (2008). "Emissions from Light Duty Gasoline Vehicles Operating on Low Blend Ethanol Gasoline and E85." Atmospheric Environment 42: 4498-4516.
13. Renewable Technology (2005). Renewable Diesel Subcommittee of the WSDA Technical Work Group. WSDA.
14. Aaron Williams, et al. (2006). Effect of Biodiesel Blends on Diesel Particulate Filter Performance. SAE.
15. EPA (2002). A Comprehensive Analysis of Biodiesel Impacts on Exhaust Emissions. US Environmental Protection Agency.
16. Thomas D. Durbin, J. Wayne Miller, Kent Johnson (2009). For the CeCERT Engine Testing portion for the CARB Assessment of the Emissions from the Use of Biodiesel as a Motor Vehicle Fuel in California "Biodiesel Characterization Study" Testing on 2006 Cummins ISM. California Air Resources Board.
17. SAE (2004). Automotive Handbook. Society of Automotive Engineers.
18. William Tahil (2007). The Trouble with Lithium. Meridian International Research.
19. Joyce A. Ober (2008). Lithium. US Geological Survey.
20. USCAR. (2007). "What's recycled more than any other item in the U.S.? Here's a hint -- USCAR's VRP IS involved." Retrieved, from http://www.uscar.org/commands/files_download.php?files_id=125.
21. Annette Hebert (2008) A-021-0479 Cummins
22. Annette Hebert (2008) A-021-0458-1 Cummins
23. OEHHA (2003). Air Toxics Hot Spots Program Risk Assessment Guidelines. California Office of Environmental Health Hazard Assessment.
24. ARB (1998). PROPOSED IDENTIFICATION OF DIESEL EXHAUST AS A TOXIC AIR CONTAMINANT. California Air Resources Board.

25. ARB (2002). Public Hearing to Consider Amendments to the Ambient Air Quality Standards for Particulate Matter and Sulfates. California Air Resources Board.
26. ARB (2007). Health Risk Assessment for the Union Pacific Railroad Commerce Railyard. California Air Resources Board.
27. ARB (2006). Emission Reduction Plan for Ports and Goods Movement in California. California Air Resources Board.
28. ARB (2000). Risk Reduction Plan to Reduce Particulate Matter Emissions from Diesel-Fueled Engines and Vehicles. California Air Resources Board.
29. SCAQMD (2000). MULTIPLE AIR TOXICS EXPOSURE STUDY. South Coast Air Quality Management District.
30. EPA (2004). USER'S GUIDE FOR THE AMS/EPA REGULATORY MODEL - AERMOD. US Environmental Protection Agency.
31. ARB (2007). Health Risk Assessment for the Union Pacific Railroad Commerce Railyard Stationary Source Division. California Air Resources Board.
32. ARB (2006). ARB Almanac 2006. California Air Resources Board.
33. ARB and OEHHA (2002). Public Hearing to Consider Amendments to the Ambient Air Quality Standards for Particulate Matter and Sulfates. California Air Resources Board.
34. ARB (2006). Emission Reduction Plan for Ports and Goods Movement. California Air Resources Board.
35. EPA (2004). Final Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines. US Environmental Protection Agency.
36. EPA (1999). The Benefits and Costs of the Clean Air Act 1990 to 2010. US Environmental Protection Agency.
37. EPA (2005). Regulatory Impact Analysis for the Final Clean Air Interstate Rule. US Environmental Protection Agency.
38. ARB (2008). Methodology for Estimating the Premature Deaths Associated with Long-term Exposures to Fine Airborne Particulate Matter in California. California Air Resources Board.
39. Alan C. Lloyd and Thomas A. Cackette (2001). "Diesel Engines: Environmental Impact and Control." *Journal of the Air & Waste Management Association* 51: 809-847.
40. F Diminici and et al. (2005). "Revised Analyses of the National Morbidity, Mortality, and Air Pollution Study: Mortality Among Residents Of 90 Cities." *Journal of Toxicology & Environmental Health: Part A* 68(13/14): 1071-1092.
41. MEREDITH FRANKLIN, ARIANA ZEKA, and JOEL SCHWARTZ (2007). "Association between PM_{2.5} and all-cause and specific-cause mortality in 27 US communities." *Journal of Exposure Science and Environmental Epidemiology* 17(3): 279-287.
42. Michael Jerrett and et al. (2005). "Spatial Analysis of Air Pollution and Mortality in Los Angeles." *Epidemiology* 16(6): 727-736.
43. C. Arden Pope III, et al. (2002). "Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution." *Journal of the American Medical Association* 287(9): 1132-1141.
44. Mark A. Thayer (2003). The Economic Value of Respiratory and Cardiovascular Hospitalizations. UC San Diego.

45. EPA (2000). Guidelines for Preparing Economic Analyses. US Environmental Protection Agency.
46. Katherine Mrowka (2008). Division of Water Rights, State Water Resources Control Board.
47. Bart Christensen PE (2008). Division of Water Quality, State Water Resources Control Board.
48. Andy Aden (2007). Water Usage for Current and Future Ethanol Production. National Renewable Energy Laboratory.
49. Bureau of Reclamation. (2009). "Central Valley Project - Folsom and Sly Park." Retrieved, from <http://www.usbr.gov/dataweb/html/folsom.html>.