Regulatory Impact Analysis: Renewable Fuel Standard Program

United States
Environmental Protection
Agency

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Assessment and Standards Division
Office of Transportation and Air Quality
U.S. Environmental Protection Agency

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Statement of Need

The United States currently consumes about 190 billion gallons of gasoline and diesel fuel annually to meet its transportation fuel needs. Of this volume, about 65 percent, or 124 billion gallons, is derived from foreign sources. The United States' dependence on imported petroleum to meet its growing demand for transportation fuel exacts a cost on the nation in terms of energy security. In addition, petroleum-based fuel exacts a cost on the nation with respect to environmental quality. The Renewable Fuel Standard (RFS) program increases national energy security by creating a market for renewable fuel as a substitute for petroleum-based fuel. By incorporating incentives for investing in research and development of renewable fuels, the RFS program also seeks to accelerate the nation's progress toward energy independence. In addition, the RFS program helps to reduce the country's greenhouse gas emissions, thereby reducing the nation's contribution to global climate change and its potential effects on the U.S. economy, security, and public health.

Overview

EPA is finalizing standards which would implement a renewable fuel program as required by the Energy Policy Act of 2005 (the Act). The Act specifies the total volume of renewable fuel that is required to be used each year, and directs EPA to adjust this amount under certain circumstances. The resulting standards represent a level of renewable fuel that each refinery or importer must account for relative to its annual volume of gasoline produced or imported. In reality, however, renewable fuel use is forecast to exceed the RFS standards due to market forces. The analyses of the impacts associated with this increase in renewable fuel use are discussed in this Regulatory Impact Analysis (RIA).

Chapter 1: Industry Characterization
This chapter discusses current gasoline, diesel and renewable fuel production, importation, marketing and distribution, as well as likely future changes as a result of increased renewable fuel use.

Chapter 2: Changes to Motor Vehicle Fuel Under the RFS Program
This chapter discusses our gasoline and renewable fuel consumption predictions (compared to a 2004 base year), and the expected impacts of various ethanol blends on gasoline properties.

Chapter 3: Impacts on Emissions from Vehicles, Nonroad Equipment, and Fuel Production Facilities
This chapter evaluates the impacts on vehicle and nonroad equipment emissions under various oxygenate assumptions, specifically increasing ethanol and decreasing MTBE, and different modeling techniques. The effect of biodiesel use on diesel-powered vehicle emissions is also presented. Finally, emissions from ethanol and biodiesel production facilities are discussed.

Chapter 4: National Emissions Inventory Impacts
This chapter discusses the methods used to develop the national emissions inventories, and quantifies the impact of expanded ethanol and biodiesel use on those inventories.

Chapter 5: Air Quality Impacts
This chapter discusses the impacts of expanded renewable fuel use on ozone and particulate matter formation.

Chapter 6: Lifecycle Impacts on Fossil Energy and Greenhouse Gases
This chapter discusses our fuel lifecycle modeling, that is, analysis which accounts for all energy and emissions of the fuel production process. A description of the model we used, how we used it, and the results are presented. Impacts on greenhouse gases, including $CO_{2,}$ fossil fuel use, and petroleum use are presented. The effects on petroleum imports, import expenditures, and domestic energy security are also discussed.

Chapter 7: Estimated Costs of Renewable Fuels, Gasoline and Diesel

This chapter contains our analysis of the cost of corn and cellulosic ethanol. We also discuss biodiesel and renewable diesel production costs. Costs associated with distributing the volumes of ethanol necessary to meet the requirements of the program, and the costs to prepare gasoline and diesel blendstocks (for blending with renewable fuels) are also presented. Finally, we present the overall fuel cost impacts of expanded renewable fuel use.

Chapter 8: Agricultural Sector Impacts

This chapter discusses the likely economic impacts on the agricultural sector that may occur as a result of the large expansion of renewable fuel production and use expected in the future. On-going work using the FASOM model is also described.

Chapter 9: Small Business Flexibility Analysis

This chapter discusses our Small Business Flexibility Analysis (SBFA) which evaluates the rule to ensure that concerns regarding small businesses, which would be affected by the rule, are sufficiently considered.

List of Acronyms and Abbreviations

AAM	Alliance of Automobile Manufacturers
ABT	Averaging, Banking, and Trading
ACE	American Coalition for Ethanol
The Act	Energy Policy Act of 2005 (also the Energy Act)
ADM	Archer Daniels Midland
AEO	Annual Energy Outlook (an EIA publication)
ANL	Argonne National Laboratory
AQIRP	Auto/Oil Air Quality Improvement Research Program
ARMS	Agricultural Resource Management Survey
B0, B5, B20, etc	Percent of biodiesel, e.g., B5= 5% biodiesel, 95% diesel
bbl	Barrel
BEA	Bureau of Economic Analysis
Bgal, bgal, bilgal, billgal, bg	Billions of gallons
BGY	Billions of gallons per year
BPCD	Barrels Per calendar day
BPSD	Barrels per stream day
bpd, bbls/day	Barrels Per Day
BTU	British Thermal Unit
BU	Bushel
Bu/acre	Bushels per acre
BZ	Benzene
CA	California
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CARB	California Air Resources Board
CaRFG3	California Phase 3 RFG
CBG	Cleaner Burning Gasoline
CBI	Caribbean Basin Initiative
CD	Census Division
CFEIS	EPA’s Certification and Fuel Economy Information System
CFR	Code of Federal Regulations
c/gal	Cents per gallon
CG	Conventional Gasoline
CHP	Combined Heat and Power Technology
CO	Carbon Monoxide
CO2	Carbon Dioxide
Co-op	Cooperative
CRC	Coordinating Research Council
DDGS	Distillers’ Dried Grains with Solubles
DOE	Department of Energy
DRIA	Draft Regulatory Impact Analysis
E&C	Engineering and Construction
E0	Gasoline Blend which Does Not Contain Ethanol
E10	Gasoline Blend containing a nominal 10 percent ethanol by volume
E85	Gasoline Blend containing 85 percent ethanol by volume
E200	Percent of Fuel Evaporated at 200 Degrees F (ASTM D 86)
E300	Percent of Fuel Evaporated at 300 Degrees F (ASTM D 86)
EIA	Energy Information Administration (part of the U.S. Department of Energy)

Energy Act	Energy Policy Act of 2005 (also the Act)
EO	Executive Order
EPA	Environmental Protection Agency
EPAct	Energy Policy Act of 2005 (also ‘the Energy Act’ or ‘the Act’)
ETBE	Ethyl Tertiary Butyl Ether
ETOH	Ethanol
ex CA	Excluding California
F, °F	Fahrenheit
FAPRI	Farm and Agricultural Policy Research Institute
FASOM	Forestry and Agriculture Sector Optimization Model
FBP	Feed Boiling Point (also Final Boiling Point)
FCC	Fluidized Catalytic Cracker
FCCU	Fluidized Catalytic Cracking Unit
FHWA	Federal Highway Administration
FOEB	Fuel Oil Equivalent Barrel
FR	Federal Register
FRM	Final Rulemaking
FRTP	Fixed Reduction Trigger Point
FFV	Flexible Fuel Vehicle
FTP	Federal test procedure
GAL	Gallon
g/Btu	Grams per Btu
g/day	Grams per day
GDP	Gross Domestic Product
GHG	Greenhouse Gases
GPA	Geographic Phase-in Area
GREET	Greenhouse Gas, Regulated Emissions, and Energy Use in Transportation model
GWP	Global warming potentials
HC	Hydrocarbon(s)
HCO	Heavy Cycle Oil (a refinery stream)
HDN	Naphtha Hydrotreater (also Hydro-Denitrogenation Unit)
HSR	Heavy Straight Run (a refinery stream)
HVGO	Heavy Vacuum Gas Oil (a refinery stream)
IBP	Initial Boiling Point
k	Thousand
kbbl	Thousand barrels
kwh	Kilowatt Hour
Lb	Pound
LCO	Light Cycle Oil (a refinery stream)
LEV	Low emission vehicle
LLE	Liquid-Liquid Extraction
LNS	Light Naphtha Splitter
LP	Linear Programming (a type of refinery model)
LSR	Light Straight Run (a refinery stream)
mg/m^3	Milligrams per cubic meter
MGY, MMgy	Million Gallons per Year
MM	Million
MMBTU	Million British Thermal Units
MMbbls/cd	Millions of barrels per calendar day
MMGal/yr	Millions of gallons per year
MOBILE (5, 6, 6.2)	EPA’s Motor Vehicle Emission Inventory Model (versions)
MON	Motor Octane Number
MOVES2006	EPA’s Next Generation Highway Vehicle Emission Model

MSAT	Mobile Source Air Toxics
MSAT1	2001 Mobile Source Air Toxics Rule
MSAT2	2006 Proposed Mobile Source Air Toxics Rule
MTBE	Methyl Tertiary-Butyl Ether
NAAQS	National Ambient Air Quality Standards
NAICS	North American Industrial Classification System
NASS	National Agricultural Statistics Service
NBB	National Biodiesel Board
NCSU	North Carolina State University
NGL	Natural gas plant liquids
NMHC	Non-Methane Hydrocarbons
NMIM	National Mobile Inventory Model (EPA software tool)
NMOG	Non-methane organic gases
NONROAD	EPA’s Non-road Engine Emission Model
NONROAD2005	EPA’s Non-road Engine Emission Model Released in 2005
NO_x	Oxides of nitrogen
NPRM	Notice of Proposed Rulemaking
NREL	National Renewable Energy Laboratory
OMB	Office of Management and Budget
OMHCE	Organic Material Hydrocarbon Equivalent
ORNL	Oak Ridge National Laboratory
OTAQ	Office of Transportation and Air Quality
Oxy-fuel, oxyfuel	Winter oxygenated fuel program
PADD	Petroleum Administration for Defense District
PM	Particulate Matter
PM_{10}	Coarse Particle
$PM_{2.5}$	Fine Particle
PMA	Petroleum Marketing Annual (an EIA publication)
POM	Polycyclic Organic Matter
PONA	Paraffin, Olefin, Naphthene, Aromatic
ppb	Parts per billion
ppm	Parts Per million
PRTP	Percentage Reduction Trigger Point
PSI	Pounds per Square Inch
QBtu	Quadrillion btu
Quadrillion	10^{15}
(R+M)/2	Octane calculation (RON+MON)/2
RBOB	Reformulated Blendstock for Oxygenate Blending
RFA	Regulatory Flexibility Act
RFG	Reformulated Gasoline
RFS	Renewable Fuels Standard
RIA	Regulatory Impact Analysis
RIMS	Regional Input-Output Modeling System
RIN	Renewable Identification Number
RON	Research octane number
RPMG	Renewable Products Marketing Group
RSM	Response Surface Model
RVP	Reid Vapor Pressure
S	Sulfur
SBA	Small Business Administration
SBAR Panel, or ‘the Panel’	Small Business Advocacy Review Panel
SBFA	Small Business Flexibility Analysis
SBREFA	Small Business Regulatory Enforcement Fairness Act (of 1996)

scf	Standard cubic feet
SOA	Secondary Organic Aerosol
SOx	Oxides of Sulfur
SULEV	Super ultra low emission vehicle
T50	Temperature at which 50% (by volume) of fuel evaporates (ASTM D 86)
T90	Temperature at which 90% (by volume) of fuel evaporates (ASTM D 86)
TAME	Tertiary Amyl Methyl Ether
ULEV	Ultra low emission vehicle
U.S.C.	United States Code
USDA	U.S. Department of Agriculture
VGO	Vacuum Gas Oil (a refinery stream)
VMT	Vehicle Miles Traveled
VOC	Volatile Organic Compound
vol%	Percent by volume, volume percent
wt%	Percent by weight, weight percent
yr, y	Year

Chapter 1: Industry Characterization

1.1 Transportation Fuel Providers

1.1.1 Petroleum Refiners

As of the end of 2005, there were 142 crude oil refineries operating in the United States, representing a total of 16.4 million barrels/day of refining capacity. (These refineries produce gasoline and other products and are a separate category than "blender refiners" that do not process crude oil, but make gasoline from blendstocks.) The greatest number of refineries per PADD is in PADD 3 (the Gulf Coast region) which has 52 operating refineries as of the end of 2005. This PADD also has the greatest refining capacity, at 7.9 million barrels per day. Table 1.1-1 presents the refineries and their crude oil production capacity, and identifies the PADD where the refinery is located.

Table 1.1-1.
Refining Capacity by Individual Refinery
(crude oil processing basis)

Company	Capacity (MMbbls/cd)	PADD
Conoco Phillips	**2.2**	
Wood River, IL	*0.31*	*2*
Belle Chasse, LA	*0.25*	*3*
Sweeny, TX	*0.25*	*3*
Westlake LA	*0.24*	*3*
Linden, NJ	*0.24*	*1*
Ponca City OK	*0.19*	*2*
Trainer, PA	*0.19*	*1*
Borger TX	*0.15*	*3*
Wilmington CA	*0.14*	*5*
Ferndale WA	*0.10*	*5*
Rodeo CA	*0.08*	*5*
Billings MT	*0.06*	*4*
Valero Energy Corp.	**2.0**	
Port Arthur TX	*0.26*	*3*
Memphis TN	*0.18*	*2*
Lima OH	*0.15*	*2*
Texas City TX	*0.21*	*3*
Corpus Christi TX	*0.14*	*3*
Houston TX	*0.08*	*3*
Sunray TX	*0.16*	*3*
Three Rivers TX	*0.09*	*3*
Norco LA	*0.19*	*3*
Paulsboro NJ	*0.16*	*1*
Benecia CA	*0.14*	*5*
Wilmington CA	*0.01*	*5*
Ardmore OK	*0.08*	*2*
Wilmington CA	*0.08*	*5*

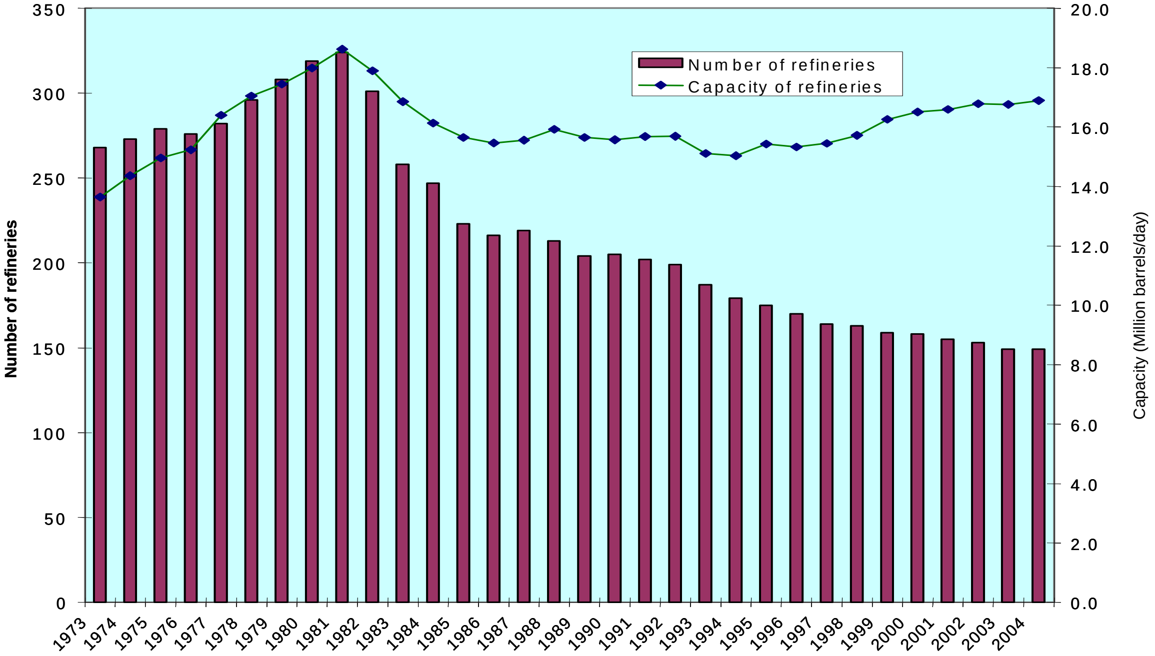
Company	**Capacity (MMbbls/cd)**	**PADD**
Krotz Springs LA	*0.08*	*3*
Exxon Mobil Corp.	**2.0**	
Baytown TX	*0.56*	*3*
Baton Rouge LA	*0.50*	*3*
Beaumont TX	*0.34*	*3*
Joliet IL	*0.24*	*2*
Torrance CA	*0.15*	*5*
Billings MT	*0.06*	*4*
Chalmette, LA	*0.19*	*3*
BP PLC	**1.5**	
Texas City TX	*0.44*	*3*
Whiting IN	*0.41*	*2*
Toledo OH	*0.13*	*2*
Los Angeles CA	*0.26*	*5*
Ferndale WA	*0.23*	*5*
Chevron Corp.	**0.9**	
Pascagoula MS	*0.33*	*3*
El Segundo CA	*0.26*	*5*
Richmond CA	*0.24*	*5*
Honolulu HI	*0.05*	*5*
Salt Lake City UT	*0.05*	*4*
Marathon Oil Corp.	**1.0**	
Garyville LA	*0.25*	*3*
Cattlettsburg KY	*0.22*	*2*
Robinson IL	*0.19*	*2*
Detroit MI	*0.10*	*2*
Canton OH	*0.07*	*2*
Texas City TX	*0.07*	*3*
Saint Paul Park MN	*0.07*	*2*
Sunoco, Inc.	**0.58**	
Marcus Hook PA	*0.18*	*2*
Toledo OH	*0.16*	*2*
Westville NJ	*0.15*	*1*
Tulsa OK	*0.09*	*2*
PDV America, Inc.	**0.81**	
Citgo; Lake Charles LA	0.43	*3*
Citgo, Lemont IL	0.17	*2*
Citgo; Corpus Christi TX	0.16	*3*
Koch Industries	**0.57**	
Corpus Christi TX	*0.29*	*3*
Saint Paul MN	*0.28*	*2*
Motiva Enterprises LLC	**0.76**	
Port Arthur TX	*0.29*	*3*
Convent LA	*0.24*	*3*
Norco LA	*0.23*	*3*
Tesoro Corp.	**0.51**	
Anacortes WA	*0.12*	*5*
Salt Lake City UT	*0.06*	*4*

Company	**Capacity (MMbbls/cd)**	**PADD**
Martinez CA	*0.17*	*5*
Kapolei HI	*0.09*	*5*
Kenai AK	*0.072*	*5*
Royal Dutch/Shell Group	**0.82**	
Martinez CA	*0.16*	*5*
Anacortes WA	*0.15*	*5*
Wilmington CA	*0.10*	*5*
Saraland AL	*0.08*	*3*
Deer Park, TX	*0.33*	*3*
Lyondell Chem. Co. (Houston)	**0.27**	*3*
Total SA (Port Arthur, TX)	**0.23**	*3*
Sinclair Oil	**0.17**	
Tulsa OK	*0.07*	*2*
Sinclair WY	*0.07*	*4*
Evansville WY	*0.03*	*4*
Murphy Oil	**0.15**	
Meraux LA	*0.12*	*3*
Superior WI	*0.03*	*2*
Frontier Oil	**0.15**	
El Dorado KS	*0.11*	*2*
Cheyenne WY	*0.04*	*4*
Cenex Harvest States, Inc.	**0.14**	
McPherson KS	*0.08*	*2*
Laurel MT	*0.06*	*4*
Coffeyville Acquisitions (Coffeyville KS)	**0.11**	*2*
Navajo Refining Corp.	**0.11**	
Artesia NM	*0.07*	*3*
Woods Cross UT	*0.03*	*4*
Great Falls MT	*0.01*	*4*
Pasadena Refining Systems (Pasadena TX)	**0.10**	*3*
Giant Industries, Inc.	**0.10**	
Yorktown VA	*0.06*	*1*
Gallup NM	*0.02*	*3*
Bloomfield NM	*0.02*	*3*
Big West Oil (North Salt Lake UT)	**0.10**	*4*

Source: Table 5 in Energy Information Administration, Refinery Capacity 2006 found at http://www.eia.doe.gov/pub/oil_gas/petroleum/data_publications/refinery_capacity_data/current/table5.pdf

Refining capacity has steadily increased in the U.S. due to increased demand for petroleum products, with gasoline representing approximately 45 percent of product demand. Refining capacity (crude oil input) was about 14 million bbls/day in 1973 and 17 million bbls/day in 2005. While refining capacity has increased, however, the number of refineries has decreased as less economical refineries have been forced to close. (Many of these came into existence for a very short time due to oil price supports in the 1970's.) In the 1970's, the number of refineries in the U.S. was approximately 270 and has decreased by 47 percent. Figure 1.1-1 shows the number of refineries and total capacity in the U.S. from 1973 through 2004.

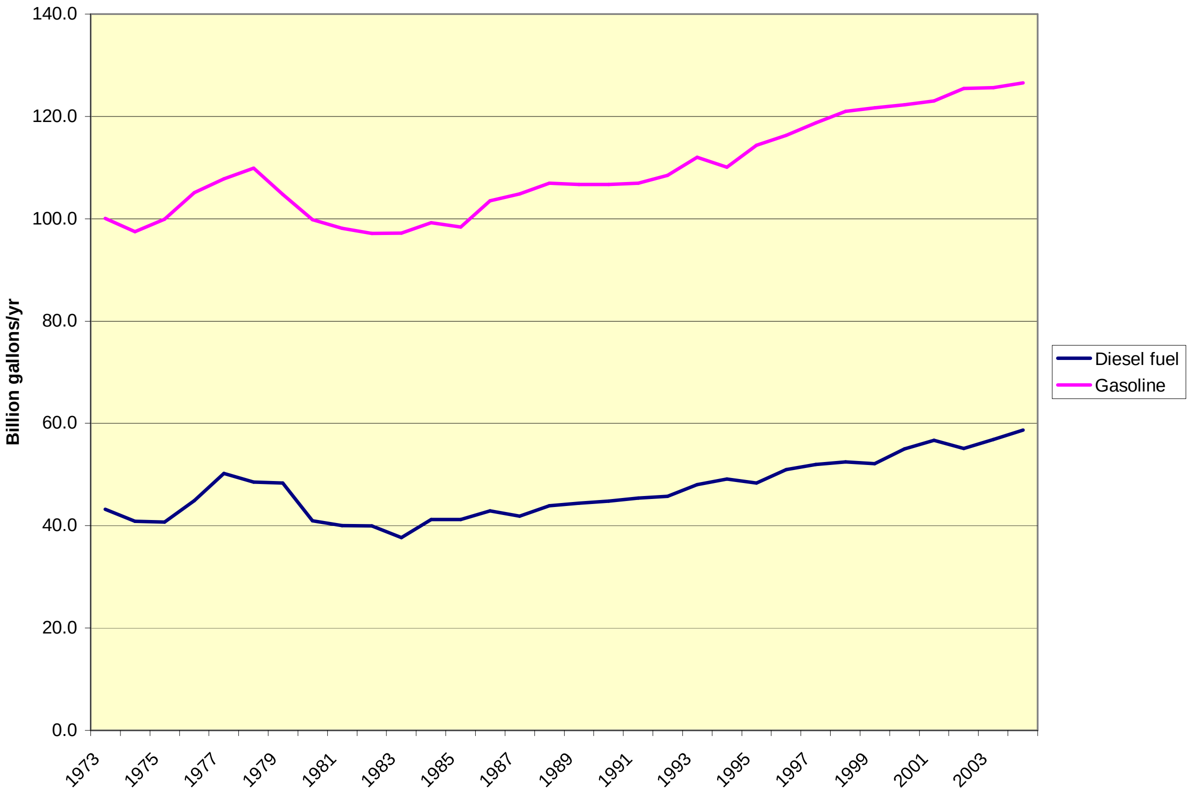
Figure 1.1-1.
Number of Refineries and Total Capacity in the U.S. from 1973-2004



Source: EIA; Annual Energy Report, 2005 (Table 5.9)

The increase in capacity combined with the decrease in amount of refineries and the increased demand for gasoline and diesel fuels, has resulted in an increase in the average utilization rate of refineries. In the 1970's, the utilization rate ranged from 84 to 94 percent. In the last ten years, however, the utilization rate has ranged from 91 to 96 percent. Refineries therefore have to produce more with less overall capacity. The amount of gasoline and diesel produced by U.S. refiners has steadily increased. Since 1973 through 2004, gasoline and diesel production has increased 27 and 36 percent, respectively. Figure 1.1-2 shows the change in gasoline and diesel production from 1973 through 2004

Figure 1.1-2.
Amount of Gasoline and Diesel Fuels Produced in the U.S.



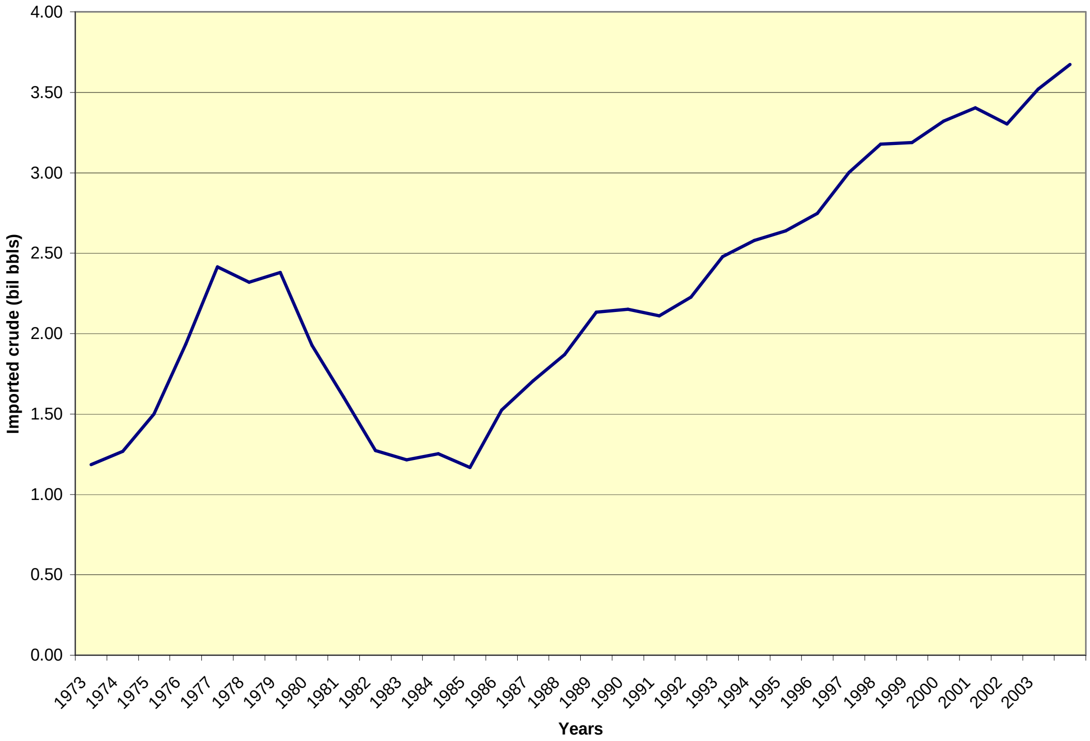
Source: EIA Annual Energy Report, 2005; Table 5.8

1.1.2 Petroleum Imports

The decrease in U.S. refining capacity discussed in Section 1.1.3, has resulted in increases in the amount of gasoline and diesel fuels imported into the U.S. As of 2004, 5.4 and 11.5 percent of the total respective volumes of gasoline and diesel consumed in the U.S. were imported.

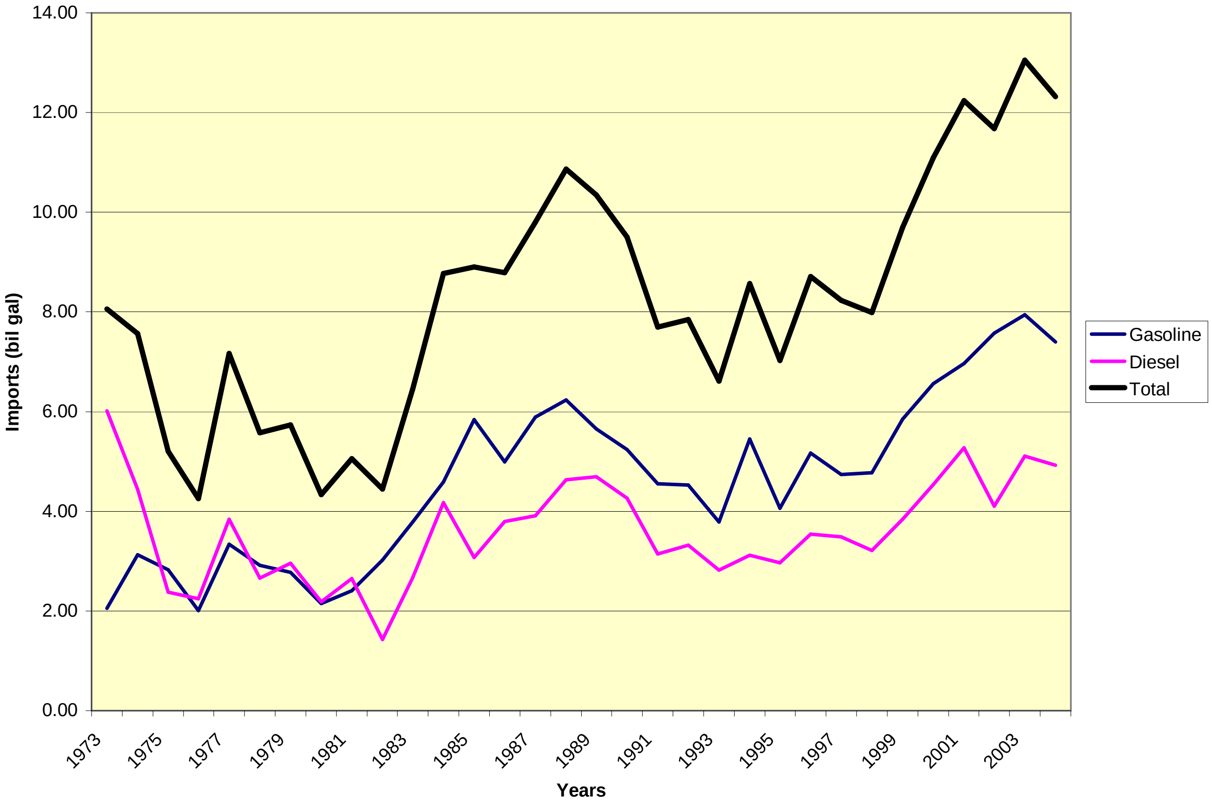
Today, the United States imports approximately 70 percent of all petroleum products used, with two-thirds of these products being used for transportation. From 1973 to 2004, the amount of crude oil imported has increased from 1.2 to 3.7 billion barrels per year, a tripling of volume, representing an average annual increase of about 6 percent. Over the same time period, the amount of gasoline imported has increased from 2 to 7.4 billion gallons per year, more than three times the amount of volume. The amount of diesel imported in the same time period decreased slightly from 6 to 5 percent. Figures 1.1-3 and 1.1-4 show the increase in crude oil and gasoline/diesel fuel imports, respectively, from 1973 to 2004.

Figure 1.1-3.
Increase in Crude Oil Imports from 1973-2004



(Source: Annual Energy Outlook, 2005; Energy Information Administration)

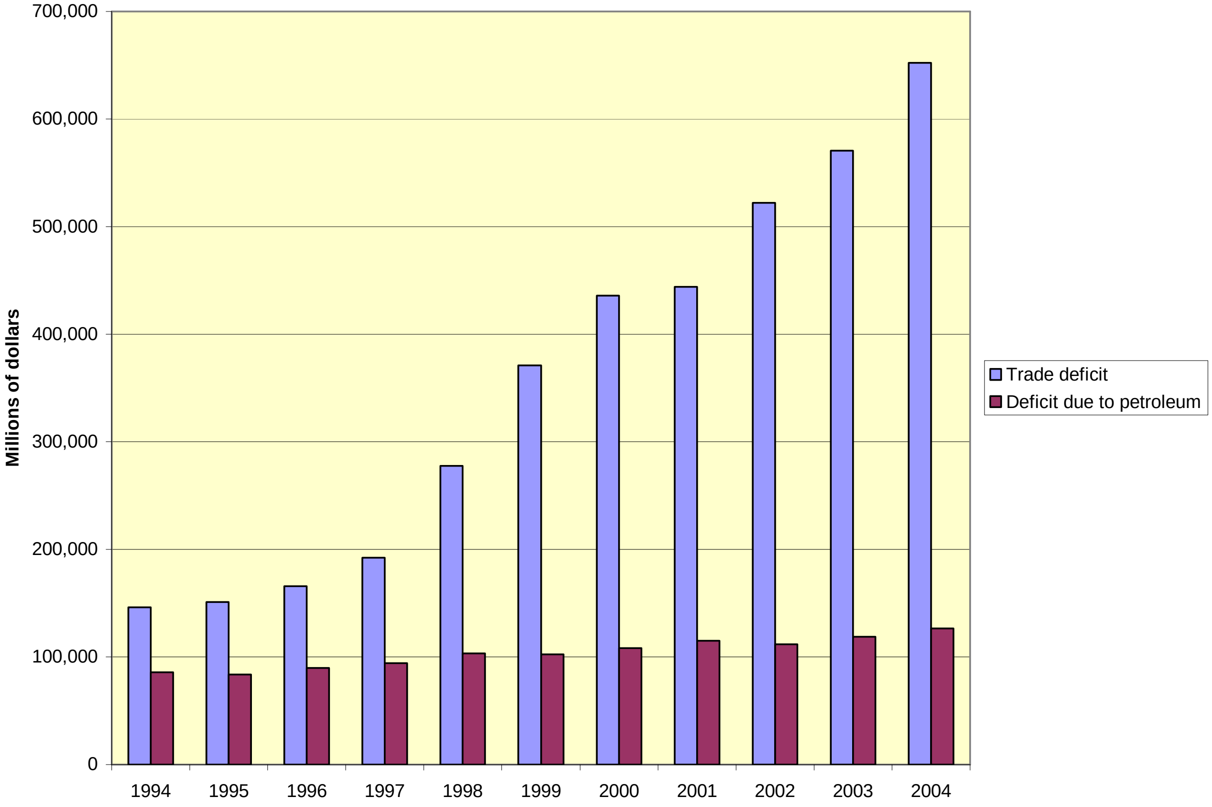
Figure 1.1-4.
Change in Volumes of Imported Gasoline and Diesel fuels (1973-2004)



Source: Annual Energy Outlook, 2005; Energy Information Administration

Approximately twenty percent of our trade deficit is from imported petroleum products, a deficit which reached $782 billion in 2005. Figure 1.1-5 shows the trade deficits from 1994 through 2004 (earlier data on petroleum imports is not available from the U.S. Census web site at this time). While the overall contribution of petroleum imports to the total deficit is decreasing as shown in Figure 1.1-5, this is due to a more rapid growth in the total deficit from other goods and services. The portion of the deficit due to petroleum imports by itself is increasing by approximately 4 percent per year. Over the last 25 years, the cumulative cost of imported crude oil has reached $2.0 trillion in 2005 dollars.

Figure 1.1-5.
U.S. Trade Deficit and Portions Due to Petroleum Imports
1994-2004
(Millions of dollars, chain weighted to 2000)



Source: U.S. Census Bureau, Foreign Trade Statistics, 2006

The amount of import facilities in the U.S. has stayed relatively constant since the U.S. EPA has been requiring such facilities to register. In 1995 there were a total of 39 such facilities in the U.S. The amount has remained relatively constant, in the 50's since that time and as of 2004 there were 53 such facilities registered with U.S. EPA. The great majority of such facilities are located in PADD 1; as of 2004, 35 facilities were in PADD 1, and a total of 18 in the other four PADDs.

1.2 Renewable Fuel Production

While the definition of renewable fuel in the Act does not limit compliance with the standard to any one particular type of renewable fuel, ethanol is currently the most prevalent renewable fuel blended into motor vehicle fuels today. Biodiesel represents another form of renewable fuel, which while not as widespread as ethanol use (in terms of volume), has been increasing in production capacity and use over the last several years. Ethanol and biodiesel are expected to continue to dominate renewable fuel use in the timeframe when the RFS rule will be phasing in.

1.2.1 Current U.S. Ethanol Production

1.2.1.1 Overview

There are currently 110 ethanol production facilities in the United States with a combined production capacity of 5.2 billion gallons per year[1]. This baseline, or starting point, for this regulatory impact analysis is based on U.S. ethanol production facilities operational as of October 2006.[2ABCDE]

Approximately 92 percent of today's ethanol production capacity is produced exclusively from corn, mainly from a dry-milling process. The remainder is derived from corn/grain blends, cheese whey, and other starches. The majority of ethanol plants are located in Midwest where the bulk of corn is produced. PADD 2 accounts for just over 5 billion gallons (or 96 percent) of the total U.S. ethanol production. Leading the Midwest in ethanol production are Iowa, Illinois, Nebraska, Minnesota, and South Dakota which together represent 76 percent of the total domestic product. In addition to the concentration of facilities located in PADD 2, there are also a sprinkling of ethanol plants situated outside of the Midwest as far west as California and as far south as Georgia.

1.2.1.2 Ethanol Feedstocks & Processing Technologies

All of the ethanol currently produced today comes from grain or starch-based feedstocks that can easily be broken down into ethanol via traditional fermentation processes. The primary feedstock is corn, although grain sorghum (milo), wheat, barley, beverage waste, cheese whey, and sugars/starches are also fermented to make fuel-grade ethanol.

The majority of ethanol (almost 92 percent by volume) is produced exclusively from corn. Most of the corn originates from the Midwest and most of the ethanol is produced in PADD 2 close to where the corn is grown. However, several corn-ethanol plants are also situated outside the traditional "corn belt". In California, Colorado, New Mexico, and Wyoming corn is shipped from the Midwest to supplement locally grown grains or in some cases, serve as the sole feedstock. As for the remaining ethanol, almost eight percent is produced from a blend of corn and/or similarly processed grains (milo, wheat, or barley) and less than one percent is

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[1] This analysis does not consider ethanol plants that may be located in (or planned for) the Virgin Islands or U.S. territories.

[2] The October 2006 ethanol production capacity baseline was generated based on the June 2006 NPRM plant list and updated on October 18, 2006 based on a variety of data sources including: Renewable Fuels Association (RFA), Ethanol Producer Magazine (EPM), ICF International, BioFuels Journal, and ethanol producer websites. The baseline includes small-scale ethanol production facilities as well as former food-grade ethanol plants that have since transitioned into the fuel-grade ethanol market. Where applicable, current ethanol plant production levels have been used to represent plant capacity, as nameplate capacities are often underestimated.

produced from waste beverages, cheese whey, and sugars/starches combined. A summary of ethanol production by feedstock is presented in Table 1.2-1.

Table 1.2-1.
2006 U.S. Ethanol Production by Feedstock

Plant Feedstock	Capacity MMgy	% of Capacity	No. of Plants	% of Plants
Cheese Whey	8	0.1%	2	1.8%
Corn[a]	4,780	91.6%	90	81.8%
Corn, Barley	40	0.8%	1	0.9%
Corn, Milo[b]	244	4.7%	8	7.3%
Corn, Wheat	90	1.7%	2	1.8%
Milo, Wheat	40	0.8%	1	0.9%
Sugars, Starches	2	0.0%	1	0.9%
Waste Beverages[c]	16	0.3%	5	4.5%
Total	**5,218**	**100.0%**	**110**	**100.0%**

[a] Includes two facilities processing seed corn and another facility processing corn which intends to transition to corn stalks, switchgrass, and biomass in the future.

[b] Includes one facility processing small amounts of molasses in addition to corn and milo.

[c] Includes two facilities processing brewery waste.

There are two primary plant configurations for processing grains into ethanol: dry mill and wet mill. A summary of the processing technologies used by today's ethanol plants is found below in Table 1.2-2.

Dry mill plants simply grind the entire kernel and feed the flour into the fermentation process to produce ethanol. At the end, the unfermentable parts are recovered as distillers' grains along with a soluble liquid containing vitamins, minerals, fat and protein. The distillers' grains are concentrated with the solubles stream to make a single co-product, referred to as distillers' grains with solubles (DGS). The co-product is either sold wet (WDGS) or more commonly dried (DDGS) to the agricultural market as animal feed. If the feed is going to be used by local markets, it's usually sold wet precluding the need for process dryers. However, if the feed is going to be shipped (usually by train) to more distant locations, the product is usually dried to facilitate storage and transportation.

Wet mill plants typically separate the kernel into four products: starch, gluten feed, gluten meal, and oil. The starch is used in a fermentation process the same as in dry mill plants, while the gluten, oil, and other co-products are sold into food and agricultural markets. Production of these multiple streams is more capital-intensive than the dry milling process, and thus wet mill plants are generally more expensive to build and tend to be larger in size.

Table 1.2-2.
2006 U.S. Ethanol Production by Processing Technology

Processing Technology	Capacity MMgy	% of Capacity	No. of Plants	% of Plants
Dry Milling	4,057	77.7%	92	83.6%
Wet Milling	1,137	21.8%	10	9.1%
Other[a]	25	0.5%	8	7.3%
Total	**5,218**	**100.0%**	**110**	**100.0%**

[a] Plants that do not process traditional grain-based crops and thus do not require milling. This category includes plants processing cheese whey, sugars & starches, or waste beverages.

As shown above in Table 1.2-2, dry milling is the most predominant production process used by today's ethanol plants. Of the 102 facilities processing corn and/or other similarly processed grains, 92 utilize dry milling technologies and the remaining 10 plants rely on wet milling processes (refer to Table 1.2-3 below). The remaining "other" eight plants listed above process waste beverages, cheese whey, or sugars/starches and operate differently than their grain-based counterparts. These facilities do not require milling and instead operate a simpler enzymatic fermentation process.

Table 1.2-3.
2006 U.S. Grain Ethanol Production - Wet Mill Plants

Ethanol Plant	Location	Capacity MMgy
Archer Daniels Midland[a]	Cedar Rapids, IA	300
Archer Daniels Midland[a]	Clinton, IA	150
Archer Daniels Midland	Columbus, NE	90
Archer Daniels Midland[a]	Decatur, IL	250
Archer Daniels Midland	Marshall, MN	40
Aventine Renewable Energy	Pekin, IL	100
Cargill, Inc.	Eddyville, IA	35
Cargill, Inc.	Blair, NE	85
Grain Processing Corp	Muscatine, IA	20
Tate & Lyle	Loudon, TN	67
Total		**1,137**

[a] Estimated ADM plant capacities

In addition to grain and starch-to-ethanol production, another method exists for producing ethanol from a more diverse feedstock base. This process involves converting cellulosic materials such as bagasse, wood, straw, switchgrass, and other biomass into ethanol. Cellulose consists of tightly-linked polymers of starch, and production of ethanol from it requires additional steps to convert these polymers into fermentable sugars. Scientists are actively pursuing acid and enzyme hydrolysis as well as gasification to achieve this goal, but the technologies are still not fully developed for large-scale commercial production. As of October 2006, the only known cellulose-to-ethanol plant in North America was Iogen in Canada, which produces approximately one million gallons of ethanol per year from wood chips. Several companies have announced plans to build cellulose-to-ethanol plants in the U.S., but most are still in the research and development or pre-construction planning phases. The majority of the plans involve converting bagasse, rice hulls, wood, switchgrass, corn stalks, and other agricultural waste or biomass into ethanol. For more a more detailed discussion on future cellulosic ethanol plants and production technologies, refer to RIA Sections 1.2.3.6 and 7.1.2, respectively.

1.2.1.3 Ethanol Plant Energy Sources

Ethanol production is a relatively resource-intensive process that requires the use of water, electricity, and steam. Steam needed to heat the process is generally produced onsite or by other dedicated boilers. Of today's 110 ethanol production facilities, 101 burn natural gas, 7 burn coal, 1 burns coal and biomass, and 1 burns syrup from the process to produce steam[3]. Our research suggests that 11 plants currently utilize co-generation or combined heat and power (CHP) technology, although others may exist. CHP is a mechanism for improving overall plant efficiency. Whether owned by the ethanol facility, their local utility, or a third party; CHP facilities produce their own electricity and use the waste heat from power production for process steam, reducing the energy intensity of ethanol production. A summary of the energy sources and CHP technology utilized by today's ethanol plants is found below in Table 1.2-4.

Table 1.2-4.
2006 U.S. Ethanol Production by Energy Source

Plant Energy Source	Capacity MMgy	% of Capacity	No. of Plants	% of Plants	CHP Tech.
Coal	1,042	20.0%	7	6.4%	2
Coal, Biomass	50	1.0%	1	0.9%	0
Natural Gas[a]	4,077	78.1%	101	91.8%	9
Syrup	49	0.9%	1	0.9%	0
Total	**5,218**	**100.0%**	**110**	**100.0%**	**11**

[a]Includes three facilities burning natural gas which intend to transition to coal or biomass in the future.

1.2.1.4 Ethanol Production Locations

The majority of domestic ethanol is currently produced in the Midwest within PADD 2 – where most of the corn is grown. Of the 110 U.S. ethanol production facilities, 100 are located in PADD 2. As a region, PADD 2 accounts for about 96 percent (or over five billion gallons) of domestic ethanol production, as shown in Table 1.2-5.

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[3] Facilities were assumed to burn natural gas if the plant fuel type was not mentioned or unavailable.

Table 1.2-5.
2006 U.S. Ethanol Production by PADD

PADD	Capacity MMgy	% of Capacity	No. of Plants	% of Plants
PADD 1	0.4	0.0%	1	0.9%
PADD 2	5,012	96.0%	100	90.9%
PADD 3	30	0.6%	1	0.9%
PADD 4	105	2.0%	4	3.6%
PADD 5	71	1.4%	4	3.6%
Total	**5,218**	**100.0%**	**110**	**100.0%**

Leading the Midwest in ethanol production are Iowa, Illinois, Nebraska, Minnesota, and South Dakota with capacities of 1.62, 0.71, 0.61, 0.55, 0.49 billion gallons, respectively. Together, these five states' 70 ethanol plants account for 76 percent of the total domestic ethanol production. However, although the majority of ethanol production comes from PADD 2, there are a growing number of plants situated outside the traditional corn belt. In addition to the 15 states comprising PADD 2, ethanol plants are currently located in California, Colorado, Georgia, New Mexico, and Wyoming. Some of these facilities ship in feedstocks (namely corn) from the Midwest, others rely on locally grown/produced feedstocks, while others rely on a combination of the two. A summary of ethanol production alphabetically by state is found in Table 1.2-6.

Table 1.2-6.
2006 U.S. Ethanol Production by State

State	Capacity MMgy	% of Capacity	No. of Plants	% of Plants
California	71	1.4%	4	3.6%
Colorado	93	1.8%	3	2.7%
Georgia	0.4	0.0%	1	0.9%
Iowa	1,618	31.0%	25	22.7%
Illinois	706	13.5%	6	5.5%
Indiana	122	2.3%	2	1.8%
Kansas	219	4.2%	8	7.3%
Kentucky	38	0.7%	2	1.8%
Michigan	155	3.0%	3	2.7%
Minnesota	546	10.5%	16	14.5%
Missouri	155	3.0%	4	3.6%
North Dakota	51	1.0%	2	1.8%
Nebraska	606	11.6%	12	10.9%
New Mexico	30	0.6%	1	0.9%
Ohio	3	0.1%	1	0.9%
Oklahoma	2	0.0%	1	0.9%
South Dakota	493	9.4%	11	10.0%
Tennessee	67	1.3%	1	0.9%
Wisconsin	233	4.5%	6	5.5%
Wyoming	12	0.2%	1	0.9%
Total	**5,218**	**100.0%**	**110**	**100.0%**

In addition to the domestic ethanol production described above, the U.S. also receives a small amount of ethanol from other countries. A discussion on ethanol imports is found in Section 1.5

1.2.1.5 Ethanol Producers and Marketers

The U.S. ethanol industry is currently comprised of a mixture of corporations and farmer-owned cooperatives (co-ops). More than half (or 60) of the plants are owned by corporations and the remainder (50 plants) are farmer owned co-ops. On average, a U.S. ethanol production facility has a mean plant capacity of about 47 million gallons per year. In general, plants owned by corporations ("company-owned") are above average in size while farmer-owned co-ops are below average. Similarly, company-owned plants tend to have a much broader range in ethanol production levels than farmer-owned co-ops. A summary of these results is presented in Table 1.2-7.

Table 1.2-7.
2006 U.S. Ethanol Production by Plant Ownership

Plant Ownership	**No. of Plants**	**Production Capacity, MMgy**			
		Total	**Avg**	**Min**	**Max**
Company-Owned[a]	60	3,315	55	0.4	300
Farmer-Owned	50	1,903	38	3	60
Total	**110**	**5,218**	**47**	**0.4**	**300**

[a]Includes ethanol producers with public offerings.

Based on the dominating number of company-owned plants and their above-average production size, company-owned plants account for nearly 64 percent of the total domestic product. Further, more than 50 percent of today's U.S. ethanol production capacity comes from plants owned by just 6 different companies. A list of the top six ethanol producing companies and their respective plant capacities is found in Table 1.2-8.

Table 1.2-8.
2006 Top Six U.S. Ethanol Producers

Company[a]	**Capacity MMgy**	**No. of Plants**
Archer Daniels Midland	1,070	7
Broin	838	18
VeraSun Energy	230	2
Hawkeye Renewables, LLC	200	2
Global / MGP Ingredients	190	3
Aventine Renewable Energy	150	2
Total	**2,678**	**34**

[a]Includes majority and minority plant ownership.

Over 80 percent of today's U.S. ethanol production is sold to the gasoline industry by eight marketing companies[4]. A list of the top eight ethanol marketers and their respective marketing capacities based on plant affiliations is found in Table 1.2-9. The remaining ethanol is marketed by Kinergy Marketing, The Andersons, Murex International, Noble Americas, and other small marketing companies.

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[4] Based on information obtained from ethanol marketer websites, ethanol producer websites, and conversations with ethanol marketers/producers.

Table 1.2-9.
2006 Top Eight U.S. Ethanol Marketers

Marketing Company	Capacity MMgy[a]	No. of Plants
Archer Daniels Midland	1,172	9
Ethanol Products	991	22
Renewable Products Marketing Group	612	15
Aventine Renewable Energy	666	14
Eco-Energy	325	5
Provista (formerly UBE)	217	5
Cargill, Inc.	120	2
Abengoa Bioenergy	110	3
Total	**4,212**	**75**

[a] Volumes based on marketing agreements and respective ethanol plant capacities

1.2.2 Forecasted Growth in Ethanol Production

1.2.2.1 Overview

Over the past 25 years, domestic fuel ethanol production has steadily increased due to environmental regulation, federal and state tax incentives, and market demand. More recently, ethanol production has soared due to the phase out of MTBE, an increasing number of state ethanol mandates, and elevated crude oil prices. As shown in Figure 1.2-1, over the past three years, domestic ethanol production has nearly doubled from 2.1 billion gallons in 2002 to 4.0 billion gallons in 2005. For 2006, the Renewable Fuels Association is anticipating about 4.7 billion gallons of domestic ethanol production[5].

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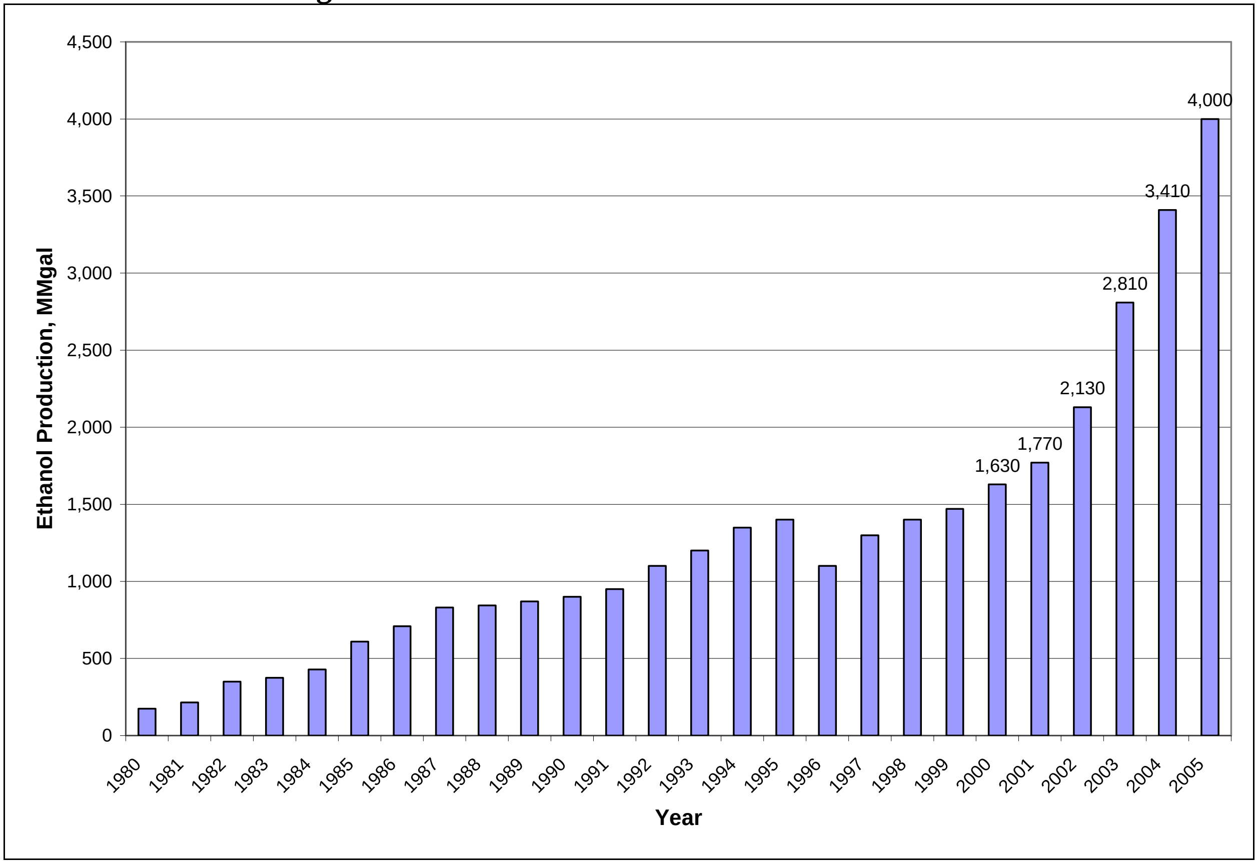
[5] Based on RFA comments received in response to the proposed rulemaking, 71 FR 55552 (September 22, 2006).

Figure 1.2-1. U.S. Ethanol Production Over Time



Source: Renewable Fuels Association, From Niche to Nation: Ethanol Industry Outlook 2006

EPA forecasts that domestic ethanol production will continue to grow into the future. In addition to the past impacts of federal and state tax incentives, as well as the more recent impacts of state ethanol mandates and the removal of MTBE from all U.S. gasoline, crude oil prices are expected to continue to drive up demand for ethanol. As a result, the nation is on track to exceed the renewable fuel requirements contained in the Act, as explained below.

1.2.2.2 Expected Increases in Plant Capacity

Today's ethanol production capacity (5.2 billion gallons) is already exceeding the 2007 renewable fuel requirement (4.7 billion gallons). In addition, there is another 3.4 billion gallons of production capacity currently under construction.[6FGH] A summary of the new construction and plant expansion projects currently underway (as of October 2006) is found in Table 1.2-10.

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[6] Under construction plant locations, capacities, feedstocks, and energy sources as well as planned/proposed plant locations and capacities were derived from a variety of data sources including Renewable Fuels Association (RFA), Ethanol Producer Magazine (EPM), ICF International, BioFuels Journal, and ethanol producer websites.

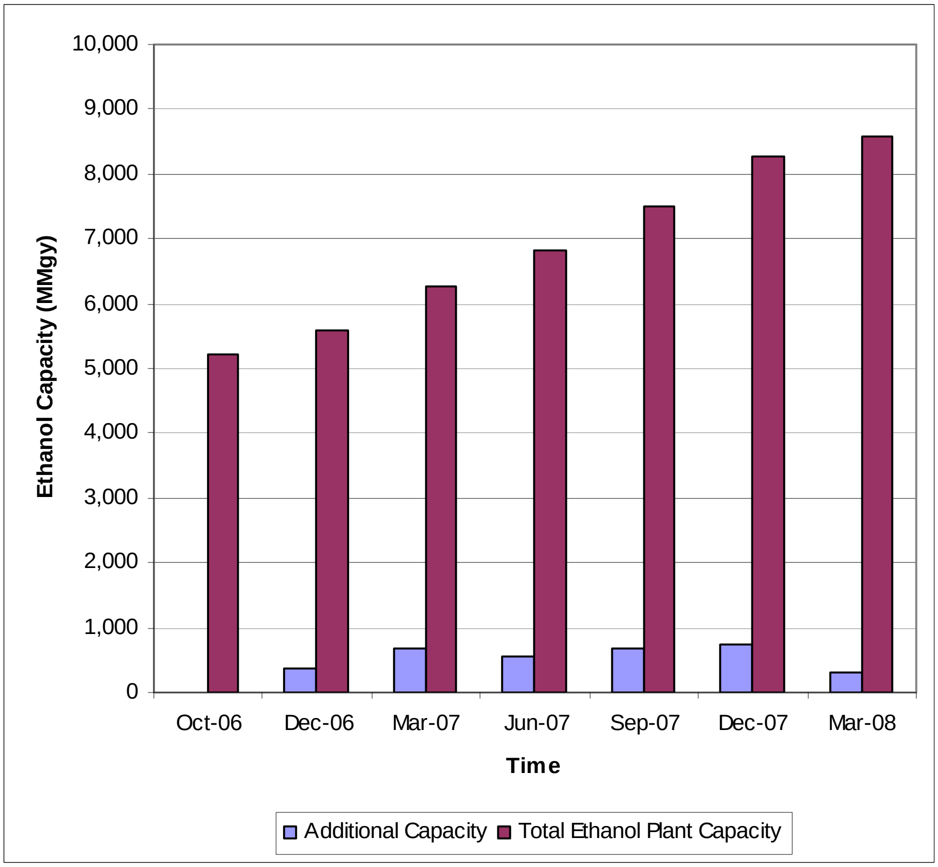
Table 1.2-10. Under Construction U.S. Ethanol Production Capacity

	Oct. 2006 Baseline		Under Const.		Base + Under Const.	
PADD	MMgy	Plants	MMgy[a]	Plants	MMgy[a]	Plants
PADD 1	0.4	1	115	1	115	2
PADD 2	5,012	100	2,764	39	7,776	139
PADD 3	30	1	230	3	260	4
PADD 4	105	4	50	1	155	5
PADD 5	71	4	198	3	269	7
Total	**5,218**	**110**	**3,357**	**47**	**8,575**	**157**

[a] Includes plant expansions

A select group of builders, technology providers, and construction contractors are completing the majority of the construction projects described in Table 1.2-10. As such, the completion dates of these projects are staggered over approximately 18 months, resulting in the gradual phase-in of ethanol production shown in Figure 1.2-2[7].

Figure 1.2-2. Estimated Phase-In of Under Construction Plant Capacity



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[7] Construction timelines based on information obtained from press releases and ethanol producer websites.

As shown in Table 1.2-10 and Figure 1.2-2, once all the construction projects currently underway are complete (estimated by March 2008), the resulting U.S. ethanol production capacity would be about 8.6 billion gallons. Without even considering forecasted biodiesel production (discussed below in 1.2.5), this would be more than enough renewable fuel to satisfy the 2012 RFS requirements (7.5 billion gallons). However, ethanol production is expected to continue to grow. There are more and more ethanol projects being announced each day. These potential projects are at various stages of planning from conducting feasibility studies to gaining local approval to applying for permits to financing/fundraising to obtaining contractor agreements. Together these potential projects could result in an additional 21 billion gallons of ethanol production capacity (as shown in Table 1.2-11).

Table 1.2-11.
Other Potential U.S. Ethanol Production Capacity

	Base + Under Const.		Planned		Proposed	
PADD	**MMgy[a]**	**Plants**	**MMgy[a]**	**Plants**	**MMgy[a]**	**Plants**
PADD 1	115	2	548.0	8	934	21
PADD 2	7,776	139	4,633	44	11,722	136
PADD 3	260	4	250	4	876	14
PADD 4	155	5	100	1	783	14
PADD 5	269	7	232	8	775	23
Subtotal	**8,575**	**157**	**5,763**	**65**	**15,090**	**208**
Total[b]			**14,339**	**222**	**29,428**	**430**

[a]Includes plant expansions
[b]Total including existing plus under construction plants.

Although there is clearly a great potential for ethanol production growth, it is highly unlikely that all the announced projects would actually reach completion in a reasonable amount of time, or at all, considering the large number of projects moving forward. Since there is no precise way to know exactly which plants will come to fruition in the future, we have chosen to focus our subsequent discussion on forecasted ethanol production on plants which are likely to be online by 2012.[8] This includes existing plants as well as projects which are under construction (refer to Table 1.2-10) or in the final planning stages (denoted as "planned" in Table 1.2-11). The distinction between "planned" versus "proposed" is that as of October 2006 planned projects had completed permitting, fundraising/financing, and had builders assigned with definitive construction timelines whereas proposed projects did not.

As shown in Table 1.2-11, once all the under construction and planned projects are complete, the resulting U.S. ethanol production capacity would be 14.3 billion gallons. This volume, expected to be online by 2012, exceeds the EIA AEO 2006 demand estimate (9.6 billion gallons by 2012, discussed more in RIA Section 2.1.4.1). The forecasted growth would nearly triple today's production capacity and greatly exceed the 2012 RFS requirement (7.5 billion

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[8] A more detailed summary of the plants we considered is found in a March 5, 2007 note to the docket titled: RFS Industry Characterization – Ethanol Production.

gallons). While our forecast represents ethanol production capacity (actual production could be lower), we believe it is still a good indicator or what domestic ethanol production could look like in the future. In addition, we predict that domestic ethanol production will continue to be supplemented by imports in the future. A more detailed discussion on future ethanol imports is found in Section 1.5.

1.2.2.3 Changes in Feedstocks & Processing Technologies

Of the 112 forecasted new ethanol plants (47 under construction and 65 planned), 106 would rely on grain-based feedstocks. More specifically, 89 would rely exclusively on corn, 13 would process a blend of corn and/or similarly processed grains (milo or wheat), 3 would process molasses, and 1 would process a combination of molasses and sweet sorghum (milo). Of the remaining six plants (all in the planned stage), four would process cellulosic biomass feedstocks and two would start off processing corn and later transition to cellulosic materials. Of the four dedicated cellulosic plants, one would process bagasse, one would process a combination of bagasse and wood, and two would process biomass. Of the two transitional corn/cellulosic plants, one would ultimately process a combination of bagasse, rice hulls, and wood and the other would ultimately process wood and other agricultural residues. In addition to the forecasted new plants described above, an existing corn ethanol plant plans to expand production and transition to corn stalks, switchgrass, and biomass in the future.

A summary of the resulting overall feedstock usage (including current, under construction, and planned projects) is found in Table 1.2-12. A discussion on how the plants predicted to process cellulosic feedstocks would help the nation meet the Act's cellulosic biomass ethanol requirement is found in Section 1.2.2.6

Table 1.2-12. Forecasted 2012 U.S. Ethanol Production by Feedstock

Plant Feedstock	Capacity MMgy	% of Capacity	No. of Plants	% of Plants
Bagasse	7	0.1%	1	0.5%
Bagasse, Wood	2	0.0%	1	0.5%
Bagasse, Wood, Rice Hulls[a]	108	0.8%	1	0.5%
Biomass	55	0.4%	2	0.9%
Cheese Whey	8	0.1%	2	0.9%
Corn[b]	12,495	87.1%	178	80.2%
Corn, Barley	40	0.3%	1	0.5%
Corn, Milo[c]	1,132	7.9%	20	9.0%
Corn, Wheat	235	1.6%	3	1.4%
Corn Stalks, Switchgrass, Biomass[a]	40	0.3%	1	0.5%
Milo, Wheat	40	0.3%	1	0.5%
Molasses[d]	52	0.4%	4	1.8%
Sugars, Starches	2	0.0%	1	0.5%
Waste Beverages[e]	16	0.1%	5	2.3%
Wood Agricultural Residues[a]	108	0.8%	1	0.5%
Total	**14,339**	**100.0%**	**222**	**100.0%**

[a] Facilities plan to start off processing corn.
[b] Includes two facilities processing seed corn.
[c] Includes one facility processing small amounts of molasses in addition to corn and milo.
[d] Includes one facility planning to process sweet sorghum (milo) in addition to molasses.
[e] Includes two facilities processing brewery waste.

As shown above, the majority of future plants are predicted to process grains (namely corn). Similarly, the vast majority of plants are expected to pursue dry milling technology. Our analysis does not foresee any new wet mill facilities, with the exception of a new 100 MMgy wet mill plant that is planned for Fort Dodge, IA and a 37 MMgy plant expansion project that is underway in Loudon, TN. Further, we do not predict that there will be any new plants processing cheese whey, waste beverages, or sugars/starches (which do not require milling). The forecasted cellulosic feedstock plants (described in more detail in Section 1.2.2.7) will not require milling. However, these facilities will require complex forms of pretreatment (described in more detail in Section 7.1.2) to break down the lignocellulosic and hemicellulosic polymers into fermentable sugars. A summary of the resulting overall feedstock processing technology utilization is found below in Table 1.2-13.

Table 1.2-13.
Forecasted 2012 U.S. Ethanol Production by Processing Technology

Processing Technology	Capacity MMgy	% of Capacity	No. of Plants	% of Plants
Dry Milling	12,668	88.3%	192	86.5%
Wet Milling	1,274	8.9%	11	5.0%
Other[a]	397	2.8%	19	8.6%
Total	**14,339**	**100.0%**	**222**	**100.0%**

[a] Plants that do not process traditional grain-based crops and thus do not require milling. This category includes plants processing cheese whey, sugars & starches, or waste beverages as well as plants that plan to process molasses or cellulosic feedstocks.

1.2.2.4 Changes in Plant Energy Sources

Of the 112 forecasted new plants, 100 would burn some amount of natural gas - at least initially. More specifically, 91 plants would rely exclusively on natural gas; two would rely on a combination of natural gas, bran and biomass; one would burn a combination of natural gas, distillers' grains and syrup; and six would start off burning natural gas and later transition to coal. As for the remaining 12 plants, three would burn manure-derived methane (biogas); seven would rely exclusively on coal; one would burn a combination of coal and biomass; and one would burn a combination of coal, tires and biomass. In addition to the new ethanol plants, three existing plants currently burning natural gas are predicted to transition to alternate boiler fuels in the future. More specifically, two plants plan to transition to biomass and one plans to start burning coal.

Our research suggests that seven of the new plants (mentioned above) would utilize combined heat and power (CHP) technology, although others may exist. Three of the new CHP plants would burn natural gas, three would burn coal, and one would burn a combination of coal, tires, and biomass. Among the existing CHP plants, two are predicted to transition from natural gas to coal or biomass at this time. Overall, the net number of CHP ethanol plants would increase from 11 to 18. A summary of the resulting overall plant energy source utilization is found below in Table 1.2-14. A discussion on how the plants predicted to burn waste materials could help the nation meet the Act's cellulosic biomass ethanol requirement is found in Section 1.2.2.6.

Table 1.2-14. Forecasted 2012 U.S. Ethanol Production by Energy Source

Plant Energy Source	Capacity MMgy	% of Capacity	No. of Plants	% of Plants	CHP Tech.
Biomass[a]	112	0.8%	2	0.9%	1
Coal[b]	2,095	14.6%	21	9.5%	6
Coal, Biomass	75	0.5%	2	0.9%	0
Coal, Biomass, Tires	275	1.9%	1	0.5%	1
Manure Biogas[c]	144	1.0%	3	1.4%	0
Natural Gas	11,275	78.6%	189	85.1%	10
Natural Gas, Bran, Biomass	264	1.8%	2	0.9%	0
Natural Gas, Distillers' Grain, Syrup	50	0.3%	1	0.5%	0
Syrup	49	0.3%	1	0.5%	0
Total	**14,339**	**100.0%**	**222**	**100.0%**	**18**

[a] Represents two existing natural gas-fired plants that plan to transition to biomass.

[b] Includes two plants planning on burning lignite coal or coal fines. Includes one existing plant currently burning natural gas that plans to transition to coal. Includes six new plants that will start off burning natural gas and later transition to coal.

[c] Includes one facility planning on burning cotton gin in addition to manure biogas.

1.2.2.5 Changes in Ethanol Production Locations

Once all the forecasted ethanol projects are complete, 87 percent of the domestic production capacity would originate from PADD 2, followed by PADDs 1, 3, 5, and 4 (all contributing less than 5 percent). A summary of the findings is found below in Table 1.2-15.

Table 1.2-15.
Forecasted 2012 U.S. Ethanol Production by PADD

PADD	Capacity MMgy	% of Capacity	No. of Plants	% of Plants
PADD 1	663	4.6%	10	4.5%
PADD 2	12,409	86.5%	183	82.4%
PADD 3	510	3.6%	8	3.6%
PADD 4	255	1.8%	6	2.7%
PADD 5	501	3.5%	15	6.8%
Total	**14,339**	**100.0%**	**222**	**100.0%**

While PADD 2 ethanol production is expected to more than double (from 5.0 to 12.4 billion gallons), this represents a decrease in Midwest marketshare (from 96 to 87 percent). This predicted shift in marketshare is attributed to the growing number of ethanol plants located outside the cornbelt. Arizona, Florida, Hawaii, Louisiana, New York, Oregon, Pennsylvania and Texas are scheduled to join the 19 ethanol producing states described in Table 1.2-5. A summary of future ethanol production by state is found below in Table 1.2-16.

Table 1.2-16.
Forecasted 2012 U.S. Ethanol Production by State

State	Capacity MMgy	% of Capacity	No. of Plants	% of Plants
Arizona	55	0.4%	1	0.5%
California	244	1.7%	7	3.2%
Colorado	243	1.7%	5	2.3%
Florida	80.0	0.6%	2	0.9%
Georgia	150.4	1.0%	3	1.4%
Hawaii	59.2	0.4%	5	2.3%
Iowa	3,016	21.0%	38	17.1%
Illinois	1,606	11.2%	16	7.2%
Indiana	855	6.0%	11	5.0%
Kansas	569	4.0%	13	5.9%
Kentucky	38	0.3%	2	0.9%
Louisiana	110	0.8%	2	0.9%
Michigan	212	1.5%	4	1.8%
Minnesota	882	6.2%	20	9.0%
Missouri	382	2.7%	6	2.7%
New York	325	2.3%	4	1.8%
North Dakota	251	1.7%	5	2.3%
Nebraska	2,543	17.7%	31	14.0%
New Mexico	30	0.2%	1	0.5%
Ohio	420	2.9%	7	3.2%
Oklahoma	112	0.8%	3	1.4%
Oregon	143	1.0%	2	0.9%
Pennsylvania	108	0.8%	1	0.5%
South Dakota	953	6.6%	16	7.2%
Tennessee	109	0.8%	2	0.9%
Texas	370	2.6%	5	2.3%
Wisconsin	463	3.2%	9	4.1%
Wyoming	12	0.1%	1	0.5%
Total	**14,339**	**100.0%**	**222**	**100.0%**

1.2.2.6 Meeting the Cellulosic Ethanol Requirement in 2013

The Energy Policy Act of 2005 (the Energy Act or the Act) requires that 250 million gallons of the renewable fuel consumed in 2013 and beyond meet the definition of cellulosic biomass ethanol. The Act defines cellulosic biomass ethanol as ethanol derived from any lignocellulosic or hemicellulosic matter that is available on a renewable or recurring basis including dedicated energy crops and trees, wood and wood residues, plants, grasses, agricultural residues, fibers, animal wastes and other waste materials, and municipal solid waste. The term also includes any ethanol produced in facilities where animal or other waste materials are digested or otherwise used to displace 90 percent of more of the fossil fuel normally used in the production of ethanol.

As discussed above in Section 1.2.2.3, there are seven "planned" ethanol plants planning on processing cellulosic feedstocks in the future. A summary of these facilities is found below in Table 1.2.17.

Table 1.2-17. Potential Cellulosic Feedstock Plants

Ethanol Plant	Location	Plant Feedstock	Capacity MMgy	Status
Worldwide Energy Group[a]	Kaumakani, HI	Bagasse	7	Planned
Celunol Corp.[b]	Jennings, LA	Bagasse, Wood	2	Planned
GS Agrifuels Corporation[c]	Memphis, TN	Biomass	5	Planned
Xethanol Coastal LLC	Augusta, GA	Biomass	50	Planned
Bionol	Lake Providence, LA	Corn then Bagasse, Rice Hulls, Wood	108	Planned
Xethanol Corporation	Blairstown, IA	Corn then Corn Stalks, Switch Grass, Biomass	40	Planned[d]
BioEnergy International	Clearfield County, PA	Corn then Wood, Agricultural Residues	108	Planned
Total Cellulosic Ethanol Potential Based on Plant Feedstocks			**320**	

[a] Company also/formerly known as Clearfuels Technology
[b] Company also/formerly known as BC International
[c] Project also/formerly known as Mean Green Biofuels
[d] Includes 5 Mmgy existing plant capacity plus 35 MMgy planned expansion.

It is unclear whether the above-mentioned cellulosic feedstock plants would be online and capable of producing 250 million gallons of ethanol by 2013 to meet the Act's cellulosic biomass ethanol requirement. However, as described above in Section 1.2.2.4 there are 12 facilities that burn or plan to burn waste materials to power their ethanol plants in the future. These facilities, summarized below in Table 1.2.18, could also potentially meet the definition of cellulosic biomass ethanol under the Act.

Table 1.2-18. Potential Waste Energy Plants

Ethanol Plant	Location	Plant Energy Source	Capacity MMgy	Status
Corn LP	Goldfield, IA	Coal, Biomass	50	Existing
E Caruso Ethanol	Goodland, KS	Coal, Biomass	25	Under Construction
Archer Daniels Midland	Columbus, NE	Coal, Tires, Biomass	275	Planned
E3 Biofuels, LLC	Mead, NE	Manure Biogas	24	Under Construction
Harrison Ethanol, LLC	Cadiz, OH	Manure Biogas	20	Planned
Panda Ethanol	Hereford, TX	Manure Biogas, Cotton Gin	100	Under Construction
Central Minnesota Ethanol Co-op	Little Falls, MN	Natural Gas then Biomass	22	Existing
Chippewa Valley Ethanol Co.	Benson, MN	Natural Gas then Biomass	90	Existing[a]
Ethanex at SEMO Port	Cape Girardeau, MO	Natural Gas, Bran, Biomass	132	Planned
Ethanex Southern Illinois[b]	Benton, IL	Natural Gas, Bran, Biomass	132	Planned
Green Plains Renewable Energy[c]	Superior, IA	Natural Gas, Distillers Grain, Syrup	50	Under Construction
Corn Plus, LLP	Winnebago, MN	Syrup	49	Existing
Total Cellulosic Ethanol Potential Based on Plant Energy Sources			**969**	

[a] Includes 45 MMgy existing plant capacity plus 45 MMgy planned expansion.
[b] Joint venture with Star Ethanol
[c] Project also/formerly known as Superior Ethanol

Depending on how much fossil fuel is displaced by burning these waste materials (on a plant-by-plant basis), a portion or all of the above-mentioned 969 MMgy ethanol production capacity could potentially qualify as "cellulosic biomass ethanol" under the Act. Combined with the additional 320 MMgy of ethanol production capacity from plants processing cellulosic feedstocks, the overall cellulosic ethanol potential could be as high as 1.3 billion gallons. Even if only one fifth of this ethanol were to end up qualifying as cellulosic biomass ethanol or come to fruition by 2013, it would be more than enough to satisfy the 250 million gallon requirement specified in the Act.[9]

1.2.3 Current Biodiesel Production

Biodiesel is defined in several sections of the Act, which we have used in formulating our definition for the regulations, which call for meeting ASTM specifications. Biodiesel is registered with the EPA for commercial sale and is legal for use at any blend level in both highway and nonroad diesel engines although most engine manufacturers will only honor the warranty if biodiesel is used in blends of 2, 5 or, in some limited circumstances, 20 percent.

Biodiesel can be made from almost any vegetable or animal fat, with most of the world's production coming from plants oils, notably soy bean and rapeseed (canola) oil. Biodiesel fuel production is rapidly increasing in many regions of the world. The choice of the feedstock oil used to make it is dependent upon the vegetable oils and fat supplies that are economically available. For the U.S. market, there are many potential plant oil feedstocks that can be used to make biodiesel, including soybean, peanut, canola, cottonseed and corn oil. Biodiesel can also be made from animal fats such used restaurant grease (yellow grease) and tallow. Though, typically for the U.S. market, soybean oil has been the primary major feed stock supply, followed by use of yellow grease and animal tallow.

The resulting biodiesel product can be used as a fuel for diesel engines with minor modifications and is commonly blended with refinery produced diesel fuel. Raw vegetable and animal oils consist of fatty acids and glycerine products. Though these oils can directly be used in engines and give good short term performance, this is highly discouraged as their use can cause severe engine problems. This is primarily due to the raw oils forming engines deposits, with coking and plugging in engine injectors nozzles, piston rings, lubricating oil, etc. 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. The biodiesel production process converts the raw vegetable and animal oils into esters, though the virgin oils themselves are sometimes (inappropriately) referred to as biodiesel. The production process called transesterification consists of adding methanol or ethanol to the virgin vegetable oil and animal oil, in the presence of a catalyst such as sodium or potassium hydroxide, resulting in esters or biodiesel and a byproduct glycerol. A subsequent step is usually

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[9] We anticipate a ramp-up in cellulosic ethanol production in the years to come so that capacity exists to satisfy the Act's 2013 requirement (250 million gallons of cellulosic biomass ethanol). Therefore, for subsequent analysis purposes, we have assumed that 250 million gallons of ethanol would come from cellulosic biomass sources by 2012.

needed, however, to remove glycerin, catalysts and other compounds, to allow the biodiesel to meet the required ASTM specifications.

Biodiesel blends such as B2, B5 and in some cases B20, can be used in existing engines without modification, and most engines exhibit no performance problems with the use of biodiesel, though this depends on the blend and the season. However, engine fuel filters may need to be changed more often, and there may be cold temperature operations due to biodiesel's higher cloud point. As a result most engine manufacturers will only recognize their warranties if biodiesel is used in low concentrations. Biodiesel produced from vegetable oil has practically zero amounts of sulfur and aromatics and a high cetane value, thus making it a good for blending into 15 ppm highway and offroad diesel fuel, though biodiesel made from yellow grease and animal fat may contain about 24 ppm of sulfur[I]. Biodiesel also has good lubricity qualities and can be used in concentration (~2 vol%) as a lubricity-enhancing additive for conventional diesel.

1.2.4 Forecasted Biodiesel Production

Biodiesel production has been increasing rapidly over the past five years and is projected to continue at a high rate in part because of the Renewable Fuel Standard (RFS) program. This expansion has primarily been driven by better economics, due to the recent large increase in diesel prices associated with the run up in crude prices, along with the Biodiesel Blenders Tax Credit programs and the Commodity Credit Commission Bio-energy Program, both of which subsidize producers and offset production costs. The Act extended the Biodiesel Blenders Tax Credit program to year 2008, which provides about one dollar per gallon in the form of a federal excise tax credit to biodiesel blenders from virgin vegetable oil feedstocks and 50 cents per gallon to biodiesel produced from recycled grease and animal fats. This program was started in 2004 under the American Jobs Act. The existing Commodity Credit Commission Bio-energy Program also pays biodiesel producers grants when the economics to produce biodiesel are poor; the program averaged about one dollar per gallon in 2004. Recent payments through the Commodity Credit program have been reduced, however, and the program is expiring in fiscal year 2006. Historically, the cost to make biodiesel was an inhibiting factor to production. The cost to produce biodiesel was high compared to the price of petroleum derived diesel fuel, even with consideration of the benefits of subsidies and credits provided by federal and state programs. Mandates from states and local municipalities that require the use of biodiesel in transport fuels are another factor which is expanding the use of biodiesel.

In 2005 approximately 91 million gallons of biodiesel were produced in the U.S. based on program payments to biodiesel producers under USDA's Bio-energy Program. This volume represents approximately 0.15 percent of all diesel fuel consumed in the domestic market. EIA projects the future production volume to expand to 414 million gallons per year in 2007 and then decrease to about 303 MM gallons per year in 2012, assuming that the biodiesel blender tax credits program expires in 2007 (see Table 1.2-19).

Table 1.2-19. Estimated Biodiesel Production[a]

Year	Million Gallons per Year
2001	5
2002	15
2003	20
2004	25
2005	91
2006	150
2007	414
2012	303

[a] Historical data from 2001-2004 obtained from estimates from John Baize " The Outlook and Impact of Biodiesel on the Oilseeds Sector" USDA Outlook Conference 06. Year 2005 data from USDA Bioenergy Program. Year 2006 data from verbal quote based on projection by NBB in June of 06. Production data for years 2007 and higher are from EIA's AEO 2006.

With the increase in biodiesel production, there has also been a corresponding rapid expansion in biodiesel production capacity. Presently, there are 85 biodiesel plants in operation with an annual production capacity of 580 million gallons per year[J]. The majority of the current production capacity was built in 2005 and 2006, and was first available to produce fuel in the later part of 2005 and in 2006. Though the capacity has grown, historically the biodiesel production capacity has far exceeded actual production with only 10-30 percent of this being utilized to make biodiesel, see Table 1.2-20.

Table 1.2-20. U.S. Production Capacity History

	2001	2002	2003	2004	2005	2006
Plants	9	11	16	22	45	85
Capacity (MM gals/yr)	50	54	85	157	290	580
Production, (MM gals/yr)	5	15	20	25	91	150
Capacity Utilization for Biodiesel, %	10	28	24	16	31	26

Note: Capacity Data based on surveys conducted.

Excess production capacity is not easily quantified, though since some of these plants may not run at full rate all of the time and may be "idled" for certain days of the week, seasons, time of day, etc. The capacity can be classified into two types of producers; capacity dedicated to biodiesel production and capacity available from the ole-chemical industry. The plants that primarily operate in the ole-chemical industry produce esters for use in the chemical industry. These plants are swing producers of biodiesel, which means that when the economics are favorable they can shift their operations and make biodiesel esters instead of products for the ole-chemical market.[10] The capacity from the ole-chemical industry produces mono-alkyl esters using a similar transesterification process, with the ester products being sold for to make plasticizers, soaps, paints, solvents and other industrial uses. Additionally, the biodiesel production capacity volumes may be optimistic, as this is not officially tracked. The capacities listed here are those based on each company's self reported volumes to the National Biodiesel Board and may have some inaccuracies due to informal reporting procedures.

We anticipate that future capacity additions will be geared more towards production of biodiesel for use as transportation fuel, rather than serving primarily the oleochemicals markets. As of September 2006, there were 65 plants in the construction phase and 13 existing plants that are expanding their capacity. All of this new capacity when installed would provide about 1.4 billion gallons per year of additional throughput capacity. Table 1.2-21 presents the data for the biodiesel plant capacities per the categories discussed.

Table 1.2-21. Biodiesel Plant Capacities

	Existing Plants	**Construction Phase**
Number of Plants	85	78
Total Plant Capacity, (MM Gallon/year)	580	1,400

Considering that it takes 12 to 18 months to construct a biodiesel plant (from the time of project feasibility analysis to startup date), a large portion of the capacity in the construction phase in late 2006 will be available to produce fuel in 2007.[K] Data on biodiesel plant construction reveals most of the new capacity that is currently being constructed is expected to be online and producing fuel in 2006 or by end of 2007. Therefore, the existing capacity plus the capacity in the construction phase totals an aggregate amount of about two billion gallons per year. Though there is no volume mandate for biodiesel fuel under the RFS program, the total capacity available from new and existing plants exceeds EIA's projected biodiesel volume of 414 MM in 2007 and 303 MM in 2012 by a wide margin.

The plants in the construction phase are larger than existing biodiesel plants, with average capacity of existing plants at 8.4 MM gallons per year, while plants in construction phase are

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[10] Oleochemicals are derived from biological fats and oils using hydrolysis or alcoholysis with products of fatty acid esters and glycerol.

averaging 20.9 MM gallons per year, as presented in Table 1.2-22. The distribution of biodiesel plants by size and number of companies within each size range are presented in Table 1.2-23.

Table 1.2-22. Average Plant Capacity by Feedstock (MM gallons per year)

Feedstock	Existing*	Construction*
Canola		57.5
Multi Feedstock	6.0	16.7
Other Vegetable	2.0	
Recycled Cooking Oil	0.5	1.0
Soybean Oil	8.8	19.3
Tallow	5.0	

Table 1.2-23. Biodiesel Plant Size versus Number of Companies

Plant Size (MM gallons per year)[a]	Existing Plants	Construction Phase
<1.00	9	5
1.0- 5.0	28	9
5.0-10.0	17	10
10.0 to 15 .0	9	7
15.0 to 20.0	2	3
20.0+	10	28
Average Plant Size	8.4	20.9

[a] Total capacity of plants in each category; existing plants are 580 MM gal/yr while those in the construction phase are 1,400 MM gal/yr.

Because newer plants are likely to be larger than existing plants, have better technology and may have greater alignment with feedstock and feed sources, some of the older plants may operate at an economic disadvantage once the new plants come on line. At the moment, it is not possible to predict actual biodiesel production based on capacity, since in the past the capacity was used at rates less than maximum. Thus, how excess production capacity evolves will be dictated by economics, profitability, and fuel demand.

The majority of existing biodiesel plant capacity is located in the middle and Midwestern parts of the country and use soy bean oil as the feedstock. The other plants are scattered with locations based on the east and west coasts, with feedstocks based on use of soybean, canola and other oils as well as yellow grease as the feedstock. The new plants are being built to process a wider variety of feedstocks, with multi-feedstock and recycle grease capability. The feedstocks for these plants are listed in Table 1.2-24.

Table 1.2-24. Feedstock Selection for Biodiesel Producers

Feedstock	Existing	Construction
Camelia		
Canola		2
Cottonseed	1	
Multi Feedstock	29	29
Palm Oil		
Recycled Cooking Oil	7	3
Soybean oil	39	36
Tallow/Poultry Fat	2	
Unknown	7	8

1.2.5 Baseline and Projected Biodiesel Volumes for Analysis

For cost and emission analysis purposes, three biodiesel usage cases were considered: a 2004 base case, a 2012 reference case, and a 2012 control case. The 2004 base case was formed based on historical biodiesel usage (25 million gallons as summarized in Table 1.2-16). The reference case was computed by taking the 2004 base case and growing it out to 2012 in a manner consistent with the growth of diesel fuel (described in Section 2.1.3). The resulting 2012 reference case consisted of approximately 30 million gallons of biodiesel. Finally, for the 2012 control case, forecasted biodiesel use was assumed to be 300 million gallons based on EIA's AEO 2006 report (rounded value from Table 1.2-16). Unlike forecasted ethanol use (described in 2.1.4), biodiesel use was assumed to be constant at 300 million gallons under both the statutory and higher projected renewable fuel consumption scenarios.

1.3 Renewable Fuel Distribution

1.3.1 Current Renewable Fuel Distribution System

Ethanol and biodiesel blended fuels are not currently shipped by petroleum product pipeline due to operational issues and additional cost factors.[L] The ability to ship by pipeline is also limited because the sources of ethanol and biodiesel are frequently not in the same locations as the sources of gasoline and petroleum-based diesel fuel. Hence, a separate distribution system is needed for ethanol and biodiesel up to the point where they are blended into petroleum-based fuel as it is loaded into tank trucks for delivery to retail and fleet operators. Ethanol and biodiesel can either be added by “splash blending” where the renewable is added separately to the tank truck, or by in-line injection where the renewable is injected into the petroleum fuel stream as it is being dispensed into the tank truck. Ethanol and biodiesel are sometimes added to petroleum-based fuels downstream of the terminal, but this accounts for little of the total volume of used.

In cases where ethanol and biodiesel are produced within 200 miles of a terminal, trucking is often the preferred means of distribution. However, most renewable fuel volumes are produced at greater distances from potential centers of demand. For longer shipping distances, the preferred method of bringing renewable fuels to terminals is by rail and barge. Dedicated pipelines have not been used to distribute renewable fuels to terminals due to the high cost of installing new pipelines, the relatively large shipping volumes that would be needed to justify such expenditures, and the fact that renewable fuel production facilities tend to be relatively numerous and dispersed.

The relatively low volumes of ethanol used prior to 2002 constrained the ability of the distribution system to efficiently move ethanol to distant markets. Ethanol shipments by rail were typically made on an individual car basis. Under such an approach, small groups of rail cars travel to market as part of trains that carry other goods. This approach results in relatively high transportation costs, longer transit times, and potential delays in delivery. Substantial improvements in the efficiency of distributing ethanol by rail are being made due the need to move large volumes of ethanol over long distances as a consequence of the elimination of MTBE in California, New York, and Connecticut beginning in 2004. The use of unit trains, sometimes referred to as “virtual pipelines” reduces delivery costs, shortens delivery times, and improves reliability. Unit trains are composed entirely of approximately 100 rail cars containing ethanol. Ethanol shipped by unit trains is delivered to hub terminals for further distribution to other terminals by barge and tank truck.

Substantial volumes of ethanol can potentially be shipped down the Mississippi river by barge for temporary storage in New Orleans.[M] From New Orleans, ethanol can be loaded onto ocean transport for delivery to the East and West Coast. There is also potential to move ethanol via the Missouri and Ohio as well as other river systems and the Great Lakes. Marine shipments of ethanol require a relatively large minimum shipment size, determined by the minimum size of the marine tank compartment.[11] Similar to the case for “unit trains”, there are also efficiencies in dedicating whole barges, barge tows, or marine tankers to ethanol distribution. The increased demand for ethanol has made it possible to better benefit from these efficiencies of scale.

The use of inland barges to transport ethanol from production facilities is in large part driven by whether there is river access at such facilities. Historically, corn prices tend to be higher near river systems that serve as arteries for the export of corn than at inland locations distant from these river systems. To take advantage of lower corn prices at inland locations and to avoid competing for corn with grain elevators that serve the export market, all of the new ethanol production facilities that have been built since 1999 have been built at inland locations.[N]

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[11] River barges typically have a capacity of 10,000 barrels. Ocean barges typically have a capacity of 20,000 barrels. Barges are sometimes subdivided into 2 or 3 compartments.

Consequently, the majority of the growth in ethanol freight volumes since 1999 has been in the rail sector.

1.3.2 Changes to the Renewable Fuel Distribution System Due to Increased Demand

This section addresses that changes that we expect will take place in the renewable fuel distribution system in response to the anticipated increase in demand for such fuels through 2012. There may be some limited opportunity to ship renewable fuels by pipeline in the future as demand increases. However, because of the constraints discussed previously (see section 1.3.1), we believe that rail and barge are likely to remain the predominant means of transportation. The 2002 DOE Study also reached this conclusion.[O] While this constraint on the ability to ship ethanol and biodiesel by pipeline presents logistical challenges that result in additional transportation costs, the need to transport these alternative fuels by other means may work to the overall advantage of the fuel distribution system. Petroleum product pipelines are nearing capacity. Thus, it seems likely that the pipeline distribution system will find it increasingly difficult to keep pace with annual increases in the demand for transportation fuels. Displacing some of the volume of transportation fuels from the pipeline distribution system through the use of ethanol and biodiesel will relieve some of this strain.

Small volume rail shipments made on a by-car basis are likely to remain an important feature in supplying markets that demand limited volumes. However, as the demand for ethanol increases we anticipate that the expansion of the use of unit trains will continue, and that this will be a significant means of bringing ethanol to distant markets. There has been some expansion of capacity at existing ethanol plants with river access and some new plants are projected to be built with river access. However, we anticipate that most new ethanol capacity will not have river access. In addition, at least one new ethanol plant slated for production that does have river access is planning to move its ethanol to market via rail. Nevertheless, in cases where rail is the means to transporting ethanol to hub terminals, marine transport can play an important role in further distribution to satellite terminals.

Substantial improvements to the rail, barge, tank truck, and terminal distribution systems will be needed to support the transport of the volumes of renewable fuels necessary to meet the requirements of the RFS program. These improvements include the addition of a significant number of additional rail cars, and tank trucks. Additional marine barges will also be needed. To facilitate the increased use of unit trains, new rail spurs will be needed at terminals. Terminals will also need to add facilities to store and blend ethanol. In addition, those terminals and retail facilities that had not previously handled ethanol blended fuel will need to make certain one-time upgrades to ensure the compatibility of their systems with ethanol. These types of changes have been occurring as demand for ethanol and biodiesel has grown rapidly over the last several years, and there is no reason to suspect that they would not continue as demand continues to warrant it. The costs associated with these changes are discussed in Chapter 7.3 of this RIA.

The most comprehensive study of the infrastructure requirements for an expanded fuel ethanol industry was conducted for the Department of Energy (DOE) in 2002 .[P] The conclusions reached in this study indicate that the changes needed to handle the increased volume of ethanol required under the RFS will not represent a major obstacle to industry.[12] While some changes have taken place since this report was issued (as discussed below), we continue to believe that the rail and marine transportation industries can manage the increased growth in an orderly fashion. This belief is supported by the demonstrated ability of the industry to handle the rapid increases and redistribution of ethanol use across the country over the last several years as MTBE was removed. Given that future growth in ethanol use is expected to take place in an orderly fashion in response to economic drivers, we anticipate that the distribution system will be able to respond appropriately.

The use of unit trains has accelerated beyond that anticipated in the 2002 DOE report, leading to the more efficient distribution of ethanol by rail. As a result, rail has taken a relatively greater role in the transportation of new ethanol volumes as compared to shipment by barge than was projected in the report. Thus, there is likely to be a relatively greater demand on the rail distribution system and somewhat less demand on the marine distribution system than was projected in the DOE study.

The 2002 DOE study estimated that the increase in the volume of ethanol shipped by rail needed to facilitate the use of 10 billion gallons of ethanol annually would represent an increase in total tank car loadings of 0.33 percent. The increase in tank car loadings for Class I railroads was estimated at 4.75 percent. The DOE report concluded that this increase is relatively modest by railroad industry standards and could be accommodated given the available lead time. The DOE study estimated that the increase in demand on barge movements due to the need to carry an increased volume of ethanol would equate to a one percent increase in the total tonnage moved by barge. Given that on the one hand relatively few new ethanol plants are projected to be cited with river access, and that on the other hand barge is expected to play an important role in redistributing ethanol from rail hub terminals, we estimate that the increase in barge movements will be 30 percent less than that projected in the 2002 DOE study. This equates to an increase in total tank car loadings of 0.44 percent rather than the 0.33 percent projected in the DOE study. We believe that this relatively modest potential increase in the demand on the rail distribution system can be accommodated without major difficulty given the available lead time.

Although, the 2002 DOE study generally concluded that the projected one percent increase in the demand on the river barge industry could be accommodated without major difficulty, it highlighted two potential concerns. The report noted that delays are already being experienced at locks on the Mississippi river. The question was raised regarding how the projected increase of one percent in river traffic due to increased ethanol shipments might be accommodated at these locks. The report also raised concerns regarding the availability of sufficient marine vessels capable of traveling between two ports in the United States (Jones Act compliant vessels). Given that it appears that there will be less demand placed on the river barge industry to transport ethanol than was projected in the 2002 DOE study, the concerns raised in the study regarding the capability of the inland waterway system to cope with the increased traffic associated with shipping the anticipated new volume of ethanol will be less pronounced.

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[12] See section 7.3 of this RIA regarding the projected costs of the necessary infrastructure improvements.

At the present time, the industry is experiencing a shortage of tractor trailers and drivers to transport ethanol. The boom in demand for truck transport is due to a number of factors, including the precipitous removal of MTBE from gasoline and its replacement by ethanol[13] which has taken place when the demand for truck transport was already growing at a rapid place due to the increased imports. The implementation of EPA's ultra-low sulfur diesel (ULSD) program this summer may also cause an increase in the demand for tank trucks if more trucks must be dedicated to ULSD service. Given the gradual increase expected from year to year in ethanol production, we anticipate that the industry will be able to add sufficient additional tank truck service in an orderly fashion without undue burden.

The necessary facility changes at terminals and at retail stations to dispense ethanol containing fuels have been occurring at a record pace due to the removal of MTBE from gasoline. The use of ethanol has also become more economically attractive due to higher gasoline prices. Now that MTBE has been removed, a more steady increase in the use of ethanol is anticipated over time. This will also allow for a smooth transition for terminals and retail operators.

The volumes of biodiesel that are expected to be used by 2012 to comply with the RFS will be relatively modest (approximately 300,000,000 gallons). Consequently, we anticipate that biodiesel will continue to be distributed to terminals by tank truck and by individual rail car shipments. One hundred percent biodiesel (B100)[14] forms wax crystals when the temperature falls to 35 to 45 degrees Fahrenheit.[15] Thus, storage tanks for B100 need to be heated to maintain flow-ability during the cold seasons. Shipping vessels used to transport B100 such as barges, rail cars, and tank truck containers also typically must either be insulated (and sometimes heated) during the cold season or alternatively facilities can be provided at the terminal to reheat the vessel prior to delivery. Biodiesel that is blended with diesel fuel and enhanced with cold flow additives (if needed) can have comparable cold flow performance to petroleum based diesel fuel.[16]

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[13] MTBE is typically blended with gasoline at the refinery. MTBE production plants are often located nearby to refineries allowing transport to the refinery by dedicated pipeline. In cases where, the sources of MTBE are more distant from the refinery, barge and rail are the preferred means of transport and relatively little MTBE is transported by truck.

[14] The concentration of biodiesel in a biodiesel blend is indicated by the number following the "B" designation. For example, B99.9 indicates a biodiesel blend containing 99.9 percent biodiesel, and B80 indicates a blend containing 80 percent biodiesel. Manufactures of biodiesel sometimes blend in one tenth of one percent diesel fuel into biodiesel to create B99.9 prior to shipping the fuel to terminals to create more dilute biodiesel blends so that the producer can claim the biodiesel tax credit (pursuant to Internal Revenue Service requirements).

[15] The point at which wax crystals form is referred to as the cloud point. The cloud point of B100 varies depending on the feed stock used in its production.

[16] The relatively low concentration biodiesel blends that are typically used in vehicles (up to 20% biodiesel) can be formulated to have comparable cold flow performance to petroleum based diesel fuel. Thus, there is no need to heat such biodiesel blends in vehicle fuel tanks.

As temperatures fall during the cold seasons, some terminals currently avoid the need for heated B100 tanks and facilities to heat shipping vessels by accepting progressively less concentrated biodiesel blends (for final blending to produce fuels for use in vehicles). During the warm seasons, such terminals typically accept B100 or B99.9. As the weather grows colder, the terminal might switch to accepting B80 and during the coldest parts of the year might accept B50 (that contains 50 percent number one diesel fuel). The need for insulated tank trucks and tank cars is also sometimes avoided if transit times are brief by shipping warmed biodiesel. We believe that as the volume of biodiesel grows, most terminals will opt to receive B100 (or B99.9) year round for blending into diesel fuel for the consistency in operations which this practice offers. A number of terminals are already following this practice. These terminals have installed heated storage tanks for biodiesel and insist that biodiesel be delivered in insulated tank trucks (or rail cars) so that it may be pumped into the terminal storage tank without concern about the potential need for reheating. The cost of the necessary heated and/or insulated equipment is not insignificant. However, the modest additional volumes that will need to be shipped via rail and tank truck due to the use of biodiesel do not materially affect the conclusions reached above regarding the ability of the fuel distribution system to cope with the increased volumes of renewable fuels.

1.4 Blenders

1.4.1 Ethanol Blending

Ethanol is miscible with water, and thus can introduce water into the distribution system causing corrosion and durability problems as well as fuel quality problems. For this reason, ethanol is blended downstream at terminals or into tank trucks.

The distribution of ethanol is described in more detail in Section 1.3. Briefly, ethanol producers provide ethanol either directly to terminals, to marketers or to terminals that are owned by refiners. In the first case, ethanol is provided to terminals that are owned entities other than refining companies. They receive ethanol from the ethanol producer, and gasoline from any number of refiners. The blenders then add ethanol to the gasoline at the terminal. For RFG, the terminals receive the blendstock for RFG, called Reformulated Blendstock for Oxygenate Blending or RBOB, to which they add the amount of ethanol called for on the Product Transfer Document that accompanies such shipments. Once the ethanol is added to the RBOB, the product becomes a finished gasoline (RFG) and is sent via truck to retailers. For conventional gasoline (CG) ethanol is also added and shipped to retailers. The tracking mechanism for CG is not as detailed as it is for RFG, however. The majority of ethanol that is blended into CG has historically been “splash-blended” although an increasing volume of ethanol is being blended into special blends of conventional gasoline (e.g. sub-octane), or “match blended”. Finally, a very small amount is blended as E85.

1.4.2 Biodiesel Blending

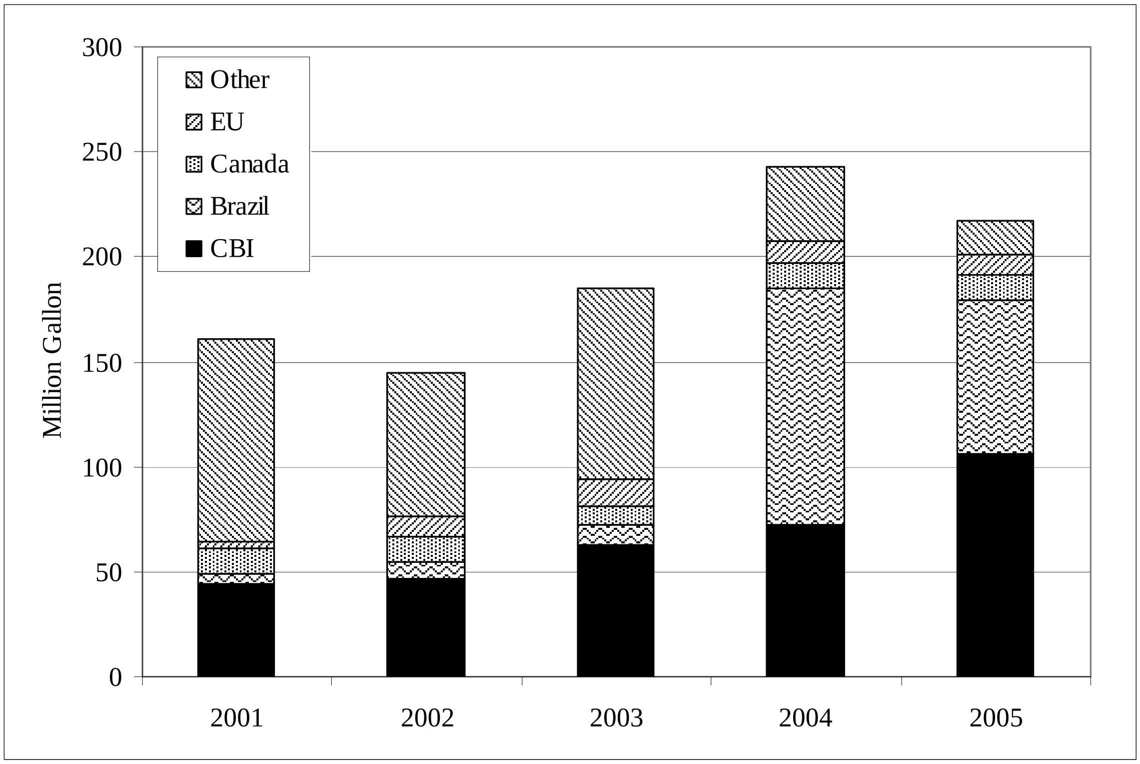
Biodiesel generally leaves the production facility in its neat form and is shipped by truck to locations where it can be blended with conventional diesel fuel. The blending generally occurs at centralized distribution points such as terminals, although it also sometimes occurs within tank trucks themselves. Biodiesel is only rarely used in its neat (unblended) form.

1.5 Imports/Exports of Renewable Fuel

Since the early 1980s, the U.S. has maintained a 54 cent per gallon tariff on imported ethanol, primarily to offset the blending tax subsidy of the same magnitude that had been put in place to support alternative energy production and domestic agriculture. Legislation and agreements implemented since then have waived or significantly reduced the tariff on imports from Canada, Mexico, and about two dozen Central American and Caribbean nations covered by the Caribbean Basin Initiative (CBI). Under the Caribbean Basin Economic Recovery Act, which created the CBI, these countries can export ethanol duty free to the U.S. at a rate up to 7% of the U.S. fuel alcohol market; quantities above this limit have additional stipulations for feedstocks being grown within the supplying country.

Historically, the CBI nations have had little ethanol production capacity of their own but have supplemented it by importing Brazilian ethanol and re-exporting it to the U.S. duty free. More recently, with the rapid phase-out of MTBE and the high price of ethanol, it has become economically viable to import significant quantities of ethanol directly from other nations despite the tariff. Brazil, currently the largest ethanol producing nation in the world, has become the largest single country supplier to the U.S. market. As shown in Figure 1.5-1, total imports have increased more than 30% in 2004-5 over the previous three-year average.

Figure 1.5-1. Historic U.S. Ethanol Import Volumes and Origins[a]



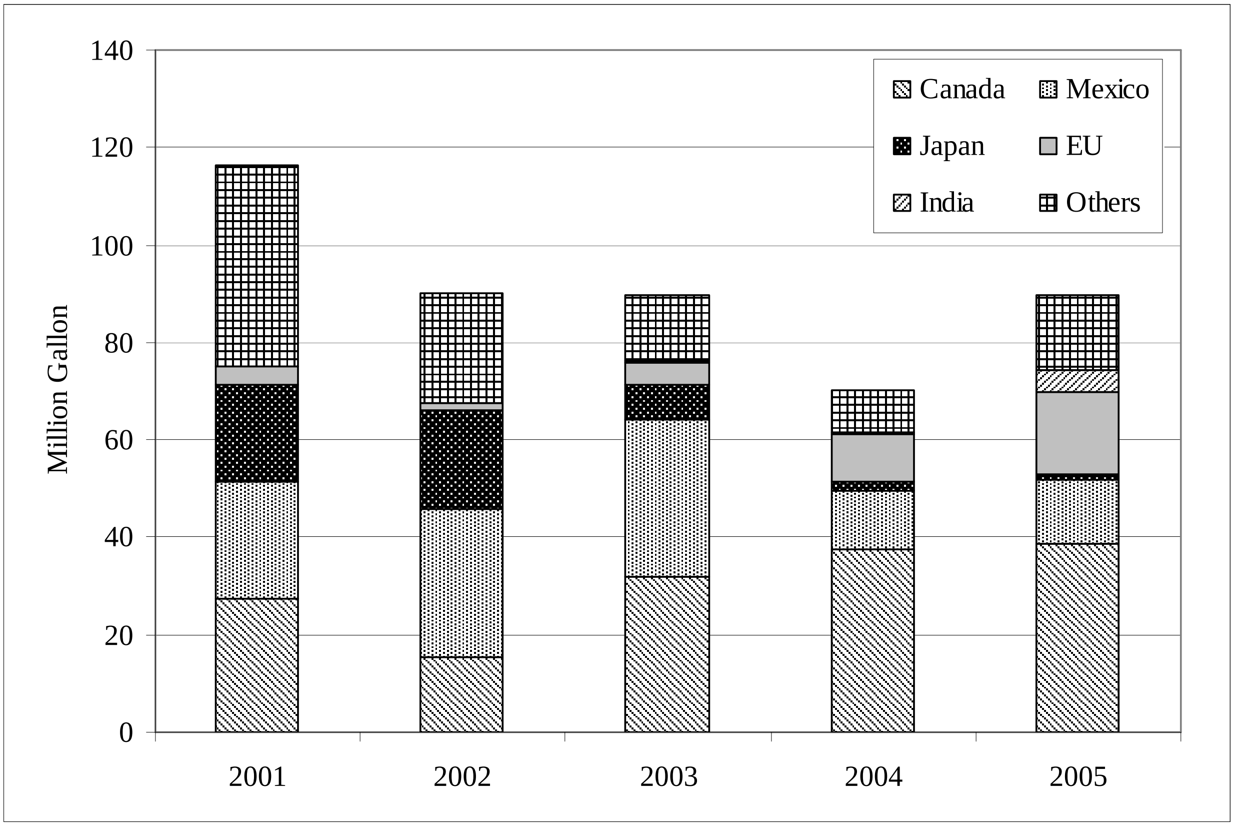
[a] F.O. Licht, "World Ethanol Markets, The Outlook to 2015" (2006). Gross imports (does not account for export volumes) including hydrous, dehydrated, and denatured volumes.

Going forward, as domestic ethanol production capacity increases rapidly, its price is expected to fall back into the historic range of 30-40 cents per gallon above gasoline (before blending subsidy). This is expected to once again make direct imports from Brazil and other full-tariff producers less attractive, and to decrease total imports. According to a current report by F.O. Licht, U.S. net import demand is estimated to be around 300 million gallons per year by 2012, being supplied primarily through the CBI, with some direct imports from Brazil during times of shortfall or high price.[Q]

Changes in the production and trade climate may influence this however. The Caribbean countries with duty free status are seeing both internal and foreign investment to increase ethanol production capacity significantly over the next several years, making more cheap imports available. It is unclear at this point what volume of ethanol will be supplied through these channels.

On the export side, the U.S. has averaged about 100 million gallons per year since 2000, mostly to Canada, Mexico, and the E.U. Figure 1.5-2 shows historical U.S. exports. There is a trend over the past five years of exporting larger quantities to fewer countries, with declining volumes to Asia and increasing volumes to the E.U. and India. The demand for ethanol in all these areas remains strong, and it appears that Asian imports from Brazil and China are making up for the decrease in U.S. ethanol moving into the region.

Figure 1.5-2. Historic U.S. Ethanol Export Volumes and Origins[a]



[a] F.O. Licht, "World Ethanol Markets, The Outlook to 2015" (2006). Gross exports (does not account for import volumes), includes hydrous, dehydrated, and denatured volumes.

These numbers are expected to increase modestly as more production comes online, with more dramatic increases possible during periods of depressed domestic prices or stock surges. Looking out over the next decade, the E.U. has a biofuels directive in place that will bolster demand, and Japan and South Korea are expected to increase their use of biofuels steadily as well. World ethanol production is projected to grow from the current 10 billion gallons per year to more than 25 in 2015, and the international biofuels markets are just beginning to take shape. During this period we can expect significant changes in who is supplying and who is demanding as the players determine their places and forge agreements on subsidies and tariffs. As of 2005, the U.S. became largest ethanol producing nation, eclipsing Brazil, and ample foreign markets will be available if conditions are right.

Chapter 2: Changes to Motor Vehicle Fuel Under the Renewable Fuel Standard Program

In this regulatory impact analysis, we begin by describing the renewable fuel volume scenarios we used to measure the environmental and economic impacts of increased renewable fuel blending. From there we narrow our discussion in on ethanol - the predominant renewable fuel expected to be used in the future. We describe historical ethanol use, current use and our projections of future ethanol use. The discussion starts with an in-depth examination of current ethanol use. More specifically, what factors drive ethanol use and where ethanol blending currently occurs - by state, season, and fuel type. The discussion then shifts to where ethanol is expected to be used in the future. We discuss the ongoing trend in increased ethanol use, the anticipated phase-out of MTBE, and ultimately present our LP modeling results which predict where ethanol will likely be used in 2012 by PADD, season, fuel type. From there, we describe our methodology for allocating ethanol usage by state and in some cases, make distinctions on how we think ethanol would fill urban and rural areas. Once we understand how ethanol use is expected to change in the future, we measure the anticipated impacts on gasoline fuel quality (which later feeds into our emissions and air quality analyses). At the end of this chapter, we also provide a brief estimate on how increased biodiesel blending will impact diesel fuel properties.

2.1 Renewable Fuel Volume Scenarios

The Energy Policy Act of 2005 (the Energy Act or the Act) stipulates that the nationwide volumes of renewable fuel required under the Renewable Fuel Standard (RFS) program must be at least 4.0 billion gallons in 2006 and increase to 7.5 billion gallons by 2012. However, we expect that actual renewable fuel usage will exceed the RFS requirement by a significant margin. In Annual Energy Outlook 2006 (AEO 2006), the Energy Information Administration (EIA) projects that total renewable fuel demand would be 9.9 billion gallons by 2012. More specifically, EIA predicts that 9.6 billion gallons of ethanol and 303 million gallons of biodiesel would be consumed in 2012. The projected renewable fuel consumption levels were estimated using EIA's LP refinery model which was based on a crude oil price of $48/bbl. This figure is lower than today's crude oil price (tracking around $55/bbl at the time of our analysis).[17RS] Therefore, current market conditions indicate that renewable fuel production could be even more favorable and/or prevalent in the future based on economics.[18] However, EIA's AEO

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[17] West Texas Intermediate (WTI) crude oil pricing was $59.08/bbl in November, 2006; $61.96/bbl in December, 2006; and $54.51/bbl in January 2007 according to EIA spot pricing.

[18] In AEO 2007, EIA forecasted an even higher ethanol consumption of 11.2 billion gallons by 2012. The draft report was issued on December 5, 2006, and we were unable to incorporated it into the refinery modeling used to conduct our analyses.

2006 analysis also considers the feasibility of building production facilities to accommodate for the growing renewable fuel demand. Accordingly, we interpret EIA's ethanol and biodiesel projections to be reasonable estimates considering both economics and the rate at which new plants could feasibly come on-line. As a result, in assessing the impacts of expanded renewable fuel use, we evaluated two renewable fuel usage scenarios (described in more detail below). The first represents the statutorily-required minimum and the second reflects the higher levels projected by EIA in AEO 2006. Although the actual renewable fuel volumes produced in 2012 may differ from both the required and projected volumes, we believe that these two volume scenarios represent a reasonable range for analysis purposes.

The Act also requires that at least 250 million gallons of the total renewable fuel use in 2013 and beyond meet the definition of cellulosic biomass ethanol. As described in Chapter 1, there are a number of companies planning to produce ethanol from cellulosic feedstocks and/or waste-derived energy sources that could potentially meet the definition of cellulosic biomass ethanol. Accordingly, we anticipate a ramp-up in cellulosic biomass ethanol production in the coming years. Furthermore, for analysis purposes, we have assumed that the 250 million gallon requirement would be met by 2012.

As discussed in more detail below in Section 2.2.2, we chose 2004 to represent current baseline conditions. In 2004, 3.5 billion gallons of ethanol and 25 million gallons of biodiesel were consumed in motor vehicle fuels. To compare fuel quality impacts on emissions and air quality, we created a 2012 reference case that maintained current fuel quality parameters (with the exception of sulfur) but incorporated forecasted increases in vehicle miles traveled, changes in fleet demographics, etc. The 2012 fuel reference case was developed by growing out the 2004 renewable fuel baseline according to EIA's forecasted energy growth rates. In AEO 2006, EIA predicted that gasoline demand would grow by 11.2 percent and diesel fuel demand would grow by 20.5 percent from 2004 to 2012. As a result, the 2012 reference case is based on 3.9 billion gallons of ethanol use and 30 million gallons of biodiesel use in 2012.

For our analyses, we created two 2012 control cases representing expanded renewable use – the "RFS Case" and the "EIA Case". In both cases, cellulosic biomass ethanol use was assumed to be 250 million gallons (statutory required minimum) and biodiesel use was assumed to be 303 million gallons (EIA AEO 2006 estimate). The RFS Case was designed to exactly meet the RFS program requirements considering the effects of higher equivalence values for cellulosic ethanol and biodiesel. Per § 80.1115, one gallon of cellulosic ethanol counts 2.5 times towards compliance and one gallon of biodiesel counts 1.5 times towards compliance. As a result, in the RFS Case we predict that less than 7.5 billion gallons of renewable fuel would actually be consumed in 2012. The actual volume of renewable fuel analyzed for the RFS Case was computed to be approximately 7.0 billion gallons. The EIA Case represents EIA's projections of renewable fuel use in 2012. Based on AEO 2006, the actual volume of renewable fuel

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analyzed for the EIA Case was 9.9 billion gallons. A summary of the renewable fuel volume scenarios we evaluated is found below in Table 2.1-1.

Table 2.1-1 Renewable Fuel Volume Scenarios (MMgal)

Renewable Fuel	2004 Base Case[a]	2012 Ref Case[b]	 RFS Case	 EIA Case[c]
Corn Ethanol[d]	3,548	3,947	6,421	9,388
Cellulosic Ethanol[e]	0	0	250	250
Biodiesel	25	30	303	303
Total Renewable Volume	3,573	3,977	6,974	9,941
Total Compliance Volume[f]	n/a	n/a	7,500	n/a

[a] Historical ethanol usage derived from EIA's June 2006 Monthly Energy Review. Biodiesel usage derived from "The Outlook and Impact of Biodiesel on the Oilseeds Sector" presented by John Baize at the 2006 USDA Outlook Conference.

[b] The reference case was calculated by applying the 2004-2012 gasoline/diesel energy growth rates reported in AEO 2006 to the 2004 Base Case.

[c] EIA Case based on ethanol and biodiesel energy contributions reported in AEO 2006.

[d] Includes ethanol imports.

[e] Ethanol meeting the definition of cellulosic biomass ethanol in The Act.

[f] Based on applying a 2.5 equivalence value to cellulosic biomass ethanol and a 1.5 equivalence value to biodiesel.

2.2 Current Gasoline Oxygenate Use

2.2.1 Why are oxygenates currently blended into gasoline?

The blending of oxygenates into gasoline dates back to the 1970's. However, their use greatly expanded in response to the Clean Air Act (CAA) amendments of 1990. Areas found to be out of compliance (i.e., in non-attainment) with the National Ambient Air Quality Standards (NAAQS) for ozone were required to reformulate their gasoline and use oxygenates year-round. In addition, several states began to use oxygenated fuel (oxy-fuel) in the wintertime to address carbon monoxide non-attainment. In addition, oxygenates (namely ethanol) have historically been used as a gasoline volume extender and more recently, to meet state mandates. This section summarizes the current driving forces behind gasoline oxygenate use in the U.S.

2.2.1.1 Federal Reformulated Gasoline Program

As mentioned above, areas found to be in ozone non-attainment were required to use reformulated gasoline (RFG) year-round. The federal RFG program contained a minimum oxygenate requirement as well as other fuel quality standards.[19] Adding

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[19] RFG oxygenate requirement found at 40 CFR 80.41(f). This requirement was effective for 2004 but has since been eliminated by the Energy Act Section 1504, promulgated on May 8, 2006 at 71 FR 26691.

oxygen to gasoline and reformulating other gasoline properties has helped to reduce the production of smog-forming pollutants that contribute to unhealthy ground-level ozone. Besides ozone non-attainment areas, several states/areas also opted into the RFG program (otherwise known as "opt-in"). In addition, California and Arizona have state programs that promote the use of oxygenated gasoline.

A list of the 2004 federal RFG areas and their corresponding oxygenate(s) is provided in Table 2.2-1. For the purpose of this analysis, only ethanol (ETOH) and methyl tertiary-butyl ether (MTBE) have been considered.[20]

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[20] Other low-usage oxygenates (e.g. ETBE, TAME, etc.) were assumed to be negligible for the purpose of this analysis.

Table 2.2-1. 2004 Federal RFG Areas by State[T]

State	City	No. of Counties[a]	Type of RFG Area	Primary Oxygenate[b]
California	Los Angeles	5	Req'd	ETOH
	Sacramento	6	Req'd	ETOH
	San Diego	1	Req'd	ETOH
	San Joaquin Valley	8	Req'd	ETOH
Connecticut[c]	Hartford	6	Req'd	ETOH
	Long Island Area	1	Req'd	ETOH
	Windham County	1	Opt In	ETOH
Delaware[c]	Sussex County	1	Opt In	MTBE
	Wilmington	2	Req'd	MTBE
District of Columbia[c]	Washington DC Area	1	Opt In[d]	MTBE
Illinois	Chicago Area	8	Req'd	ETOH
Indiana	Chicago Area	2	Req'd	ETOH
Kentucky	Covington	3	Opt In	ETOH
	Louisville	3	Opt In	ETOH
Maryland	Baltimore	6	Req'd	MTBE
	Philadelphia Area	1	Req'd	MTBE
	Queen Anne/Kent Counties	2	Opt In	MTBE
	Washington DC Area	5	Opt In[d]	MTBE
Massachusetts[c]	Boston Area	10	Opt In	MTBE
	Springfield	4	Opt In	MTBE
Missouri	St. Louis	5	Opt In	ETOH
New Hampshire	Boston Area	4	Opt In	MTBE
New Jersey[c]	Atlantic City	2	Opt In	MTBE
	Long Island Area	12	Req'd	Both
	Trenton	6	Req'd	MTBE
	Warren County	1	Opt In	MTBE
New York	Poughkeepsie	2	Opt In	ETOH
	Long Island Area	11	Req'd	ETOH
Pennsylvania	Philadelphia Area	5	Req'd	MTBE
Rhode Island[c]	Providence Area	5	Opt In	MTBE
Texas	Dallas/Fort Worth	4	Opt In	MTBE
	Houston/Galveston	8	Req'd	MTBE
Virginia	Norfolk/Virginia Beach	11	Opt In	MTBE
	Richmond	7	Opt In	MTBE
	Washington DC Area	10	Opt In[d]	MTBE
Wisconsin	Milwaukee-Racine	6	Req'd	ETOH

[a] Includes partial counties.

[b] Oxygenate determination based on 2004 FHWA gasohol data and EPA fuel survey results.

[c] Entire state/district operates under the Federal RFG program.

[d] Was "opt-in" in 2004, now a required RFG area.

As shown above in Table 2.2-1, a little more than half of the Federal RFG areas (on a county-by-county basis) used MTBE as opposed to ethanol as an oxygenate in 2004. However, on a volumetric basis, more ethanol was consumed in RFG than MTBE

(2.2 billion gallons compared to 1.9 billion gallons as shown in Tables 2.1.5 and 2.1.3, respectively).

2.2.1.2 State Oxygenated Fuel Programs

In addition to the RFG program, several states require oxygenated fuel (oxy-fuel) to be used in the wintertime to address carbon monoxide (CO) non-attainment. CO is formed from the incomplete combustion of hydrocarbons (found in all gasoline blends). Production of the poisonous gas is more prevalent in oxygen-deficient environments and more harmful to human health in the wintertime due to temperature inversions.[21] Together, the winter oxy-fuel program coupled with improving vehicle emissions control systems has helped to reduce CO emissions. Many areas have and are continuing to come into attainment with the CO national ambient air quality standards (NAAQS). However, many former non-attainment areas continue to use the winter oxy-fuel program as part of a maintenance plan for remaining in compliance with the CO NAAQS. A list of the 2004 oxy-fuel areas is provided in Table 2.2-2. All oxy-fuel areas were assumed to use ethanol in 2004 based on information obtained from regional EPA offices.

Table 2.2-2. 2004 State-Implemented Winter Oxy-Fuel Programs[U]

Oxy-Fuel Area Location		Oxy-Fuel Period	Carbon Monoxide Status		Winter Oxy-Fuel Program	
State	City		Designation	Pursuing RD[a]	Required	Part of MP[b]
Alaska	Anchorage	11/1-2/29	Non-attainment[c]	X	X	
Arizona	Tucson	10/1-3/31	Attainment			X
	Phoenix	11/2-3/15	Non-attainment	X	X	
California	Los Angeles	10/1-2/29	Non-attainment	X	X	
Colorado	Denver/Boulder	11/1-1/31	Attainment			X
	Longmont	11/1-1/31	Attainment			X
Montana	Missoula	11/1-2/29	Non-attainment	X	X	
Nevada	Las Vegas	10/1-3/31	Non-attainment		X	
	Reno	10/1-1/31	Non-attainment	X	X	
New Mexico	Albuquerque	11/1-2/29	Attainment			X
Oregon	Portland	11/1-2/29	Attainment			X
Texas	El Paso	10/1-3/31	Non-attainment		X	
Utah	Provo/Orem	11/1-2/29	Non-attainment	X	X	
Washington	Spokane	9/1-2/29	Non-attainment[d]	X	X	

[a] Currently pursuing redesignation to CO attainment.
[b] Area is in currently in CO attainment but oxy-fuel program remains as part of maintenance plan.
[c] Area was redesignated to attainment effective 7/23/04.
[d] Area was redesignated to attainment effective 8/29/05.

2.2.1.3 Other Motivations for Blending Ethanol

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[21] Temperature inversions in the lower atmosphere are relatively common, especially during winter months in cold climates. A temperature inversion occurs when cold air close to the ground is trapped by a layer of warmer air, creating stagnation and trapping pollution close to the ground.

In addition to the RFG and oxy-fuel programs, gasoline refiners have several other motivations for blending oxygenate (namely ethanol) into gasoline. First and foremost, the state they provide gasoline to could be operating under a state ethanol mandate. In 2004, Hawaii joined Minnesota in approving a state ethanol requirement.[22] Second, blending ethanol into gasoline could help them meet their mobile source air toxics (MSAT1) performance standards as determined by the Complex Model.[23] Third, adding ethanol increases both octane and total fuel volume, thus helping refiners extend their gasoline production. Finally, and perhaps most importantly, with record-high crude oil prices and the growing availability of grain-based ethanol (especially in PADD 2), ethanol use has become increasingly economical. The 1.1 billion gallons of ethanol used in PADD 2 conventional gasoline in 2004 (refer to Table 2.2-5 in Section 2.2.2.4) is a good indicator of this trend.

In addition to the increasing availability of ethanol, consumer demand is also increasing based on the growing number of ethanol-friendly vehicles on the road. Conventional vehicles consume the majority of fuel ethanol and are limited to gasoline with 10 volume percent (vol%) ethanol (E10) or less. However, there are currently around 6 million flexible fuel vehicles (FFVs) on the road today with more being produced and sold each day[V]. FFVs are specifically designed to handle a wide range of gasoline/ethanol blends up to 85 vol% ethanol (E85).

2.2.2 Development of the Base Case

As discussed in 2.1, to evaluate the impacts of increased ethanol blending and decreased MTBE blending on gasoline properties (and in turn air quality), we had to create a point of comparison. To do so, we assembled a 2004 Base Case to represent current baseline conditions, i.e., current gasoline, ethanol, and MTBE use. The methodology for assembling the base case, as well as a summary of the results, is described below.

2.2.2.1 Strategy for Establishing the 2004 Base Case

For the purpose of this regulatory impact analysis, the 2004 calendar year was selected to reflect current baseline conditions. This period represented the most current year for which gasoline and oxygenate data were available and also captured the California, New York, and Connecticut MTBE bans (effective 1/1/04) while avoiding the 2005 calendar year hurricane upsets.

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[22] For analysis purposes, both states were assumed to have ethanol mandates which required 100% of the gasoline to contain 10% ethanol. However, in reality, Hawaii's ethanol mandate only requires that 85% of the gasoline contain 10% ethanol.

[23] This RFS proposal is based on MSAT1 conditions. Impacts of the recent MSAT2 rule (72 FR 8428) which removes individual refinery toxic performance standards (baselines) in exchange for a nationwide benzene standard are reflected in the analysis for that rulemaking.

The approach for assembling the 2004 base case consisted of obtaining gasoline, ethanol, and MTBE usage for all 50 states as well as the District of Columbia. As mentioned earlier, other low-volume oxygenate use (e.g., ETBE, TAME, etc.) was assumed to be negligible and thus ignored for this analysis. All ethanol-blended gasoline was assumed to contain 10 vol% ethanol, with the exception of California "RFG" (Federal RFG and California Phase 3 RFG (CaRFG3)).[24] Current California gasoline regulations make it very difficult to meet the NOx emissions performance standard with ethanol content higher than about 6 vol%. For our analysis, all California RFG was assumed to contain 5.7 vol% ethanol based on discussions with California Air Resources Board (CARB). This percentage was also applied to California RFG supplied to the Phoenix metropolitan area in the summertime under Arizona's clean burning gasoline (CBG) program.[25] Finally, all MTBE-blended gasoline was assumed to contain 11 vol% MTBE.

Total gasoline consumption was obtained from the 2004 Petroleum Marketing Annual (PMA) report published by the Energy Information Administration (EIA).[W] The reported annual average sales volume for each state was interpreted as total blended gasoline (including additives, namely oxygenates). 2004 MTBE usage by state was obtained from EIA.[26,X] The data received was exclusive to states with RFG programs (including Arizona's CBG program). Thus, for the purpose of the 2004 base case analysis, MTBE use was assumed to be limited to RFG areas. 2004 ethanol usage by state was derived from a compilation of data sources and assumptions. As a starting point, total domestic ethanol consumption was acquired from EIA's Monthly Energy Review published in June 2006[Y]. State ethanol contributions originated from the 2004 Federal Highway Administration (FHWA) gasohol report[Z]. However, there was some ambiguity with the 2004 FHWA data. First, the total ethanol consumption did not match up with EIA's reported value (3.7 billion gallons compared to 3.5 billion gallons). Second, the gasohol (and thus ethanol) volumes were derived from potentially imprecise motor vehicle fuel tax reports.[27] And third, not all states using ethanol reported their

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[24] The small volumes of E85 (85 percent ethanol) gasoline have been ignored for this analysis.

[25] For the Base Case analysis, all Arizona CBG was classified as "RFG". In 2004, wintertime Arizona RFG was assumed to contain 10% ethanol (governed by the Phoenix oxy-fuel program). Summertime RFG was assumed to be comprised of 2/3 California RFG (containing 5.7 percent ethanol) and 1/3 PADD 3 RFG (containing either 10 percent ethanol or 11 percent MTBE in 2004).

[26] EIA reported 2004 total MTBE usage (in RFG) as 2.0 billion gallons. The reported MTBE usage was reduced from 2.0 to 1.9 billion gallons under the assumption that CA, NY, and CT implemented their state MTBE bans on time (by 1/1/04). (EIA showed small amounts of MTBE use in these states in 2004). EIA's allocation of MTBE by state was also adjusted based on fuel survey results. Most noteworthy, EIA reported MTBE usage in Arizona "RFG" as zero. However, the 2004 Phoenix fuel survey results suggest otherwise. As such, an appropriate amount of MTBE was allocated to Arizona based on the assumption that 1/3 of all summertime Arizona "RFG" resembles PADD 3 RFG (which contained some level of MTBE in 2004).

[27] The U.S. Department of Treasury requires a distinction between gasohol and gasoline on motor vehicle fuel tax reports for states with gasohol sales tax exemptions. These financial records are the source of FHWA's gasohol/ethanol data. However, since state gasohol tax exemptions have become virtually

gasohol usage so FHWA had to model-estimate 19 states' ethanol usage (accounting for 60% of the total ethanol volume). To improve upon the FHWA data, we used a series of oxygenate verification tools including knowledge of state ethanol mandates, state MTBE bans, Arizona's CBG program, and fuel survey results.[AABB] The state-by-state FHWA data was adjusted accordingly and allocated by fuel type (RFG, CG, and/or oxy-fuel). The summarized oxygenate results are presented throughout this section.

2.2.2.2 2004 Gasoline/Oxygenate Consumption by PADD

In 2004, 3.5 billion gallons of ethanol and 1.9 billion gallons of MTBE were blended into gasoline to supply the transportation sector with a total of 136 billion gallons of gasoline. A breakdown of the 2004 gasoline and oxygenate consumption by PADD is found below in Table 2.2-3.

Table 2.2-3. 2004 Gasoline & Oxygenate Consumption by PADD

		Ethanol			MTBE[a]		
PADD	**Gasoline MMgal**	**MMgal**	**% of Gasoline**	**% of Tot ETOH**	**MMgal**	**% of Gasoline**	**% of Tot MTBE**
PADD 1	49,193	660	1.3%	18.9%	1,360	2.8%	72.4%
PADD 2	38,789	1,616	4.2%	46.2%	1	0.0%	0.1%
PADD 3	20,615	79	0.4%	2.3%	498	2.4%	26.5%
PADD 4	4,542	83	1.8%	2.4%	0	0.0%	0.0%
PADD 5[b]	7,918	209	2.6%	6.0%	19	0.2%	1.0%
California	14,836	853	5.8%	24.4%	0	0.0%	0.0%
Total	**135,893**	**3,500**	**2.6%**	**100.0%**	**1,878**	**1.4%**	**100.0%**

[a]MTBE blended into RFG

[b]PADD 5 excluding California

As shown above, in 2004, almost half (or 46 percent) of the ethanol was consumed in PADD 2, where the majority of ethanol was produced. The next highest region of use was the State of California which accounted for nearly a quarter (or 24 percent) of domestic ethanol consumption. This makes sense since California alone accounts for over 10 percent of the nation's total gasoline consumption. And in 2004, following their MTBE ban, all fuel (both Federal RFG and CaRFG3) was presumed to contain 5.7 vol% ethanol. The next highest region of use was PADD 1 (19 percent) which makes sense considering the high concentration of RFG areas (most of which used ethanol in 2004 as shown in Table 2.2-1). The remaining 10 percent of ethanol use occurred collectively in PADDs 3, 4, and 5/

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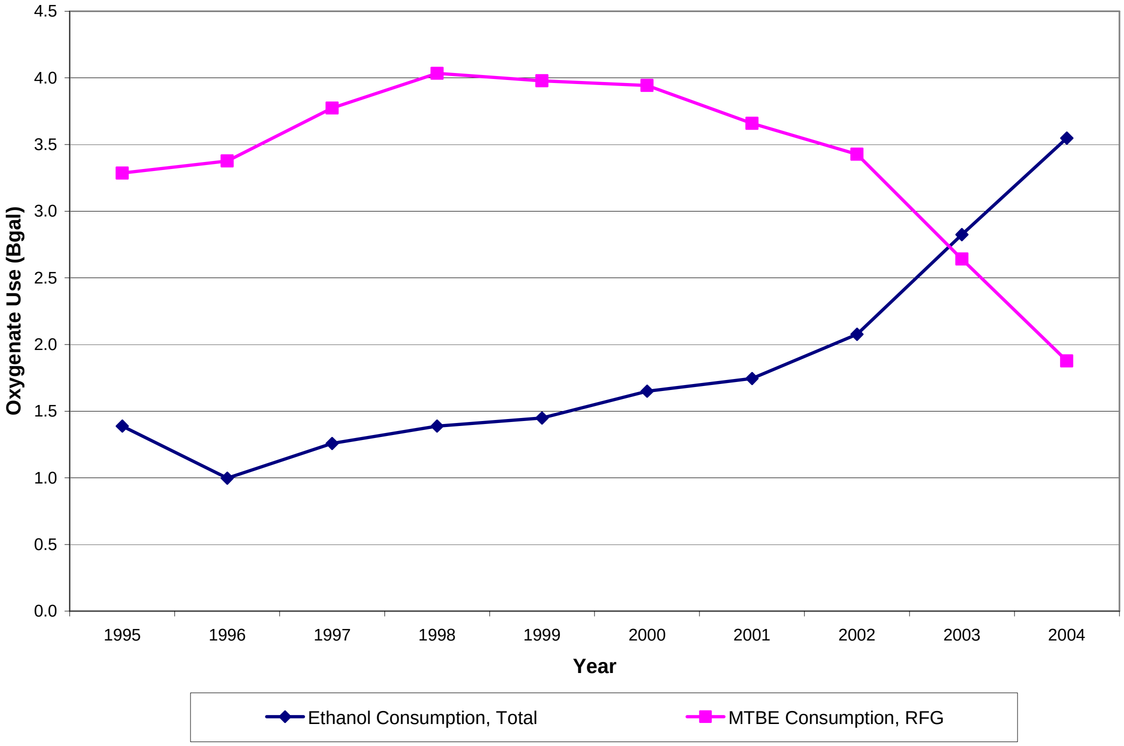
nonexistent over the past several years, gasohol reporting (namely the distinction between gasoline and gasohol) has suffered.

In 2004, total ethanol use exceeded MTBE use. Ethanol's lead oxygenate role is relatively new, however the trend has been a progression over the past few years. From 2001 to 2004, ethanol consumption more than doubled (from 1.7 to 3.5 billion gallons), while MTBE use (in RFG) was virtually cut in half (from 3.7 to 1.9 billion gallons). A plot of oxygenate use over the past decade is provided below in Figure 2.2-1.

Figure 2.2-1. Oxygenate Consumption vs. Time[CC,DD]



The nation's transition to ethanol is linked to states' responses to recent environmental concerns surrounding MTBE groundwater contamination. Traces of MTBE have been found in both surface and ground water in and around RFG areas. The MTBE is thought to have made its way into the water from leaking underground storage tanks, gasoline spills, and engines. Concerns over drinking water quality prompted several states to significantly restrict or completely ban MTBE use in gasoline. At the time of our analysis, 19 states had adopted MTBE bans. Ten states had bans that impacted the entire 2004 calendar year, four states had bans that impacted a portion of the year, and five states had bans that became effective in 2005 and beyond. A list of the states with MTBE bans (listed in order of phaseout date) is provided below in Table 2.2-4.

Table 2.2-4. States MTBE Bans by Phaseout Date[EE]

State[a]	Phaseout Date	Type of Ban[b]
Iowa	07/01/00	Partial
Minnesota	07/02/00; 07/02/05	Partial; Complete
Nebraska	07/13/00	Partial
South Dakota	07/01/01	Partial
Colorado	04/30/02	Complete
Michigan	06/01/03	Complete
California	12/31/03	Complete
Connecticut	01/01/04	Complete
New York	01/01/04	Complete
Washington	01/01/04	Partial
Kansas	07/01/04	Partial
Illinois	07/24/04	Partial
Indiana	07/24/04	Partial
Wisconsin	08/01/04	Partial
Ohio	07/01/05	Partial
Missouri	07/31/05	Partial
Kentucky	01/01/06	Partial
Maine	01/01/07	Partial
New Hampshire	01/01/07	Partial

[a] Arizona is not included because they do not have an official state MTBE ban. They adopted legislation on 4/28/00 calling for a complete phaseout of MTBE as soon as feasible but no later than six months after California's phaseout. The legislation expired on June 30, 2001, so it's not official policy. Although the state still informally encourages the phaseout of MTBE.

[b] A partial ban refers to no more than 0.5 vol% MTBE except in the case of MN (1/3%), NE (1%), and WA (0.6%)

As explained above in 2.2.2.1, all MTBE consumption was assumed to occur in reformulated gasoline in 2004. As shown in Table 2.2-3, 99 percent of MTBE use (by volume) occurred in PADDs 1 and 3. This reflects the high concentration of RFG areas in the northeast (PADD 1) and the local production of MTBE in the gulf coast (PADD 3). PADD 1 receives a large portion of its gasoline from PADD 3 refineries who either produce the fossil-fuel based oxygenate or are closely affiliated with MTBE-producing petrochemical facilities in the area.

2.2.2.3 2004 Gasoline/Oxygenate Consumption by Season

In 2004, according to EIA Petroleum Marketing Annual (PMA), approximately 40 percent of gasoline was consumed in the summertime and 60 percent was consumed in the wintertime.[FF] Similarly, according to EIA Monthly Energy Review June 2006, 38 percent of the ethanol was consumed in the summertime and 62 percent was consumed in the wintertime.[28,GG]

Total gasoline use is higher in the wintertime because it's a longer season. The RFG regulations define summertime fuel as gasoline produced from May 1st to September 15th (4.5 months total).[29] The remaining 7.5 months are considered to be wintertime gasoline. Even though on an average per day basis summertime consumption is higher, more gasoline is still sold and consumed in the wintertime based on the length of the season.

Seasonal ethanol use follows the same general trend as gasoline. However, besides the associated correlation with seasonal gasoline consumption, there are additional reasons why 2004 ethanol use may have been higher in the wintertime. First, the oxy-fuel program requires oxygenate to be used in certain areas in the wintertime only. These same areas, which do not require oxygenate in the summer, were all presumed to use ethanol as their oxygenate (as described in 2.2.1.2). Thus, more areas use ethanol during the winter months than the summer. Secondly, there is an economic penalty associated with blending ethanol into summertime RFG. Refiners supplying summertime gasoline to RFG areas have to remove butanes and pentanes from their gasoline in order to add ethanol and still comply with the 7 psi Reid vapor pressure (RVP) requirement.

2.2.2.4 2004 Gasoline/Oxygenate Consumption by Fuel Type

According to fuel survey results, in 2004, approximately 2.2 billion gallons of ethanol were blended into reformulated gasoline and the remaining 1.3 billion gallons were used in conventional gasoline (including wintertime oxy-fuel).[HH,II] A breakdown of the 2004 ethanol consumption by fuel type and PADD is found in Table 2.2-5.

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[28] Aforementioned seasonal split for gasoline and ethanol based on RFG production seasons (Summer: May 1 through September 15th; Winter: January 1st through April 30th and September 16th through December 31st).

[29] We acknowledge that the aforementioned seasonal split does not exactly match the new summer/winter seasons defined in the Energy Act (Summer: April 1st through September 30th; Winter: January 1st through March 31st and November 1st through December 31st).

Table 2.2-5.
2004 Ethanol Consumption by Fuel Type (MMgal)

PADD	CG	OXY[a]	RFG[b]	Total
PADD 1	0	0	660	660
PADD 2	1,072	0	544	1,616
PADD 3	31	21	26	79
PADD 4	0	83	0	83
PADD 5[c]	45	89	75	209
California	0	0	853	853
Total	**1,149**	**193**	**2,158**	**3,500**

[a] Winter oxy-fuel programs
[b] Federal RFG plus CA Phase 3 RFG and Arizona CBG
[c] PADD 5 excluding California

As mentioned above in Section 2.2.2.1, 100 percent of the 1.9 billion gallons of MTBE blended into gasoline in 2004, was assumed to be consumed in reformulated gasoline.

2.2.2.5 2004 Gasoline/Oxygenate Consumption by State

In 2004, ethanol was blended into gasoline in 34 of the 50 states. No ethanol use was observed in the remaining 16 states: Maine, New Hampshire, Vermont, Pennsylvania, Delaware, Georgia, North Carolina, South Carolina, West Virginia, Tennessee, Oklahoma, Mississippi, Arkansas, Louisiana, Idaho, and West Virginia, nor was any ethanol used in Washington DC. A summary of 2004 ethanol usage by state is presented in Table 2.2-6. Note that a state ethanol percentage less than 10 indicates that only a percentage of the gasoline pool was blended with ethanol, not that ethanol itself was blended in less than 10 vol% (E10) proportions, except in the case of California gasoline (E5.7). Figure 2.2-2 shows the percentage of E10 by state.

The states consuming the highest volumes of ethanol in 2004 were California, Illinois, New York, Minnesota, and Ohio, respectively. With respect to gasoline use, the highest percentage of ethanol use occurred in Minnesota, Hawaii, Connecticut, Illinois, and Iowa. Four out of the five states are not surprising. The first two states have ethanol mandates and the last two are located in the “corn belt” where ethanol is produced. Connecticut’s high percentage of ethanol use may come as a surprise at first glance. However, the entire state operates under the RFG program (refer to Table 2.2-1), and since they also have a state MTBE ban, ethanol is found in each gallon of gasoline.

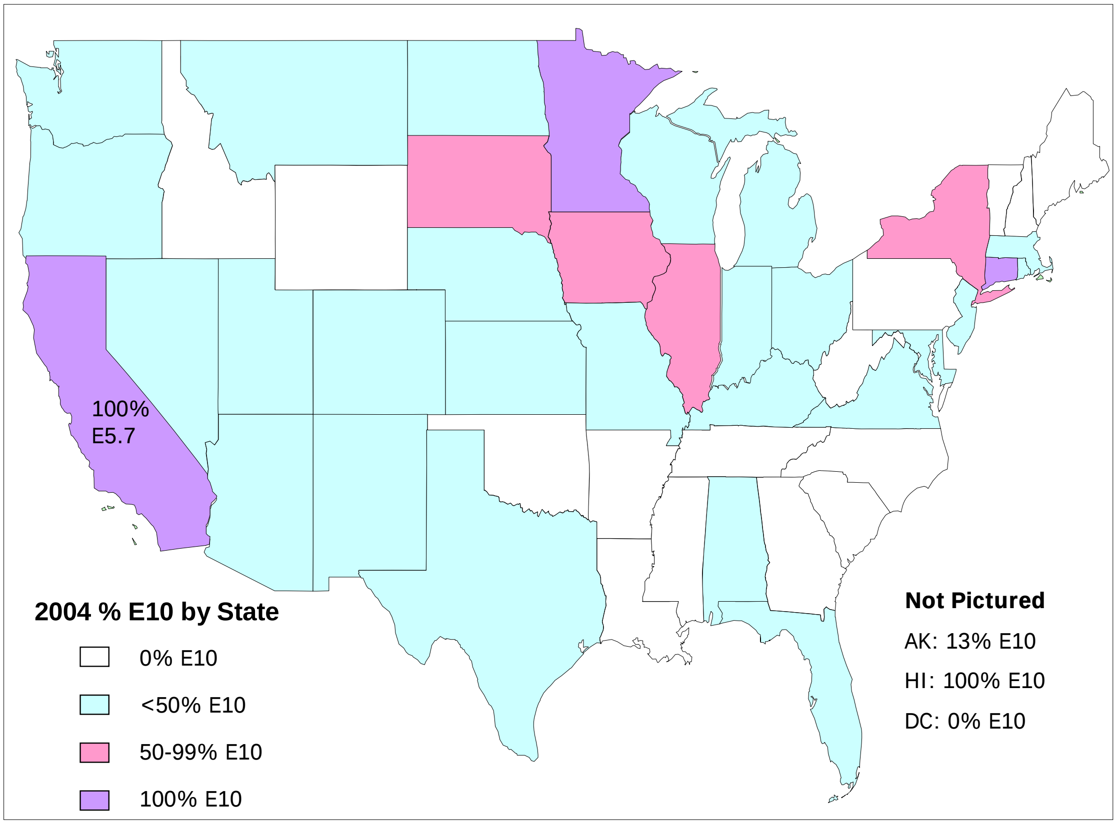
Table 2.2-6. 2004 Gasoline/Ethanol Consumption by State

		Ethanol				Ethanol	
State	**Gasoline MMgal**	**MMgal**	**% of Gasoline**	**State**	**Gasoline MMgal**	**MMgal**	**% of Gasoline**
Alabama	2,392	31	1.3%	Montana	503	1	0.2%
Alaska	302	3	1.1%	Nebraska	819	37	4.5%
Arizona	2,187	88	4.0%	Nevada	857	23	2.7%
Arkansas	1,406	0	0.0%	New Hampshire	705	0	0.0%
California	14,836	853	5.8%	New Jersey	4,235	188	4.4%
Colorado	1,999	80	4.0%	New Mexico	966	8	0.8%
Connecticut	1,522	152	10.0%	New York	5,626	301	5.4%
Delaware	449	0	0.0%	North Carolina	4,302	0	0.0%
District of Columbia	119	0	0.0%	North Dakota	350	11	3.0%
Florida[b]	8,605	0	0.0%	Ohio	5,156	192	3.7%
Georgia	4,729	0	0.0%	Oklahoma	2,158	0	0.0%
Hawaii[a]	452	45	10.0%	Oregon	1,500	31	2.1%
Idaho	632	0	0.0%	Pennsylvania	4,786	0	0.0%
Illinois	5,177	422	8.1%	Rhode Island[b]	490	0	0.1%
Indiana	3,059	148	4.8%	South Carolina	2,422	0	0.0%
Iowa	1,635	117	7.1%	South Dakota	434	24	5.5%
Kansas	1,396	41	2.9%	Tennessee	3,251	0	0.0%
Kentucky	2,177	50	2.3%	Texas	11,948	39	0.3%
Louisiana	2,287	0	0.0%	Utah	1,097	2	0.2%
Maine	757	0	0.0%	Vermont	338	0	0.0%
Maryland[b]	2,480	0	0.0%	Virginia[b]	3,920	0	0.0%
Massachusetts	2,934	18	0.6%	Washington	2,621	18	0.7%
Michigan	4,861	77	1.6%	West Virginia	772	0	0.0%
Minnesota	2,684	268	10.0%	Wisconsin	2,471	109	4.4%
Mississippi	1,617	0	0.0%	Wyoming	311	0	0.0%
Missouri	3,159	122	3.9%	**Total**	**135,893**	**3,500**	**2.6%**

[a] Hawaii was assumed to have a 100% E10 mandate in the 2004 Base Case based on RFA's Homegrown for the Homeland: Ethanol Industry Outlook 2005.

[b] Trace amounts of ethanol use (<1 MMGal) in FL, MD, RI and VA.

Figure 2.2-2. 2004 Ethanol Consumption, % E10 by State



2.2.3 Development of the 2012 Reference Case

To establish the 2012 reference case, we started with the 2004 Base Case (presented in Table 2.2-3) and grew out gasoline/oxygenate use according to the EIA AEO 2006 motor gasoline energy growth rate from 2004 to 2012.[JJ] Accordingly, in the resulting 2012 reference case, ethanol and MTBE use was proportional to 2004 use by both region and fuel type. A summary of the 2012 ethanol reference case is found in Table 2.2-7.

Table 2.2-7.
2012 Reference Case - Gasoline & Oxygenate Consumption by PADD (MMgal)[30]

PADD	Gasoline MMgal	Ethanol MMgal	Ethanol % of Gasoline	Ethanol % of Tot ETOH	MTBE[a] MMgal	MTBE[a] % of Gasoline	MTBE[a] % of Tot MTBE
PADD 1	54,743	735	1.3%	18.9%	1,513	2.8%	72.4%
PADD 2	43,166	1,798	4.2%	46.2%	2	0.0%	0.1%
PADD 3	22,941	88	0.4%	2.3%	554	2.4%	26.5%
PADD 4	5,055	93	1.8%	2.4%	0	0.0%	0.0%
PADD 5[b]	8,812	232	2.6%	6.0%	21	0.2%	1.0%
California	16,509	949	5.8%	24.4%	0	0.0%	0.0%
Total	**151,225**	**3,895**	**2.6%**	**100.0%**	**2,090**	**1.4%**	**100.0%**

[a] MTBE blended into RFG

[b] PADD 5 excluding California

2.2.4 Development of the 2012 Control Cases

In Section 2.2.2 we described our methodology behind building the 2004 Base Case, which was used to produce the 2012 Reference Case (described above). In this section we will describe how we developed the two 2012 control cases representing increased ethanol fuel use – the RFS Case and the EIA Case. Both control cases incorporate our knowledge of future state ethanol mandates, tax incentives, and anticipated winter oxy-fuel usage. Our analysis relied on LP modeling (described in more detail below) to determine how much ethanol would be used in each PADD, season, and fuel type. From there, we conducted post-processing to determine how much ethanol would be used on a state-by-state basis and in some cases and made predictions on how ethanol would likely fill urban and rural areas.

2.2.4.1 Forecasting Ethanol Consumption / LP Modeling Results

As mentioned earlier in Section 2.2.2.2, groundwater contamination concerns have caused many states to ban the use of MTBE in gasoline. In response to the Energy Act, all U.S. refiners are expected to eliminate the use of MTBE in gasoline by the end of 2007, and certainly prior to 2012. Ethanol consumption, on the other hand is expected to continue to grow in the future. Not only are the Energy Act's RFS requirements promoting ethanol growth, ethanol is needed to fuel the growing number of ethanol-friendly vehicles being produced as well as satisfy the growing number of state ethanol

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[30] The total ethanol volume reported in table 2.2-7 (3.895 Bgal) is slightly lower than the reference case value reported in Table 2.1-1 (3.947 Bgal). The reason for the slight discrepancy is because the numbers presented here were based off the estimated 2004 base case (3.5 Bgal) whereas the numbers presented in Table 2.1-1 were based off a more precise 2004 ethanol use (3.548 Bgal) reported by EIA in July 2006 Monthly Energy Review.

mandates (Washington, Montana, Louisiana, and Missouri recently joined Minnesota and Hawaii)[31,KK,LL].

Based on projections from EIA and others, it's abundantly clear that renewable fuel use (namely ethanol) is growing much faster than the RFS requirement. However quantifying future ethanol use is a difficult task. The gasoline refining industry and ethanol industry are currently undergoing a variety of changes/expansions and there is no precise way to know exactly how things are going to "fall out" in the future. Accordingly, as explained in Section 2.1, we have considered two different 2012 renewable fuel consumption scenarios to represent a reasonable range of ethanol use. For the RFS Case we modeled 6.7 billion gallons of ethanol use and for the EIA case we modeled 9.6 billion gallons (refer to Table 2.1-1). EPA is not concluding that ethanol consumption could not possibly exceed 9.6 billion gallons by 2012, but rather that this volume is a reasonable "ceiling" for our analysis.

To estimate how ethanol use would be allocated in the future, we relied on Jacob's Consultancy LP refinery modeling.[MM] For the Base Case and Reference Case, the LP refinery model was set up to allocate fixed volumes of ethanol/MTBE to regions consistent with our analysis of current gasoline oxygenate use (described above in Sections 2.2.2 and 2.2.3). This essentially fixed the total ethanol and MTBE use in each PADD. From there, the oxygenates were further allocated by season and fuel grade to match the oxygen content for RFG, RBOB and CBOB based on 2004 batch report data. Any leftover ethanol was allocated to CG. Based on the resulting fuel allocation, the LP model generated CG and RFG fuel properties considering the RVP effects and blending qualities of ethanol and MTBE (such properties are discussed further and utilized in Section 2.3).

For each of the future control cases, MTBE use was assumed to be zero and the amount of ethanol added to gasoline was varied. For the RFS Case, total ethanol use was fixed at 6.7 billion gallons and for the EIA Case, ethanol use was fixed at 9.6 billion gallons. For each control case, the LP model used gasoline and ethanol blending economics (e.g., ethanol distribution costs, seasonal ethanol and gasoline blendstock prices, etc.) to determine how much ethanol would be blended into gasoline by PADD, season, and fuel type. Again, the results were used to generate CG and RFG fuel properties used in Section 2.3.

Slight adjustments had to be made to the refinery modeling outputs to ensure that sufficient ethanol was supplied in the wintertime to meet the oxy-fuel requirements in PADDs 4/5. In addition, small corrections were required to ensure that ethanol blending in a given region/state did not exceed the maximum blending criteria assumed for the

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[31] The Montana state mandate requires all gasoline to contain 10 vol% ethanol once plant production ramps up to 40 MMgal/yr. The Washington state mandate requires 20% of all gasoline to contain 10 vol% ethanol by 12/1/08. Similarly, the Louisiana state mandate requires 20% of all gasoline to contain 10 vol% ethanol once plant production ramps up to 50 MMgal/yr. Finally, the Missouri state mandate requires all gasoline to contain 10 vol% ethanol by 1/1/08. At the time of our analysis, these were the only four new state ethanol mandates. However, EPA recognizes that as of 7/13/06, several others have new/additional biofuel standards pending (California, Colorado, Idaho, Illinois, Indiana, Kansas, Minnesota, New Mexico, Pennsylvania, Virginia, and Wisconsin).

analysis - 10 volume percent (vol%) ethanol nationwide, and 5.7 vol% ethanol in California. The adjusted LP refinery modeling results for the RFS and EIA control cases are summarized below in Tables 2.2-8 and 2.2-9, respectively.

Table 2.2-8.
Adjusted LP Modeling Results for the RFS Case (MMgal)

	Summer Ethanol Use			Winter Ethanol Use			Total
PADD	**CG[a]**	**RFG[b]**	**Total**	**CG[a]**	**RFG[b]**	**Total**	**Ethanol**
PADD 1	399	679	1,078	350	706	1,057	2,134
PADD 2	1,667	59	1,726	1,082	288	1,370	3,096
PADD 3	161	47	208	146	0	146	354
PADDs 4/5[c]	135	0	135	138	0	138	274
California	0	414	414	0	398	398	813
Total	**2,362**	**1,200**	**3,562**	**1,717**	**1,392**	**3,109**	**6,671**

[a] Includes Arizona CBG and winter oxy-fuel
[b] Federal RFG and California Phase 3 RFG
[c] PADDs 4 and 5 excluding California

Table 2.2-9.
Adjusted LP Modeling Results for the EIA Case (MMgal)

	Summer Ethanol Use			Winter Ethanol Use			Total
PADD	**CG[a]**	**RFG[b]**	**Total**	**CG[a]**	**RFG[b]**	**Total**	**Ethanol**
PADD 1	610	630	1,240	267	973	1,240	2,481
PADD 2	1,735	185	1,919	1,631	366	1,998	3,917
PADD 3	901	47	949	856	0	856	1,805
PADDs 4/5[c]	339	0	339	154	0	154	492
California	0	435	435	0	470	470	905
Total	**3,584**	**1,298**	**4,882**	**2,908**	**1,809**	**4,718**	**9,600**

[a] Includes Arizona CBG and winter oxy-fuel
[b] Federal RFG and California Phase 3 RFG
[c] PADDs 4 and 5 excluding California

2.2.4.2 Resulting 2012 Ethanol Consumption by PADD

Starting with the LP refinery modeling results, we segregated the Rocky Mountain (PADD 4) and West Coast (PADD 5) ethanol use (represented as an aggregate above in Tables 2.2-8 and 2.2-9) and examined the resulting ethanol allocation by region. A summary of the 2012 forecasted ethanol consumption by region (PADDs 1-5 and California) for each control case is found below in Table 2.2-10.

Table 2.2-10.
2012 Forecasted Ethanol Consumption by PADD

PADD	6.7 Bgal RFS Case				9.6 Bgal EIA Case			
	Gasoline MMgal	ETOH MMgal	% of Gasoline	% of Tot ETOH	Gasoline MMgal	ETOH MMgal	% of Gasoline	% of Tot ETOH
PADD 1	60,468	2,134	3.5%	32.0%	60,468	2,481	4.1%	25.8%
PADD 2	48,451	3,096	6.4%	46.4%	48,451	3,917	8.1%	40.8%
PADD 3	24,845	354	1.4%	5.3%	25,112	1,805	7.2%	18.8%
PADD 4	4,869	54	1.1%	0.8%	4,928	151	3.1%	1.6%
PADD 5[a]	8,537	220	2.6%	3.3%	8,626	342	4.0%	3.6%
California	16,494	813	4.9%	12.2%	16,494	905	5.5%	9.4%
Total	**163,664**	**6,671**	**4.1%**	**100.0%**	**164,078**	**9,600**	**5.9%**	**100.0%**

[a]PADD 5 excluding California

As shown above, in 2012 PADD 2 is expected to continue to dominate ethanol use. PADD 2 ethanol consumption is expected to double from 1.8 billion gallons (Bgal) in the Reference Case (refer to Table 2.2-7) to 3.1 Bgal in the RFS Case and 3.9 Bgal in the EIA Case. This represents a slight decrease in Midwest marketshare (from 46% in Reference/RFS Case to 40% in the EIA Case). The predicted shift in marketshare is attributed to the growing amount of ethanol use outside of the traditional cornbelt.

The LP modeling suggests that ethanol usage is expected to greatly increase in PADDs 1 and 3. In PADD 1, ethanol blending is expected to more than triple from 735 million gallons in the Reference Case to 2.1 Bgal in the RFS Case and 2.5 Bgal in the EIA Case. In PADD 3, ethanol use in expected to sharply increase from 88 million gallons in the Reference Case to 354 million gallons in the RFS Case and 1.8 billion gallons in the EIA Case. This projected increase in ethanol blending on the East Coast and Gulf Coast, reflects the phase out of MTBE (replacement with ethanol) as well as ethanol blending economics.

2.2.4.3 Resulting 2012 Ethanol Consumption by Season

Furthermore, we examined the resulting ethanol allocation by season. The LP refinery modeling assumes equal 182.5-day summer and winter seasons. A summary of the resulting 2012 forecasted ethanol consumption by season for each of the control cases is found below in Table 2.2-11.

Table 2.2-11.
2012 Forecasted Ethanol Consumption by Season (MMgal)

	6.7 Bgal RFS Case			9.6 Bgal EIA Case		
PADD	**Summer**	**Winter**	**Total**	**Summer**	**Winter**	**Total**
PADD 1	1,078	1,057	2,134	1,240	1,240	2,481
PADD 2	1,726	1,370	3,096	1,919	1,998	3,917
PADD 3	208	146	354	949	856	1,805
PADD 4	29	25	54	125	25	151
PADD 5[a]	106	113	220	213	128	342
California	414	398	813	435	470	905
Total	**3,562**	**3,109**	**6,671**	**4,882**	**4,718**	**9,600**

[a] PADD 5 excluding California

As shown above, ethanol usage in 2012 is expected to be slightly more prevalent in the summertime than in the wintertime. This is a shift from our 2004 Base Case (38% of ethanol use occurred in the summertime and 62% occurred in the wintertime as explained in Section 2.2.2.3), mainly because we are changing the way we define the seasons. In the Base Case we defined the seasons based on the RFG regulations (4.5 months of "summer" and 7.5 months of "winter") whereas in this 2012 forecast we are defining them based on 6 months of each season. Since gasoline consumption (gal/day) is higher in the summertime, more ethanol-blended gasoline could potentially be consumed during the summer months. However, since there is an economic penalty associated with blending ethanol into summertime gasoline (refiners have to remove butanes and pentanes to comply with the RFG RVP requirements), the result is somewhat of a seasonal balance in both the RFS Case and the EIA Case.

2.2.4.4 Resulting 2012 Ethanol Consumption by Fuel Type

In addition to providing a PADD and seasonal breakdown, The LP modeling determined how much ethanol would be used by fuel type - conventional gasoline (CG) versus reformulated gasoline (RFG). The first thing we did was allocate a portion of the CG to the required winter oxy-fuel areas.

Strategy for Allocating Ethanol to Oxy-Fuel Areas

In the 2004 Base Case, there were 14 state-implemented winter oxy-fuel programs in 11 states (summarized previously in Table 2.2-2). Of these programs, 9 were required in response to non-attainment with the CO National Ambient Air Quality Standards (NAAQS) and 5 were implemented to maintain CO attainment status. However, in the future 4 of the 9 required oxy-fuel areas are expected to be reclassified from non-attainment to attainment and discontinue using oxy-fuel in the wintertime[32]. These areas are: Anchorage, AK; Las Vegas, NV; Provo/Orem, UT; and Spokane, WA. In addition,

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[32] Based on conversations with state officials and regional EPA officials.

Colorado is expected to discontinue using winter oxy-fuel in Denver/Boulder and Longmont to maintain CO attainment status. The use of oxy-fuel in the above-mentioned areas is expected to discontinue by 2012 or sooner. With the removal of these 6 state-implemented programs, that leaves a total of 8 oxyfuel areas in Tucson and Phoenix, AZ; Los Angeles, CA; Missoula, MT; Reno, NV; Albuquerque, NM; Portland, OR; and El Paso, TX. We assumed that these areas would continue to blend 10 vol% ethanol into their gasoline for their entire winter oxy-fuel period (duration varies by area, six month maximum) in the 2012 control cases.

Once a portion of the conventional gasoline ethanol was allocated to meet winter oxy-fuel requirements, this gave use a PADD-by-PADD breakdown of ethanol use by conventional gasoline, oxy-fuel, and reformulated gasoline as shown below in Table 2.2-12.

Table 2.2-12.
2012 Forecasted Ethanol Consumption by Fuel Type (MMgal)

	6.7 Bgal RFS Case				9.6 Bgal EIA Case			
PADD	**CG[a]**	**OXY[b]**	**RFG[c]**	**Total**	**CG[a]**	**OXY[b]**	**RFG[c]**	**Total**
PADD 1	750	0	1,385	2,134	877	0	1,603	2,481
PADD 2	2,749	0	347	3,096	3,366	0	551	3,917
PADD 3	283	24	47	354	1,733	24	47	1,805
PADD 4	54	0	0	54	151	0	0	151
PADD 5[d]	106	113	0	220	228	113	0	342
California	0	0	813	813	0	0	905	905
Total	**3,942**	**137**	**2,592**	**6,671**	**6,356**	**137**	**3,107**	**9,600**

[a] Conventional gasoline including Arizona CBG
[b] Winter oxy-fuel programs
[c] Federal RFG plus CA Phase 3 RFG
dPADD 5 excluding California

However, more post-processing was required to determine how much ethanol would be used on a state-by-state basis to feed into the emissions and air quality analyses. We begin the latter part of this discussion by explaining how we allocated the RFG ethanol to specific RFG areas and how we allocated the CG ethanol to specific states/regions considering state ethanol mandates and the economic favorability of ethanol blending

Strategy for Allocating Ethanol Among RFG

In the 2004 Base Case, there were 18 states/districts with RFG programs covering a total of 175 counties in 36 areas (summarized previously in Table 2.2-1). For our analysis of 2012 ethanol use, we assumed that the number of RFG areas would not change and accordingly, that the RFG fuel contribution to the gasoline pool would remain the same. However, we considered the amount of ethanol added to RFG to be a variable, as discussed below.

In the past, all RFG areas were required to use a minimum amount of oxygenate in their reformulated gasoline year-round, as discussed earlier in 2.2.1.1. However, effective May 5, 2006, EPA removed the RFG oxygenate requirement in response to the Act.[NN] Although the oxygenate requirement has already been eliminated, many refiners are still operating under contracts with ethanol blenders. As such, refiners true response to the removal of the oxygenate requirement is relatively unknown at this time. While it is difficult to predict exactly how each refinery supplying an RFG area would behave, the LP modeling has attempted to do so.

The modeling suggests that some refineries will continue to blend ethanol into RFG (or even increase blending) in 2012 based on octane, volume, and/or toxic performance requirements. Some RFG producers may decidedly replace MTBE with ethanol while others may pare back or discontinue ethanol use all together. A summary of the 2012 forecasted RFG ethanol consumption (by season) for each control case is found below in Table 2.2-13.

Table 2.2-13.
2012 Forecasted RFG Ethanol Consumption (MMgal)[33]

PADD/State	Seasonal RFG Use MMgal[a]	6.7 Bgal RFS Case				9.6 Bgal EIA Case				Average % ETOH in RFG
		Summer		Winter		Summer		Winter		
		ETOH MMgal	% of Gasoline	ETOH MMgal	% of Gasoline	ETOH MMgal	% of Gasoline	ETOH MMgal	% of Gasoline	
PADD 1	11,380	679	6.0%	706	6.2%	630	5.5%	973	8.5%	6.6%
PADD 2	3,661	59	1.6%	288	7.9%	185	5.0%	366	10.0%	6.1%
PADD 3 / TX	2,939	47	1.6%	0	0.0%	47	1.6%	0	0.0%	0.8%
PADD 5 / CA[b]	8,247	414	5.0%	398	4.8%	435	5.3%	470	5.7%	5.2%
Total	**26,227**	**1,200**	**4.6%**	**1,392**	**5.3%**	**1,298**	**4.9%**	**1,809**	**6.9%**	**5.8%**

[a] Equal amounts of reformulated gasoline assumed to be used in the summer and winter seasons.
[b] Includes Federal RFG and CA Phase 3 RFG

As shown above, the modeling suggests that more ethanol would be consumed in RFG in the EIA Case in the presence of more ethanol. The modeling also suggests that the greatest ethanol marketshare would occur in California RFG (5.2 vol% ethanol on average across both cases/seasons, or 91% E5.7). The next highest areas of RFG use would be PADD 1 (6.6 vol% ethanol on average, or 66% E10) followed by PADD 2 (6.1 vol% ethanol on average, or 61% E10). Little ethanol blending was predicted to occur in Texas RFG (0.8% ethanol or 8% E10).

In both control cases, more ethanol was predicted to be blended into wintertime RFG. As discussed earlier, this makes sense because in order to meet the RVP requirements pertaining to summertime RFG (7 psi), refiners have to remove butanes and

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[33] Gasoline consumed in the greater Phoenix metropolitan area under the Arizona Clean Burning Gasoline (CBG) Program, has not been considered "RFG" by the LP refinery modeling and thus discussed in the conventional gasoline section.

pentanes to accommodate for ethanol blending (which increases overall gasoline volatility). As such, in the absence of an RVP waiver (which exists exclusively for summertime CG), refiners are less inclined to blend ethanol into summertime RFG.

To allocate the RFG ethanol (aggregated by PADD and season in Table 2.2-13) by state/RFG area, we assumed that each region would behave uniformly with the exception of PADD 1 (discussed in more detail below). For example, consider PADD 2 summertime RFG. In the RFS Case, RFG in Chicago, Louisville, Milwaukee, etc. would all contain 1.6% ethanol on average. Or more accurately, 16% of all the gasoline consumed within PADD 2 RFG areas would contain 10% ethanol.

However, based on our knowledge of the refining industry and distribution patterns, we did not assume that PADD 1 RFG would be uniform in ethanol content. The LP modeling assumes that the RFG produced in PADD 1 contains ethanol but the RFG produced in PADD 3 and shipped to PADD 1 does not. RFG from PADD 3 comes up the Colonial Pipeline and passes through Virginia, Washington DC and Maryland on its way to Pennsylvania and New York. With the exception of a small Yorktown refinery, the southernmost refineries in PADD 1 are located around the Philadelphia area. However, there is no cheap way to send fuel south. Therefore, the RFG coming from PADD 3 is likely to completely fulfill the RFG demand in Virginia, Washington DC and Maryland. Beyond Maryland, the fuel from PADD 1 refineries is sold along with any leftover PADD 3 RFG, as distribution costs are roughly the same from Philadelphia north. As a result, the Virginia, Washington DC and Maryland RFG areas were assumed to receive less ethanol (in most cases zero E10) than the other RFG areas located in PADD 1. A summary of the resulting RFG ethanol distribution by state is found below in Table 2.2-14.

Table 2.2-14.
2012 RFG Ethanol Distribution by State

PADD/State	6.7 Bgal RFS Case		9.6 Bgal EIA Case	
	Summer	**Winter**	**Summer**	**Winter**
PADD 1	78% E10 in all states except DC, MD, VA (0% E10)	81% E10 in all states areas except DC, MD, VA (0% E10)	73% E10 in all states except DC, MD, VA (0% E10)	100% E10 in all states except DC, MD, VA (39% E10)
PADD 2	16% E10 in all states	78% E10 in all states	51% E10 in all states	100% E10 in all states
PADD 3/TX	16% E10 in TX	0% E10 in TX	16% E10 in TX	0% E10 in TX
PADD 5/CA	88% E5.7 in CA	85% E5.7 in CA	93% E5.7 in CA	100% E5.7 in CA

Strategy for Allocating Ethanol Among CG

The above-mentioned oxy-fuel requirements combined with state ethanol mandates created a “floor” for conventional gasoline ethanol use within each PADD. This essentially forced a specific amount of ethanol to be used in wintertime CG in PADDs 3 and 5 and a specific amount of ethanol to be added year-round in Minnesota, Montana, and Missouri (100% E10 mandates); Hawaii (85% E10 mandate); as well as Washington and Louisiana (20% E10 mandates).

To determine how the remaining ethanol would be allocated to the leftover conventional gasoline, we devised a systematic way to allocate ethanol by state/area. Since the primary motivation to blend (or not blend) ethanol is expected to be economic, we devised a way to rank CG areas, on a state-by-state and urban/rural basis, as to the economic favorability of ethanol blending. This was done by calculating an ethanol margin, which is equal to gasoline price minus ethanol delivered price. Ethanol delivered price is equal to ethanol plant gate price plus transportation costs minus any additional state plus other adjustments (explained below). The greater the ethanol margin, the greater the economic incentive and the more likely ethanol is to be used in that area.

At the time the analysis was carried out, ethanol plant gate price was taken from an older EIA NEMS model. However, since this price was assumed to be the same for all ethanol, the actual value is not important when trying to estimate relative allocation preferences between areas. All ethanol blending was assumed to be done at 10 volume percent. The gasoline prices for each state were the weighted average rack price of all conventional grades and all months, taken from EIA Petroleum Marketing Annual 2004.[OO]

Ethanol distribution costs were taken from figures given in the documentation for the EIA NEMS model, and are based on a 2002 study by DAI, Inc.[PP] For the purpose of this consumption analysis, all ethanol was assumed to be produced in the Midwest in census divisions 3 and 4 (corresponding closely to PADD 2). This is largely consistent with the production analysis presented in Chapter 1 of the RIA. While the results of the production analysis do not completely coincide with this assumption (as shown in Table 1.2-15, about 86 percent of the total ethanol plant capacity is expected to originate from PADD 2 in 2012 and the rest would originate from other areas throughout the country), this simplifying assumption is still very reasonable.

Ethanol consumed within census divisions 3 and 4 was assumed to be transported by truck, while distribution outside of those areas was via rail, ship, and/or barge. A single average distribution cost for each destination census division was generated by weighting together the 2012 freight costs given for each mode in both census divisions 3 and 4 according to their volume share. These cent per gallon figures were first adjusted upward by 10 percent to reflect higher energy prices, and then additional adjustments were applied to some individual states based on their position within the census division. In the cases of Alaska and Hawaii, differences in ethanol delivery prices from the mainland were inferred from gasoline prices. Table 2.2-15 shows the gasoline price and ethanol distribution cost for each state as used in this analysis.

Table 2.2-15.
Gasoline Price & Ethanol Distribution Costs[34]

State	Gasoline Rack Price (c/gal)	ETOH Distribution Cost (c/gal)
Alabama	123.2	7.2
Alaska	157.0	41.5
Arizona	138.0	15.4
Arkansas	123.3	7.3
Colorado	129.5	10.4
Florida	124.9	8.4
Georgia	125.8	11.4
Hawaii	151.7	36.5
Idaho	134.2	15.4
Illinois	125.7	4.4
Indiana	125.6	5.4
Iowa	127.5	3.4
Kansas	124.3	4.4
Kentucky	125.9	6.2
Louisiana	123.1	7.3
Maine	125.5	13.4
Maryland	124.8	11.4
Michigan	126.5	6.4
Minnesota	127.4	4.4
Mississippi	123.0	6.2
Missouri	126.0	4.4
Montana	130.5	13.4
Nebraska	126.0	4.4
Nevada	141.6	16.4
New Hampshire	125.3	12.4
New Mexico	128.4	12.4
New York	126.0	11.4
North Carolina	124.4	11.4
North Dakota	127.7	5.4
Ohio	126.2	5.4
Oklahoma	123.4	8.3
Oregon	133.8	16.5
Pennsylvania	126.1	8.4
South Carolina	124.9	11.4
South Dakota	127.8	4.4
Tennessee	124.5	6.2
Texas	122.5	10.3
Utah	132.3	13.4
Vermont	127.3	12.4
Virginia	123.4	11.4
Washington	132.1	16.5
West Virginia	125.8	11.4
Wisconsin	125.2	4.4
Wyoming	130.4	12.4

As the final step in the calculation, subsidies and other adjustments were applied. The federal blending credit of 51 cents per gallon was given to all areas, and five state retail incentives were included as follows (all cents per gallon of ethanol): Iowa, 29.5; Illinois, 20.1, South Dakota, 20; Maine: 7.5; Oklahoma, 1.6.[35QQ]

In addition to state subsidies, small penalty adjustments were made for distributing ethanol into rural areas in several states (as presented in Table 2.2-16). The reasoning behind this is that when large shipments of ethanol come from the Midwest by barge, ship, or rail, they will be unloaded initially at large terminals near metropolitan areas. Further storage and handling will be required to allow smaller quantities to be distributed via truck into rural areas. Several states have gasoline pipelines that traverse them with connections at various points, helping to reduce distribution burdens, but ethanol is not expected to be shipped via pipeline. Overall, the largest adjustments were applied to the Rocky Mountain states since they are generally larger in area and additional expense is required to transport freight through higher elevations and rugged terrain. Smaller adjustments were applied to states that are smaller, flatter, or have navigable water access on one or more sides. The states that do not appear on this list are either located in the Midwest (where ethanol is produced and readily available to virtually all areas at similar costs) or are small northeast states not believed to have significant differences between rural and urban distribution costs.

Table 2.2-16.
Adjustment for Ethanol Distribution into Rural Areas

States	Rural Area Adjustment (c/gal)
OH	2
AL, AR, FL, GA, KY, LA, ME, MS, NC, NY, OK, OR, PA, SC, TN, VA, WA, WV	4
AK, AZ, CO, ID, NM, NV, UT, WY, TX	5

To determine which in-use areas/counties would receive urban versus rural ethanol distribution pricing based on the economies of scale described above, we looked to the U.S. Census Bureau which considers population density and other factors.

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[34] The following states have intentionally been excluded from this CG gasoline/ethanol cost table because they do not consume any CG (100% RFG): CA, CT, DC, DE, MA, NJ, RI.

[35] EPA acknowledges that other states are considering (or may have even approved) retail pump incentives for gasohol. However, at the time this consumption analysis was completed, these were the only five states offering retail pump incentives that were likely to be applicable in 2012.

Metropolitan Statistical Areas (MSAs) served as the starting point for determining the areas within a state that would be considered “urban”. MSAs are geographic entities defined by the U.S. Office of Management and Budget (OMB) for use by federal statistical agencies in collecting, tabulating, and publishing federal statistics. An MSA is defined as having a core urban area of 50,000 or more people. Each MSA consists of one or more counties including the counties contained the core urban area, as well as any adjacent counties that have a high degree of social and economic integration with the urban core. For the purposes of this analysis, we only considered MSAs with populations greater than 1 million people, or other areas having special qualifications. Such qualifications include MSAs with less than 1 million people that happen to be the largest MSA in a less-populated state (i.e. Montana and Wyoming), or other MSAs deemed likely to receive ethanol by rail based on proximity to major rail lines.

Once the urban counties for each state were determined, county-level vehicle miles traveled (VMT) from 2002 were used (as a surrogate for fuel consumption) to weight the urban counties’ approximate fuel demand. Expressing the urban VMT as a function of statewide VMT gave us the percentage of ethanol demand that would be considered eligible for an urban ethanol distribution cost (values presented in Table 2.2-15). The remaining percentage of ethanol demand was considered to be “rural” and subject to the ethanol blending penalty adjustments found in Table 2.2-16.

Considering the urban/rural split for each state and the resulting ethanol margin (ethanol delivered price minus gasoline production cost), we came up with the resulting ranking system for distributing ethanol into conventional gasoline. For PADD 1, refer to Table 2.2-17; PADD 2, refer to Table 2.2-18, PADD 2, Table 2.2-19; and PADDs 4/5, Table 2.2-20. The summer and winter percentages are the same for each urban/rural area with the exception of states containing winter oxy-fuel areas. For these states, winter oxy-fuel was deducted from the winter urban fuel since this volume of gasoline was already accounted for (refer to Table 2.2-12).

Table 2.2-17.
Precedence for Adding ETOH to PADD 1 CG

State	Rural / Urban	Ethanol Margin (c/gal)	PADD 1 Precedence	% of CG Volume	
				Summer	Winter
ME	u	50.6	1	35.7%	35.7%
PA	u	48.7	2	44.7%	44.7%
FL	u	47.5	3	59.9%	59.9%
ME	r	46.6	4	64.3%	65.3%
VT	-	45.9	5	100.0%	100.0%
NY	u	45.6	6	67.8%	67.8%
GA	u	45.4	7	51.2%	51.2%
WV	u	45.4	8	21.1%	21.1%
PA	r	44.7	9	55.3%	55.3%
SC	u	44.5	10	20.2%	20.2%
MD	-	44.4	11	100.0%	100.0%
NC	u	44.0	12	14.7%	14.7%
NH	-	43.9	13	100.0%	100.0%
FL	r	43.5	14	40.1%	40.1%
VA	u	43.0	15	63.9%	63.9%
NY	r	41.6	16	32.3%	32.3%
WV	r	41.4	17	78.9%	78.9%
GA	r	41.4	18	48.8%	48.8%
SC	r	40.5	19	79.8%	79.8%
NC	r	40.0	20	85.3%	85.3%
VA	r	39.0	21	36.1%	36.1%

Table 2.2-18.
Precedence for Adding ETOH to PADD 2 CG

State	Rural / Urban	Ethanol Margin (c/gal)	PADD 2 Precedence	% of CG Volume	
				Summer	Winter
IA	-	84.6	1	100.0%	100.0%
SD	-	74.4	2	100.0%	100.0%
IL	-	72.4	3	100.0%	100.0%
ND	-	53.3	4	100.0%	100.0%
NE	-	52.6	5	100.0%	100.0%
OH	u	51.8	6	37.7%	37.7%
WI	-	51.8	7	100.0%	100.0%
IN	-	51.2	8	100.0%	100.0%
MI	-	51.1	9	100.0%	100.0%
KS	-	50.9	10	100.0%	100.0%
KY	u	50.7	11	10.2%	10.2%
OH	r	49.8	12	62.3%	62.3%
TN	u	49.3	13	38.4%	38.4%
OK	u	47.7	14	29.9%	29.9%
KY	r	46.7	15	89.8%	89.8%
TN	r	45.3	16	61.6%	61.6%
OK	r	43.7	17	70.1%	70.1%

Table 2.2-19.
Precedence for Adding ETOH to PADD 3 CG

State	Rural / Urban	Ethanol Margin (c/gal)	PADD 3 Precedence	% of CG Volume	
				Summer	Winter
MS	u	47.8	1	6.8%	6.8%
NM	u	47.0	2	31.3%	16.0%
AR	u	47.0	3	26.4%	26.4%
AL	u	47.0	4	31.2%	31.2%
LA	u	46.8	5	16.7%	16.7%
MS	r	43.8	6	93.2%	93.2%
TX	u	43.2	7	61.8%	58.2%
AR	r	43.0	8	73.7%	73.7%
AL	r	43.0	9	68.8%	68.8%
LA	r	42.8	10	63.3%	63.3%
NM	r	42.0	11	68.7%	68.7%
TX	r	38.2	12	38.2%	38.2%

Table 2.2-20.
Precedence for Adding ETOH to PADDs 4/5 CG

State	Rural / Urban	Ethanol Margin (c/gal)	PADDs 4/5 Precedence	% of CG Volume	
				Summer	Winter
NV	u	56.2	1	57.8%	49.2%
AZ	u	53.6	2	55.2%	5.4%
NV	r	51.2	3	42.2%	42.2%
CO	u	50.1	4	48.6%	48.6%
UT	u	49.9	5	38.7%	38.7%
ID	u	49.8	6	32.3%	32.3%
WY	u	49.0	7	11.6%	11.6%
AZ	r	48.6	8	44.8%	44.8%
OR	u	48.3	9	38.2%	1.4%
WA	u	46.6	10	43.6%	43.6%
AK	u	46.5	11	36.4%	36.4%
HI	-	46.2	12	15.0%	15.0%
CO	r	45.1	13	51.4%	51.4%
UT	r	44.9	14	61.3%	61.3%
ID	r	44.8	15	67.7%	67.7%
OR	r	44.3	16	61.8%	61.8%
WY	r	44.0	17	88.5%	88.5%
WA	r	42.6	18	36.4%	36.4%
AK	r	41.5	19	63.6%	63.6%

2.2.4.5 Resulting 2012 Gasoline/Oxygenate Consumption by State

Applying the CG order of precedence tables to the remaining conventional gasoline ethanol (less state mandated and winter oxy-fuel volumes) and factoring in the RFG ethanol distribution (described above in 2.2.4.4), we came up with an ethanol distribution by state for each control case. The resulting state-by-state ethanol distribution is summarized below in Table 2.2-21 and a graphical representation for each control case is provided in Figures 2.2-3 and 2.2-4 below.

Table 2.2-21.
2012 Forecasted Ethanol Consumption by State

(continued on next page)

		6.7 Bgal RFS Case			9.6 Bgal EIA Case		
State	**Abbrv**	**Gasoline MMgal**	**ETOH MMgal**	**% of Gasoline**	**Gasoline MMgal**	**ETOH MMgal**	**% of Gasoline**
Alabama	AL	2,869	90	3.1%	2,910	291	10.0%
Alaska	AK	324	0	0.0%	327	0	0.0%
Arizona	AZ	2,377	123	5.2%	2,397	149	6.2%
Arkansas	AR	1,686	44	0.0%	1,710	171	10.0%
California	CA	16,494	813	4.9%	16,494	905	5.5%
Colorado	CO	2,143	0	0.0%	2,169	57	2.6%
Connecticut	CT	1,827	146	8.0%	1,827	158	8.6%
Delaware	DE	538	43	0.0%	538	46	8.6%
District of Columbia	DC	143	0	0.0%	143	3	2.0%
Florida	FL	10,734	521	4.8%	10,734	474	4.4%
Georgia	GA	5,899	0	0.0%	5,899	12	0.2%
Hawaii	HI	484	0	0.0%	490	42	8.5%
Idaho	ID	677	0	0.0%	686	12	1.7%
Illinois	IL	6,737	454	6.7%	6,737	570	8.5%
Indiana	IN	3,820	352	9.2%	3,820	368	9.6%
Iowa	IA	2,017	202	10.0%	2,017	202	10.0%
Kansas	KS	1,722	86	5.0%	1,722	172	10.0%
Kentucky	KY	2,742	42	1.5%	2,742	72	2.6%
Louisiana	LA	2,743	99	0.0%	2,782	278	10.0%
Maine	ME	944	34	0.0%	944	64	6.8%
Maryland	MD	2,990	0	0.0%	2,990	52	1.7%
Massachusetts	MA	3,522	281	8.0%	3,522	304	8.6%
Michigan	MI	5,995	346	5.8%	5,995	599	10.0%
Minnesota	MN	3,310	331	10.0%	3,310	331	10.0%
Mississippi	MS	1,940	25	0.0%	1,968	197	10.0%
Missouri	MO	3,986	343	8.6%	3,986	372	9.3%
Montana	MT	539	54	10.0%	546	55	10.0%
Nebraska	NE	1,010	101	10.0%	1,010	101	10.0%
Nevada	NV	920	6	0.7%	931	52	5.6%
New Hampshire	NH	855	50	0.0%	855	54	6.3%
New Jersey	NJ	5,083	406	8.0%	5,083	439	8.6%
New Mexico	NM	1,152	35	3.0%	1,167	109	9.3%
New York	NY	6,876	289	4.2%	6,876	423	6.1%
North Carolina	NC	5,366	0	0.0%	5,366	0	0.0%
North Dakota	ND	432	43	10.0%	432	43	10.0%
Ohio	OH	6,358	438	6.9%	6,358	636	10.0%
Oklahoma	OK	2,661	0	0.0%	2,661	28	1.0%
Oregon	OR	1,623	34	2.1%	1,638	34	2.1%
Pennsylvania	PA	5,909	318	0.0%	5,909	328	5.6%
Rhode Island	RI	588	47	8.0%	588	51	8.6%
South Carolina	SC	3,022	0	0.0%	3,022	0	0.0%
South Dakota	SD	535	54	10.0%	535	54	10.0%
Tennessee	TN	4,010	37	0.0%	4,010	78	2.0%
Texas	TX	14,454	62	0.4%	14,574	759	5.2%
Utah	UT	1,176	0	0.0%	1,191	25	2.1%
Vermont	VT	422	0	0.0%	422	21	5.0%
Virginia	VA	4,786	0	0.0%	4,786	52	1.1%
Washington	WA	2,810	56	2.0%	2,843	64	2.3%
West Virginia	WV	964	0	0.0%	964	0	0.0%
Wisconsin	WI	3,117	268	8.6%	3,117	291	9.3%
Wyoming	WY	333	0	0.0%	337	2	0.6%
Total		**163,664**	**6,671**	**4.1%**	**164,078**	**9,600**	**5.9%**

Figure 2.2-3. 2012 Forecasted Ethanol Consumption 6.7 Bgal RFS Case, % E10 by State

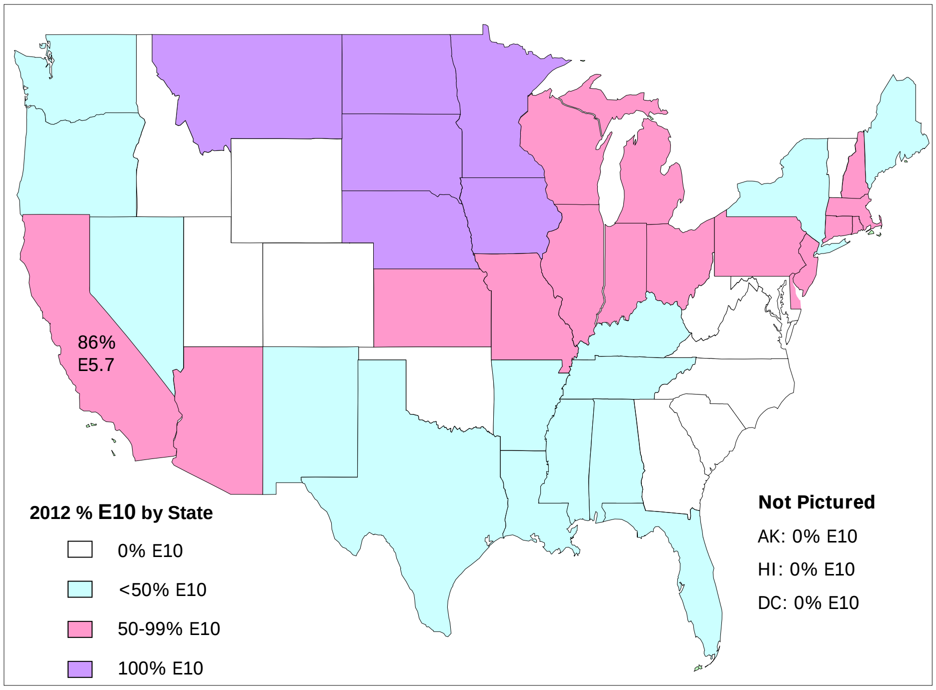
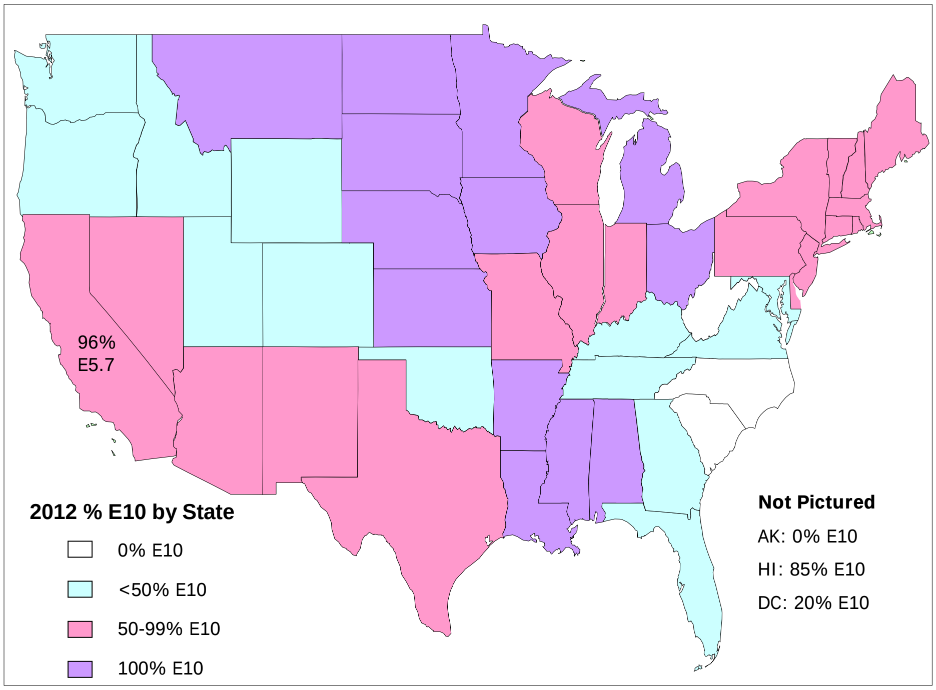


Figure 2.2-4. 2012 Forecasted Ethanol Consumption 9.6 Bgal EIA Case, % E10 by State



2.3 Effects of Ethanol and MTBE on Gasoline Fuel Properties

For the final rulemaking, we estimate the impact of increased ethanol use and decreased MTBE use on gasoline quality using refinery modeling conducted specifically for the RFS rulemaking.[36] The methods, analyses, and results of the refinery modeling are discussed in more detail in Chapter 7. In general, adding ethanol to gasoline reduces the aromatic content of conventional gasoline (CG) and the mid and high distillation temperatures (e.g., T50 and T90). RVP increases except in areas where ethanol blends are not provided a 1.0 RVP waiver of the applicable RVP standards in the summer. With the exception of RVP, adding MTBE directionally produces the same impacts. Thus, the effect of removing MTBE results in essentially the opposite impacts. Neither oxygenate is expected to affect sulfur levels, as refiners control sulfur independently in order to meet the Tier 2 sulfur standards.

The impacts of oxygenate use are smaller with respect to RFG. This is due to the applicability of VOC and toxics emission performance specifications, which limit the range of feasible fuel quality values. Thus, RVP and aromatic and benzene contents are not consistently affected by oxygenate type or level.

Table 2.3-1 shows the fuel quality of a typical summertime, non-oxygenated conventional gasoline and how these qualities change with the additional of 10 volume percent ethanol (10 vol%). Similarly, the table shows the fuel quality of a typical MTBE RFG blend and how fuel quality might change with either ethanol use or simply MTBE removal. Note that the table does not reflect county-specific fuel properties.

Table 2.3-1. CG and RFG Summer Fuel Quality With and Without Oxygenates

	Conventional Gasoline		Reformulated Gasoline [a]		
Fuel Parameter	Typical 9 RVP	Ethanol Blend	MTBE Blend	Ethanol Blend	Non-Oxygenated Blend
RVP (psi)	8.7	9.7	7.0	7.0	7.0
T50	218	205	179	184	175
T90	332	329	303	335	309
E200	41	50	60	58	52
E300	82	82	89	82	88
Aromatics (vol%)	32	27	20	20	20
Olefins (vol%)	7.7	7.7	4	14	15
Oxygen (wt%)	0	3.5	2.1	3.5	0
Benzene (vol%)	1.0	1.0	0.74	0.70	0.72

[a] MTBE blend –Reference Case PADD 1 South, Ethanol blend – RFS Case PADD 1 North, Non-oxy blend – RFS Case PADD 1 South

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[36] Refinery modeling performed in support of the original RFG rulemaking is also used to help separate the effects of the two oxygenates.

2.3.1 Effect of Ethanol on Conventional Gasoline Fuel Properties

To estimate effects of ethanol on conventional gasoline, we used the refinery model output shown below in Table 2.3-2. These values represent average properties across the five PADDs and winter and summer seasons.

Table 2.3-2. Properties of Conventional Gasoline Per Refinery Modeling

Case	Aromatics (vol%)	Olefins (vol%)	E200 (vol%)	E300 (vol%)	T50 (°F)	T90 (°F)	MTBE (vol%)	Ethanol (vol%)
2012 Reference	29.18	12.39	49.96	81.64	190.3	335.3	0.65	1.66
2012 RFS	29.02	12.12	51.89	83.68	187.4	326.2	0.00	3.87
2012 EIA	27.97	12.39	53.04	82.20	185.9	332.8	0.00	5.38

Using this output, we estimated an average change in each fuel property per vol% change in ethanol content. To derive these estimations, we first adjusted the Reference case properties to isolate the effects of ethanol by mathematically removing the effects of MTBE using factors derived from the RFG RIA[RR]. Then, we calculated the change in each fuel property per change in ethanol vol% for each combination of cases. That is, we compared Reference Case to RFS Case, Reference to EIA, and EIA to RFS. Finally, we averaged the three results from the case-to-case comparisons to derive a useful factor for adjusting county-level fuel properties for a change in county-level ethanol content. These ethanol effects are shown below in Table 2.3-3.

Table 2.3-3. Change in Conventional Gasoline Properties Per Vol% Increase in Ethanol

Aromatics (vol%)	Olefins (vol%)	E200 (vol%)	E300 (vol%)	T50 (°F)	T90 (°F)
-0.46	0.02	0.91	0.06	-1.33	-0.28

2.3.2 Effects of MTBE on Conventional Gasoline Fuel Properties

In support of the final rule implementing the RFG program in 1993, refinery modeling was performed which estimated the impact of MTBE blending on the various gasoline properties.[SS] While this modeling was performed in the context of projecting the cost of producing RFG, it is applicable to the use of MTBE in CG, as well. The refinery modeling examined a number of incremental steps involved in the production of RFG. Because RFG was mandated to contain oxygen and MTBE was expected to be the oxygenate of choice, MTBE was added in the first step of the analysis, before the fuel met the rest of the RFG requirements. Table 2.3-4 shows the results of adding MTBE based on this refinery modeling.

This modeling of MTBE effects is somewhat dated (circa 1993). However, since removing MTBE does not involve any predictions of its total usage level nor the location of its use, economics (such as crude oil price) are not a factor. It is primarily an issue of chemical properties and general refinery operation, such as octane management. Also, MTBE is always match-blended, since gasoline can be shipped with MTBE through pipelines. Thus, MTBE is always added at the refinery, allowing the refiner to take full advantage of its properties.

Table 2.3-4. Effect of MTBE on Gasoline Properties: RFG Final Rule

Fuel Parameter	Base 9 RVP Gasoline	MTBE Blend	Difference
RVP (psi)	8.7	8.7	0
T50[a]	218	207	-11
T90[a]	329	321	-8
E200 (vol%)	41	46.7	5.7
E300 (vol%)	83	84.9	1.9
Aromatics (vol%)	32.0	25.5	-6.5
Olefins (vol%)	13.1	13.1	0
Oxygen (wt%)	0	2.1	2.1
Benzene (vol%)	1.53	0.95	-0.58

[a] Estimated using correlations developed in support of EPA RFG final rule, Docket A-92-12, February 1994.

$T50 = 302 – E200 / 0.49$ and $T90 = 707 - E300 / 0.22$

As with ethanol blending, MTBE blending reduces aromatic content significantly as refiners take advantage of MTBE's high octane level. Like ethanol, MTBE also tends to increase E200 and E200 and decrease T50 and T90. Unlike ethanol, MTBE does not increase RVP.

MTBE blending is shown to modestly reduce sulfur and benzene levels, as well. This refinery modeling was performed prior to the development of the Tier 2 sulfur standards for gasoline. With these standards, gasoline must meet a 30 ppm sulfur standard on average with or without MTBE blending. As refiners can adjust the severity of their hydrotreating processes to account for various changes in feedstocks and oxygenate use, we do not expect that the removal of MTBE will result in any increase in sulfur content. Otherwise, the reversal of the differences shown in Table 2.3-4 are expected to occur when MTBE is removed from gasoline (when the MTBE content was 11 vol%).

2.3.3 Effects of Ethanol and MTBE on Reformulated Gasoline Fuel Properties

RFG has historically contained oxygenate due to the applicable 2.0 weight percent oxygen content requirement. RFG has contained 11 vol% MTBE or ten vol% ethanol, except in California, where 6 vol% ethanol blends have been common. As discussed in Section 2.2, the use of MTBE in RFG has ceased. It has been replaced by either 10 vol% or ethanol or high octane hydrocarbon blending components, such as alkylate or reformate. In either case, as discussed in Section 2.3.2, RFG will continue to have to meet stringent VOC, NOx, and toxic emission performance standards, though compliance with the NOx standard is essentially assured with compliance with the Tier 2 sulfur standards applicable to all gasoline[37].

For the NPRM, we assumed that the properties of RFG other than oxygenate would not be affected by changes in oxygenate use. For the FRM, we are utilizing the recent refinery modeling to estimate RFG properties by PADD and season for the three ethanol use scenarios.

As described above, five refinery models were developed, each representing one PADD. These models produced fuel for use in its own PADD, as well as for use in other PADDs in the several cases of PADD-to-PADD distribution of gasoline. For RFG, refinery modeling projected that a significant volume of RFG used in PADD 1 would be produced by PADD 3 refineries. Because this PADD 3 RFG is shipped to PADD 1 via pipeline, this fuel tends to be used in the southernmost RFG areas of PADD 1, namely those in Virginia, the District of Columbia and Maryland. In order to reflect this, we assumed that the RFG produced in PADD 3 will be used preferentially in the RFG areas of these three states and the RFG produced in PADD 1 will be used to fulfill the remaining demand for RFG in PADD 1. For refinery modeling, it was estimated that a small volume of RFG would be produced in PADD 3 and shipped to PADD 2. Because of the small volume involved, we did not assign this volume to a specific RFG area within PADD 2.

As part of their work, the refinery modeling contractors calibrated their model to match EPA’s estimate of fuel quality existing in 2004 (i.e., the base case in this analysis). Therefore, estimates of the properties of RFG for the base case comprise an accurate estimate of actual 2004 RFG, at least on a PADD-average basis. We also have available the results of the RFG fuel survey for each RFG area. This survey data sometimes reflects significant differences in the properties of RFG for specific RFG areas within a PADD. Good examples of this would be RFG areas in New York and Connecticut, which implemented MTBE bans starting in 2004. We considered using the more precise RFG survey data to represent RFG fuel quality in the base case, but rejected this approach for two reasons. One, this would introduce an extraneous difference in RFG fuel quality between the base case and the RFS/EIA cases. While refinery model base case projections reasonably match EPA’s estimate of 2004 fuel quality, they do not match exactly. Comparisons between the base case and the RFS and EIA cases would therefore include the difference between the RFG survey data and the refinery modeling contractor’s estimate of this data, plus the effect of additional ethanol use and reduced MTBE use. Two, we primarily present the emission impacts of the RFS rule on a nationwide basis. On a nationwide basis, reflecting differences between RFG fuel quality within a PADD would have little impact. Also, the Ozone RSM can only reflect a single change in VOC and NOx emissions in non-attainment areas (e.g., RFG areas). Thus, differences between specific RFG areas would be eliminated by the limitation that only

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[37] Though the MSAT2 final rulemaking (72 FR 8428, February 26, 2007) eliminates these air toxics and NOx requirements beginning in 2011.

the average emission effect can be modeled. Thus, we used refinery modeling projections of RFG fuel quality for all three fuel scenarios.

Tables 2.3-5, 2.3-6, and 2.3-7 present the fuel properties of summertime RFG under the base, RFS and EIA fuel scenarios, respectively. Under the RFS and EIA cases, there is no MTBE or TAME in the fuel, so these rows are not shown (i.e., total oxygen content is the same as ethanol content in terms of weight percent).

Table 2.3-5. RFG Fuel Properties: Base Case – Summer

	PADD 1 South	PADD 1 North	PADD 2	PADD 3	PADD 5	All U.S.
RVP	7.0	7.1	7.0	7.0	6.8	6.9
Sulfur ppm	6.7	22.6	4.5	6.9	10.0	13.0
Aromatics	21.0	23.9	21.6	20.0	22.0	22.3
Benzene	0.74	0.70	0.76	0.70	0.57	0.71
Olefins	4.3	13.7	8.0	4.4	5.7	8.5
E200	59.9	55.0	58.4	59.8	54.6	56.3
E300	88.9	80.3	86.0	88.9	86.2	84.7
T50	179.2	189.6	182.5	179.8	190.5	186.9
T90	302.7	341.7	316.0	302.7	315.0	321.9
Oxygen (wt%)	2.1	2.3	2.3	2.1	1.9	2.1
MTBE (wt%O)	1.9	0.5	1.3	1.9	0.0	0.7
TAME (wt%O)	0.2	0.0	0.1	0.2	0.0	0.1
Ethanol (wt%O)	0.0	1.8	0.9	0.1	1.9	1.3

Table 2.3-6. RFG Fuel Properties: RFS Case – Summer

	PADD 1 South	PADD 1 North	PADD 2	PADD 3	PADD 5	All U.S.
RVP	7.0	7.0	7.1	7.0	6.8	6.9
Sulfur ppm	20.5	7.6	21.3	19.8	9.0	13.6
Aromatics	20.1	20.0	17.9	20.0	22.5	20.5
Benzene	0.72	0.70	0.67	0.70	0.57	0.66
Olefins	14.6	13.6	17.3	14.1	5.7	11.9
E200	52.0	57.6	54.1	52.0	54.5	54.5
E300	87.5	81.9	81.8	87.5	86.2	84.9
T50	174.7	184.2	185.3	195.7	190.5	185.9
T90	308.8	334.6	334.8	308.8	315.0	321.0
Ethanol (wt%O)	0.0	3.7	0.6	0.2	1.8	1.6

Table 2.3-7. RFG Fuel Properties: EIA Case – Summer

	PADD 1 South	PADD 1 North	PADD 2	PADD 3	PADD 5	All U.S.
RVP	7.0	7.0	7.1	7.0	6.8	6.9
Sulfur ppm	23.1	10.0	19.3	22.3	8.9	14.9
Aromatics	20.2	19.7	17.9	20.0	22.6	20.5
Benzene	0.70	0.74	0.60	0.67	0.57	0.65
Olefins	18.9	10.3	14.7	18.3	5.7	12.1
E200	52.0	57.7	55.8	52.0	54.6	54.7
E300	84.3	81.8	80.9	84.3	86.2	83.8
T50	179.4	184.0	183.4	195.7	190.5	186.4
T90	323.6	334.7	339.2	323.6	315.0	325.7
Ethanol (wt%O)	0.0	3.7	1.8	0.2	1.9	1.8

As shown in Tables 2.3-6 and 2.3-7, summer RFG produced in PADD 1 under the two increased ethanol use cases contains 10 vol% ethanol (i.e., 3.7 wt% oxygen). However, RFG produced in the other PADDs contains less than the maximum 10 vol% ethanol. For other parameters the results generally support the proposed assumption that they would remain constant, although there were some small changes. The biggest changes in the RFS and EIA fuel scenarios include higher levels of olefins, T50 and T90 and lower aromatic levels.

Tables 2.3-8, 2.3-9, and 2.3-10 present the fuel properties of wintertime RFG under the base, RFS and EIA fuel scenarios, respectively.

Table 2.3-8. RFG Fuel Properties: Base Case – Winter

	PADD 1 South	PADD 1 North	PADD 2	PADD 3	PADD 5	All U.S.
RVP	11.2	12.9	12.8	11.2	11.5	12.0
Sulfur ppm	28.0	25.5	26.2	26.9	9.5	21.1
Aromatics	21.1	19.0	13.9	20.0	20.8	19.3
Benzene	0.74	0.70	0.64	0.70	0.47	0.63
Olefins	12.6	16.0	11.6	12.2	5.7	11.1
E200	63.6	57.4	66.9	63.1	59.3	61.0
E300	88.9	80.3	79.5	88.9	86.2	84.5
T50	179.2	184.7	165.4	173.1	180.8	178.5
T90	302.7	341.7	345.2	302.7	315.0	322.7
Oxygen (wt%)	2.1	2.5	3.3	2.1	2.2	2.4
MTBE (wt%O)	2.1	0.5	0.0	2.0	0.0	0.7
TAME (wt%O)	0.0	0.0	0.0	0.1	0.0	0.0
Ethanol (wt%O)	0.0	2.0	3.3	0.1	2.2	1.7

Table 2.3-9. RFG Fuel Properties: RFS Case – Winter

	PADD 1 South	PADD 1 North	PADD 2	PADD 3	PADD 5	All U.S.
RVP	11.8	13.1	13.0	11.8	11.5	12.3
Sulfur ppm	28.0	25.0	25.4	26.7	9.4	20.8
Aromatics	21.4	19.0	17.8	21.2	23.7	20.9
Benzene	0.75	0.70	0.89	0.73	0.43	0.65
Olefins	13.3	16.0	12.3	12.6	5.7	11.4
E200	53.5	63.1	63.9	53.4	58.2	59.0
E300	87.5	81.9	79.5	87.5	86.2	84.5
T50	174.7	173.0	171.4	192.9	183.0	178.4
T90	308.8	334.6	345.2	308.8	315.0	322.7
Ethanol (wt%O)	0.0	3.7	3.0	0.0	1.8	2.0

Table 2.3-10. RFG Fuel Properties: EIA Case – Winter

	PADD 1 South	PADD 1 North	PADD 2	PADD 3	PADD 5	All U.S.
RVP	11.9	12.8	12.9	11.9	11.5	12.2
Sulfur ppm	27.5	25.2	23.8	25.6	8.5	19.9
Aromatics	22.2	19.0	20.7	21.7	23.7	21.2
Benzene	0.61	0.70	0.95	0.58	0.43	0.63
Olefins	14.8	16.0	12.3	13.6	5.7	11.9
E200	52.5	63.6	64.5	52.4	59.4	60.4
E300	84.3	81.9	79.5	84.3	86.2	83.3
T50	179.4	172.1	170.1	194.9	180.6	177.5
T90	323.6	334.3	345.2	323.6	315.0	327.9
Ethanol (wt%O)	0.0	3.7	3.7	0.0	2.2	2.6

As shown in Tables 2.3-9 and 2.3-10, winter RFG produced in PADD 1 under the two ethanol use cases contains 10 vol% ethanol (i..e., 3.7 wt% oxygen). PADD 2 winter RFG contains 10 vol% ethanol in the EIA case. However, RFG produced in the other PADDs and cases contains less than the maximum 10 vol% ethanol. On an annual average basis, RFG produced for use in California contains about 5.7 vol% ethanol (2.1 wt% oxygen). This is to be expected given the increase in NOx emissions assigned by CARB's Phase 3 Predictive Model to blends with more than 2.1 wt% oxygen. As for the summer cases, changes in other fuel parameters were small and mixed.

2.3.4 Estimation of County-Specific Gasoline Properties

In order to estimate the impact of increased ethanol use and reduced MTBE use on national emissions and air quality (described in Chapters 4 and 5), we need to estimate gasoline properties on a county-specific basis throughout the U.S. In support of previous analyses of national impacts of various rules, EPA has developed a set of gasoline specifications for each county in the U.S. for various months and calendar years.[TT] We based our analysis on the fuel quality specifications for January and July of 2008, since 2008 is the first year of full implementation of the Tier 2 sulfur standard of 30 ppm. Some of the EPA county-level gasoline specifications were based on old data, so we reviewed the estimates and made several modifications before applying the changes expected due to ethanol addition and MTBE removal.

First, we adjusted RVP values using more recent information on local RVP programs and to reflect commingling. Second, we revised the oxygenate content and type in each county to match the levels estimated in Section 2.2 to be sold there under each of the three ethanol use scenarios evaluated. Third, we adjusted the other properties of gasoline which are affected by the oxygenate use determined in step three. These modifications are described in more detail below.

2.3.4.1 Adjustments to RVP Levels Prior to Oxygenate Use

Our review of the NMIM database of county-specific RVP levels for July indicated that the same RVP level was often applied to all the counties of a specific state. In many cases, this appeared reasonable, since the same RVP standard applied throughout the entire state. However, in other cases, for example, Florida, most counties have a 9.0 RVP standard, while those comprising several large urban areas have a 7.8 RVP standard. The RVP levels in the NMIM database were consistent with the 7.8 RVP control programs, implying that the 7.8 RVP fuel was sold throughout the entire state. This was true for much of the south.

As mentioned above, the NMIM fuel quality database was based primarily on fuel survey data from 1999. Fuel surveys tend to focus on large urban areas, as opposed to smaller urban or rural areas. Thus, the only available fuel survey data was likely from the areas with the tighter local RVP controls. RVP control reduces gasoline supply, since lighter hydrocarbons must be removed in order to reduce RVP. Some, but not all of these hydrocarbon components can be moved to higher RVP fuel sold elsewhere. Obviously gasoline prices are now much higher than they were in 1999. So the incentive to increase supply is greater now than in 1999. As discussed in Chapter 7, high gasoline prices are projected for the foreseeable future, at least relative to those existing in 1999. Thus, we believe that it is reasonable to project that refiners will market gasoline blends with as high a level of RVP as practical given the applicable standards. For example, in Florida, two fuels will be marketed: one to meet the 7.8 RVP standard in several urban areas and another to meet the 9.0 RVP standard applicable elsewhere. There certainly could be some spillover of the 7.8 RVP fuel into adjacent 9.0 RVP counties. However, we lack data indicating the degree to which this is occurring and might occur in the future. Lacking this data, it seems more reasonable to project only that level of RVP control which is guaranteed by the applicable standards than to assume that refiners will over-comply with RVP standards and reduce the volume of gasoline which they can produce.

Past studies have shown that a typical compliance margin for RVP is about 0.3 psi. Thus, for those counties where the standard 9.0 RVP standard applies, we set the July RVP level to 8.7 psi.

EPA maintains a list of counties where its 7.8 RVP standard applies, as well as any local standards more stringent than 9.0 RVP.[UU] Using this list, we assigned RVP values in each county equal to 0.3 psi less than the standard applicable in July. We also reduced the RVP levels of two sets of counties which had voluntary local RVP control programs (and therefore not listed the above Guide). These two areas were Seattle and Tulsa. Based on a review of annual fuel survey data collected by the Alliance of Automobile Manufacturers (AAM)[VV], the fuel being sold in these areas was very similar to that for an area with a 7.8 RVP standard. Thus, we assigned a value of 7.5 psi RVP to Tulsa County, Oklahoma, and to King, Pierce, and Snohomish Counties, Washington.

We then assigned an RVP value of 6.8 psi to counties subject to the Federal RFG program, again based on an EPA list of the counties subject to this program.[WW] The EPA list of RFG counties includes the Baton Rouge, Louisiana, area. However, litigation has held up implementation of this program, so these counties were assigned RVP values consistent with the currently applicable 7.8 RVP standard instead. The RVP value of 6.8 psi was typical for the RFG areas included in the AAM fuel surveys.

For the purposes of our analysis, we also assigned the entire State of California an RVP of 6.8 psi, since California fuel must meet a similar VOC performance standard to RFG. Likewise, RVP in Maricopa and Pinal counties in Arizona were assigned a level of 6.8 psi. These two counties are subject to Arizona's unique reformulated gasoline program. This program basically requires that gasoline sold in these two counties meet either the California RFG or Federal RFG standards. Thus, RVP in these two counties will be the same as in those other two areas, similar to national RFG fuel.

These RVP levels for 9.0 RVP and low RVP areas are appropriate when no ethanol is being blended into gasoline. However, most of these areas increase the applicable standard by 1.0 psi for ethanol blends, which is the typical impact of ethanol blending. Therefore, these levels need to be adjusted for the expected level of ethanol use, which is discussed below.

2.3.4.2 County-Specific Oxygenate Type and Content

The three ethanol use scenarios developed in Section 2.2 assign ethanol and MTBE use by state and fuel type (i.e., conventional gasoline, RFG, oxyfuel). In order to develop county level estimates of ethanol and MTBE use, we simply assume that ethanol and MTBE use within a state and fuel type is uniform. For example, if the E10 market share in conventional gasoline Iowa is 34%, then ethanol use in every county receiving conventional gasoline in Iowa was assigned an E10 market share of 34%.

As described above, we nearly always assume that ethanol use is in the form of a 10 vol% blend with gasoline. The two exceptions are California fuel and Arizona RFG.

California fuel containing ethanol is assumed to contain 5.7 vol% ethanol. Arizona RFG is assumed to be a mix of 67% California fuel and 33% Federal RFG produced in PADD 3. Therefore, its ethanol content is a 2/1 mix of the ethanol contents of California RFG and PADD 3 Federal RFG.

Similarly, we assume that MTBE is used at an 11 vol% level in RFG, since this meets the previously mandated oxygen content of 2.1 wt%. MTBE in conventional gasoline was assumed to be used at a 3 vol% level. This was somewhat arbitrary, but does not affect the outcome of the analysis. The effect of MTBE blending on emissions is very linear. Therefore, whether the fuel pool in a particular area consists of 10% of a 10 vol% MTBE blend or 33% of a 3 vol% MTBE blend is immaterial. Though MTBE is present in the 2012 Reference Case, it is assumed to be completely phased-out in the RFS and EIA ethanol use cases.

EPA's NMIM model (described in more detail in Chapter 4) will only accept a single composite fuel for each county. Therefore, we could not use the mix of fuels often projected to be supplied to counties developed in Section 2.2. In order to produce a single, composite fuel, we simply multiplied the ethanol and MTBE contents of each blend by their market share in that county in order to determine the average ethanol and MTBE contents of each county's fuel pool, respectively. For example, if the E10 market share in a specific county was 50%, the ethanol content for that fuel was set to 5 vol%. We then adjusted the other fuel properties to account for these oxygenates, which is discussed below.

2.3.4.3 Adjustments to Other Gasoline Properties for Oxygenate Use

We next adjusted other gasoline properties to account for the level of county-specific oxygenate use projected to occur under the three ethanol use scenarios. Our review of the NMIM fuel database indicated that properties, such as aromatics, reflected the level of oxygenate use existing in 1999. Therefore, we used the oxygenate levels in the NMIM database, which differ from those developed in Section 2.2 for 2004, as the basis for our adjustments of the other fuel properties. For example, if the NMIM database indicated an ethanol content of 3 vol% for fuel sold in Wayne County, Michigan, and the 2004 projection for this county was 5 vol%, we adjusted the NMIM fuel properties for this county to reflect the addition of 2 vol% ethanol.

The bases for these adjustments were those developed in Sections 2.3.1 through 2.3.4 above. As described there, these adjustments apply primarily to conventional gasoline. These adjustments are summarized in Table 2.3-11 below.

Table 2.3-11
Change in Property per 1 Vol% Increase in Ethanol and MTBE Content

	E200 (%)	E300 (%)	Aromatics (Vol%)	Olefins (Vol%)	RVP (psi)
Conventional Gasoline					
Ethanol	+1.0	+0.24	-0.5	-0.16	+0.1
MTBE	+0.52	+0.17	-0.59	0	0
Reformulated Gasoline					
Ethanol	0	0	0	0	0
MTBE	0.1	0.1	0	0	0

To calculate new fuel properties for each county, we applied the ethanol and MTBE factors to the change in county-level ethanol and MTBE content. The overall adjustment to the fuel property was the addition of the ethanol effect and the MTBE effect to the baseline fuel property.

For the impact of ethanol blending on aromatic and olefin contents, we followed a slightly different approach. We assumed that the ethanol present in 1999 had been splash-blended, while that being used in the future will be match-blended. This difference doesn't affect the adjustment of RVP, E200, or E300, since we assume that these parameters are affected in the same way regardless of whether the ethanol is splash- or match-blended. However, the change in aromatics does depend on which blending approach is used. The situation is similar for olefins, though to a lesser extent. Thus, we employed what can be thought of as a two step process in adjusting aromatic and olefin contents for the change in ethanol content between the NMIM estimate and those for the three ethanol use scenarios developed in Section 2.2.

The first step is to account for any splash-blended ethanol in the NMIM database. With splash-blending, aromatic and olefin contents are reduced simply by dilution, since ethanol contains is neither an aromatic nor an olefin. The following equation shows how the NMIM level of aromatics was adjusted:

$$\begin{matrix}\text{Intermediate}\\ \text{Aromatic}\\ \text{Content}\end{matrix} = \begin{matrix}\text{NMIM}\\ \text{Aromatic}\\ \text{Content}\end{matrix} \div \left(1 - \left(\begin{matrix}\text{NMIM}\\ \text{Ethanol}\\ \text{Content}\end{matrix}\right)\left(\begin{matrix}\text{NMIM}\\ \text{Ethanol}\\ \text{Market}\\ \text{Share}\end{matrix}\right) \div 100 \right)$$

Then, the effect of any ethanol projected to be sold in that county in the three ethanol use scenarios developed in Section 2.2 was applied using the approach described above for RVP, E200 and E300 (and for the effect of MTBE on aromatics and olefins). In this case, the NMIM ethanol content and market share is zero, since we already adjusted the NMIM aromatic and olefin contents to represent those existing for a zero ethanol content. For example, the equation for the ethanol effect is as follows:

$$\begin{array}{c}\text{New Fuel}\\ \text{Property}\\ \text{Level}\end{array} = \begin{array}{c}\text{Intermediate}\\ \text{Fuel Property}\\ \text{Level}\end{array} + \left(\begin{array}{c}\text{RFS}\\ \text{Ethanol}\\ \text{Content}\end{array}\right)\left(\begin{array}{c}\text{RFS}\\ \text{Market}\\ \text{Share}\end{array}\right) \times \left(\begin{array}{c}\text{Fuel Property}\\ \text{Change per 1}\\ \text{vol\% Ethanol}\\ \text{Increase}\end{array}\right)$$

We make one final adjustment to RVP to add a commingling effect to account for areas where vehicles may be fueled by a mix of ethanol-blend gasoline. Commingling of ethanol and non-ethanol blends can increase the average RVP of gasoline in vehicle fuel tanks by 0.1-0.3 psi. Appendix 2-A presents a detailed analysis of the impact of commingling on the RVP of gasoline in vehicle fuel tanks. Table 2.3-12 presents our estimate of the net impact of commingling on in-use RVP as a function of the market share of ethanol blends.

Table 2.3-12. Impact of Ethanol Blends on In-Use RVP (psi)

E10 market share	Commingling Impact
0%	0
2%	0
5%	0.116
10%	0.116
20%	0.202
30%	0.238
40%	0.264
50%	0.273
60%	0.263
70%	0.226
80%	0.172
90%	0.102
97%	0.102
100%	0.000

EPA’s MOBILE6.2 model normally accounts for this effect automatically. However, when NMIM is used to run MOBILE6.2, the commingling effect in MOBILE6.2 is by-passed. Therefore, any effect of commingling needs to be accounted for in the average fuel specified to be sold in each county. To roughly account for this effect, we increased RVP by 0.1-0.27 psi in all states where the E10 market share was significant (i.e., more than 5%) but less than 95%. The states which fell into this category, for CG and RFG, are shown in Table 2.3-13. The specific RVP increase depended on the ethanol market share in that county, as indicated in Table 2.3-12.

Table 2.3-13. States Where RVP was Increased Due to Commingling

Fuel Case	Conventional Gasoline
Reference	ILLINOIS SOUTH DAKOTA INDIANA NEBRASKA OHIO IOWA KANSAS NORTH DAKOTA WISCONSIN ALABAMA MICHIGAN MISSOURI
RFS	ALABAMA ARIZONA ARKANSAS COLORADO FLORIDA KENTUCKY LOUISIANA MAINE MISSISSIPPI NEVADA NEW MEXICO PENNSYLVANIA TENNESSEE WASHINGTON WYOMING
EIA	COLORADO FLORIDA KENTUCKY LOUISIANA PENNSYLVANIA TENNESSEE WASHINGTON WYOMING IDAHO NEW HAMPSHIRE NEW JERSEY NEW YORK OKLAHOMA OREGON TEXAS UTAH
	Reformulated Gasoline
Reference	ARIZONA MASSACHUSETTS NEW JERSEY TEXAS
RFS	KENTUCKY PENNSYLVANIA NEW HAMPSHIRE NEW JERSEY NEW YORK TEXAS MAINE CONNECTICUT DELAWARE ILLINOIS INDIANA MASSACHUSETTS MISSOURI RHODE ISLAND VERMONT WISCONSIN
EIA	KENTUCKY PENNSYLVANIA NEW HAMPSHIRE NEW JERSEY NEW YORK TEXAS MAINE CONNECTICUT DELAWARE ILLINOIS INDIANA MASSACHUSETTS MISSOURI RHODE ISLAND VERMONT WISCONSIN

2.4 Effects of Biodiesel on Diesel Fuel Properties

Our assessment of the effects of biodiesel on diesel fuel properties is found in the 2002 EPA report “A Comprehensive Analysis of Biodiesel Impacts on Exhaust Emissions”[XX]. Table 2.4-1 below displays the difference in fuel properties between biodiesel (B100) and conventional diesel. Note that by 2010, all highway and nonroad diesel fuel will meet a 15 ppm cap on sulfur.

The data in the table below were derived from a wide-range of biodiesels, primarily plant- and animal-based. The 2002 EPA report did not provide properties for soy-only based biodiesel.

Table 2.4-1. Comparison Between Biodiesel and Conventional Diesel Fuel[a]

	Average Biodiesel	Average Diesel
Natural cetane number	55	44
Sulfur, ppm	54	333
Nitrogen, ppm	18	114
Aromatics, vol%	0	34
T10, deg F	628	422
T50, deg F	649	505
T90, deg F	666	603
Specific gravity	0.88	0.85
Viscosity, cSt at 40 deg F	6.0	206

[a] Conventional diesel fuel sold outside of California.

Chapter 2: Appendix
Comprehensive Vehicle Refueling Model

Vehicle refueling patterns affect non-exhaust emissions in a number of ways, including the distribution of vehicle fuel tank fill levels existing at any given time and the quality of fuel in the tank. Given the interaction between these parameters, we have developed a single model which represents vehicle refueling patterns. We then use this model to estimate the distribution of vehicle fuel tank fill levels and the quality of fuel in the vehicle fuel tanks.

Vehicle fuel tank fill levels are primarily a function of the level at which people refuel their vehicles and the volume of fuel which they add. In-use, vehicle fuel tanks will slowly empty until the point of refueling again. The California Air Resources Board (CARB) recently conducted a survey of vehicle refueling patterns in three California cities. We will base our estimates of refueling patterns primarily on these data.

Most fuel parameters remain unchanged as the fuel is burned. One except is volatility, particularly RVP, which decreases due to evaporation of the fuel as the tank heats up either due to rising ambient temperatures or vehicle operation (e.g., heat transfer from the exhaust system, engine cooling air flowing under the vehicle, and fuel recirculation from the engine compartment).

While ethanol content doesn't change significantly while the vehicle is being operated, the ethanol content of gasoline in vehicle fuel tanks can be a function of vehicle refueling patterns if some of the specific gasolines being marketed in an area contain ethanol and some do not. The effect of ethanol on RVP is not linear. Thus, knowledge of the distribution of ethanol content in vehicle fuel tanks is important in estimating the RVP of gasoline in vehicle fuel tanks and non-exhaust emissions. We use the vehicle refueling model to estimate ethanol content, fuel RVP, and average fill level.

There are four main aspects of the vehicle refueling model. The first two aspects affect all types of gasoline, ethanol containing or not. The first aspect is a description of the refueling patterns of vehicle operators. How low is the tank when they refuel? How much fuel do they add? Does the volume of fuel added depend on how low the tank was when they stopped to refuel? The second aspect is the weathering of the fuel as the vehicle is operated. In general, the degree of weathering, or RVP reduction, depends on both the ambient temperature and initial RVP of the fuel.

The third aspect of the model is the effect of ethanol on RVP. While the ethanol content of gasoline tends to be either 5.7 or 10 percent by volume (vol%) at the service station, the ethanol content of gasoline in a vehicle's fuel tank can vary from zero to 10 vol%. The fourth aspect of the model is a description of the probability that a vehicle operator will purchase fuel at the same service station as the last refueling or at another outlet selling the same brand fuel (i.e., gasoline brand loyalty). Brand loyalty is relevant, because service stations carrying the same brand of gasoline almost always sell either gasoline with ethanol or gasoline without ethanol, but not both. It is the mixing of gasoline with and without ethanol is vehicles' fuel tanks that can cause the RVP of fuel in the tank to differ from that dispensed at the service station. This is referred to as the commingling effect.

Each of these four aspects of the vehicle refueling model is described below.

2A.1 Vehicle Refueling Patterns

During August and September, 2001, the CARB surveyed consumers' refueling habits at 19 service stations in three local areas (Lake Tahoe, the Bay Area and Los Angeles).[38] Basic refueling information was obtained for 396 vehicle refuelings (i.e., initial fuel tank level and volume of fuel added). Fuel samples were also obtained from 254 vehicles, though we are most interested in the volumetric data here. CARB also asked those refueling whether they refueled with the same brand gasoline the last time the vehicle was refueled.

We obtained and analyzed the raw volumetric fuel data obtained by CARB. Of the 396 sets of data, 391 included both initial fuel tank level and volume of fuel added. One of the two pieces of information was missing for five vehicles, so we discarded these partial data sets from the analysis. The tank fill level prior to refueling was recorded in terms of eighths of a fraction of a full tank, as this is usually how the tank fill level is indicated on the vehicle dash board. Table 2A-1 shows the probability of a vehicle being refueled at various fuel tank fill levels.

Table 2A-1. Fill Level Prior to Refueling

Fraction of fill level	Probability
0.000	0.414
0.125	0.133
0.250	0.253
0.375	0.054
0.500	0.095
0.625	0.020
0.750	0.020
0.875	0.010

As can be seen, over 40% of the vehicles surveyed came in with an "empty" tank.

CARB also recorded whether the vehicle operator "filled up" the tank or not. We observed that there was a trend towards a greater probability of a "fill up" as the level of the tank prior to refueling increased. Table 2A-2 shows the probability of a fill-up as a function of tank fill level prior to refueling.

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[38] "Draft Assessment of the Real-World Impacts of Commingling California Phase 3 Reformulated Gasoline, California Environmental Protection Agency, Air Resources Board, August 2003.

Table 2A-2.
Probability of Fill-Up as a Function of Initial Tank Fill Level

Initial Tank Fill Level	Likelihood of a Fill-up
0.000	0.117
0.125	0.500
0.250	0.586
0.375	0.619
0.500	0.784
0.625	0.875
0.750	0.750
0.875	0.750

Overall, when the tank was at least half full, the tank was filled up 79% of the time.

In those cases where the fuel tank was not filled to capacity, the volume of fuel added was recorded in terms of gallons. Therefore, some processing was required to estimate the final fill level in terms of fraction of tank capacity. To do so, we had to estimate the volume of each vehicle's fuel tank. CARB recorded the basic model type of each vehicle in the survey. Based on this model type, we placed each vehicle into one of six possible categories. First, each vehicle was identified as either a car or light truck. Then, we estimated whether it would have a relatively small, medium, or large fuel tank for that vehicle class. The fuel tank sizes assumed for each class are shown in Table 2A-3 below.

Table 2A-3. Estimated Fuel Tank Volumes (gallons)

Relative Size	Car	Light Truck
Small	12	16
Medium	16	20
Large	20	24

Using these tank volumes, we converted the volume of fuel added during partial fill ups to an equivalent fraction of tank volume and added this to the observed initial fill level to estimate the final fill level. In five cases (out of the 176 partial fills), the estimated final fill level exceeded 100%. Either the initial gauge reading was off or rounded up, or more likely, our estimate of the total tank volume was too small. In these cases, we reduced the final fill level to 95%. (Given that this was a partial fill-up, the final fuel tank level had to be less than 100%.)

For all of the partial fill-ups, we converted the volume of fuel added from gallons of fuel to fractional tank volume. Both the mean and standard deviation of these volumes were determined as a function of initial fill level. These figures are shown in Table 2A-4.

Table 2A-4. Volume of Fuel Added During Partial Fills (% of Fill Level)

Initial Fill Level	Volume of Fuel Added	
	Mean	Standard Deviation
0.000	0.406	0.200
0.125	0.434	0.157
0.250	0.382	0.167
0.375	0.451	0.185
0.500	0.314	0.120
0.625	0.325	---
0.750	0.225	0.04
0.875	0.030	---

As can be seen from Table 2A-4, the final fill level from partial fills is very close to a full tank when the initial fuel tank level was 0.625 or higher. The actual number of cases when vehicles initiated refueling when the tank fill level was 0.625 or higher was quite small (20). The number of partial fills surveyed was even smaller (4). Given this small number and the fact that the fraction of fill-ups for half full tanks exceeded that found for 0.75 and 0.875 full tanks (from Table 2A-3), we assumed that all tanks which were at least half full when refueling was initiated were filled-up. When the initial fill level was less than 0.5, we assumed that the mean volume of fuel added were those shown in Table 2A-4.

As also can be seen from the figures in Table 2A-4, the estimates of the standard deviation in the volume of fuel added are substantial relative to the mean volumes of fuel added. We desired to reflect this variability in the volume of fuel added during partial fills. Thus, we utilized both the estimates of the mean and standard deviation in the volume of fuel during refueling. We accomplished this by multiplying the standard deviation by a randomly generated standard normal deviate and adding this to the mean volume of fuel added to estimate the volume of fuel added during each partial refueling.

2A.2 Weathering

Fuel weathering is the result of the evaporation of the lighter components of gasoline when the temperature in the fuel tank rises. This temperature rise can be the result of diurnal swings in ambient temperature or from vehicle operation. In the latter case, the heat can be transferred either convectively from the exhaust system and engine cooling air flowing under the vehicle or conductively from recirculated fuel from the engine’s fuel system or both. Gasoline is a mixture of many different chemicals. Some of these chemicals, such as butane, evaporate more quickly than other chemicals with a higher molecular weight, such as octane. The loss of lighter chemicals can be sufficient to reduce the concentration of these lighter chemicals in the liquid gasoline. This reduces the RVP of the fuel and its tendency to evaporate as the current tank of fuel is consumed.

We base our estimate of weathering on RVP on the methodology currently in MOBILE6.2. This estimate was first developed for MOBILE4 and was also used in

MOBILE5. This methodology first calculates an effective in-use tank temperature (T_{evap}) which drives fuel evaporation. This temperature is a function of the daily minimum temperature (T_{min}) and maximum temperature (T_{max}), as indicated in the following equation:

$$T_{evap} = -1.7474 + 1.029*T_{min} + 0.99202*(T_{max} - T_{min}) - 0.0025173 * T_{min}*(T_{max} - T_{min})$$

The loss in RVP is a function of both T_{evap} and dispensed RVP, as indicated by the following equation:

$$\begin{aligned}\text{RVP reduction (psi) due to weathering} = &-2.4908 + 0.026196 * T_{evap} \\ &+ 0.00076898 * T_{evap} * \text{Dispensed Fuel RVP}\end{aligned}$$

This RVP loss is that occurring when the vehicle fuel tank is 54.57% full, which is the effective in-use average tank level for estimating non-exhaust emissions in MOBILE6.2. For a typical high ozone day where the ambient temperature might range from 72 F to 96 F, and for a dispensed RVP of 9 psi, the RVP loss due to weathering is 0.54 psi. In order to estimate weathering at other tank fill levels, we assume that weathering is linear with tank fill level.

2A.3 Effect of ethanol on RVP as a Function of Ethanol Content

In general, the chemicals comprising gasoline blend ideally. That is, the property of the finished gasoline is the sum of the property of each component weighted by its molar, volume or mass fraction, whichever is technically appropriate. Each component of gasoline has its own RVP level. Adding a component to gasoline at the level of 10 volume percent (vol%), which is the typical ethanol concentration would increase the blend's RVP by 10% of the component's RVP and decrease the blend's RVP by 10% of the original RVP. For example, normal butane with an RVP of 42 psi can be added to gasoline with an RVP of 8 psi. If the butane is added to a final level of 5 vol%, then the final RVP is 0.05 times 42 plus 0.95 times 8, or 9.7 psi.

Ethanol blending affects the RVP of the finished gasoline quite differently. Ethanol is a highly polar compound, due to the presence of the hydroxyl radical. In pure liquid ethanol, these hydroxyl radicals interact with each other, increasing the degree of attraction between ethanol molecules and lowering their tendency to evaporate. This phenomena is commonly known as hydrogen bonding and is most commonly associated with water. When added to non-polar hydrocarbons at low concentrations, such as those comprising gasoline, the evaporative tendency of ethanol increases dramatically. This increase in vapor pressure is indicated by what is referred to as the activity coefficient. The activity coefficient is the ratio of a compound's actual vapor pressure in a mixture to that predicted by ideal blending. Table 2A-5 shows ethanol's activity coefficient at various levels of concentration in a typical gasoline.

Table 2A-5. Activity Coefficient of Ethanol in Gasoline Blends [39]

Ethanol Concentration (vol%) *	Activity Coefficient
3%	7.5-8.0
6%	3.8-4.1
10%	2.3-2.5
14%	1.9-2.0
18%	1.6-1.8

As can be seen, these activity coefficients are substantially greater than 1.0, indicating a significant increase in the vapor pressure of ethanol beyond that predicted by ideal blending.

Adding ethanol to gasoline can also increase the vapor pressure of the hydrocarbon components. In general, instead of the hydrocarbons' vapor pressures decreasing with the addition of another component (e.g., by 10% with the addition of 10 vol% ethanol), they remain constant or even increase. This could be due to a tendency of the hydrocarbons in the vapor phase to "bounce" off of the ethanol molecules at the surface of the liquid phase.

A number of studies have shown that the full effect of ethanol's impact on RVP is reached at very low concentrations. For example, a study performed by the Energy and Environmental Research Center at the University of North Dakota indicates that 90% of the full impact of ethanol on RVP is reached when the ethanol concentration is only 2 vol%.[40] Researchers at the University of Delaware found the same relationship.[41] Below 2 vol% ethanol, we have assumed that the effect is essentially linear.

The full effect of ethanol on gasoline RVP is a function of the RVP of the base hydrocarbon gasoline. In general, the increase in RVP caused by ethanol blending increases as the base RVP decreases. The actual RVP of specific commercial ethanol and non-ethanol gasoline blends are generally known for a specific area being modeled. Thus, they are not a primary concern here. However, in order to develop realistic estimates of weathering and commingling across a range of ethanol blend market shares,

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[39] Harley, Robert A. and Shannon C. Coulter-Burke, "Relating Liquid Fuel and Headspace Vapor Composition for California Reformulated Gasoline Samples Containing Ethanol," Environmental Science and Technology, Volume 34, Number 19, 2000. pp 4088+4094, Figure 3. It should be noted that the ethanol concentrations shown in the reference are in terms of mole fraction, which are essentially a factor of 2 higher than volume fraction.

[40] Aulich, Ted and John Richter, "Addition of Nonethanol Gasoline to E10 – Effect on Volatility," Energy and Environmental Research Center at the University of North Dakota, July 15, 1999.

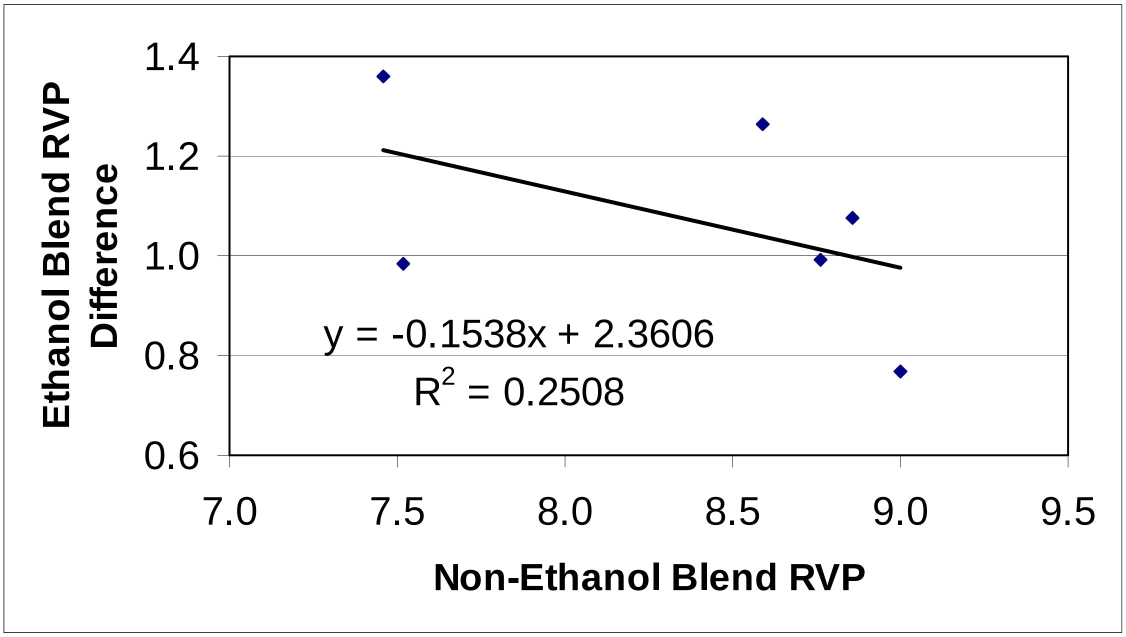
[41] Bennett, Alison, Stephan Lamm, Hasan Orbey and Stanley I. Sandler, "Vapor-Liquid Equilibria of Hydrocarbons and Fuel Oxygenates. 2," Jounal of Chemical Engineering Data, Volume 38, 1993, pp. 263-269, Figure 7. This reference shows the ethanol concentration in terms of mass fraction, which is nearly identical to volume fraction.

it would be helpful to use realistic RVP levels for commercial ethanol and non-ethanol gasoline blends.

Ethanol blending generally occurs under two types of RVP standards. One type of standard requires that both ethanol and non-ethanol blends meet the same RVP standard. This is the case in reformulated gasoline (RFG) areas. In most other areas, ethanol blends are allowed to meet an RVP standard 1.0 psi higher than that applicable to non-ethanol blends.

We will estimate the impact of weathering and commingling for both situations. For RFG-like situations, we will assume that both ethanol and non-ethanol blends have the same RVP. In order to estimate the impact of ethanol blending in areas where ethanol blends are allowed to have a higher RVP level, we evaluated recent fuel quality data collected by the Alliance of Automobile Manufacturers. We combined the data collected from 2001-2003 and found six cities where significant numbers of both ethanol and non-ethanol blends were sampled and analyzed. These six cities were: Albuquerque, Cleveland, Denver, Detroit, Minneapolis, and Seattle. The average RVP levels of the non-ethanol gasoline samples in each city ranged from 7.46-9.00 psi, while that of the ethanol blends ranged from 8.50-9.93 psi. We observed a relationship between the RVP of the non-ethanol gasolines and the difference between the RVP of the ethanol and non-ethanol blends. In general, as the RVP of the non-ethanol gasoline increased, the difference between the RVP of the ethanol and non-ethanol blends decreased. Figure 2A-1 shows this relationship for the six cities, along with a best-fit line based on least squares regression. The r-squared value for the best-fit line was 0.25.

Figure 2A-1. Effect of Ethanol Blending on RVP in Six U.S. Cities



On average, ethanol blending led to a 1.0 psi RVP higher RVP level when the RVP level of the non-ethanol gasoline was 9.0 psi. Ethanol's effect increased to 1.2 psi when the RVP level of the non-ethanol gasoline was 7.5 psi. When evaluating the effect of weathering and commingling, we will evaluate non-ethanol gasoline RVP levels of 6.8, 7.8 and 9.0 psi, as these are common RVP standards in use today. Using the relationship indicated in Figure 1, the RVP levels of the ethanol blends associated with these base RVP levels are 8.1, 9.0, and 10.0 psi, respectively.

2A.4 Brand Loyalty

CARB recently conducted a fairly extensive direct survey of vehicle refueling patterns. This study is both more recent and more extensive than those made in the past.[YY] During their refueling survey, CARB asked vehicle operators whether the vehicle was refueled with the same brand of fuel the previous time the vehicle was refueled. The resulting responses are summarized in Table 2A-6 below.

Table 2A-6. Brand Loyalty in the CARB Refueling Survey

Response to Question: Did you refuel with the	Los Angeles	Bay Area	Lake Tahoe
"Yes"	62%	59%	31%
"No"	31%	38%	67%
"Don't Know"	7%	3%	2%
Breakdown of Retail Outlets Surveyed			
Major Brands (Shell, Chevron, Texaco, Mobil, ARCO)	4 (100%)	5 (84%)	3 (33%)
Intermediate (Valero)	0 (0%)	1 (16%)	0 (0%)
Local Brands (USA, Fox, United)	0 (0%)	0 (0%)	6 (67%)

CARB thought that the relatively low level of brand loyalty in Lake Tahoe was due to a high rate of rental car usage in that city. However, they did not present any data regarding the fraction of total VMT by rental vehicles to justify their rationale. Rental vehicle VMT would have to represent roughly half of all VMT in the Tahoe area (assuming such use was negligible in the other two areas) for this factor to explain the large difference seen in Table 2A-6. This seems quite unlikely, despite Lake Tahoe being a resort area.

We believe that there is a more likely explanation for the difference. A review of the service stations surveyed in the three areas shows significant differences in the types of brands surveyed. The service stations surveyed in Los Angeles and the Bay Area were dominated by major, nationally recognized brands. Those in Lake Tahoe were dominated by more local brands. We believe that brand loyalty could easily be stronger for nationally known brands which advertise and which offer their own credit cards. A few major brands offer a significant discount when their credit card is used to buy their gasoline (e.g., Shell, BP).

The breakdown of service stations into major and local brands in the three areas is shown in the lower half of Table 2A-6. We have defined major brands to include vertically integrated oil companies which have been in the retail business for several decades, market in several regions across the U.S. and are known to widely advertise. As shown in Table 2A-6, all four retail fuel outlets surveyed in Los Angeles fell into this category, while five out of six stations in the Bay Area reflected major brands. The sixth outlet in the Bay Area was a Valero outlet. Valero is a newcomer in the retail market relative to Chevron, Shell, etc. However, it is currently the largest refiner in the U.S. and offers its own credit card. Thus, Valero appears to fall into an intermediate category somewhere between the major brands and the local brands.

The situation is essentially reversed in Lake Tahoe. Two-thirds of the retail outlets surveyed were local brands. Only three out of nine outlets represented major brands.

In order to investigate the potential difference between brand loyalty between major and non-major brands, we assumed that each type of fuel brand had its own level of loyalty across the three areas. We then estimated these two levels of brand loyalty identified to best predict the overall brand loyalty in each area. Overall, loyalty levels of 62% for major brands and 15% for non-major brands (including Valero) fit the survey data reasonably well.

The U.S. Energy Information Administration (EIA) tracks a broad range of proprietary physical and financial data from large energy producers through their Financial Reporting System. This information includes the volume of gasoline sold through retail outlets owned by or leased from these companies and selling fuel with the company’s brand name. Up to 1997, these retail outlets sold about 45% of all gasoline sold in the U.S. In 1998, EIA expanded the number of companies included in the Financial Reporting System by 50% (from 22 to 33 companies). The percentage of gasoline sold by these firms’ retail outlets increased to 62% of all gasoline sold in the U.S.

The nature of the firms included in the Financial Reporting System changed with the eleven companies added in 1998. Prior to 1998, this system included 22 companies. A few of these firms were not oil companies, (e.g., Burlington Resources, Enron, Sonat/El Paso Energy, Union Pacific Resources, USX). Several others were not major gasoline retailers, at least under their corporate names (e.g., Anadarko Petroleum, Kerr-McGee, Occidental Petroleum).

In 1998, EIA added an additional 11 companies to the Financial Reporting System. Most of these were gasoline refiners (e.g., Citgo, Clark, Equilon, Lyondell-Citgo, Motiva, Sunoco, Tesoro, Ultramar Diamond Shamrock (UDS), Valero and Williams). At the same time, the volume of gasoline sold by the original 22 companies decreased to 31% of all gasoline sold in the U.S. This drop is likely due to the spin-off of refineries by companies like Shell and Texaco to partnerships like Motiva and Equilon. The actual retailing of this 14% of gasoline sales likely didn’t change significantly (e.g., the retail brand name continued to be Shell). The net increase of 17% of U.S. gasoline sales represented the other refiners, such as Tesoro, Valero, Citgo, USD, etc. These latter companies have a much more regional footprint and have not established brand name familiarity coupled with a perception of higher quality gasoline. With the exception of the single Valero outlet in the Bay Area, none of the stations surveyed by CARB offered gasoline from these companies. Thus, we believe that the major brands included in the CARB survey are more similar to the fuel suppliers included in EIA's Financial Reporting System prior to 1998 than to those included after 1998.

Given this, we estimate that 45% of U.S. gasoline sales are sold through stations carrying a major brand. Weighting the loyalty levels of 62% for major brands by 45% and the loyalty level of 15% for other brands by 55% yields an overall national average loyalty level of 36%. For non-loyal consumers, the probability of brand selection is assumed to be random. Practically, this means that the probability of choosing either a non-ethanol or ethanol blend depends on each fuel's market share.

The exact question asked by the CARB surveyors was whether the vehicle had been refueled the last time with the same brand of fuel. CARB assumed that this meant that the vehicle was always refueled with the same brand. However, the question was limited to only the refueling immediately preceding the current one. Our primary estimate of brand loyalty is that directly addressed by the CARB survey: the likelihood that the previous refueling was with the same brand of gasoline. We also estimate the sensitivity of our estimate of commingling to the assumption made by CARB below.

2A.5 Procedures for Modeling Vehicle Refueling and Resultant Fuel Quality

We developed a model to predict the fuel tank level and fuel quality existing in a typical onroad vehicle through 500 refuelings. The vehicle is assumed to begin its life with a full tank of non-ethanol fuel. The fuel tank level at which the vehicle is refueled is based on the probabilities shown in Table 2A-1 above. First, a cumulative distribution of refueling probabilities was generated by adding the probabilities shown in the second column of Table 2A-1. Then, a random number valued between 0.0 and 1.0 is generated. If the random number is less than the cumulative probability of the tank being empty at refueling (0.414), the tank is assumed to be empty. If the random number is between this figure and the cumulative probability of the tank being 1/8 full at refueling (0.547), the tank is assumed to be 1/8 full at refueling, etc.

The RVP level of this fuel is reduced using the weathering equation shown in Section 2A.2. The level of RVP loss is assumed to be proportional to the volume of fuel used since the last refueling. For example, a vehicle might be driven from a full fuel tank down to a tank which is 20% full. Fuel usage is 80% of a tank. The above RVP weathering equation represents the RVP drop for a vehicle being driven from a full tank down to a 60% full tank, or a fuel usage of 40%. Therefore, the RVP decrease due to weathering in this case would be twice that indicated by the weathering equation in Section 2A.2. Fuel composition (i.e., ethanol content) is assumed to be unaffected by driving.

Only the hydrocarbon portion of the fuel is weathered, since the effect of ethanol on RVP is essentially independent of its concentration. Thus, the value of RVP used in the weathering equation is that for the hydrocarbon portion of the fuel, not the total RVP of the blend. This means that we need to track the RVP of the hydrocarbon portion of the fuel separately.

The probability of the fuel tank being completely filled during refueling is determined from the estimates shown in Table 2A-2. Again an independent random number is generated with a value between 0.0 and 1.0. If the value is less than the probability shown in Table 2A-2 for that initial fill level, the tank is assumed to be filled up. When a partial fill is indicated, another random number between 0.0 and 1.0 is generated. This random number is used in conjunction with the NORMINV function in Excel to generate a random level of the standard normal deviate, or the number of standard deviations to add to the mean estimate for the volume of fuel added during a partial fill-up. The values for the mean and standard deviations for volume of fuel added are shown in Table 2A-4. As discussed in Section 2A.2, whenever the initial fuel tank level is 0.5 or greater, we assume that the tank is filled up.

Occasionally, the volume of fuel added during a partial fill will exceed the capacity of the tank. This occurs when the random number generator produces a large positive number of standard deviations to be added to the mean fuel volume typically added during a partial fill. In these cases, we set the final tank level after refueling to 100%.

The type of fuel added, ethanol or non-ethanol blend, is determined both by the level of brand loyalty and the mix of fuels available in the local area. As discussed in Section 2A.4, brand loyalty is estimated to be 36%. Again, an independent random number is generated with a value between 0.0 and 1.0. If the value is less than 0.36, the type of fuel added is assumed to be the same as that added during the last refueling. Otherwise, the probability of refueling with any particular fuel is assumed to be independent of the previous fuel used. The probabilities of refueling with a non-ethanol blend and an ethanol blend are the market shares of the respective fuels. This is selection is made by choosing a new random number.

We then determine the quality of the fuel in the tank after the refueling event. The ethanol concentration of the tank fuel is simply the ethanol concentration of the fuel prior to refueling plus that of the fuel added during refueling, each weighted by their respective volumes. We assume that the fuel tank contains some volume of fuel, even when it indicates empty. Consistent with CARB in their assessment of commingling, we assume that this tank “heel” is 10% of the tank capacity. The “ethanol” portion of the ethanol blend is assumed to be 95% pure ethanol (i.e., it contains 5% denaturant). This denaturant is assumed to have the same RVP as the non-oxygenated gasoline.

Calculating the RVP of the gasoline blend after refueling is more complicated. We first calculate the RVP of the hydrocarbon portion of the fuel after refueling in the same way as described above for the ethanol concentration. The RVP of hydrocarbons blend linearly or ideally, so we simply weight the RVP of the hydrocarbon portion of the fuel left in the tank just prior to refueling (adjusted downward for weathering as indicated above) with that of the new fuel by their respective contributions to the total volume of fuel in the tank after refueling. We then increase this RVP based on the concentration of ethanol in the tank. As described in Section 2A.3, we assume that ethanol's impact on RVP is constant between 2 and 10 vol% and a function of the RVP of the hydrocarbon blendstock, as discussed above. Between zero and 2 vol%, we assume that its RVP effect increases linearly up to its full effect.

At this point, the vehicle has been refueled and we have determined the quality of the fuel currently in the tank. The next step is to repeat the entire process described above, starting with a new level at which the tank is refueled once again.

Once a vehicle has been refueled 500 times, we determine the RVP and ethanol concentration of the fuel in the tank over a range of fuel tank fill levels. We split the full range of possible tank fill levels into 10 discrete segments, each representing a 10% range of tank fill level (e.g., 20-30% full). We then determine which tank fill levels the vehicle will be driven through prior to the next refueling. For example, if a vehicle is refueled to 100% of tank capacity and is then driven down to 1/8 full before its next refueling, its tank moves from 100% full to 90% full to 80% full, etc. until it reaches 12.5% full. Thus, in this example, the tank was never in the range of 0-10% full. We assume that the vehicle spends the same amount of time and accumulates the same amount of VMT at each tank fill level between its starting and ending points. (This is simply equivalent to assuming that vehicles are driven differently depending on their level of fuel tank fill level; a safe assumption.) The RVP of the fuel in the tank is adjusted at each fill level as the vehicle is being driven, including the effect of weathering. The same is done for ethanol concentration. For each segment of fuel tank fill level, the RVP and ethanol concentration occurring between each set of refueling events is averaged.

The entire process is then repeated 50 times. Overall, both RVP and ethanol concentration versus tank fuel fill level is tracked for 25,000 refuelings (500 refuelings per model pass-through times 50 model pass-throughs). Overall averages are then determined and retained for analysis.

One output of the model which is independent of the RVP levels of the fuels is the distribution of the fuel tank levels of vehicle on the road at any one time. This distribution is shown in Table 2A-7.

Table 2A-7. Distribution of Fuel Tank Fill Levels for the In-Use Fleet

Range of Fuel Tank Fill Level		% of Vehicles
Lower Limit	Upper Limit	
0%	10%	7.6%
10%	20%	9.4%
20%	30%	12.9%
30%	40%	12.5%
40%	50%	12.2%
50%	60%	10.6%
60%	70%	9.4%
70%	80%	8.7%
80%	90%	8.4%
90%	100%	8.2%

As can be seen, the most frequent onroad fuel tank fill levels are between 20% to 50%. This distribution will be used to weight the effect of commingling which occurs for each range of fuel tank fill level.

2A.6 Modeling Results

We performed the procedure described in Section 2A.5. for a set of base gasoline RVP levels ranging from roughly 7 RVP to 9 RVP and for the two types of ethanol blending (matched RVP and increased RVP). An example of the sequence of calculations is as follows:

1) Select the RVP of non-oxygenated gasoline (E0), the RVP of the ethanol blend (E10), and the market share of E10,
2) Begin with a tank full of non-oxygenated gasoline,
3) Choose a random number which is used to probabilistically determine: a) the level at which the tank is being refueled, b) the level to which the tank is filled, c) the volume of fuel thus being added, and d) the type of fuel used to fill the tank (E0 or E10),
4) Determine which tank fill levels the vehicle passed through between the prior fill level and the point at which it was refilled and determine the fuel RVP at each 10% increment in tank fill level using the weathering equation,
5) Determine the RVP of the hydrocarbon portion of the fuel at the time of refill using the weathering equation,
6) Determine the concentration of ethanol in the refilled fuel tank using the ethanol concentration of the fuel after the prior fill-up, the volume of fuel in the tank at the time of refill, the ethanol concentration of the fuel used to refill the tank currently and the volume of fuel added during this refill,
7) Determine the RVP of the hydrocarbon portion of the fuel after refill by weighting the RVP of the hydrocarbon portion of the fuel in the tank at the time of refueling and the RVP of hydrocarbon portion of the fuel being added by the volume of the hydrocarbon portion of the fuel in the tank at the time of refill and the volume of the hydrocarbon portion of the fuel being added during refueling, respectively,

8) Determine the RVP of the total fuel in the tank after refueling from the RVP of the hydrocarbon portion of the fuel from step 6 and the effect of ethanol on RVP using its concentration from step 5.
9) Return to step 2) and proceed through 500 refuelings.

Once the model has been applied to 500 refuelings (essentially the life of the vehicle), the results are compiled. The average RVP level for each interval of tank fill level is determined. For example, over 500 refuelings, approximately 200 have the tank being refilled when it was less than one-eighth full, so that the vehicle was driven when the tank was 10% full. For these 200 occurrances, the tank RVP level is averaged. This becomes the average RVP at a fuel tank fill level of 10%. Approximately 260 refueling involve the vehicle being driven when the fuel tank fill level is 20%. Fuel RVP is again averaged for these 260 situations. The process is repeated for a 30% fuel tank fill level, 40%, and so on through 100% full (which occurs every time the tank is completely filled up). The RVP predictions of the model for various mixes of 9 RVP non-oxygenated gasoline and a 10 RVP ethanol blend are shown in Tables 2A-8 through 2A-13. The last line of each table shows the weighted average RVP level using the distribution of in-use fuel tank fill levels shown above in Table 2A-7.

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Table 2A-8. In-Use Fuel Tank RVP Levels – 9 RVP CG with Ethanol Waiver (psi)

Fuel Tank Fill Level	Ethanol Blend Market Share														
	0%	2%	5%	10%	20%	30%	40%	50%	60%	70%	80%	90%	95%	98%	100%
5%	8.15	8.19	8.26	8.35	8.52	8.67	8.79	8.90	8.98	9.05	9.11	9.15	9.17	9.17	9.17
15%	8.23	8.27	8.33	8.42	8.58	8.74	8.87	8.97	9.05	9.12	9.18	9.22	9.24	9.25	9.25
25%	8.29	8.33	8.40	8.49	8.65	8.81	8.93	9.04	9.11	9.19	9.24	9.29	9.30	9.31	9.31
35%	8.35	8.39	8.45	8.55	8.71	8.87	8.99	9.09	9.17	9.25	9.30	9.35	9.36	9.37	9.37
45%	8.40	8.44	8.50	8.60	8.77	8.93	9.05	9.15	9.23	9.31	9.35	9.40	9.41	9.41	9.41
55%	8.44	8.48	8.56	8.65	8.82	8.98	9.11	9.21	9.29	9.36	9.40	9.45	9.46	9.46	9.46
65%	8.50	8.55	8.62	8.71	8.89	9.05	9.17	9.27	9.35	9.43	9.46	9.51	9.52	9.52	9.52
75%	8.58	8.62	8.70	8.79	8.97	9.13	9.25	9.35	9.43	9.50	9.54	9.58	9.59	9.60	9.60
85%	8.66	8.71	8.78	8.87	9.05	9.22	9.34	9.44	9.52	9.59	9.63	9.67	9.68	9.68	9.68
95%	8.75	8.80	8.87	8.97	9.15	9.31	9.43	9.53	9.61	9.68	9.72	9.76	9.77	9.77	9.77
Wtd.Avg.	8.42	8.47	8.53	8.63	8.80	8.96	9.08	9.18	9.26	9.34	9.38	9.42	9.44	9.44	9.44

Table 2A-9. In-Use Fuel Tank RVP Levels – 7.8 RVP CG with Ethanol Waiver (psi)

Fuel Tank Fill Level	Ethanol Blend Market Share														
	0%	2%	5%	10%	20%	30%	40%	50%	60%	70%	80%	90%	95%	98%	100%
5%	7.08	7.13	7.20	7.30	7.50	7.64	7.79	7.91	8.01	8.10	8.15	8.19	8.21	8.22	8.22
15%	7.14	7.19	7.26	7.36	7.56	7.71	7.85	7.97	8.07	8.15	8.21	8.25	8.27	8.28	8.28
25%	7.20	7.25	7.31	7.41	7.62	7.76	7.91	8.03	8.12	8.21	8.27	8.30	8.32	8.34	8.34
35%	7.24	7.30	7.36	7.46	7.67	7.81	7.96	8.08	8.17	8.26	8.31	8.35	8.37	8.38	8.38
45%	7.29	7.34	7.41	7.51	7.71	7.86	8.01	8.13	8.22	8.30	8.35	8.40	8.41	8.42	8.42
55%	7.33	7.38	7.45	7.55	7.76	7.92	8.06	8.18	8.27	8.35	8.40	8.44	8.45	8.46	8.46
65%	7.38	7.43	7.50	7.61	7.82	7.97	8.12	8.23	8.33	8.40	8.45	8.49	8.51	8.51	8.51
75%	7.44	7.49	7.57	7.67	7.88	8.04	8.19	8.30	8.40	8.47	8.52	8.55	8.57	8.58	8.58
85%	7.51	7.56	7.64	7.75	7.95	8.12	8.27	8.38	8.47	8.54	8.59	8.62	8.64	8.65	8.65
95%	7.59	7.64	7.72	7.82	8.03	8.19	8.35	8.45	8.55	8.61	8.67	8.70	8.72	8.73	8.73
Wtd.Avg.	7.31	7.36	7.43	7.53	7.74	7.89	8.04	8.15	8.25	8.33	8.38	8.42	8.44	8.45	8.45

Table 2A-10. In-Use Fuel Tank RVP Levels – 6.8 RVP CG with Ethanol Waiver (psi)

	Ethanol Blend Market Share														
Fuel Tank Fill Level	0%	2%	5%	10%	20%	30%	40%	50%	60%	70%	80%	90%	95%	98%	100%
5%	6.19	6.24	6.31	6.43	6.63	6.82	6.96	7.09	7.19	7.29	7.35	7.40	7.41	7.42	7.43
15%	6.24	6.29	6.37	6.48	6.68	6.86	7.02	7.13	7.24	7.33	7.40	7.45	7.46	7.47	7.48
25%	6.29	6.34	6.41	6.53	6.73	6.91	7.07	7.18	7.29	7.38	7.45	7.50	7.51	7.52	7.53
35%	6.33	6.38	6.46	6.57	6.77	6.95	7.11	7.23	7.34	7.42	7.49	7.53	7.55	7.56	7.57
45%	6.36	6.42	6.49	6.61	6.81	7.00	7.16	7.27	7.38	7.47	7.53	7.57	7.59	7.59	7.60
55%	6.40	6.45	6.53	6.65	6.86	7.04	7.20	7.31	7.42	7.51	7.57	7.61	7.62	7.63	7.64
65%	6.44	6.50	6.57	6.69	6.90	7.09	7.25	7.36	7.47	7.56	7.61	7.65	7.67	7.67	7.68
75%	6.50	6.55	6.63	6.75	6.96	7.15	7.31	7.42	7.53	7.61	7.67	7.71	7.72	7.72	7.73
85%	6.56	6.61	6.69	6.81	7.02	7.21	7.37	7.49	7.59	7.67	7.73	7.77	7.78	7.79	7.79
95%	6.63	6.68	6.76	6.88	7.09	7.28	7.44	7.55	7.66	7.74	7.79	7.84	7.85	7.85	7.86
Wtd.Avg.	6.39	6.44	6.51	6.63	6.84	7.02	7.18	7.30	7.40	7.49	7.55	7.59	7.61	7.61	7.62

Table 2A-11. In-Use Fuel Tank RVP Levels as – 9 RVP Gasoline with No Ethanol Waiver

	Ethanol Blend Market Share														
Fuel Tank Fill Level	0%	2%	5%	10%	20%	30%	40%	50%	60%	70%	80%	90%	95%	98%	100%
5%	8.15	8.17	8.20	8.26	8.33	8.38	8.40	8.41	8.40	8.36	8.32	8.26	8.23	8.20	8.19
15%	8.23	8.24	8.28	8.33	8.40	8.45	8.47	8.47	8.46	8.43	8.39	8.33	8.30	8.28	8.27
25%	8.29	8.31	8.34	8.39	8.47	8.51	8.54	8.54	8.53	8.50	8.45	8.40	8.37	8.35	8.33
35%	8.35	8.37	8.40	8.45	8.52	8.58	8.60	8.60	8.59	8.56	8.51	8.45	8.42	8.40	8.39
45%	8.39	8.42	8.45	8.50	8.58	8.63	8.65	8.66	8.65	8.61	8.56	8.50	8.47	8.45	8.43
55%	8.44	8.47	8.50	8.55	8.63	8.69	8.71	8.72	8.71	8.67	8.62	8.55	8.52	8.50	8.48
65%	8.50	8.53	8.56	8.62	8.70	8.75	8.78	8.78	8.77	8.73	8.68	8.62	8.58	8.56	8.54
75%	8.58	8.60	8.64	8.69	8.77	8.83	8.86	8.86	8.85	8.81	8.76	8.69	8.66	8.63	8.62
85%	8.67	8.69	8.72	8.78	8.86	8.92	8.95	8.95	8.94	8.90	8.85	8.78	8.74	8.72	8.70
95%	8.76	8.78	8.81	8.87	8.95	9.01	9.04	9.04	9.03	8.99	8.94	8.87	8.84	8.81	8.79
Wtd.Avg.	8.43	8.45	8.48	8.53	8.61	8.66	8.69	8.69	8.68	8.64	8.60	8.53	8.50	8.48	8.46

Table 2A-12. In-Use Fuel Tank RVP Levels – 8 RVP Gasoline with No Ethanol Waiver (psi)

	Ethanol Blend Market Share														
Fuel Tank Fill Level	0%	2%	5%	10%	20%	30%	40%	50%	60%	70%	80%	90%	95%	98%	100%
5%	7.26	7.28	7.32	7.36	7.44	7.50	7.53	7.53	7.52	7.48	7.43	7.36	7.33	7.31	7.28
15%	7.33	7.35	7.38	7.43	7.50	7.57	7.59	7.60	7.57	7.55	7.49	7.42	7.39	7.37	7.35
25%	7.39	7.41	7.44	7.49	7.56	7.62	7.64	7.66	7.64	7.60	7.56	7.48	7.45	7.43	7.41
35%	7.43	7.45	7.49	7.54	7.62	7.68	7.70	7.71	7.69	7.66	7.60	7.53	7.50	7.47	7.46
45%	7.47	7.50	7.53	7.59	7.67	7.73	7.75	7.76	7.74	7.71	7.65	7.57	7.54	7.52	7.50
55%	7.52	7.54	7.57	7.63	7.72	7.78	7.80	7.81	7.79	7.76	7.70	7.62	7.59	7.56	7.54
65%	7.57	7.59	7.63	7.69	7.77	7.84	7.86	7.87	7.85	7.81	7.75	7.67	7.64	7.61	7.59
75%	7.63	7.66	7.69	7.75	7.84	7.91	7.93	7.94	7.92	7.88	7.82	7.74	7.70	7.67	7.66
85%	7.71	7.73	7.77	7.83	7.92	7.98	8.01	8.02	7.99	7.96	7.90	7.82	7.78	7.75	7.73
95%	7.79	7.81	7.85	7.91	8.00	8.06	8.09	8.10	8.07	8.04	7.98	7.90	7.86	7.83	7.81
Wtd.Avg.	7.50	7.52	7.56	7.61	7.69	7.76	7.78	7.79	7.77	7.73	7.68	7.60	7.57	7.54	7.52

Table 2A-13. In-Use Fuel Tank RVP Levels – 7 RVP Gasoline with No Ethanol Waiver (psi)

	Ethanol Blend Market Share														
Fuel Tank Fill Level	0%	2%	5%	10%	20%	30%	40%	50%	60%	70%	80%	90%	95%	98%	100%
5%	6.37	6.40	6.43	6.49	6.57	6.63	6.66	6.66	6.65	6.61	6.56	6.48	6.44	6.41	6.40
15%	6.43	6.45	6.48	6.54	6.62	6.68	6.71	6.71	6.70	6.66	6.61	6.54	6.49	6.47	6.45
25%	6.47	6.50	6.53	6.59	6.68	6.73	6.76	6.76	6.75	6.71	6.66	6.59	6.54	6.51	6.50
35%	6.51	6.54	6.58	6.64	6.72	6.78	6.81	6.81	6.79	6.76	6.70	6.63	6.58	6.56	6.54
45%	6.55	6.58	6.62	6.68	6.77	6.82	6.85	6.85	6.84	6.80	6.74	6.67	6.62	6.59	6.58
55%	6.59	6.61	6.66	6.72	6.81	6.87	6.90	6.90	6.89	6.84	6.78	6.71	6.66	6.63	6.61
65%	6.63	6.66	6.70	6.77	6.86	6.92	6.96	6.95	6.94	6.89	6.83	6.75	6.70	6.67	6.65
75%	6.69	6.72	6.76	6.82	6.92	6.98	7.02	7.01	7.00	6.95	6.89	6.81	6.76	6.73	6.71
85%	6.75	6.78	6.82	6.89	6.98	7.05	7.08	7.08	7.06	7.02	6.95	6.88	6.82	6.79	6.77
95%	6.82	6.85	6.89	6.96	7.05	7.11	7.15	7.15	7.13	7.08	7.02	6.94	6.89	6.86	6.84
Wtd.Avg.	6.57	6.60	6.64	6.70	6.79	6.85	6.88	6.88	6.86	6.82	6.76	6.69	6.64	6.61	6.60

The next step is to estimate the impact of commingling on in-use RVP. We use the in-use tank RVP levels shown in the previous six tables for ethanol blend market shares of zero and 100% to represent situations where no commingling occurs. In the absence of commingling at intermediate levels of ethanol blend market share, the RVP should vary linearly between those found at zero and 100%. The impact of commingling is then the difference between the actual level of RVP estimated by the model and the RVP estimated from the zero and 100% ethanol blend market share RVP levels. Table 2A-14 shows the impact of commingling for the case where gasoline RVP is 9 psi and ethanol blends are allowed a 1.0 psi RVP waiver.

Table 2A-14.
Commingling as a Function of Fuel Tank Fill Level and Ethanol Blend Market Share – 9 RVP CG with Ethanol Waiver

Fuel Tank Fill Level	Ethanol Blend Market Share												
	2%	5%	10%	20%	30%	40%	50%	60%	70%	80%	90%	95%	98%
5%	0.016	0.049	0.101	0.167	0.213	0.235	0.234	0.220	0.183	0.132	0.073	0.036	0.013
15%	0.017	0.047	0.096	0.164	0.210	0.229	0.228	0.214	0.179	0.129	0.070	0.037	0.015
25%	0.019	0.049	0.098	0.166	0.210	0.228	0.230	0.217	0.180	0.130	0.072	0.036	0.014
35%	0.021	0.049	0.097	0.170	0.217	0.234	0.235	0.222	0.184	0.134	0.071	0.037	0.015
45%	0.023	0.051	0.101	0.175	0.224	0.243	0.243	0.229	0.192	0.138	0.073	0.039	0.013
55%	0.023	0.052	0.105	0.181	0.232	0.251	0.252	0.240	0.197	0.143	0.076	0.042	0.015
65%	0.025	0.054	0.110	0.185	0.238	0.259	0.260	0.246	0.201	0.147	0.078	0.043	0.014
75%	0.025	0.055	0.112	0.187	0.240	0.263	0.263	0.250	0.204	0.150	0.078	0.042	0.013
85%	0.026	0.055	0.112	0.186	0.242	0.265	0.266	0.251	0.206	0.150	0.078	0.042	0.013
95%	0.025	0.055	0.112	0.186	0.242	0.265	0.266	0.252	0.206	0.151	0.079	0.043	0.013
Wtd.Avg.	0.022	0.051	0.104	0.176	0.226	0.246	0.246	0.233	0.192	0.140	0.074	0.039	0.014

As can be seen, the impact of commingling increases slightly moving from low levels of fuel tank fill level to high levels. As found by previous studies of commingling, the impact of commingling is lowest when either E0 or E10 fuels predominate the market and peaks when the mix of E0 and E10 is approximately 50/50. Again, the weighted average of the commingling impact is determined by applying weighting the commingling impact at each fuel tank fill level by the distribution of fill levels in-use shown in Table 2A-7.

Table 2A-15 shows the weighted average commingling impacts for the six fuel cases.

Table 2A-15. Weighted Average Commingling Impact for Various Sets of E0 and E10 Fuels (psi)

E0/E10 RVP Level	Ethanol Blend Market Share												
	2%	5%	10%	20%	30%	40%	50%	60%	70%	80%	90%	95%	98%
9/10	0.022	0.060	0.102	0.171	0.227	0.249	0.249	0.227	0.199	0.143	0.084	0.045	0.020
7.8/8.9	0.029	0.065	0.110	0.201	0.239	0.273	0.274	0.255	0.218	0.160	0.082	0.043	0.019
7/8.2	0.028	0.067	0.122	0.203	0.265	0.299	0.290	0.275	0.236	0.173	0.094	0.046	0.015
9/9	0.022	0.051	0.104	0.176	0.226	0.246	0.246	0.233	0.192	0.140	0.074	0.039	0.014
8/8	0.021	0.055	0.110	0.189	0.249	0.269	0.278	0.253	0.218	0.160	0.080	0.045	0.019
7/7	0.027	0.065	0.125	0.212	0.267	0.298	0.294	0.277	0.233	0.172	0.096	0.047	0.017

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Ethanol use in the three RFS rule fuel cases (Reference, RFS, and EIA) occurs predominately under three situations: 1) 9 RVP CG with an RVP waiver for ethanol, 2) 7.8 RVP CG with an RVP waiver for ethanol, and 3) 7 RVP RFG. In order to simplify application of the impact of commingling to our emission modeling, we averaged the commingling impacts for these situations from Table 2A-15 and applied that to the entire U.S. as a function of ethanol blend market share. This average set of commingling impacts is shown in Table 2A-16.

Table2A-16.
Commingling Impact Applied in RFS Rule Emission Modeling

Ethanol Blend Market Share	Commingling Impact (psi)
0%	0
2%	0.026
5%	0.064
10%	0.113
20%	0.194
30%	0.244
40%	0.273
50%	0.272
60%	0.253
70%	0.217
80%	0.159
90%	0.087
95%	0.045
98%	0.019
100%	0.000

Chapter 3: Impacts on Emissions from Vehicles, Nonroad Equipment, and Fuel Production Facilities

As described in Chapter 2, there are a large number of potential fuels that qualify as renewable. However, only two are expected to be used in significant volumes by 2012: ethanol and biodiesel. Of these, ethanol use is expected to predominate. In particular, ethanol is expected to dominate the "growth" in renewable fuel use between now and 2012. Thus, our primary focus here will be on the impact of the use of ethanol on emissions in spark-ignited vehicles and equipment. We will more briefly touch on the impact of biodiesel fuel use on emissions.

Similarly, we expect that the bulk of the impact of ethanol use on emissions and air quality will be associated with emissions from spark-ignited vehicles and equipment using low level ethanol-gasoline blends. We expect the use of high level ethanol-gasoline blends, like E85 to be relatively small in comparison. Thus, the discussion here will focus on emissions from the use of low level ethanol blends. We will more briefly discuss the per vehicle impacts of use of high level ethanol-gasoline blends relative to gasoline.

Finally, we present estimates of the emissions related to the production and distribution of both ethanol and biodiesel. The emissions related to the production and use of ethanol can be significant relative to the emission impacts of the use of ethanol blends, due to the significantly increase in the volume of ethanol expected to be produced in the future.

3.1 Effect of Fuel Quality on Onroad Spark-Ignited Vehicle Emissions

Ethanol belongs to a group of gasoline additives commonly referred to as oxygenates. The two most commonly used oxygenates are ethanol and MTBE, though TAME has been used in significant volumes, as well. All oxygenates have relatively high levels of octane (i.e., greater than 100 R+M/2). Both ethanol and MTBE have been used historically to meet the gasoline oxygen requirements for oxyfuel and RFG. Historically, MTBE was the predominant oxygenate used in gasoline in the U.S. Over time, MTBE use has decreased in the U.S, while ethanol use has increased, to the point where ethanol use now predominates. This trend appears to be accelerating, to the point where it appears that essentially all MTBE use will cease in the U.S sometime in 2007.

The impact of oxygenate use on emissions from motor vehicles has been evaluated since the mid-1980's. Several models of the impact of gasoline quality on motor vehicle emissions were developed in the early 1990's and updated periodically since that time. We use the most up-to-date versions of these models here to estimate the impact of changes in oxygenate use on emissions. Still, as will be described below, significant uncertainty exists as to the effect of these gasoline components on emissions from both motor vehicle and nonroad equipment, particularly from the latest models equipped with the most advanced emission controls. Assuming adequate funding, we plan to conduct significant vehicle and equipment testing over the next several years to improve our estimates of the impact of these additives and other gasoline properties on emissions. The results of this testing are not available for inclusion in this analysis. We hope that the results from these test programs will be available for reference in the comprehensive evaluation of the emission and air quality impacts of all the fuel-related requirements of the Energy Act required by Section 1506. A draft of this study is required to be completed in 2009. As we discuss the emission impacts of increased ethanol use below, we identify the areas where current estimates appear to be the most uncertain and where we hope to obtain additional data prior to the 2009 study.

3.1.1 Low Level Ethanol and MTBE-Gasoline Blends

EPA has developed a number of emission models relating the impact of gasoline quality on emissions from motor vehicles. In 1993, EPA published the Complex Model, which predicts the effect of gasoline quality on VOC, NOx and air toxic emissions from 1990 model year light-duty motor vehicles (i.e., Tier 0 vehicles). This model is used to determine refiners' compliance with RFG and anti-dumping standards. The Complex Model also contains estimates of the impact of gasoline RVP on non-exhaust VOC emissions. These estimates were taken from the then-current version of the MOBILE emissions model, MOBILE5.

In 2001, in responding to California's request for a waiver of the RFG oxygen mandate, EPA performed a new analysis of the impact of gasoline quality on exhaust VOC and NOx emissions from Tier 0 vehicles. This analysis included essentially all of the data used to develop the Complex Model, as well as some additional data developed since 1993. It also used more advanced statistical tools, such as a mixed statistical model, which were not available in 1993. These VOC and NOx models are referred to here as the EPA Predictive Models. Thus, in terms of both supporting data and modeling tools, the EPA Predictive Models represent an improvement over the Complex Model, at least for exhaust VOC and NOx emissions. Because the criteria for granting California a waiver of the oxygen requirement focused on ozone and PM impacts, EPA did not develop a similar model for toxics or CO emissions.

In roughly the same timeframe, EPA developed its latest motor vehicle emission inventory model, MOBILE6. Some of the fuel-emission relationships from the Complex Model were incorporated into MOBILE6. These included the effect of selected gasoline properties on exhaust VOC and NOx emissions and the fraction of VOC emissions represented by several air toxics (benzene, formaldehyde, acetaldehyde, and 1,3-butadiene). The EPA Predictive Models were not available in time for their incorporation into MOBILE6. MOBILE6 also contains estimates of the effect of certain gasoline parameters on CO emissions, namely RVP and oxygen content. The effect of RVP on non-exhaust VOC emissions contained in MOBILE6.2 represents an update of the MOBILE5 and Complex Model estimates.

We desire in this RFS analysis to utilize the most up to date estimates of the impact of gasoline quality on emissions currently available. No one model currently contains the most up to date estimates for all the pollutants of interest. Therefore, we have broken up the remainder of this sub-section into six parts. The first discusses emissions of VOC and NOx, as the EPA Predictive Models address these pollutants. The second discusses CO emissions, as neither the Complex Model nor the EPA or CARB Predictive Models address this pollutant. The third section addresses emissions of air toxics, as a combination of models represents the best estimate of the impact of fuel quality on these emissions. The fourth section addresses non-exhaust VOC emissions. The fifth section addresses PM emissions. The sixth section addresses emissions of aromatic hydrocarbons. The seventh and final section presents the impact of ethanol and MTBE blending on per mile emissions from gasoline-fueled motor vehicles.

3.1.1.1 Exhaust VOC, CO and NOx Emissions

In this section we evaluate the various models available which predict the impact of gasoline quality on exhaust VOC, CO and NOx emissions. Several such models have been developed over the past 15 years. We first discuss the EPA Complex Model, the EPA Predictive Models and the CARB Predictive Models due to the wide range of fuel parameters which they address and their similar form. We next describe the fuel effects contained in EPA's MOBILE6.2 emission inventory model, as this model addresses CO emissions, which the other models do not. These models best predict emissions from Tier 0 vehicles, as most of the emission data upon which they were based were from these vehicles. A number of fuel effects test programs which tested later model year vehicles have been performed since the above emission models were developed. We summarize these studies below and develop emission projections based on consistent statistical procedures. Finally, we select which model best predicts the effect of fuel quality for each pollutant. Due to the uncertainty involved with predicting the impact of fuel quality on emissions from Tier 1 and later vehicles, we develop two alternative approaches to making such predictions for the purpose of this rule.

3.1.1.1.1 EPA Complex Model and CARB and EPA Predictive Models

In 1993, EPA published the Complex model to investigate the effects of changing gasoline fuel parameters on the exhaust emissions of Tier 0 and older vehicles. This model predicts the effect of gasoline quality on exhaust VOC, toxics and NOx emissions and non-exhaust emissions of VOC and benzene. The Complex Model is used to determine compliance with the emissions performance requirements for federal RFG by comparing the predicted emissions of a candidate fuel to that of a baseline fuel for common baseline vehicle technology. The baseline fuel and the baseline vehicle technology represent those fuels and vehicles included in the 1990 US light duty vehicle fleet (Tier 0 technology).

In 1999, the state of California petitioned EPA for a waiver of the oxygen requirement in RFG. The reasoning behind the waiver request centered on the California Air Resources Board's (CARB) analysis which showed that reducing the amount of oxygen in RFG would lead to reduced NOx exhaust emissions. The model that CARB developed to support their claim was called the Phase 3 predictive model[ZZ]. This model differed from the previous version of CARB's predictive model (the Phase 2 model) in a number of ways. The most significant difference included a substantially expanded database, mainly for model year 1986 and newer vehicles, as well as an improved version of the statistical analysis software package used to develop the model (SAS® PROC MIXED). According to CARB, the Phase 3 predictive model displays a steeper NOx/Oxygen response than the Phase 2 Predictive model as a result of eliminating the RVP by Oxygen term which the previous model had erroneously included. This caused an increase in the NOx exhaust emissions predicted, and for many areas this increase would lead to NOx levels exceeding those set by National Ambient Air Quality Standards (NAAQS).

According to the 1990 Clean Air Act, EPA can waive the RFG oxygen requirement if it prevents compliance with a NAAQS. In order to properly perform an environmental impact analysis in response to this waiver request, EPA considered using both its Complex Model, as well as CARB's Phase 3 Predictive Model to estimate the impact of gasoline quality on emissions. The EPA Complex model, while considered statistically robust due to the large number of vehicles comprising the dataset, was not considered to be adequate for a number of reasons. First, the Complex Model was based on an emissions database which did not include several studies that have since been published. Second, the EPA Complex Model was developed using a fixed effects statistical modeling approach[42]. In contrast, both the CARB Phase 2 and 3 models were mixed models, employing a more sophisticated statistical approach than was available at the time of development of the Complex model.

EPA also rejected using CARB's Phase 3 Predictive Model in its analysis of the waiver request. While CARB had developed a very detailed protocol for developing the Phase 3 model, it rejected the results of this protocol because the resulting model differed too substantially from the Phase 2 model. Thus, EPA decided to create its own "predictive models" for exhaust VOC and NOx emissions which combined the protocols used to develop the Complex Model with the expanded database and improved statistical tools which were now available. EPA relied on existing EPA models for evaporative VOC emission effects. However, these latter estimates were augmented with recent data indicating that ethanol increased permeation emissions, as well as the consideration of several commingling models and associated assumptions about drivers' refueling behavior.

One main conclusion drawn by EPA in the California Oxygen waiver analysis was that insufficient data existed at that time to conclusively determine the response of Tier 1 and newer vehicles to fuel parameters other than sulfur.[43] Some data indicated that oxygen increased NOx emissions from Tier 1 and later vehicles, while other data contradicted this. Due to this inconsistency, EPA assumed that oxygen did not affect exhaust VOC, NOx or CO emissions from Tier 1 and later vehicles in its analysis of CARB's request for a waiver of the RFG oxygen mandate.

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[42] A "fixed effects" model of this kind makes no attempt to estimate the error introduced by sampling from some larger population of vehicles or fuels. The model just describes quantitatively the relationships among variables that are present in the dataset that was analyzed. A "mixed" model, as was used by CARB in both the Phase 2 and Phase 3 predictive models' construction, attempts to go beyond description of the available data to make statistical inference to some larger population from which the available data were sampled. In this case CARB treated the vehicle effects as random (assuming that the test vehicles were sampled from some larger fleet) while fuel effects were treated as "fixed" (assuming that all fuels of interest were represented in the data). Such a modeling approach makes it possible to estimate the probable error in modeled effects in a way that is not possible with a fixed effects model. The approach, moreover, improves the accuracy of the significance measures used to decide which terms to include in the model.

[43] At the time of that 1999 analysis, sufficient data existed on the emissions effects of Sulfur on Tier 1 vehicles to be modeled. However, sulfur levels were not expected to change as a result of the removal of oxygen from RFG in California, so the effect of sulfur was moot in this situation.

None of the three models discussed above (i.e., the Complex Model, the CARB Predictive Model, and the EPA Predictive Models) address CO emissions. Historically, this is because the RFG program did not mandate a specific reduction in CO emissions and the lesser role of CO emissions in forming ambient ozone. The CARB Predictive Model considers the impact of fuel oxygen content beyond 2 wt%, but does not address the full range of oxygen levels on CO emissions, nor the impact of other fuel parameters. The only EPA model which predicts the impact of fuel quality on CO emissions is MOBILE6.2, which is discussed in the next section.

3.1.1.1.2 MOBILE6.2

The exhaust emission effects contained in MOBILE6.2 often differ for normal and high emitting vehicles. They can also vary by model year. As it is difficult to determine the fraction of emissions coming from each model year's vehicles in MOBILE6.2, as well as normal and high emitters, it is not feasible to predict outside of the model how a specific fuel is going to affect in-use emissions. In addition, the split between normal and high emitters varies depending on the presence and type of inspection and maintenance (I/M) program applicable in a particular local area. Thus, the effect of a specific fuel on emissions can vary to some degree from one county to another.

In order to quantify the effect of various fuel parameters on exhaust emissions in MOBLIE6.2 under the conditions existing in the 2012-2020 timeframe, we compared the changes in emissions predicted by the NMIM modeling described in Chapter 4 of the Draft RIA with the changes in fuel quality occurring in the ethanol use scenarios. Specifically, we first determined the percentage change in exhaust VOC, CO and NOx emissions by county for the base and 7.2 Minimum RFG Use scenarios evaluated for the NPRM. We then performed a series of linear regressions of these ratios against the change in fuel RVP, ethanol content and MTBE content. We did this for the 2012, 2015 and 2020 emission projections separately. For each combination of county and calendar year, the only property that changed was fuel quality. All other parameters relevant to emissions (e.g., the distribution of vehicles by age and class, VMT, ambient temperature, etc.) were otherwise identical. The results are summarized in Table 3.1-1.

Table 3.1-1. Fuel-Exhaust Emission Effects in MOBILE6.2

	RVP (% / psi)	Ethanol (% / Vol %)	MTBE (% / Vol%)	Adjusted r-Square
2012 (fleet average)				
VOC	7.1%	-1.1%	-0.7%	0.83
NOx	0.6%	0.0%	0.0%	0.95
CO	12.7%	-0.75%	-0.4%	0.36
2015 (fleet average)				
VOC	7.0%	-1.2%	-0.7%	0.85
NOx	0.6%	0.0%	0.0%	0.95
CO	12.7%	-0.73%	-0.4%	0.36
2020 (fleet average)				
VOC	6.7%	-1.2%	-0.7%	0.87
NOx	0.6%	0.0%	0.0%	0.95
CO	12.6%	-0.67%	-0.4%	0.39

For comparative purposes, the effect of RVP, ethanol and MTBE on exhaust VOC and NOx emissions from the EPA Predictive Models are shown in Table 3.1-2. The base fuel is a typical non-oxygenated, summertime, conventional gasoline, with 8.7 RVP, 30 ppm sulfur, 32 vol% aromatics, 13 vol% olefins, T50 of 218 F, T90 of 329, and no oxygen.

Table 3.1-2.
Fuel-Exhaust Emission Effects per the EPA Predictive Models

	RVP (% / psi)	Ethanol (% / Vol %)	MTBE (% / Vol%)
VOC	1.1%	-0.16%	-0.17%
NOx	1.1%	0.75%	0.36%

As can be seen, the exhaust emission effects contained in the EPA Predictive Models differ quite dramatically from those in MOBILE6.2. Regarding the effect of RVP, both models predict that an increase in RVP will increase both exhaust VOC and NOx emissions. However, MOBILE6.2 predicts that an increase of 1.0 psi will increase exhaust VOC by roughly 7%, while the EPA Predictive Models predict only a 1% increase. Regarding NOx emissions, the EPA Predictive Models predict the larger effect (1%), while the effect in MOBILE6.2 is smaller (0.6%). While the ratio of these two effects is significant, the absolute difference (0.4%) is very small.

Regarding the addition of ethanol, the two models again predict very different results. MOBILE6.2 predicts roughly 7 times the exhaust VOC reduction per volume percent of ethanol added, with no increase in NOx. The EPA Predictive Models project a significant increase in NOx emissions. The relative differences are similar for the addition of MTBE to gasoline, though the difference between the two estimates of exhaust VOC reduction is smaller.

Regarding CO Emissions from Tier 0 vehicles, MOBILE6.2 projects that a 3.5 wt% oxygen fuel (i.e., E10) will reduce CO emissions from normal emitters by 11% and those from high emitters by 19%.[44] For Tier 1 and later vehicles, MOBILE6.2 projects that a 3.5 wt% oxygen fuel (i.e., E10) will have no effect on CO emissions from normal emitters and will reduce CO emissions from high emitters by the same 19% estimated for Tier 0 vehicles. This latter projection was based on a similar assumption to those made during EPA's review of California's request for a RFG oxygen waiver due to the same lack of relevant emission data. We estimate that the fraction of CO emissions coming from high emitters is 64.8% based on the overall effect of 6.7% in 2020 shown in Table 3.1-1 for 2020, when the fleet is entirely Tier 1 and later vehicles. This produces a fleet wide CO emission reduction for an E10 blend of 13.8% for Tier 0 vehicles and 6.7% for Tier 1 and later vehicles. MOBILE6.2 does not project any impact of the other relevant fuel parameters (aromatics, olefins, T50, and T90) on CO emissions for either Tier 0 or Tier 1 vehicles.

Since that time, the results of several test programs have been published. Given the dwindling numbers of Tier 1 vehicles on the road, these more recent studies have focused on vehicles certified to California's low emission vehicle (LEV), ultra low emission vehicle (ULEV), and super ultra low emission vehicle (SULEV) standards, as well as federal LEV and Tier 2 standards. The results of these more recent studies, as well as the few available in 2001, are discussed in the following section.

3.1.1.1.3. CRC E-67 Study

3.1.1.1.3.1 Overview

In early 2006, the Coordinating Research Council (CRC) published the results of their E-67 study investigating the effects of three fuel parameters, ethanol, T50 and T90, on exhaust emissions from recent model year vehicles.[2] The twelve vehicles tested included both cars and light trucks, certified to California LEV, ULEV and SULEV standards, with model years ranging from 2001 to 2003. A matrix of twelve (12) fuels was tested in this program, with varying levels of ethanol, T50, and T90. Each fuel parameter (ethanol, T50, and T90) was tested at each of three levels. However, a full factorial matrix of 27 test fuels was deemed unnecessarily large due to subtle differences between fuels that may not have yielded statistically significant results, or due to practical considerations regarding the fuels that could be blended using existing refinery streams.

The E-67 report presents the results of emission testing for each fuel, as well as a mixed statistical model created from the emission data. The model indicates that each of the three fuel parameters always has a statistically significant effect on both NMHC[45] and NOx emissions. In addition, significant interactions between the three fuel parameters are also often present.

The first step in our analysis of the CRC E-67 model was to compare the emissions changes predicted by the CRC mixed model to the actual emissions changes observed for each

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[44] A normal emitter is generally a vehicle whose emissions are no more than twice its certification emission standards. A high emitter is a vehicle whose emissions exceed this level.

[45] NMHC is essentially equivalent to VOC for our purposes in this study.

fuel in the test program. We calculated average NMHC and NOx emissions over the Federal Test Procedure for all twelve vehicles on each fuel. The CRC mixed model predicts the percentage change in emissions for each fuel relative to another fuel. These changes in predicted exhaust emissions for each fuel were applied to the measured emissions for fuel "H" in order to create a set of absolute emission levels for each fuel. We then compared the emissions predicted by the CRC E-67 model to the measured emission levels to observe how well the model predicted the effects of each fuel. The fuel properties of the CRC E-67 test fuels are listed in Table 3.1-3[AAA], below, and in greater detail in Table 3A-1 of Appendix 3A. We selected CRC fuel "H" as the "base" fuel since its properties are the closest to a national average non-oxygenated conventional gasoline (0% Ethanol, 215ºF T50, 330 ºF T90). (See Table 2.2-6 in Chapter 2 for data pertaining to gasoline survey results across the U.S.)

Table 3.1-3. CRC E-67 Test Program Fuels Properties[a]

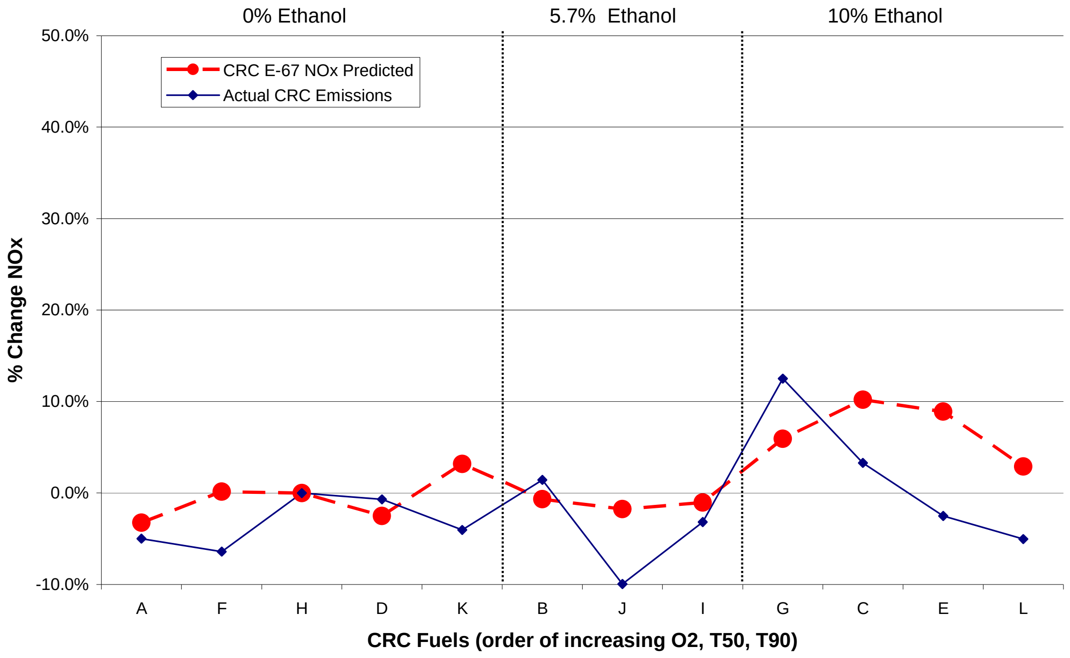
	Target Properties for Design Variables				Actual Values		
Fuel	T50 (ºF)	T90 (ºF)	Ethanol (%)		T50 (ºF)	T90 (ºF)	Ethanol
A	195	295	0		195	294	0
B	195	295	5.7		191	290	5.6
C	195	330	10		193	329	10.4
D	195	355	0		199	355	0
E	195	355	10		198	352	10.3
F	215	295	0		217	295	0
G	215	295	10		212	291	10.1
H	215	330	0		216	327	0.1
I	215	355	5.7		216	354	5.9
J	235	330	5.7		237	329	5.9
K	235	355	0		236	355	0
L	235	355	10		233	349	10.5

[a] See Table 3A-1 in Appendix 3A for detailed properties of all E-67 test fuels

The comparison between predicted and measured NOx emissions is shown in Figure 3.1-1. The fuels are shown to indicate a trend in ethanol content, from the lowest levels on the left to the highest levels on the right. Within a constant level of ethanol content, the fuels are then shown in order of their level of T50 (lowest again on the left and highest on the right). The y-axis scale in this figure is set to match that for NMHC emissions, which will be presented and discussed next.

Figure 3.1-1. CRC E-67 Predicted vs. Actual Emissions

Relative NOx Emissions Change from Base (CRC H: 215 T50, 330 T90, 0% EtOH)

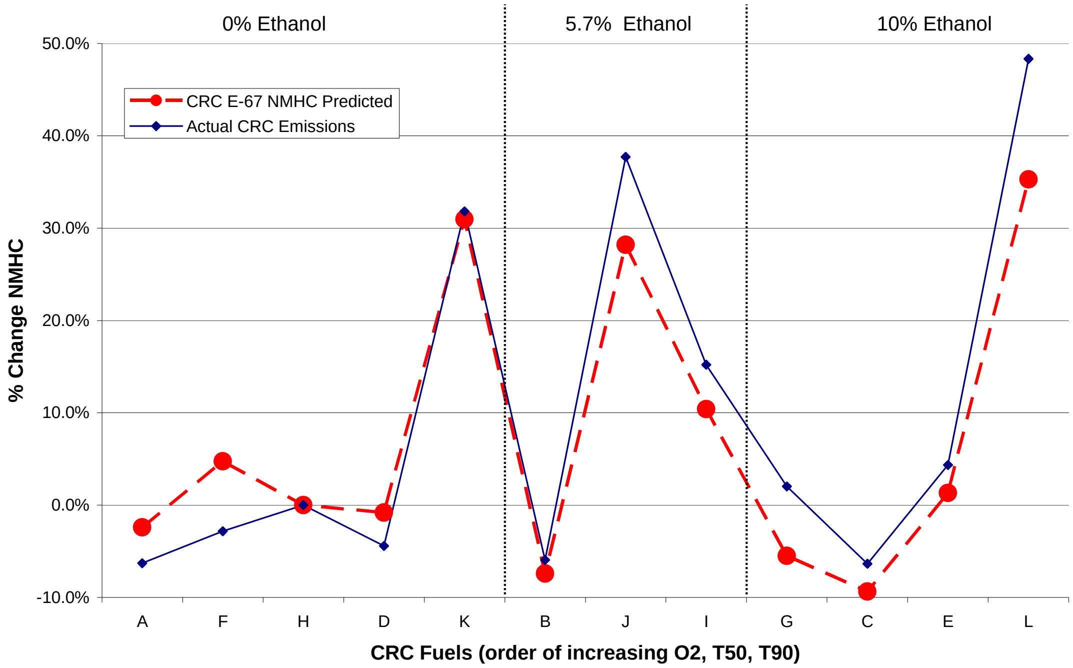


As shown in Figure 3.1-1, the CRC model for NOx emissions predicts the general trend in the emission data, which roughly indicates an increase in NOx emissions with increasing ethanol content. However, the model clearly does not reflect many of the fuel to fuel differences indicated by the actual emissions data. One example of this is the change between fuels G and C – two 10% ethanol blends with relatively low distillation temperatures. In changing from fuel G to fuel C, the CRC E-67 model predicts a 4.3% increase in NOx emissions whereas the actual test data clearly shows a 9.2% decrease. This likely indicates the existence of interactions between the fuel parameters which are more complex than those which could be included in the model. While fuel parameters other than ethanol, T50, and T90 were held as constant as possible among all the test fuels, the level of specific compounds (such as toluene or the various xylenes) could not be held constant. It is possible that some of these compounds are affecting NOx emissions and confounding the ability of the model based just on ethanol, T50, and T90 to predict the observed changes.

Figure 3.1-2 repeats this comparison for NMHC.

Figure 3.1-2. CRC E-67 Predicted vs. Actual Emissions

Relative NMHC Emissions Change from Base (CRC H: 215 T50, 330 T90, 0% EtOH)



First, it is very apparent that NMHC emissions are much more sensitive to fuel quality than NOx emissions. The largest increase in NMHC emissions relative to Fuel H is three times that for NOx emissions. Except for Fuels A and F (and of course Fuel H), the CRC model generally under-predicts the measured NMHC data. Directionally, however, the predicted emissions changes are very consistent with those observed in the test results. For this dataset at least, the effect of fuel quality on NMHC emissions are much more predictable than NOx emissions.

The fuels studied in this test program were varied independently at low, medium, and high levels of T50, T90, and Ethanol. If you include all the possible linear, quadratic, and interactive terms, there are a total of possible 10 combinations. The CRC E-67 models included 8 out of the10 possible fixed effects for the NOx, NMHC, and CO models. These terms were: T50, T90, ethanol (EtOH), T50 squared, T90 squared, EtOH squared, T50 by EtOH, and T90 by EtOH. The excluded terms were T50 by T90, and T50 by T90 by EtOH, which CRC excluded from consideration since previous studies had indicated that these terms had little effect on emissions.

Also, several of the terms that were included in the CRC model had p-values greater than 0.1, indicating that those terms are less than marginally significant.[46] Specifically, the EtOH by EtOH term in the NMHC model and the T90, T90 by T90 and T90 by EtOH terms in the NOx model all had p-values above 0.10. In developing both the Complex Model and the EPA

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[46] Using the widely accepted criteria of a 95% confidence interval, $p \leq 0.05$ is considered to be statistically significant, $0.05 < p \leq 0.10$ is marginally significant, and $p > 0.10$ is not considered statistically significant.

Predictive Models, our procedures would normally exclude the least significant term. A new regression would then be performed without this term being included in the model. This process would be repeated until all the remaining terms were statistically significant.[47]

We desired to determine how these statistically insignificant terms might be affecting the predicted emission changes. This, plus the discrepancies between the CRC E-67 model and the actual emissions data, especially for the NOx model, prompted us to create our own NOx and NMHC models using the CRC E-67 dataset. Conducting our own modeling also provides us with the opportunity to apply a wide range of statistical tests in order to better understand the role of various fuel parameters in affecting emissions from these vehicles. The following sections provide details pertaining to the verification of the CRC model and the motivation for constructing a new model from this data.

3.1.1.1.3.2. Development of a New Mixed Model: The EPA E-67 Model

Using the E-67 dataset provided by the CRC, EPA first verified the coefficients and p-values of the CRC E-67 model using the full E-67 dataset (no outliers were removed) with the same 8 fixed fuel effects that were included by CRC. This was successful and the coefficient and p-values resulting from this modeling are shown in Table 3.1-4.

Table 3.1-4. CRC E-67 Model P-Values and Coefficients

CRC E-67	NMHC		CO		NOx	
Effect	**P-Value**	**Coefficient**	**P-Value**	**Coefficient**	**P-Value**	**Coefficient**
Intercept	<.0001	-3.2942	0.0001	-0.7966	<.0001	-2.6183
T50	<.0001	0.0063	0.3099	0.001227	0.8939	-0.00013
T50*T50	<.0001	0.000176	0.0428	0.000099	0.2182	-0.00006
T90	0.0541	0.001685	0.0051	-0.0045	0.762	0.00024
T90*T90	0.0035	0.000058	0.0815	0.000045	0.1163	0.000043
EtOH	0.1124	0.005679	0.0174	-0.01581	0.0504	0.00571
EtOH*EtOH	0.2816	0.000722	0.0005	0.003118	0.0861	0.001622
T50*EtOH	0.084	0.000195	0.0182	0.000355	0.0414	-0.00032
T90*EtOH	0.0004	0.000244	0.0534	0.000174	0.99	-1.19E-06

EPA then created a new model starting with all combinations of T50, T90, and EtOH along with their squares, cross products, and the interactive terms T50 by T90 by EtOH for a total of 10 fixed effects. From this “full model”, variables were eliminated in order to improve the fit statistics between the model and the test data until a “final model” was created that contained 7 fixed fuel effects for NMHC and CO, and 6 fixed fuel effects for NOx. Table 3.1-5, on the following page, shows the p-values and coefficients for the fixed effect terms of each model.

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[47] One exception to this process is that the linear form of a variable, such as ethanol, would always be retained in the model if a second order term included ethanol (e.g., the ethanol by T90 term).

Table 3.1-5. EPA E-67 Model P-Values and Coefficients

EPA E-67	NMHC		CO		NOx	
Effect	**P-Value**	**Coefficient**	**P-Value**	**Coefficient**	**P-Value**	**Coefficient**
Intercept	<.0001	-3.2773	0.0002	-0.7684	<.0001	-2.6418
T50	<.0001	0.006272	0.5815	0.00066	0.687	-0.00037
T50*T50	<.0001	0.000168				
T90	0.0498	0.00172	0.0059	-0.00437	0.7761	0.000224
T90*T90	0.0039	0.000057			0.0735	0.000047
EtOH	0.101	0.005892	0.0111	-0.01726	0.062	0.005393
T50*EtOH	0.0987	0.000186	<.0001	0.003843	0.0446	0.001854
T90*EtOH	0.0002	0.00025	0.0299	0.000178	0.0426	-0.00031
T50*T90			<.0001	0.000126		
T50*T90*EtOH			0.0003	0.000023		

As shown in Table 3.1-5, the EPA E-67 Model does not include terms with p-values greater than 0.10 (except for linear terms included in statistically significant higher order terms). Statistical tests show that these two models are not significantly different from one another. The null hypothesis in this case is that EPA E-67 fits the data just as well as the original CRC E-67 model based on a chi-squared test. However, based on several fit statistics (AIC, AICC, and BIC) the EPA E-67 model provides a slightly better fit to the test data than either the original CRC E-67 model or the full model with all 10 terms included. The next step is to compare the EPA E-67 model predictions to both the E-67 data and the predictions of the EPA Predictive Models, which reflect the emission effects for older vehicles.

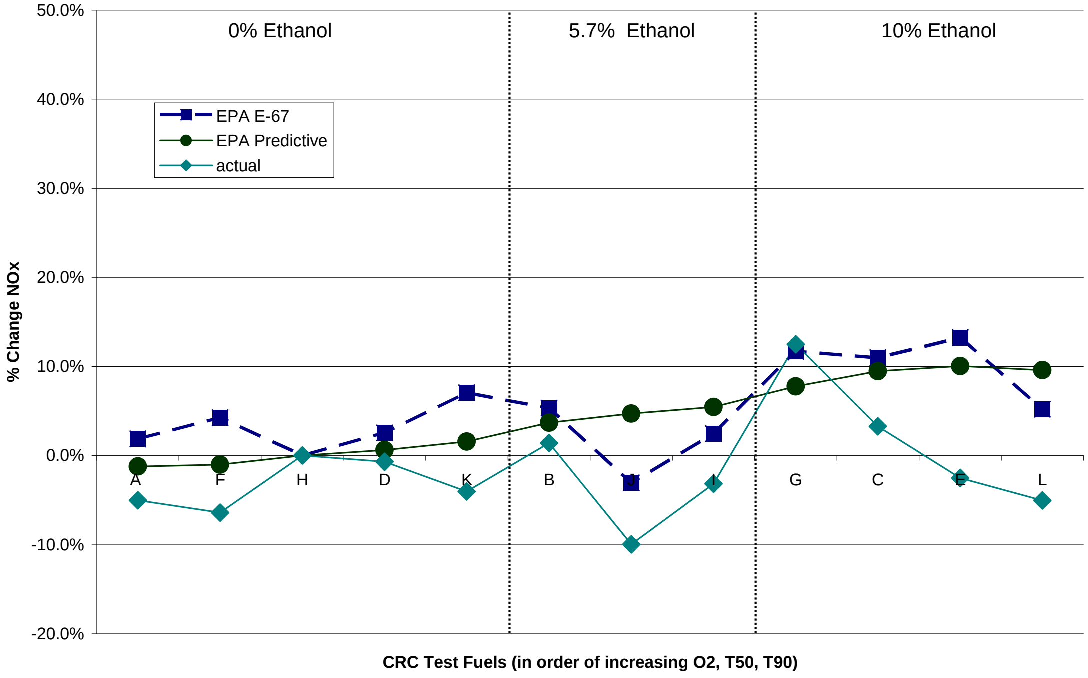
Both the EPA E-67 and EPA Predictive models are mixed models that predict the relative changes in exhaust emissions due to carefully controlled changes in gasoline quality, including the addition of an oxygenate such as ethanol. The models are not intended to be accurate at predicting absolute emission levels, but rather the difference in emissions when fuel properties are varied. The goal of this analysis is to determine if the EPA Predictive models, which were developed using data from Tier 0 and earlier vehicles, predict the same relative changes in emissions as the Tier 1 vehicles used for the EPA E-67 model.

A key difference between the models is that there are only three fuel parameters used as inputs for the EPA E-67 model: T50, T90, and ethanol content. The EPA Predictive Models use these three properties along with RVP, aromatic content, olefin content, and sulfur content as fuel parameter inputs to the model.

We ran the EPA E-67 and EPA predictive models with the 12 fuels used in the CRC test program, inputting the applicable fuel properties used in each model. Following the same procedure as outlined above, CRC test fuel H was selected as a “base” fuel in order to compare relative changes between this fuel and others with varying amounts of ethanol, T50, and T90. The NOx emissions predicted by the EPA E-67 and EPA Predictive models, together with the actual E-67 study data, are shown graphically in Figure 3.1-3, below.

Figure 3.1-3. EPA E-67 and EPA Predictive vs. Actual Emissions

Relative NOx Emissions Change from Base (CRC H: 215 T50, 330 T90, 0% EtOH)



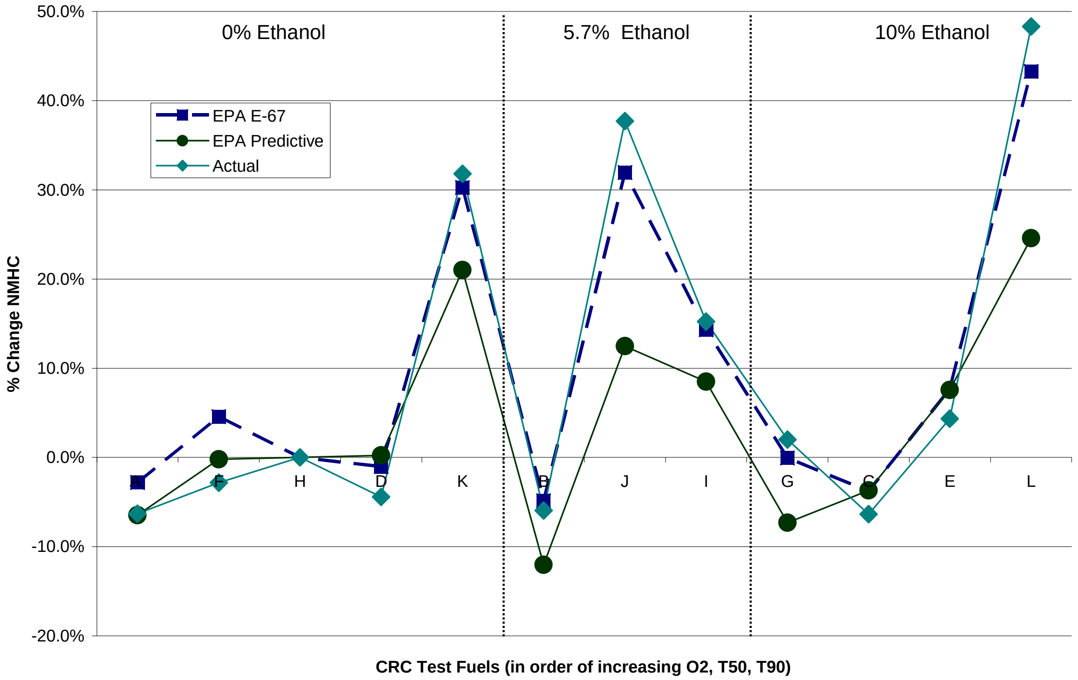
As shown in Figure 3.1-3, neither model predicts the actual test data with complete accuracy. The EPA E-67 shows the same general relationship to the emission data as did the CRC E-67 NOx model. Thus, removing the statistically insignificant terms had little impact on the relative fit of the model to the data. The EPA Predictive NOx models, on the other hand, appear to be primarily sensitive to ethanol, with T50 and T90 playing very limited roles in affecting NOx emissions. In contrast, the E-67 model shows sensitivities to all three parameters.

Overall, the E-67 study indicates that NOx emissions from recent model year vehicles (LEVs, ULEVs and SULEVs) are still sensitive to at least several fuel parameters. As indicated by the inability of either the EPA E-67 model or the EPA Predictive Models to accurately predict all of the changes seen in the E-67 data, this study is very valuable in identifying the continued sensitivity of LEV and cleaner vehicles to changes in fuel quality.

Figure 3.1-4, below, shows the comparison of NMHC emissions predicted by the EPA E-67 and Predictive models together with the E-67 study data.

Figure 3.1-4. EPA E-67 and EPA Predictive vs. Actual Emissions

Relative NMHC Emissions Change from Base (CRC H: 215 T50, 330 T90, 0% EtOH)



From Figure 3.1-4, it is apparent that both models do a better job at predicting changes in NMHC emissions than was the case for NOx emissions. The EPA E-67 model is clearly the more accurate of the two models. However, this is to be expected given it was based on the data being depicted. The ability of the EPA Predictive Model to predict the general trend of nearly all the CRC E-67 test fuels is impressive, given it is based on data from Tier 0 vehicles with 5-10 times the NMHC emission levels of the vehicles in the E-67 test program. Overall, it appears that NMHC emissions from LEVs and cleaner vehicles are even more sensitive to changes in fuel quality than NMHC emissions from Tier 0 vehicles.

The preceding figures illustrate the differences between the models for all 12 fuels included in the E-67 test program. Some of these fuels are more practical, or likely to be commercially produced, than others. Based on the results of AAM fuel surveys presented in Chapter 2, summertime E10 blends will generally have levels of T50 and T90 that are about 29 ºF and 7 ºF lower than non-ethanol blends. Thus, it could be useful to focus on sets of fuels in the CRC E-67 study which reflect these differences.

The fuel pair which most closely reflects these differences are CRC fuel "C", a 10 vol% ethanol blend, and CRC fuel "H", a non-oxygenated fuel. Both fuels have a mid-range level of T90. A second, more complex set of fuels involve those with higher levels of T90. The CRC "E" fuel contains 10 vol% ethanol and has the high level of T90. However, there is not a good match to this fuel which is non-oxygenated. Yet two non-oxygenated fuels ("D" and "K"), when considered together, represent a reasonable match to fuel "E. Fuel D reflects no change in T50 relative to fuel E, while fuel K reflects slightly more than a typical drop in T50. Thus, by averaging the emissions for fuels K and D and then comparing this to the emissions with fuel E, we are able to generate a second direct indication of the impact of ethanol blending on emissions from these low emitting vehicles. The general properties of these five fuels and the emissions changes predicted by the two models are shown in Table 3.1-6 below.

Table 3.1-6.
Predicted NOx and NMHC Emissions Changes for EPA E-67and Predictive Models[48]

Fuel Changes	**H to C**	**K to E**	**D to E**
T50 (ºF)	Mid - Low	High – Low	Low - Low
T90 (ºF)	Mid - Mid	High – High	High - High
Oxygen (vol%)	0 - 10	0 – 10	0 - 10
Change in Emissions			
EPA Predictive Model NOx	9.5%	8.4%	9.4%
EPA E-67 NOx	11.0%	5.8%	10.4%
Actual E-67 Data	3.3%	1.6%	-1.8%
EPA Predictive Model NMHC	-3.7%	-11.1%	7.3%
EPA E-67 NMHC	-3.8%	-17.3%	8.8%
Actual E-67 Data	-6.3%	-21.0%	9.2%

As shown in Table 3.1-6, the two models agree quite closely on the effect of fuel C relative to fuel H on both NMHC and NOx emissions. However, that said, both models tend to overestimate the impact of fuels C and E on NOx emissions and underestimate the impact of these fuels on NMHC emissions.

Regarding the comparison of fuel E to fuels K and D, the two models tend to agree on the effect of fuel E to fuel D, but differ more with respect to the effect of fuel E to fuel K, particularly for NMHC emissions. One reason for the difference in the latter comparison is that the EPA E-67 NMHC model is more sensitive to very high levels of T50 than the EPA Predictive Model for NMHC.

Overall, the results of the E-67 study suggest that our assumption that Tier 1 and later vehicles would not be sensitive to fuel parameters such as ethanol, T50 ad T90 (made in our consideration of California’s request for a waiver of the RFG oxygen requirement) may not be valid. The observation that NMHC emissions from LEVs, *et. al*. could actually be more sensitive than Tier 0 vehicles (on a percentage basis), particularly challenges our assumption. While the effect of fuel quality on NOx emissions from low emitting vehicles is still not clear from the recent test data, these emissions do appear to be sensitive to fuel quality.

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[48] For an additional comparison between the models with an expanded set of fuels to be used later in this analysis, refer to Table 3A-2 in Appendix 3A.

3.1.1.1.3.3. Effect of Oxygen Content Alone on Emissions: CRC E-67 Study

In order to provide an estimate of fuel-emission effects comparable to those of the other studies of the effect of fuel quality on emissions from LEV and later vehicles, we selected three pairs of fuels tested in the CRC E67 study where the only change in fuel properties was oxygen content. One pair of fuels compared non-oxygenated fuel versus E6 (fuels A and B). Two pairs of fuel compared non-oxygenated fuel versus E10 (fuels D and E and fuels F and G). We applied mixed univariate statistical models to the logarithm of the emission data from fuels A and B and to fuels D, E, F and G, with vehicle as a random variable and fuel type as a fixed variable. Table 3.1-7 presents the results in terms of the percentage change in emissions between the non-oxygenated fuel and the ethanol blend in each pair.

Table 3.1-7.
Matched Fuel Pair Results from the CRC E-67 Study: Effect of Oxygen Alone

	NMHC	CO	NOx
	% Change	% Change	% Change
6 vol% ethanol vs. no oxygenate (Fuels A and B)	-4.5%*	-7.5%	2.6%
10 vol% ethanol vs. no oxygenate (Fuels D, E, F and G)	**4.7%**	**-18.1%**	**9.5%**

* Bold type indicates the difference was significant at a 90% confidence level.

As can be seen, the addition of 6 vol% ethanol increased NOx emissions, while decreasing NMHC and CO emissions. None of the effects were statistically significant at a 90% confidence level. The addition of 10 vol% ethanol decreased CO emissions, while increasing NMHC and NOx emissions. All three pollutant effects were statistically significant at a 90% confidence level.

3.1.1.1.4. AAM-AIAM Sulfur and Oxygenate Study

AAM, together with AIAM and Honda, performed a test program in 2001 to evaluate the effect of fuel sulfur and oxygen on emissions of CARB Tech 5 vehicles (i.e., LEV and later vehicles)[BBB]. This program was performed at the request of the CARB in conjunction with the MTBE ban and new Phase 3 Cleaner Burning Gasoline regulations. The first of the program's two distinct goals was to evaluate the emissions of very low sulfur fuels at 1, 30, and 100 ppm sulfur, with other fuel parameters held constant. Part two was to compare the emissions effects of MTBE and ethanol blended fuels to non-oxygenated fuel, again with other parameters held as constant as possible. The fuel specifications for the oxygenated fuel matrix are shown in Table 3.1-8. (The sulfur-related testing is not relevant here, so the fuels which only reflect a change in sulfur are not shown.)

Table 3.1-8.
AAM Fuel Properties for Oxygenated Test Fuels

Test Fuel	Non-Oxy	MTBE	E10
RVP (psi)	7.1	6.9	7.1
Arom (vol.%)	24.6	22	21.6
Olefins (vol.%)	4.6	3.4	4.1
T50 (ºF)	210	202	205
T90 (ºF)	297	294	291
MTBE/EtOH (vol.%)	0	11.3	11.5
Sulfur (ppm)	35	31	28

The sulfur effects portion of this study tested 13 TLEV, LEV, and ULEV vehicles while the oxygenate phase of the study used 8 and 2 of phase 1's LEV and ULEV vehicles, respectively. These vehicles were a mixture of light and medium duty passenger cars and trucks of undisclosed make and model year. The FTP 75 was selected as the drive cycle, with regulated data collected both at the tailpipe and engine out for a subset of vehicles to evaluate catalyst efficiency.

The sulfur related testing found a clear relationship between the level of sulfur in the fuel and the natural log of emissions (CO, NOx and NMHC). Bag weighted emissions of NOx, CO, and HC emissions were reduced by 16%, 12%, and 11% (respectively) when fuel sulfur levels were reduced from 30 to 1 ppm. The effects found in the oxygenate portion of the study were less clear, since some results were not statistically significant. Average bag weighted emissions of HC and CO tended to decrease with increasing oxygen content. Both oxygenated fuels showed a decrease in NOx emissions, with MTBE having slightly lower emissions than ethanol. The details of the statistical procedures applied to the data were not described in the documentation.

In order to provide a consistent basis for comparing the results of this study to the other studies of the effect of oxygenate on LEV and later vehicle emissions, we applied a mixed univariate statistical model to the logarithm of the emission data from the AAM-AIAM oxygenate study, with vehicle as a random variable and fuel as a fixed variable. Table 3.1-9 presents the results in terms of the percentage change in emissions between the 11 vol% MTBE blend, the 11 vol% ethanol blend and the non-oxygenated fuel.

Table 3.1-9.
Fuel Effects from the AAM-AIAM Oxygenate Study: EPA Mixed Model

	NMHC	CO	NOx
	% Change	% Change	% Change
11 vol% MTBE vs. no oxygenate[a]	**-15.3%**[b]	**-23.7%**	**-12.7%**
11 vol% ethanol vs. no oxygenate	**-12.6%**	**-24.6%**	**-6.6%**
11 vol% ethanol vs. 11 vol% MTBE	-1.4%	-5.7%	**25.2%**

[a] Fewer vehicles were tested on the MTBE blend.

[b] Bold type indicates the difference was significant at a 90% confidence level.

As can be seen in Table 3.1-9, the addition of 11 vol% MTBE was found to significantly reduce the emissions of all three pollutants by 10% or more relative to the non-oxygenated California RFG. The addition of 11 vol% ethanol was also found to significantly reduce the emissions of all three pollutants relative to the non-oxygenated California RFG. However, the reductions were smaller than those of the MTBE blend for all three pollutants. Also, the reduction in NOx emissions was not statistically significant at a 90% confidence level. When we compared the emissions with the ethanol blend to those with the MTBE blend, we found that the increases were all statistically significant at a 90% confidence level.

Based solely on this single study of seven vehicles and three fuels, it appears that adding ethanol to a severely reformulated gasoline while holding other properties constant tends to reduce NMHC, CO and NOx emissions. However, replacing MTBE with the same volume of ethanol tends to increase these emissions. Focusing on just this one study, the effect of increased ethanol use could differ in RFG areas, where MTBE has traditionally been used, and conventional fuel areas, where no oxygenate has traditionally been used. However, this one study is not a sufficient basis to draw a firm conclusion regarding the effect of ethanol blending on exhaust emissions.

3.1.1.1.5. ExxonMobil Study of Oxygenate Type and Content

In the fall of 1999, ExxonMobil (Mobil Oil at that time) conducted a test program to investigate the emissions effects of MTBE and ethanol on LEV and ULEV vehicles. The information which follows was made publicly available on the CARB website[CCC] and is taken directly from a presentation posted on that webpage. The vehicles tested are listed in Table 3.1-10.

Table 3.1-10. Vehicles Tested in 1999 ExxonMobil Study

Make/Model	Emissions Calibration	Engine	Fuel System
1999 Dodge Stratus	LEV	2.4L	MFI
1999 Chevrolet Malibu	LEV	3.1L	PFI
1999 Mazda Protégé	ULEV	1.6L	MPF
1999 Ford Crown Victoria	LEV	4.6L	SFI
1998 Honda Accord	ULEV	2.3L	MFI

Four test fuels were developed with varying MTBE and ethanol content, with other parameters controlled as tightly as possible. The fuel specifications are listed below in Table 3.1-11.

Table 3.1-11. ExxonMobil Test Fuel Specifications

Test Fuel	M1	M2	M3	M4
RVP, psi	6.5	6.4	7.3	7.2
T50 (ºF)	192	191	198	203
T90 (ºF)	279	272	274	282
MTBE (vol%)	0	10	0	0
Ethanol (vol%)	0	0	7	10
Aromatics (vol%)	21	21	21	21
Olefins (vol%)	<1	<1	<1	<1
Oxygen (wt%)	0	1.82	2.436	3.48

Vehicles were tested in duplicate over the FTP 75 drive cycle, and composite weighted emissions for regulated pollutants reported. The average results for all vehicles, based on least squares means from the analysis of variance, is shown in Table 3.1-12., below. The oxygenate effect is the percent change in emissions between a given fuel and the base fuel M1.

Table 3.1-12. Average Exhaust Emissions: ExxonMobil Study (all vehicles)

		Exhaust Emissions, g/mi			Oxygenate Effect (a)		
Fuel	**Oxygenate**	**HC**	**CO**	**NOx**	**HC**	**CO**	**NOx**
M1	None	0.058	0.70	0.187			
M2	10% MTBE	0.058	0.72	0.198	0%	3%	6%
M3	7% EtOH	0.059	0.66	0.213	1%	-6%	**14%**
M4	10% EtOH	0.061	0.66	0.239	5%	-6%	**28%**

(a) Bold font represents statistically significant (α=0.1)

The bold numbers in the above table represent statistically significant differences in emissions at the 90% confidence level. Only the effect of ethanol on NOx emissions was found to be statistically significant while the effects on other criteria pollutants were not. As was the case for the AAM-AIAM study, the presentation to CARB did not describe the statistical analysis applied to the detail in sufficient detail to replicate the results. Thus, we applied a mixed univariate statistical model to the logarithm of the emission data from the ExxonMobil oxygenate study, with vehicle as a random variable and fuel type as a fixed variable. Because of the greater number of fuels in this study, we applied two different types of mixed models. One set of models compared emissions between various pairs of fuels (e.g., M1 and M2). We applied five models of this type. A sixth model used oxygen content as the fuel variable and considered the significance of the square of oxygen content, as well. The upper half of Table 3.1-13 presents the results in terms of the percentage change in emissions between the various fuel pairs. The bottom half of Table 3.1-13 presents the estimated emission effects for 2.1 wt% and 3.5 wt% oxygen fuels using the results of the fuel oxygen content based model.

Table 3.1-13. Fuel Effects from the ExxonMobil Oxygenate Study

	THC	CO	NOx
	% Change	% Change	% Change
Two Fuel Comparisons			
10 vol% MTBE vs. no oxygenate	-2.5%[a]	-5.1%	-0.4%
7 vol% ethanol vs. no oxygenate	-0.9%	**-11.3%**	9.3%
10 vol% ethanol vs. no oxygenate	3.6%	**-11.6%**	**20.3%**
10 vol% ethanol vs. 10 vol% MTBE	**6.3%**	-7.6%	**21.1%**
Oxygen Content model			
2.1 vol% Oxygen	**-2.0%**	**-9.1%**	**2.9%**
3.5 vol% Oxygen	**3.5%**	**-15.2%**	**17.3%**

[a] Bold type indicates the difference was significant at a 90% confidence level.

As can be seen, the results of our statistical analysis differ from those performed by ExxonMobil. This may have been due to our focus on the logarithm of emissions or the use of a mixed model. As shown in Table 3.1-13, the addition of 10 vol% MTBE was found to reduce the emissions of all three pollutants relative to the non-oxygenated California RFG. While the differences tended to be substantial in magnitude on average, they were not statistically significant at a 90% confidence level. The addition of 7 vol% ethanol to the non-oxygenated California RFG (with an increase of roughly 1.0 psi RVP) was also found to reduce the emissions of all three pollutants. Again, the reductions in NMHC and NOx emissions were not statistically significant. While the reduction in CO emissions was slightly smaller on average than that for MTBE, the effect was more consistent across vehicles and statistically significant at a 90% confidence level. The addition of 10 vol% ethanol to the non-oxygenated California RFG (again with an increase of roughly 1.0 psi RVP) was also found to reduce emissions of NMHC and CO, but increased NOx emissions slightly. Like that for the 7 vol% ethanol blend, only the CO emission effect was statistically significant at a 90% confidence level. Finally, the substitution of 10 vol% ethanol for 10 vol% MTBE was found to increase emissions of THC and NOx substantially, while reducing CO emissions slightly. None of the effects were significant at a 90% confidence level, though the NOx increase was nearly so (e.g., 89% confidence).

With respect to the model using oxygen content to describe the four fuels in the study, the effect of oxygen on emissions was found to be statistically significant for all three pollutants. In addition, the square of the oxygen content was statistically significant at the 90% confidence level for THC and NOx emissions. The predictions shown in Table 3.1-13 utilize the square of oxygen content for these two pollutants, but not for CO emissions. As can be seen, a 2.1 wt% oxygen fuel (e.g., an 11 vol% MTBE or 6% ethanol blend) is predicted to decrease THC and CO emissions, but increase NOx emissions. A 3.5 wt% oxygen fuel (e.g., a 10% ethanol blend) is predicted to decrease CO emissions, but increase THC and NOx emissions.

The two modeling approaches produce markedly different predictions for a 10 vol% ethanol blend, especially for THC and NOx. The direct comparison of the clear fuel and the E10 blend shows the E10 blend to reduce THC and NOx slightly. In contrast, the oxygen content approach predicts that the E10 blend will increase both THC and NOx emissions. This underlines the need for more data to accurately predict the emission effect of various types and levels of oxygenate on modern vehicles.

3.1.1.1.6. Toyota Study of MTBE and Ethanol Blends

Toyota Motor Company of Japan performed a small study, presented in 2000, evaluating the effect of MTBE and ethanol blended gasoline on exhaust emissions of nine LEV, TLEV, ULEV vehicles.[DDD] The model years for these vehicles were not presented.. Three test fuels were evaluated in this study: Phase 2 California RFG containing MTBE, a matched RVP E10 and a higher RVP E10. However, exhaust emission testing was only performed on the MTBE fuel and the higher RVP ethanol fuel. The fuel properties for these test fuels are listed in Table 3.1-14, below:

Table 3.1-14. Fuels Tested in the Toyota Oxygenate Test Program

Fuel Parameter	MTBE Blend	Matched RVP Ethanol Blend	Higher RVP Ethanol Blend
RVP (psi)	6.8	7	7.6
Arom (vol.%)	24	23	24.1
Olefins (vol.%)	5	5	3.4
T50 (°F)	156	208	212
T90 (°F)	290	294	297
MTBE (vol.%)	11.1	0	0
EtOH (vol.%)	0	11.2	8.9
Sulfur (ppm)	30	29	30

As can be seen in the above table, aromatics, olefins, and sulfur were held relatively constant while other parameters varied. The emission test cycle used was not stated. We assume it was the FTP 75 test. Only regulated emissions results are provided.

The study found that, on average across all vehicles and tests, NOx emissions increased by 5% for E10-B relative to MTBE. Correspondingly, CO emissions were reduced by 6% and NMHC emissions were decreased by 0.6% for E10-B relative to MTBE.

Again for comparison purposes, we applied a mixed univariate statistical model to the logarithm of the emission data from the Toyota oxygenate study, with vehicle as a random variable and fuel type as a fixed variable. Table 3.1-15 presents the results in terms of the percentage change in emissions between the 11 vol% MTBE and the 9 vol% ethanol blends.

Table 3.1-15. Fuel Effects from the Toyota Oxygenate Study

	NMHC	CO	NOx
	% Change	% Change	% Change
9 vol% ethanol vs. 11 vol% MTBE	-0.8% [a]	-6.1%	3.8%

[a] Bold type indicates the difference was significant at a 90% confidence level.

As can be seen, the substitution of 9 vol% ethanol for 11 vol% MTBE in a RFG-type blend was found to reduce the emissions of NMHC and CO, but increase NOx emissions. None of the emission effects was found to be statistically significant at a 90% confidence level.

Based solely on this single study of nine vehicles and three fuels, it appears that replacing MTBE with roughly the same volume of ethanol in reformulated gasoline while holding other properties constant (except RVP) tends to reduce NMHC and CO, and increases NOx emissions. It is not possible to separate the effect of ethanol from RVP in this study.

3.1.1.1.7. Mexican Petroleum Institute Fuel-Emission Effects Study

In 2006, the Instituto Mexicano del Patroleo (hereafter referred to as Mexican Petroleum Institute) published a paper on a recently conducted research program investigating the effects of gasoline properties on exhaust and evaporative emissions on 30 light duty cars and trucks, ranging in model year from 1993 to 2002.[EEE] The fuel quality parameters investigated include RVP, oxygen, Sulfur, olefins, aromatics, and distillation parameters. The results of this study were used to develop a statistical model for predicting emissions based on fuel quality for use in guiding national air quality improvement program policy. In their analysis, a comparison was made between the “predictive model,” developed based in this test data, and EPA’s Complex model. The end result is a general qualitative agreement with the EPA Complex model, with some quantitative differences pertaining to the vehicles and fuels used in each model’s development. Selected properties of the test fuels are shown below in Table 3.1-16.

Table 3.1-16. Fuel Tested in the Mexican Petroleum Institute Fuel Effects Study

Fuel	Aromatics (vol%)	Olefins (vol%)	Oxygen[a] (wt%)	Benzene (vol%)	RVP (psi)	T50 (ºF)	T90 (ºF)	Sulfur (ppm)
1	19.1	6.6	0	0.86	6.8	224	325	411
2	19.3	6.6	0.98	1.09	6.8	222	324	412
3	18.8	6.5	2.03	0.9	6.9	216	324	406
4	20.6	6.7	2.1	1.13	7	227	326	386
5	19	6.6	1	1.15	8.6	213	323	423
6	18.7	6.9	1.03	0.98	10.7	199	325	387
7	40.2	6.9	0.98	2.26	6.6	233	324	402
8	20.7	15	1.07	1.31	10.9	197	322	415
9	35.8	15.5	1.06	1.25	10.8	209	326	403
10	19.8	5	1.03	0.6	6.6	220	335	89
11	20	7.4	0.98	0.8	6.7	223	321	209
12	19.8	6.1	1.05	0.75	6.6	222	321	817
L-S	40.3	4.8	1.14	1.06	8.1	232	324	34
Ref	28	13.5	0.34	1.14	8.9	207	332	724
ZM	24.1	9	1.21	1	7.7	213	326	403

[a] Oxygenate is MTBE, except fuel 4 (Ethanol)

The base fuel from which other fuel parameters were varied to form additional fuels is indicated as fuel 2 in the above table, and is a low-level MTBE fuel blended to represent a composite average of all brands of commercially available Mexican gasoline. The reference fuel for comparative fuel effects purposes, fuel “Ref”, is a fuel blended to have refinery average levels of sulfur, benzene, RVP, aromatics, olefins, and distillation properties for the year 2000.

The technology groups investigated were referred to as either “Tier 0” and “Tier 1” vehicles, which is a bit of a misnomer as these vehicles were not equipped with on-board diagnostic equipment (OBD), nor were they subject to emissions durability standards[49]. Rather, each technology class acts as a surrogate for emission control technologies with the certification standards shown in Table 3.1-17.

Table 3.1-17. Certification Standards of Test Vehicles by Technology Class

Technology class	# of Vehicles	Model Years	CO (g/km)	NMHC (g/km)	NOx (g/km)
"Tier 0"	12	1993-1998	2.1	0.25 (THC)	0.62
"Tier 1"	14	1999-2002	2.1	0.156	0.25

Vehicles were tested on a chassis dynamometer over the FTP-75 test. Regulated emissions, as well as speciated hydrocarbons and carbonyls, were collected for each test. The procedures and statistical methods employed to develop the predictive model for this test program were similar to those used to construct the complex models for exhaust VOC and NOx emissions.

The emissions test results were separated into “Tier 0” and “Tier 1” categories, and reported as mean emissions rates for all vehicles of that type on each test fuel. The natural logarithm of emissions was then regressed to develop a predictive model, using a statistical approach that is “similar to the techniques used to construct the complex model for exhaust VOC and NOx emissions” (Schifter et al, 1275). The report then goes into details on the experimental vs. model predicted results, as well as a validation of their model which will not be discussed here. The model predicted percent changes in emissions (for both vehicle fleets) for the Mexican Petroleum Institute predictive model and EPA Complex model are shown in Figures 3.1-5 and 3.1-6, below.

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[49] The Mexican Environmental Agency currently mandates emissions durability certificates to be issued on new vehicles

Figure 3.1-5. Emissions Effects Predicted by EPA Complex Model

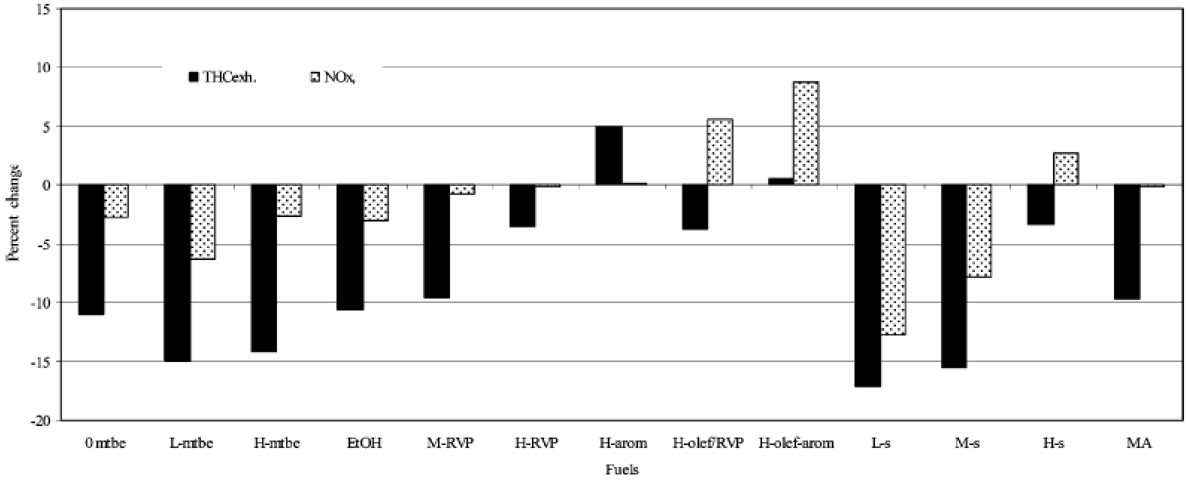
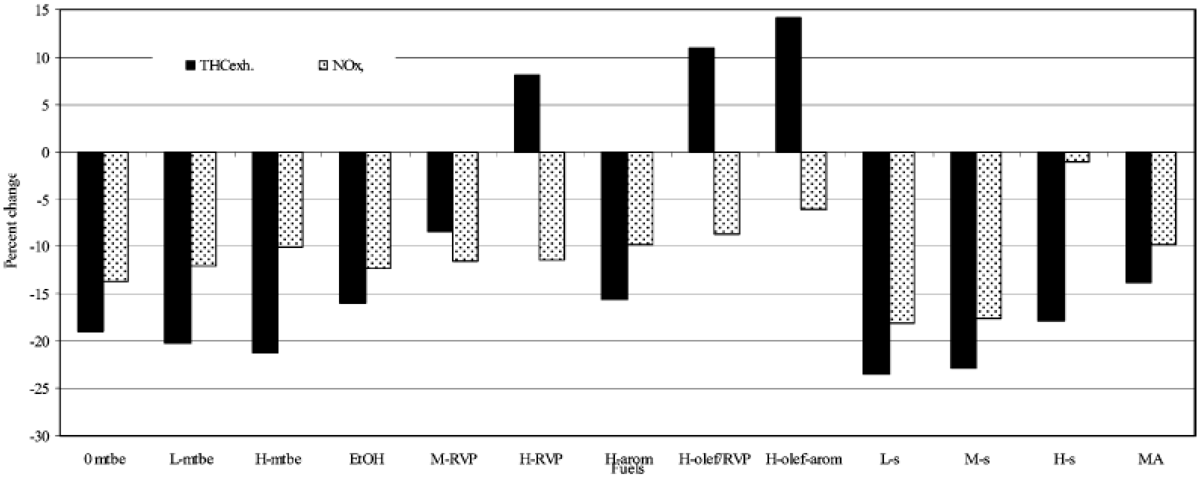


Figure 3.1-6. Emissions Effects Predicted by Mexican Petroleum Institute "Predictive" Model



The values above represent average emissions across both vehicle technology fleets considered together, and with the industry average fuel ("Ref") as a baseline for predicted changes in emissions. As you can see, their model predicts an even greater reduction in exhaust THC and NOx emissions with ethanol (and MTBE) than the complex model, along with directionally inconsistent results for fuels with high aromatics, RVP, and olefins. This is partly due to differences in the fuels and vehicles used to develop each model (along with the properties of the base fuel selected) and speaks to the fact that there is a high degree of uncertainty and sensitivity to consider when extrapolating the results of a fuel effects model to the larger vehicle and fuel population.

As with the other studies, we applied a mixed univariate statistical model to the logarithm of the emission data from the Mexico fuel study, with vehicle as a random variable and fuel type as a fixed variable. We restricted the vehicles to those which had NOx emissions of 0.20 g/mi or less on the low sulfur fuel (30 ppm) included in the test matrix. This resulted in the inclusion of seven vehicles (numbers 9, 15, 25, 27, 28, 29, and 31). Table 3.1-18 presents the results in terms of the percentage change in emissions between the non-oxygenated base fuel, the 5.5 vol% and 11 vol% MTBE blends and the 6 vol% ethanol blend.

Table 3.1-18. Fuel Effects from the Mexico Fuels Study

	NMHC	CO	NOx
	% Change	% Change	% Change
5.5 vol% MTBE vs. no oxygenate	11.1% [a]	-5.5%	-3.1%
11 vol% MTBE vs. no oxygenate	**-11.1%**	-9.7%	10.0%
6 vol% ethanol vs. no oxygenate	3.9% [a]	-6.3%	**27.2%**
6 vol% ethanol vs. 6 vol% MTBE	-5.8%	-0.9%	**32.8%**
6 vol% ethanol vs. 11 vol% MTBE	**19.5%**	4.0%	14.2%

[a] Bold type indicates the difference was significant at a 90% confidence level.

As can be seen, the addition of 5.5 vol% MTBE to a low-RVP type fuel at constant RVP was found to increase the emissions of NMHC and CO, and decrease NOx emissions. The addition of 11 vol% MTBE to a low-RVP type fuel at constant RVP was found to increase the emissions of NOx and CO, and decrease NMHC emissions. Only the NMHC reduction was found to be statistically significant at a 90% confidence level. The addition of 6 vol% ethanol to a low-RVP type fuel at constant RVP was found to reduce the CO emissions, and increase NMHC and NOx emissions. Only the NOx emission increase was statistically significant at a 90% confidence level.

The substitution of 6 vol% ethanol for 11 vol% MTBE at constant RVP and oxygen content was found to decrease NMHC emissions and increase NOx emissions. CO emissions were essentially unchanged. Only the NOx emission increase was statistically significant at a 90% confidence level. The substitution of 10 vol% ethanol for 11 vol% MTBE was found to increase emissions of all three pollutants. Only the NMHC emission increase was statistically significant at a 90% confidence level.

Based solely on this single study of six vehicles and three fuels, it appears that either MTBE or ethanol blends with roughly 2 wt% oxygen increase NOx emissions, while the effect on NMHC and CO emissions are inconsistent. Substituting ethanol for MTBE at the same oxygen content appears to increase NMHC, CO and NOx emissions.

3.1.1.1.8. Overview of LEV and Later Vehicle Studies

The differences in the details of the various studies prevent a simple quantitative comparison of their results. However, we have performed a qualitative comparison by simply determining whether the study found an increase or a decrease in emissions of 2% or more and whether the effect was statistically significant at 90% confidence or not. The results of this determination are shown in Table 3.1-19 below for a number of fuel pairs.

Table 3.1-19. Summary of Oxygenate Emission Effects: LEV and Later Vehicles

	THC/NHMC		CO		NOx	
	Lower	Higher	Lower	Higher	Lower	Higher
10/11 vol% MTBE	**AAM-AIAM** **Mexico** ExxonMobil*		**AAM-AIAM** Mexico ExxonMobil		**AAM-AIAM** Mexico	
E6/E7	Mexico CRC E67		Mexico **ExxonMobil** CRC E67			**Mexico** ExxonMobil CRC E67
E10/E11	**AAM-AIAM**	**CRC E67** ExxonMobil	**AAM-AIAM** **ExxonMobil** **CRC E67**		**AAM-AIAM**	**ExxonMobil** **CRC E67**
E10/11 vs. MTBE	Toyota AAM-AIAM	**ExxonMobil**	ExxonMobil AAM-AIAM		Toyota	**AAM-AIAM** **ExxonMobil**

Starting with MTBE, none of the three studies which tested both non-oxygenated and MTBE fuels found MTBE to increase the emissions of any of the pollutants. One to two studies found statistically significant reductions in THC/NMHC, CO and NOx emissions with the use of MTBE.

Three studies tested a non-oxygenated fuel and a 6-7 vol% ethanol blend. Ethanol blending at this level likely reduces CO emissions and increases NOx emissions. Two of the three studies showed an increase in NMHC emissions, but neither result was statistically significant at a 90% confidence level. Thus, the effect of E6 on NMHC emissions is particularly unclear.

Three studies tested a non-oxygenated fuel and a 10-11 vol% ethanol blend. Ethanol blending at this level likely reduces CO emissions, as all three studies showed a statistically significant reduction. Two of three studies found an increase in NOx emissions, while one found a decrease, all statistically significant at a 90% confidence level. Again, the effect of ethanol blending on exhaust NMHC emissions is not clear. Two of three studies found an increase in THC/NMHC emissions, while one found an increase. The results of one of the two studies finding an increase and those of the study finding a decrease were statistically significant at a 90% confidence level.

Finally, three studies tested both MTBE and 10-11 vol% ethanol blends. Ethanol blending at this level appears to reduce CO emissions relative to MTBE. The effect on the other two pollutants is less clear. Two of three studies found a decrease in THC/NMHC emissions, though the one study finding an increase was the only one where the result was statistically significant at a 90% confidence level. Two of three studies found an increase in NOx emissions and both of these were statistically significant at a 90% confidence level.

3.1.1.1.9 Selection of Models for Exhaust NMHC, CO and NOx Emissions

3.1.1.1.9.1 Exhaust NMHC and NOx Emissions

For Tier 0 vehicles, the EPA Predictive Models are based on more data and the most advanced statistical tools. Therefore, we will use these models here to project the effect of increased ethanol use and decreased MTBE use on exhaust VOC and NOx emissions.

For Tier 1 and later vehicles, the choice is much less clear. In our analysis of California's request for an RFG oxygen waiver, we assumed that there was too little data upon which to project the effect of fuel quality on the emissions of these vehicles. Substantially more data exist on the effect of oxygenates on LEV and later vehicle exhaust emissions than did in 2001. However, as indicated by the summary of these results shown in Table 3.1-19, there does not appear to be sufficiently consistency to confidently predict the impact of oxygenate type and content on exhaust NMHC and NOx emissions.

For the NPRM, we developed two separate sets of predictions: a primary analysis assuming no effect of oxygen on NMHC and NOx emissions from Tier 1 and later vehicles, and a sensitivity analysis which applied the Predictive Model effects to Tier 1 and later vehicles. The qualitative summary shown in Table 3.1-19 supports a continuation of this approach. The effect of ethanol blending on NMHC emissions is unclear in Table 3.1-19. This is reasonable bracketed by the primary and analysis, which assumes no effect and the sensitivity analysis which assumes a reduction. Table 3.1-19 also indicates that five out of six studies found that 6-10 vol% ethanol blends increased NOx emissions from LEV and later vehicles. This is also reasonable bracketed by the primary and analysis, which assumes no effect and the sensitivity analysis which assumes an increase. Given the uncertainty in the fuel-emissions effects for Tier 1 and later vehicles, there is also some value in maintaining consistency with our analysis conducted in response to California's request for an RFG oxygen waiver. The primary analysis does this.

The varied results across these studies indicate the need for additional test data. It may also be possible in the future to combine the emission data from all such studies (as was done for the Complex and Predictive Models) in order to develop a more robust estimate of the impacts of oxygenate blending on emission from late model year vehicles.

3.1.1.1.9.1 Exhaust CO Emissions

For Tier 0 vehicles, MOBILE6.2 is the standard modeling tool for estimating the effect of fuel quality on CO emissions. Therefore, we will use that model here to project the effect of increased ethanol use and decreased MTBE use on CO emissions.

Regarding later vehicles, the five studies of LEV and later vehicles all found that increasing oxygen content in terms of MTBE or ethanol reduces CO emissions. This is consistent with both the primary and sensitivity analyses, as both approaches include a reduction in CO emissions.

The five studies of LEV and later vehicles all tested normally emitting vehicles. MOBILE6.2 estimates that an E10 blend will reduce CO emissions from Tier 0 vehicles by 11%. The quantitative results of the five studies generally support this degree of reduction (Toyota, ExxonMobil, Mexican Petroleum Institute) or perhaps a larger degree of reduction (CRC E67, AAM-AIAM). Due to the absence of an EPA Predictive Model for CO emissions, for the NPRM, we did not develop a sensitivity case for CO emissions. However, given the possibility that the CO emission reduction is larger than that currently estimated by MOBILE6.2 for these vehicles, it appears reasonable to include a sensitivity analysis for CO emissions, as well as NMHC and NOx. An approach analogous to that taken for NMHC and NOx emissions appears reasonable. That is, for the primary analysis, we will continue to use MOBILE6.2 to project the effect of fuel properties on CO emissions. This means essentially a 6.7% reduction in CO emissions from Tier 1 and later vehicles for an E10 blend. For the sensitivity analysis, we will apply the MOBILE6.2 CO emission reduction of 13.8% for Tier 0 vehicles to Tier 1 and later vehicles.

As discussed above, the five studies of LEV and later vehicles are not sufficient for use in quantitatively projecting the impact of fuel quality on emissions from these vehicles. Additional data must still be collected over a broader set of vehicles, fuel changes, and conditions.

3.1.1.2 Exhaust Toxic Emissions

Two EPA models project the impact of fuel quality on exhaust toxic emissions: the Complex Model and MOBILE6.2. The Complex Model projects the impact of fuel quality on toxic emissions directly. That is, any impact of fuel quality on total exhaust VOC emissions (which includes the air toxics) is implicitly included in the model's predictions. MOBILE6.2 separates the process into two steps. Total exhaust VOC emissions are projected first, in part based on fuel quality. Then, the fraction of VOC represented by each air toxic is estimated, in part based on fuel quality.

The effect of fuel quality on exhaust VOC emissions in MOBILE6.2 was already discussed above. The effect of fuel quality on the fraction of exhaust VOC emissions represented by each air toxic in MOBILE6.2 is based on the projections contained in the Complex Model. These Complex Model's effects of fuel quality on exhaust toxic emissions were used with the effect of fuel quality on exhaust VOC emissions backed out. Thus, with respect to the effect of fuel quality on the fraction of exhaust VOC emissions represented by each air toxic, the Complex Model is the basis of both the Complex Model and MOBILE6.2 predictions.

With respect to exhaust VOC emissions, we already decided above that the EPA Predictive Models represent the best estimate for Tier 0 vehicles. For Tier 1 and later vehicles, we assume in our primary analysis that these vehicles' exhaust VOC emissions are unaffected by fuel quality. As a sensitivity analysis, we decided to extend the impacts indicated by the EPA Predictive Models to all vehicles.

We follow the two-step process taken in MOBILE6.2 here in modeling the impact of fuel quality on exhaust toxic emissions. We will use the EPA Predictive Models to project the impact of fuel quality on exhaust VOC emissions, as discussed above. We will use the effects of fuel quality on the toxic fractions of exhaust VOC emissions contained in MOBILE6.2.

3.1.1.3 Non-Exhaust Emissions

Both the Complex Model and MOBILE6.2 evaluate the effect of gasoline quality on non-exhaust VOC emissions. However, the effects in the Complex Model were taken from an older version of MOBILE, as was mentioned above. Therefore, MOBILE6.2 represents the better of the two estimates of the effect of gasoline quality on non-exhaust VOC emissions. The EPA Predictive Models do not address non-exhaust emissions, so they are not applicable here.

In EPA's second analysis of California's request for a waiver of the RFG oxygen requirement, we enhanced the estimate of non-exhaust emissions in MOBILE6.2 by adding additional permeation emissions related to the use of ethanol.[FFF] Recent testing at that time indicated that ethanol increases the rate of permeation of hydrocarbons through plastic fuel tanks and elastomers used in fuel line connections, as well as permeating ethanol itself. Subsequent testing has confirmed this effect. Therefore, we have added the effect of ethanol on permeation emissions to MOBILE6.2's estimate of non-exhaust VOC emissions in assessing the impact of gasoline quality on emissions here.

Air Improvement Resource, Inc. for the American Petroleum Institute, recently summarized the available test data on the effect of ethanol on permeation emissions and developed a methodology for estimating in-use permeation emissions in several U.S. cities.[GGG] This study provides a useful starting point for incorporating these emissions into this RFS analysis.

Before examining this study, it is useful to point out that the non-exhaust emission estimates in MOBILE6.2 include permeation emissions for non-oxygenated gasoline. Typical extended diurnal emission tests (e.g., those lasting 2-3 days) automatically include any emissions permeating through plastic and elastomeric fuel system components. However, since the emission tests used as the basis of the MOBILE6.2 estimates of non-exhaust emissions primarily were performed with non-oxygenated gasoline. Those tests that did include ethanol blends only exposed the vehicle to this fuel for a few days. The CRC study of ethanol-related permeation indicates that it takes at least a week or two for the effect of ethanol to fully develop. Therefore, it is very unlikely that the tests performed by EPA and others to assess the impact of ethanol and other fuel components on non-exhaust emissions included the effect of ethanol on permeation emissions. In those cases where a vehicle may have been exposed to an ethanol blend for some time prior to testing, the increased permeation emissions likely were still present when the vehicle was tested on a non-oxygenated gasoline, still masking the effect. Therefore, our task here is to develop an estimate of the incremental impact of ethanol use on permeation emissions, and not an estimate of total permeation emissions with and without ethanol.

The primary source of ethanol permeation emission data is the CRC E-65 study.[HHH] This study tested 10 vehicles, 6 cars and 4 light trucks, ranging in model year from 1989 to 2001. Permeation emissions were measured using two fuels, a non-oxygenated gasoline and a 6 vol% ethanol blend like that commonly sold in California. AIR placed these vehicles into three groups, based on a combination of model year and applicable evaporative emission standards. The vehicles in the test program were certified to two distinct evaporative emission requirements. The older vehicles were certified to EPA's or California's 2 gram hot soak plus diurnal emission standard based on an accelerated one-hour diurnal test. The three newest vehicles were certified to the enhanced evaporative emission requirements first implemented in the 1996 model year, which included an extended two or three day diurnal test. In addition, the data indicated that the three pre-1990 model year vehicles had much larger incremental ethanol permeation emissions than the later pre-enhanced evaporative emission vehicles. Therefore, AIR split the pre-enhanced evaporative emission category into two groups, pre-1990 model year vehicles and 1990 and later model year vehicles. We believe that this is appropriate and apply this split here, as well.

Since the earliest calendar year during which emissions are assessed in the RFS analysis is 2012 and MOBILE6.2 only considers vehicles which are 24 years old or newer, at most only two model years of pre-1990 vehicles are present in our analysis. Due to accumulated scrappage, these vehicles comprise a very small percentage of the on-road fleet in 2012 and disappear from our analysis by 2015. Therefore, we decided to ignore the pre-1990 model year data here.

AIR estimated the average incremental ethanol permeation emission rates for the 1990 and later model year pre-enhanced evaporative emission vehicles to be 0.86 gram per day (g/day), while that enhanced evaporative emission vehicles was 0.80 g/day. Given the small number of vehicles tested and the variability in the rates measured for individual vehicles, for the purposes of this analysis, we consider these two levels to be generally equivalent. Therefore, we use an average incremental ethanol permeation emission rate of 0.8 g/day for all vehicles. A follow-on study performed by CRC indicates that the permeation emissions associated with a 10 vol% ethanol blend could not be distinguished statistically from those of the 6 vol% blend.[III] Therefore, we use the 0.8 g/day incremental permeation emission rate for both 6 vol% and 10 vol% ethanol blends here.

Beginning with the 2004 model year, EPA and California implemented further enhancements to their evaporative emission standards. The EPA "Tier 2" requirements include accumulating mileage on durability data vehicles with an ethanol blend. However, actual emission testing is still performed using non-oxygenated gasoline. We believed that this combination of requirements would incorporate any effects of ethanol on emissions, including potential permeation effects. Because of these and other aspects of the 2004 and later standards, AIR estimated that the permeation emissions due to ethanol would be reduced to 0.43 g/day for these vehicles.

We believe that it is likely that permeation emissions for non-oxygenated blends will be lower for these vehicles, due to the fact that the diurnal emission standard was reduced from 2 g/day to 0.95 g/day and lower in some cases. However, as mentioned above, the effect of ethanol on permeation emissions takes about 2 weeks to fully develop and to fully disappear. Therefore, it is possible to accumulate mileage on a certification vehicle using an ethanol blend, change the fuel to the emission test fuel, wait two weeks and then test the vehicle. In this case, the effect of ethanol on permeation will have disappeared during the certification testing. Thus, until EPA requires certification emission testing with ethanol blends, we have no assurance that manufacturers will modify their vehicle designs to address the effect of ethanol on permeation. Thus, for the purposes of this analysis, we maintain the estimate of 0.8 g/day for Tier 2, and earlier vehicles.

Permeation emissions vary significantly with ambient temperature, with emissions increasing with increases in temperature. The 0.8 g/day emission estimate applies at an average temperature of 95 F. The literature indicates that permeation varies exponentially with temperature. The CRC testing indicates that permeation emissions double with every increase in temperature of 18 F. Vice versa, permeation emissions drop 50% with every decrease in temperature of 18 F. We apply this relationship in Chapter 4 in developing incremental ethanol permeation emissions for each hour of the day in each county in the U.S.

We plan to update our projections of the effect of gasoline quality on non-exhaust VOC emissions from Tier 1 and later model year vehicles based on additional testing which is expected to begin in 2007. Additional testing of permeation emissions is already underway with the CRC E-77 test program. These updated projections will be used in the comprehensive assessment of the impact of the fuel-related provisions of the Energy Act which due in 2009.

Non-exhaust emissions are a function of ambient temperature and temperatures vary across the nation. Therefore, it is not as simple to determine the effect of RVP and other fuel qualities on non-exhaust emissions on a per vehicle basis as it is for exhaust emissions. Therefore, we performed a regression of the non-exhaust VOC and benzene emissions developed in Chapter 4 as a function of fuel properties in order to estimate these effects on a per vehicle basis. Specifically, we regressed the ratio of non-exhaust VOC and benzene emissions in each county in July between two fuel scenarios (the RFS case and the base case) against the change in RVP, ethanol content and MTBE content. The results are summarized in Table 3.1-20.

Table 3.1-20. Fuel-Non-Exhaust Emission Effects in MOBILE6.2: 2012

	RVP (%/psi)	Ethanol (%/Vol %)	MTBE (%/Vol%)	Adjusted r-Square
VOC	11.8%	0.3%	0.0%	0.53
Benzene	2.0%	1.0%	-0.5%	0.50

Non-exhaust emissions of benzene are estimated in MOBILE6.2. MOBILE6.2 adjusts these emissions for RVP, benzene fuel content, MTBE fuel content, temperature and the total non-exhaust VOC emissions produced by the vehicle fleet in question. We will use MOBILE6.2 here to project the impact of decreased MTBE use and increased ethanol use on non-exhaust benzene emissions.

Benzene is also emitted via permeation. Just as MOBILE6.2 does not include the effect of ethanol on VOC emissions via permeation, it does not include the effect of ethanol on benzene emissions via permeation. Thus, we will add this effect outside of the MOBILE6.2 model in the same way as was just described for VOC emissions via permeation.

Both the CRC E-65 study and the E-65 Phase 3 follow-on study referenced above measured the benzene content of permeation emissions during some of the tests performed. Table 3.1-21 presents the available data by fuel type for both studies.

Table 3.1-21. Benzene Permeation Emissions: CRC E-65 Studies

E-65 Phase	No. of Vehicles	E0	E6 (Average Aromatics)	E6 (High Aromatics)	E10	MTBE Blend
Fuel Benzene Content (vol%)						
Phase 1	---	0.73	0.72	---	---	0.53
Phase 3	---	0.41	0.55	0.43	0.51	---
Benzene Emissions (% of total permeation emissions)						
Phase 1	10	2.5-2.6%	2.2%	---	---	2.2%
Phase 3	4-5	1.4%	1.4%	1.4%	1.7%	---
Benzene Emissions Adjusted to 0.88 vol% Fuel Benzene (% of total permeation emissions)						
Phase 1	10	3.0-3.1%	2.7%	---	---	3.6%
Phase 3	4-5	3.0%	2.2%	2.8%	2.9%	---

As can be seen from Table 3.1-21, the benzene content of permeation emissions is slightly higher for the Phase 1 study than Phase 3. This is consistent with the higher benzene contents of the fuels tested in Phase 1. The Phase 1 fuels have particularly low benzene contents compared to levels typical across the U.S. Therefore, assuming a linear relationship between benzene fuel content and benzene permeation emissions, we adjusted the benzene permeation emissions to those for a fuel benzene content of 0.87 vol%, which is the average of the benzene fuel content of summertime gasoline produced nationwide in the base, RFS and EIA cases from the recent refinery modeling described in Chapter 2. We focused on summer benzene content since permeation emissions are a strong function of temperature. These figures are shown in the bottom third of Table 3.1-21. As can be seen, the benzene content of permeation emissions is much more consistent across the two Phases of E-65 after being adjusted to consistent fuel benzene content than before this adjustment.

There appears to be no definite trend in the benzene content of permeation emissions with increasing ethanol fuel content. Both CRC studies found that the addition of ethanol does not simply increase permeation emissions via increased emissions of ethanol, but also through increased emissions of other fuel components. Thus, we will assume for this analysis that the benzene fraction of permeation emissions is independent of ethanol fuel content (i.e., benzene emissions increase at the same rate as total permeation emissions). This is also consistent with our conclusion in Chapter 2 that ethanol blending does not affect benzene fuel content. Given this, we determined the average benzene fraction of permeation emissions by averaging the benzene fraction across all the fuels and vehicles tested, excluding the MTBE blend. This average was 3%. This figure will be used here to estimate the benzene portion of the increase in permeation emissions resulting from ethanol blending.

Given this, we determined the average benzene fraction of permeation emissions by averaging the benzene fraction across vehicles. Thus, the average benzene fraction of permeation emissions is the average of the figures in the rightmost column of Table 3.1-21, or 2%.

3.1.1.4 PM Emissions

The amount of data evaluating the impact of ethanol and MTBE blending on direct emissions of PM from gasoline-fueled vehicles is extremely limited. Three fairly limited studies have evaluated the impact of ethanol blending on PM emissions from gasoline vehicles. These studies are summarized below.

The Colorado Department of Public Health and Environment tested 24 vehicles on two winter grade commercial fuels at 35ºF in Denver (i.e., at high altitude).[JJJ] Both fuels were obtained from a local refinery. One fuel was non-oxygenated and represented fuel sold outside of the Denver area. The other contained 10 vol% ethanol and represented fuel sold in the Denver area, which has an oxygenated fuel mandate. As would be expected, the fuels differed in other qualities besides ethanol content. The ethanol blend had a 2 vol% lower aromatic content, which is somewhat less than expected. However, it also had a 53 F lower T50 level, which is a much greater difference than is typical. The two fuels used during this testing appear to have been used in random order (i.e., sometimes the non-oxygenated fuel was tested first, other times the E10 fuel was tested first).

Half of the 24 vehicles were certified to Tier 0 emission standards, while the other half were certified to Tier 1 standards. Each group of 12 vehicles included 8 cars and 4 light trucks.

The study found that PM emissions for the 24 vehicles over the FTP decreased from about 9 mg/mi to about 6 mg/mi with the ethanol blend, for a reduction of 36%. In addition, the vehicles with the highest base PM emission rates showed by far the largest reductions, both in absolute terms and in terms of percentage. PM emissions from Tier 1 vehicles decreased from roughly 5.5 mg/mi to 4 mg/mi with the ethanol blend, for a reduction of 27%. Essentially all of the emission reduction occurred during Bag 1 of the test (i.e., related to the cold start).

PM emissions were also measured over a warmed up California Unified Cycle (i.e., no cold start). PM emissions for the 24 vehicles over this cycle for the two fuels were not statistically different. The ethanol blend increased PM emissions from the Tier 0 vehicles slightly and decreased those from the Tier 1 vehicles slightly.

Finally, PM emissions were also measured over an EPA REP05 Cycle, again with no cold start. PM emissions over this cycle were 4-5 times those over the California Unified Cycle, indicating the impact of high speed, aggressive driving on PM emissions. However, despite this general increase in PM emissions, for the 24 vehicles PM emissions over the REP05 cycle were again very similar for the two fuels. This time, however, the ethanol blend decreased PM emissions from the Tier 0 vehicles slightly and increased those from the Tier 1 vehicles slightly.

Overall, this testing indicates that the effect of ethanol (together with lower aromatics and T50 levels) may reduce PM emissions due to cold starting at 35 F under high altitude conditions.

However, PM emissions during warmed up driving are very low and an effect of fuel quality was indiscernible.

The State of Alaska, in conjunction with General Motors Corp. and EPA, measured PM emissions from ten vehicles ranging in model year from 1977 to 1994 using two fuels.[KKK] The non-oxygenated fuel was a commercial wintertime fuel from the Fairbanks areas. The ethanol blend in this study was created from the non-oxygenated fuel via splash blending. Testing was performed in Alaska using a portable dynamometer. Three of the vehicles were also tested at EPA's laboratory in Research Triangle Park, N.C, ranging in model year from 1987 to 1994. The testing in Alaska was performed at -20ºF, 0ºF, and 20ºF. The EPA testing was performed at these same temperatures plus 75 F. Both sets of testing began with the non-oxygenated fuel, followed by testing with the E10 fuel. This could introduce a bias into the results, but the degree of this is unknown.

The cold conditions led to difficulties in measuring PM emissions in Alaska. Therefore, few acceptable measurements of PM were made and the results were not presented in the paper. The fact that the EPA testing was conducted in a laboratory made vehicle conditioning and operation and particulate collection more feasible. The PM emissions from the three vehicles tested by EPA on the two fuels are presented in the paper.

Only one measurement of PM emissions was made for each combination of vehicle, fuel and temperature. Thus, no direct measurement of test to test variability is available. We calculated the percentage difference in PM emissions between the E10 and E0 fuel for each of the eleven combinations tested. PM emissions with the ethanol blend ranged from 81% lower to 84% higher than those with the E0 fuel. Thus, there appears to be considerable variability in the test results. Taken together, the average of the percentage changes for each condition showed the ethanol blend reducing PM emissions by 21%. However, this decrease was not statistically significant at the 90% confidence level. The ethanol blend more consistently decreased PM emissions at -20 F and 0F, but not at 20 F or 75 F. The paper states that PM emissions at the higher two temperatures were very low and the differences tended to be within measurement accuracy. It is important to note, however, that the lower end of this range is 20 F. Only a small percentage of driving in the U.S. occurs below this temperature.

The third and final study was performed by EPA's laboratory in Research Triangle Park, N.C.[LLL] This study was conducted in three phases; the last two of which are relevant here. In Phase II, PM emissions from two 1993-1995 model year vehicles were tested at -20 F, 0 F, and 20 F. In Phase III, PM emissions from an additional five 1987-2001 model year vehicles were tested at -20 F, 0 F, 20 F and 40 F. Both phases utilized two fuels, one a wintertime non-oxygenated fuel and the other a 10 vol% ethanol fuel created from the non-oxygenated fuel via splash blending. Both phases measured PM emissions over the FTP and over a series of four back-to-back IM240 tests.[50] It is not clear whether the fuels were always tested in the same order or tested randomly. Some testing was performed with various malfunctions induced on the

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[50] The IM240 test is a warmed up test consisting of a portion of the FTP driving cycle. It was designed as a short transient test cycle for use in vehicle inspection and maintenance programs.

vehicles, like disconnecting the oxygen sensor. We focus on the emissions from the properly operating vehicles here.

Of the 26 combinations of vehicles and temperatures tested, valid PM measurements over the FTP were successfully obtained for both fuels in 21 of them. The average percent change in PM emissions due to ethanol blending was +1%, in other words a very slightly increase. In contrast to the results of the two test programs discussed previously, the ethanol blend did not show a benefit at -20 F, and showed only a very slight 1% reduction in PM emissions at 0 F. The data show some tendency for the ethanol blend to produce a greater PM emission reduction for the highest emitting vehicles. However, this trend is not as clear as in the Colorado study. Thus, this study indicates no clear effect of ethanol on PM emissions.

The IM240 testing showed much lower PM emission levels due to the warmed up nature of the test. There was also no clear trend in the effect of ethanol on PM emissions in this testing.

The available data indicate that ethanol blending might reduce exhaust PM emissions under very cold weather conditions (i.e., 0 F or less), particularly at high altitude. There is no indication of PM emission reductions at higher temperatures and under warmed up conditions. The data are certainly too limited to support a quantitative estimate of the effect of ethanol on PM emissions.

Fine particles can also be formed through a series of chemical reactions in the atmosphere from gasses such as sulfate (SO_4^{2-}), nitrate (NO_3^-), ammonia (NH_3), and volatile organic compounds (VOC) emitted from motor vehicles. This aerosol formed secondarily in the atmosphere through these gas to particle conversions will be discussed in greater detail in Chapter 5 of this document. Emerging science is indicating that gaseous aromatic compounds are likely among the most important VOCs which are precursors of carbonaceous PM which is formed in the atmosphere. Therefore, we discuss the effect of fuel quality on aromatic hydrocarbon emissions in the next section.

3.1.1.5 Aromatic Emissions

The Auto/Oil Air Quality Improvement Research Program tested over 100 vehicles from model years 1983 - 1989 on a fuel matrix of over 80 fuel blends to determine the exhaust emission effects of varying fuel parameters - including ethanol and aromatics.[MMM] Phase 1 of this study tested two fleets of vehicles: twenty (20) 1989 model year vehicles, and fourteen (14) 1983-1985 model year vehicles. A matrix of 16 fuels (Matrix A) was developed in the first portion of the study with half the fuels containing 20% aromatics by volume and half with 45% aromatics by volume. This data was used to investigate the impact of changing aromatic levels in the fuel on the aromatics emitted in the exhaust as a function of total hydrocarbon emissions. Linear regression of the test data indicates that there is a linear relationship between the level of aromatics by volume in the fuel and the mass of aromatics emitted in the exhaust. Based on the results of this regression, aromatics have a tendency to be emitted less than proportionally to their percent volume in the fuel, as shown in the following equation:

$$Aromatics_{Exhaust}(wt\%) = 0.64 \times Aromatics_{Fuel}(vol\%)$$

The coefficient in the above equation was statistically significant at the 90% confidence level (0.64 ± 0.02). However, when we considered the presence of an intercept, it was not statistically significant (-0.35 ± 2.26). Therefore, we forced the regression line through zero and repeated the regression.

The Auto/Oil program also produced data which allows the effect of ethanol on aromatic hydrocarbon emissions to be assessed. As discussed in Section 2.2, ethanol blending tends to reduce the aromatic content of gasoline. Of interest here is whether ethanol has any other effect on aromatic hydrocarbon emissions beyond that associated with reducing the aromatic content of gasoline.

The Auto/Oil data contained a subset of fuels designed specifically for this analysis. A total of 4 ethanol blends were produced by splash blending ethanol into four non-oxygenated fuels. Two of the non-oxygenated fuels came from the original group of sixteen tested during Phase 1 of the research study. Base fuel A (industry average fuel) was a 9 RVP fuel with 32% aromatics. Base fuel F was also a 9 RVP gasoline with 20% aromatics. Two new non-oxygenated fuels were created from base fuels A and F. In both cases, and butane was removed to lower the RVP level by 1 psi resulting in fuels V and S, respectively. To each of these 4 non-oxygenated fuels, 10% ethanol was splash blended resulting in the final 8 fuel test matrix. A summary of the differences between the expected and actual aromatic content in the fuel and in the exhaust as a function of THC is shown in Table 3.1-22.[NNN]

Table 3.1-22.
Expected vs. Predicted Non-Oxy and E10 Fuel Properties and Exhaust Aromatics Reductions for Auto/Oil AQIRP "Fuel Matrix B"

Non-Oxy Fuel	Fuel Aromatics	E10 Fuel	Fuel Aromatics Expected[a]	Measured Fuel Aromatics	% Reduction in Exhaust Aromatics Expected	% Reduction in Exhaust Aromatics Actual
A	32	X	28.8	27.2	2.05	2.39
V	33.5	W	30.15	29.0	2.14	1.54
F	20	U	18	19.1	1.28	0.93
S	21.2	T	19.08	18.1	1.36	0.63

[a] Based on dilution as a result of splash blending 10% ethanol

The aromatic contents of the ethanol blends, as listed in Table 3.1-22, do not reflect the 10% reduction from the aromatic contents of their non-oxygenated base fuels which would be expected from splash blending with 10 vol% ethanol. The discrepancies between the measured and estimated fuel aromatic contents are small, on the order of 1-2 vol% aromatics. However, when the total difference is on the order of 3 vol% ethanol, these discrepancies are significant. The discrepancies are likely the result of measurement uncertainty of both base and ethanol fuels.

Using the relationship between fuel aromatic content and aromatic hydrocarbon emissions developed above, we can predict the reduction in exhaust aromatic emissions associated with the differences in the aromatic contents of the non-oxygenated fuels and their ethanol containing counterparts. We believe that it is most accurate to use the expected aromatic contents for the ethanol blends rather than the measured levels, since it is likely that the volume of ethanol added was very close to 10 vol%.

The expected reduction in the percentage of VOC emissions represented by aromatic hydrocarbons based on the expected reduction in fuel aromatic content is shown in the second to the last column in Table 3.1-22. The measured reduction in the percentage of VOC emissions represented by aromatic hydrocarbons is shown in the last column. In three out of four cases (all but fuels A and X), the actual reduction in aromatic emissions is less than the predicted reduction based on dilution. Had we used the measured aromatic contents for the ethanol blends, the outcome would have been the same: In three out of four cases (in this case all but fuels F and U), the actual reduction in aromatic emissions is less than the predicted reduction based on dilution.

Qualitatively, this indicates that there does not appear to be any additional benefit in reducing aromatic hydrocarbon emissions associated with the use of ethanol beyond that expected from the reduction in the aromatic content of gasoline portion associated with ethanol blending.

Based on our analysis in Section 2.2, increased ethanol blending will significantly reduce gasoline aromatic content. This could cause a corresponding reduction in the aromatic fraction of exhaust VOC emissions relative to non-oxygenated conventional gasoline. In addition, ethanol also reduces total exhaust VOC emissions from older vehicles and may do so from newer vehicles, based on the CRC E-67 study. This would further reduce emissions of aromatic hydrocarbons. As will be discussed further in Chapter 5, this reduction in aromatic hydrocarbon emissions could reduce ambient levels of secondary organic PM.

3.1.1.6 Emission Effects Associated with Specific Fuel Blends

3.1.1.6.1 Conventional Gasoline Analysis

In Section 2.2 of Chapter 2, we estimated the effect of blending ethanol and MTBE on the quality of conventional gasoline (see Tables 2.2-3 and 2.2-4). Here, we present the effect of these changes in fuel quality on emissions from motor vehicles in percentage terms, relative to those of a typical non-oxygenated U.S. gasoline blend. Because of the Tier 2 sulfur standards, sulfur is held constant at 30 ppm. Also, due to the MSAT standards, we assume that benzene levels are not affected, as well. Table 3.1-23 presents the gasoline qualities of a typical 9 RVP CG, as well as MTBE and ethanol blends which reflect the effect of adding these two oxygenates to gasoline.

Table 3.1-23. CG Fuel Quality With and Without Oxygenates[a]

Fuel Parameter	Typical 9 RVP CG	MTBE CG Blend	Ethanol CG Blend
RVP (psi)	8.7	8.7	9.7
T50	218	207	205
T90	332	321	329
Aromatics (vol%)	32	25.5	27.4
Olefins (vol%)	7.7	7.7	7.5
Oxygen (wt%)	0	2	3.5
Sulfur (ppm)	30	30	30
Benzene (vol%)	1.0	1.0	1.0

[a] Assumes summer (July) conditions

Table 3.1-24 presents the differences in emissions of the MTBE and ethanol blends relative to that of non-oxygenated conventional gasoline.

Table 3.1-24. Effect of Oxygenates on Conventional Gasoline Emissions[a]

Pollutant	Source	11 Vol% MTBE	10 Vol% Ethanol	9.7 RVP CG
Exhaust VOC	EPA Predictive Models	-9.2%	-7.4%	+1.1%
NOx		2.6%	7.7%	+1.1%
CO[b]	MOBILE6.2	-6% / -11%	-11% / -19%	+12.7%
Exhaust Benzene	EPA Predictive and Complex Models	-22.8%	-24.9%	-2.6%
Formaldehyde		+21.3%	+6.7%	-3.7%
Acetaldehyde		+0.8%	+156.8%	-2.0%
1,3-Butadiene		-3.7%	-13.2%	-2.6%
Non-Exhaust VOC	MOBILE6.2	Zero	+30%	+30%
Non-Exhaust Benzene	MOBILE6.2 & Complex Models	-9.5%	+15.8%	+15.8%

[a] Assumes summer (July) conditions

[b] The first figure shown applies to normal emitters; the second applies to high emitters.

The two oxygenated blends both reduce exhaust VOC and CO emissions, but increase NOx emissions. The MTBE blend does not increase non-exhaust VOC emissions due to the fact that non-oxygenated and MTBE blends have to meet the RVP standard. Ethanol blending increases non-exhaust VOC emissions in two ways. First, ethanol blends are allowed 1.0 psi higher RVP levels in most areas with CG. Second, ethanol increases permeation emissions. The most notable effect on toxic emissions in percentage terms is the increase in acetaldehyde with the use of ethanol. Acetaldehyde emissions more than double. However, as will be seen below, base acetaldehyde emissions are low relative to the other toxics. Thus, the absolute increase in emissions is relatively low.

3.1.1.6.2 Reformulated Gasoline (RFG) Analysis

The previous section discussed the relative emission changes to expect when adding ethanol to the conventional non-oxygenated gasoline pool. A second scenario to consider is the case where RFG areas change from MTBE, a commonly used oxygenate in RFG areas, to either ethanol RFG or a non-oxygenated RFG.

Table 3.1-25 presents the gasoline qualities of three types of RFG: non-oxygenated, a typical MTBE RFG as has been marketed in the Gulf Coast and a typical ethanol RFG which has been marketed in the Midwest. The fuel specifications shown are based on specific RFGs predicted by the refinery modeling discussed in Chapter 2 for the cases and PADDs shown. These specific fuels were selected as they represented PADD-wide RFGs which contained primarily one oxygenate at the desired volumetric concentration.

Table 3.1-25. Summer RFG Fuel Quality With and Without Oxygenates[a]

Fuel Parameter	Non-Oxygenated RFG	MTBE RFG	Ethanol RFG
Case	PADD 3 Reference	PADD 1 Reference	PADD 2 RFS
OXYGEN (wt%)	0.0	2.1	3.7
SULFUR (ppm)	30.0	30.0	30.0
RVP (psi)	7.0	7.0	7.0
E200 (%)	52.0	59.9	57.6
E300 (%)	87.5	88.9	81.9
T50 (F)	184	190	185
T90 (F)	335	342	335
AROMATICS (vol%)	20.1	21.0	20.0
OLEFINS (vol%)	14.6	4.3	13.6
BENZENE (vol%)	0.7	0.7	0.7

[a] Assumes summer (July) conditions

Table 3.1-26 presents the emission impacts of these three types of RFG relative to the 9 RVP CG described in Table 3.1-23.

Table 3.1-26.
Effect of RFG on Per Mile Emissions from Tier 0 Vehicles
Relative to a Typical Conventional Gasoline[a]

Pollutant	Source	Non-Oxy RFG	11 Volume Percent MTBE	10 Volume Percent Ethanol
Exhaust Emissions				
VOC	EPA Predictive Models	-13.4%	-15.3%	-9.7%
NOx		-2.4%	-1.7%	7.3%
CO	MOBILE6.2	-22%	-31%	-36%
Exhaust Benzene	EPA Predictive and Complex Models	-21.2%	-29.7%	-38.9%
Formaldehyde		-5.9%	19.4%	2.3%
Acetaldehyde		-0.2%	-9.5%	173.7%
1,3-Butadiene		20.9%	-29.2%	6.1%
Non-Exhaust Emissions				
VOC	MOBILE6.2 & CRC E-65	-30%	-30%	-18%
Benzene	MOBILE6.2 & Complex Models	-40%	-43%	-32%

[a] Assumes summer (July) conditions

As can be seen, the oxygenated RFG blends are predicted to produce a greater reduction in CO emissions, but increase NOx emissions. Exhaust VOC emission effects are mixed. Non-exhaust VOC emissions with the exception of permeation are roughly the same due to the fact that the RVP level of the three blends is the same. However, the increased permeation emissions associated with ethanol reduces the overall effectiveness of ethanol RFG. The most notable effect on toxic emissions in percentage terms is the increase in acetaldehyde with the use of ethanol. Acetaldehyde emissions more than double. However, as will be seen below, base acetaldehyde emissions are low relative to the other toxics. Thus, the absolute increase in emissions is relatively low. The ethanol RFG also produces a greater reduction in exhaust benzene emissions and somewhat lower reduction in non-exhaust benzene emissions.

The exhaust emission effects shown for VOC and NOx emissions only apply to Tier 0 vehicles in our primary analysis. In the sensitivity analysis, these effects are extended to Tier 1 and later vehicles. The effect of RVP on non-exhaust VOC emissions is temperature dependent. The figures shown above represent the distribution of temperatures occurring across the U.S. under summer conditions (average July fuel specifications).

3.1.2 High-Level Ethanol Blends

The vast majority of ethanol blended into gasoline as a result of the RFS is expected to be used in a 10 vol% ethanol blend (E10) rather than an 85 vol% ethanol blend (E85), as discussed in Chapter 1. At the same time, some ethanol is likely to be used as E85, and its use is growing. Current estimates indicate that roughly 6 million FFVs are on the road today, with US automakers projecting an additional 3 to 5 million FFVs produced annually over the next several years. The analysis to follow relies upon the limited amount of data available on both older and current technology (Tier 2) FFVs, the later of which will dominate the FFV fleet in future years. Based on this data of Tier 2 vehicles, we believe that with the increased use of E85 (which is inherently a low-sulfur fuel) emissions should be neutral or better than operation on E0 or E10 fuel blends for CO and NOx. NMOG emissions may be higher primarily due to emissions of unburned ethanol at cold starts, while running NMOG emissions are lower with E85 based on certification data. The sections to follow examine these issues in greater detail.

3.1.2.1 Exhaust emissions

3.1.2.1.1 Regulated Gaseous Pollutants

Relatively little data is available for investigating the effects of high level ethanol blends on exhaust emissions. Part of the 1993 Auto/Oil Air Quality Improvement Research Program (AQIRP) investigated the emissions associated with the use of E85 blends. Emissions over the Federal Test Procedure (FTP) were measured from three Tier 0 and Tier 1 certified flexible-fuel vehicles with three test fuels. A source of emission data for Tier 2 FFVs is EPA's Certification and Fuel Economy Information System (CFEIS) database, which contains certification data for five model year 2006 FFVs certified to Tier 2 standards (bins 5-8).[OOO] However, certification data, composed of regulated emissions while operating on E85, represents very limited operating conditions. It does not include aggressive driving or cooler ambient temperature starts or operation.

The Auto/Oil Study found that E85 reduced FTP composite NOx emissions by 49% compared to conventional gasoline with 1988 industry average fuel properties. This is likely the result of improved catalyst efficiency due to the low sulfur concentration in E85 (only 5 ppm vs. 339 ppm in the industry average fuel). The 2006 CFEIS data from Tier 2 FFVs, on the other hand, shows only a 3% decrease in NOx emissions with E85 from a cold start test but a significant 45% decrease in hot running NOx emissions. CO emissions are reduced at least 33% on a cold start according to CFEIS, while the Auto/Oil study did not find statistically significant changes in CO emissions. Emissions of Non-Methane Organic Gases (NMOG) increased 10% for the Tier 2 CFEIS vehicles. The Auto/Oil data showed NMOG increased by 26%, but this change was not statistically significant (p-value of 0.28). However, CFEIS data indicated a 50% reduction in CO and HC emissions during hot operation. The measurement used to determine NMOG in both CFEIS and Auto/Oil data include the mass of oxygen in all measured organic species except methane.

While the emissions of NMOG appear to increase with E85 compared to E0 for Tier 2 certified vehicles, the majority (~55%) of E85 NMOG emissions are direct emissions of ethanol, which has a relatively low reactivity compared to other NMOG species. Thus there may still be a slight NMOG benefit based on ozone reactivity despite a potential net increase in total NMOG emissions. An important point worth noting is that the cold start emissions with E85 represent a greater % of bag weighted emissions than with E0. This manifests itself primarily in the form of unburned ethanol emissions during cold start, before the combustion chamber has reached a high enough temperature to promote complete ethanol vaporization. Thus NMOG emissions with E85 at colder temperatures could be much greater (2 to 3 times higher) than with E0 due to prolonged periods at low temperature. Because of this unique start behavior and the lower emissions observed during hot operation, emissions from E85 may be better quantified if separated between starts and hot driving operation.

3.1.2.1.2 Air Toxics

With increasing use of E85, some air toxics may increase while others decrease relative to E0. Emissions of Benzene and 1,3-Butadiene decrease while acetaldehyde, formaldehyde, and emissions of ethanol increase. The net result is an increase in total air toxics, but this is largely driven by increase ethanol and acetaldehyde emissions. Table 3.1-27, below, shows the percent change in FTP composite g/mile emissions of several air toxics for the three FFVs tested on three fuels as part of the 1993 Auto/Oil study. The fuels tested were AQIRP gasoline with1988 Industry average qualities (CG), a 1996 California phase 2 reformulated gasoline (RFG blended with MTBE), and an E85 blend with identical gasoline specs as RFG.[PPP]

Table 3.1-27.
Percent Difference in Toxic Emissions Between E0 and E85

	% Difference Between Fuels		
	RFG vs CG	E85 vs CG	E85 vs RFG
Formaldehyde	-2	93	97
Benzene	-55	-87	-72
1,3-Butadiene	-31	-85	-79
Acetaldehyde	-18	2620	3220
Total Toxics	-42	108	255

The increase in acetaldehyde emissions is substantial, on the order of 20 to 30 times that of E0. This is substantially higher than the15 to 20 fold increase shown with Tier 2 FFVs in the CFEIS data. Emissions of benzene, 1,3-butadiene, ethylbenzene, hexane, styrene, toluene, m-xylene, p-xylene, o-xylene, and naphthalene are all expected to decrease significantly (50-80%) with the use of E85 vs. E0 according to CFEIS, which is consistent with the Auto/Oil results presented in Table 3.1-27. Regardless of vehicle technology, the increased emissions of acetaldehyde could be a potential concern due to its strong odor, as well as its respiratory system irritating and potentially carcinogenic properties.

3.1.2.1.3 Particulate Matter

Even less data exists to draw firm conclusions on direct particulate matter emissions due to increased E85 use. Theoretically, E85 use has the potential to increase direct emissions of PM under modes of rich engine operation. This is especially important at cold start, before the catalyst has reached its operating temperature and when an E85 fueled vehicle runs substantially richer than if it were fueled with E0. In this situation, the low temperatures in the combustion chamber, compounded by the evaporative cooling effect of ethanol, makes fuel vaporization difficult and may increases exhaust emissions of raw fuel and PM at cold start. Sustained periods of high load may also have increased emissions of PM with E85 than with E0 due to richer operation with E85. Results from a 2003 SAE paper showed a negligible increase in direct PM emissions from E85 vs. E0 fueled vehicles over the European Test Cycle (Directive 70/220/EEC and its amendments).[QQQ] Tests conducted at 23ºC and 16ºC showed an increase in PM emissions with decreasing temperature for both E0 and E85, with slightly higher PM emissions at cold temperature with E85. This study only used one E85 blend and one model year 2002 FFV, however, so these results cannot be considered entirely representative of the on-road FFV vehicle fleet. Again, since the projected use of ethanol as E85 is very small compared to its use as E10, the emissions impacts associated with E85 will be also be quite small on an absolute scale.

As discussed above, emerging science is beginning to identify gaseous aromatics as an important precursor to secondary organic aerosol. Exhaust aromatic emissions should be reduced with E85 since the fuel aromatics content of E85 is much lower than that for E0 or E10 blends. This reduction in exhaust aromatics should reduce the formation of secondary organic aerosol. However, as mentioned earlier, no specifications currently exist for the 15% gasoline portion of E85. Thus, the degree to which the aromatic content of E85 will be lower than gasoline is not known with any confidence. Lack of data regarding the speciation of VOC emissions also prevents any quantitative estimate of any benefit in this area.

3.1.2.2 Non-Exhaust Emissions

We currently have very little data regarding non-exhaust emissions from E85 vehicles. Theoretically, evaporative emissions of E85 fueled vehicles have the potential to be lower than with E0 or E10. This is because ethanol blended with a given gasoline at the 85% level is likely to be less volatile than E0 or E10 (with the same gasoline fuel quality). This is not entirely certain, however, since there is no fuel specification for the hydrocarbon composition of the 15% of E85 that is gasoline. Thus, the RVP of the final E85 blend could be closer to that of E0 or E10 fuels than commonly thought to be the case. Moreover, since the volatility of ethanol blends peaks between 6 and 30 vol% ethanol, the fuel in the tank of drivers of flex-fuel vehicles who alternate between E85 and gasoline will experience a wide range of ethanol concentrations in the fuel at any given time, and therefore a wide variation in the corresponding evaporative emissions.

Similarly, we have very little data with which quantitative predictions of the impact of E85 use on non-exhaust emissions of air toxics (e.g., benzene) can be drawn. The Auto/Oil study mentioned in the previous section tested the same three Tier 0 and Tier 1 vehicles for hot-soak evaporative emissions. They found no statistically significant change in NMOG or OMHCE[51] evaporative emissions, yet found a statistically significant 60% reduction in benzene emissions. Directionally, you would expect both hydrocarbon and air toxic evaporative emissions to decrease due to the dilution of the hydrocarbon portion of the fuel with ethanol. However, again, it is highly dependent on the volatility of the gasoline component of the specific E85 used and its benzene content, neither of which is regulated.

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[51] Organic Material Hydrocarbon Equivalent

3.2 Effect of Fuel Quality on Spark-Ignited Nonroad Equipment Emissions

We use EPA's NONROAD emission model to estimate the effect of gasoline quality on emissions from nonroad equipment. We use the 2005 version of this model, NONROAD2005, which includes the effect of ethanol on permeation emissions from several types of equipment: all small spark-ignition equipment (including handheld and non-handheld equipment less than or equal to 25 hp), all spark-ignition recreational marine watercraft (includes all outboard, stern-drive inboard, and personal watercraft). Note that these categories do not include recreational vehicles (motorcycles, ATVs, and snowmobiles) or large spark-ignition equipment.

Only a limited number of fuel parameters affect emissions in NONROAD. Exhaust VOC, CO and NOx emissions are a function of sulfur and oxygen. Here, only the latter fuel parameter is of interest. Emissions of all three pollutants are assumed to change proportionally with fuel oxygen content. Table 3.2-1 shows the effect of moving to a 10 volume percent ethanol blend (3.5 wt% oxygen) on these emissions, either from a non-oxygenated fuel or from an 11 volume percent MTBE blend (2.0 wt% oxygen).[RRR]

Table 3.2-1.
Effect of a 10 Volume Percent Ethanol Fuel on Nonroad Exhaust Emissions

	4-Stroke Engines		2-Stroke Engines	
Base Fuel	Non-Oxygenated	11 Volume Percent MTBE	Non-Oxygenated	11 Volume Percent MTBE
VOC	-16%	-7%	-2%	-1%
CO	-22%	-9%	-23%	-10%
NOx	+40%	+17%	+65%	+28%

As can be seen, the higher oxygen content of ethanol blends reduces exhaust VOC and CO emissions. However, it also increases NOx emissions quite substantially, especially from 4-stroke engines. However, it should be noted that NOx emissions from these engines tend to be fairly low to start with, given the fact that these engines run richer than stoichiometric. Thus, a large percentage increase of a relative low base value can be a relatively small increase in absolute terms. This will be seen below in Chapter 4, when we evaluate the impact of increased ethanol use on the local and national emission inventories.

Non-exhaust VOC emissions (other than permeation) are a function of gasoline RVP and ethanol content in NONROAD2005. Ethanol content only affects permeation emissions. Both of these emissions are temperature dependent, so the effect of ethanol and RVP is also temperature dependent. Based on the results of modeling national emissions in July, a 10 volume percent ethanol blend increases non-exhaust VOC emissions by 15 percent. This assumes a 1.0 psi increase in RVP.

Hose permeation emissions in the public version of NONROAD2005 are independent of fuel quality. In support of the development of new emission standards for small nonroad engines, EPA has been testing small nonroad engines for hose permeation emissions using fuels with and without ethanol. Based on this testing, as well as discussions with nonroad equipment manufacturers, we developed new hose permeation emission rates for NONROAD2005 for both gasoline and E10 fuels. Roughly, these revised permeation rates indicate that emissions with E10 are 2-3 times higher than those for gasoline. This increase is similar to that found for the three oldest onroad vehicles in the CRC E-65 study, discussed in section 3.1.1.1.4 above.[52] The NONROAD2005 hose permeation factors[SSS] were adjusted as follows:

> 1) Permeation emissions in the public version of NONROAD2005 were 450 grams per meter-squared per day (g/m^2/day) for both small spark-ignition engines and for the supply hoses on portable fuel tanks in recreational marine watercraft, applicable to all fuels. For both types of equipment, the permeation emission rates were changed to 122 g/m^2/day for gasoline and 222 g/m^2/day for E10.
>
> 2) Permeation emissions in the public version of NONROAD2005 were 100 g/m^2/day for supply hoses on outboard recreational marine watercraft (> 25 hp), 300 g/m^2/day for supply hoses on personal watercraft (PWC), and 110 g/m^2/day for fill neck hoses on both outboards and PWC. These three permeation emission rates were changed to 42 g/m^2/day for gasoline and 125 g/m^2/day for E10.
>
> 3) Permeation emissions from sterndrive/inboard recreational marine watercraft in the public version of NONROAD2005 were 100 g/m^2/day for supply hoses and 110 g/m^2/day for fill neck hoses. Both of these permeation emission rates were changed to 22 g/m^2/day for gasoline and 40 g/m^2/day for E10.
>
> 4) Permeation emissions in the public version of NONROAD2005 were 0 g/m^2/day for vent hoses on all recreation marine watercraft. This permeation emission rate was changed to 2.5 g/m^2/day for gasoline and 4.9 g/m^2/day for E10.
>
> 5) One final adjustment was to double the vent hose length for all gasoline-fueled outboards, personal watercraft, and sterndrive/inboard watercraft.

The NONROAD emissions model does not estimate emissions of toxic air pollutants from nonroad equipment. However, the National Mobile Inventory Model (NMIM) does make such estimates. NMIM utilizes the MOBILE and NONROAD models to develop national emission estimates for motor vehicles and nonroad equipment. For the most part, NMIM provides the relevant inputs to MOBILE6.2 and NONROAD and processes the results. However, with respect to nonroad toxic emissions, NMIM takes exhaust and non-exhaust VOC emission estimates from NONROAD and applies a set of toxic fractions of VOC emissions based on fuel quality.[TTT] NMIM contains estimates of the toxic fractions of VOC emissions for three fuels: a non-oxygenated gasoline, an MTBE blend and an ethanol blend. NMIM applies the fraction of VOC emissions represented by each of the air toxics to either the exhaust or non-

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[52] Permeation emissions from nonroad equipment are not regulated. Thus, the elastomers used in the fuel systems of nonroad equipment are likely to be more similar to those of older onroad vehicles than those of later onroad vehicles which were subject to stringent non-exhaust VOC emission standards.

exhaust VOC emissions estimated by NONROAD. The toxic fractions of VOC were derived from motor vehicle testing. Thus, they are considered approximate.

We hope to update our projections of the effect of gasoline quality on exhaust and non-exhaust emissions from nonroad equipment based on additional testing to be conducted over the next several years if funding allows. These updated projections could be used in the comprehensive assessment of the impact of the fuel-related provisions of the Energy Act which is due in 2009.

3.3 Effect of Fuel Quality on Compression-Ignited Vehicle and Equipment Emissions – Biodiesel

Biodiesel is expected to be one of two renewable fuels to be used in significant volumes through 2020. While ethanol will dominate the market, biodiesel use is likely to grow considerably reaching 300 million gallons by 2012, according to EIA estimates. It is produced domestically from vegetable oils, animal fats and recycled cooking oils, with the majority of this product coming from soybean oil. It is typically used in 2%, 5% and 20% blends with diesel fuel which have been assigned B2, B5 and B20 designations, respectively.

In 2002, EPA issued a report entitled "A Comprehensive Analysis of Biodiesel Impacts on Exhaust Emissions" based on existing data from various test programs. This report included a technical analysis of biodiesel effects on regulated and unregulated pollutants from diesel powered vehicles and concluded that biodiesel fuels improved PM, HC and CO emissions of diesel engines while slightly increasing their NOx emissions.

While the conclusions reached in the 2002 EPA report relative to biodiesel effects on VOC, CO and PM emissions have been generally accepted, the magnitude of the B20 effect on NOx remains controversial due to conflicting results from different studies. Significant new testing is being planned with broad stakeholder participation and support in order to better estimate the impact of biodiesel on NOx and other exhaust emissions from the in-use fleet of diesel engines. We hope to incorporate the data from such additional testing into the analyses for other studies required by the Energy Act in 2008 and 2009, and into a subsequent rule to set the RFS program standard for 2013 and later.

3.4 Emissions from Fuel Production Facilities

3.4.1 Ethanol

The primary impact of renewable fuel production and distribution regards ethanol, since it is expected to be the predominant renewable fuel used in the foreseeable future. For the NPRM, we estimated the impact of increased ethanol production, including corn farming, on emissions based on DOE's GREET model, version 1.6. This estimate also included emissions related to distributing the ethanol and take credit for reduced emissions related to distributing displaced gasoline. Since the time of the NPRM analysis, DOE has published the next version of

GREET, version 1.7. The emission estimates related to ethanol production and distribution in GREET1.7 differ significantly from those in GREET1.6. In addition, through EPA's regional offices, we contacted a number of States to obtain the latest emission estimates for ethanol plants currently in production. These plant-specific estimates provide a useful comparison to the inherently generic emission factors used by a nationwide-average model, such as GREET.

In Section 3.4.1.1, we describe and compare the emission estimates from the GREET model, both versions 1.6 and 1.7. In Section 3.4.1.2, we describe the data obtained from the States and consolidate it into two sets of emission factors; one for wet mills and one for dry mills. Finally, in Section 3.4.1.3, we describe how we will use both the GREET and State estimates in estimating national emissions from new ethanol plants in Chapter 4.

3.4.1.1 GREET Emission Estimates

The emissions related to producing and distributing ethanol for use in gasoline blends from both GREET1.6 and 1.7 are summarized in Table 3.4-1. GREET presents emission factors in a variety of units, such as per bushel of corn harvested, gallons of ethanol produced, etc. All the emission factors shown in this table have been converted to a per gallon of ethanol produced or distributed basis using the default conversion factors contained in GREET. One of GREET's default assumptions is that 80% of ethanol plants are associated with dry corn milling, while the other 20% are associated with wet milling. Nearly all future ethanol plants are planned to be dry mill facilities. Therefore, we only show the emission factors for dry mill ethanol plants below.

Table 3.4-1.
Well-to-Pump Emissions for Producing and Distributing Ethanol from Corn Dry Mill Facility (grams per gallon ethanol)

Pollutant	Corn Farming and Transportation	Ethanol Production	Co-Product Credits	Ethanol Trans-portation	Gasoline Transportation Credit	Total Emissions
Dry Mills - GREET1.6						
VOC	0.8	6.8	-4.1	0.5	-0.9	3.1
CO	4.3	2.9	-3.3	0.2	-0.1	4.1
NOx	11.3	4.6	-6.9	1.5	-0.4	10.1
PM10	8.1	0.4	-2.5	0.0	0.0	6.1
SOx	1.2	6.1	-0.9	0.2	-0.1	6.5
Dry Mills - GREET1.7						
VOC	1.6	2.6	-2.5	1.6	-1.5	1.8
CO	4.0	1.7	-1.7	0.2	-0.1	4.1
NOx	10.7	3.9	-4.1	1.3	-0.4	11.4
PM10	1.1	4.2	-0.5	0.0	0.0	4.9
SOx	5.0	3.7	-2.4	0.2	-0.1	6.4
Wet Mills - GREET1.6						
VOC	0.8	6.8	-1.8	0.5	-0.9	5.5
CO	4.3	3.3	-2.1	0.2	-0.1	5.7
NOx	11.3	6.2	-4.8	1.5	-0.4	13.8
PM10	8.1	0.5	-2.3	0.0	0.0	6.4
SOx	1.2	9.2	-0.6	0.2	-0.1	9.9
Wet Mills - GREET1.7						
VOC	1.6	2.6	-3.2	1.6	-1.5	1.1
CO	4.0	2.3	-2.1	0.2	-0.1	4.3
NOx	10.7	4.9	-4.6	1.3	-0.4	11.9
PM10	1.1	5.9	-0.6	0.0	0.0	6.5
SOx	5.0	4.1	-2.7	0.2	-0.1	6.5

As can be seen, the emission estimates from the two versions of GREET differ significantly. In particular, VOC emissions in GREET1.7 are about 60% as large as those estimated in GREET1.6 for dry milss and even lower for wet mills. The other differences are in the ±20% range, and differ in direction depending on pollutant.

The default mix of dry and wet mill ethanol plants is 80/20 in both versions of GREET. This is a reasonable estimate for current production. However, the vast majority of new plants are expected to be of the dry mill variety. Therefore, we will use the above emission factors for a 80/20 mix of dry and wet mill plants to estimate the emissions from current ethanol plants and the dry mill emission factors to estimate the emissions from future plants.

While emissions related to ethanol production and distribution will increase,,areas with refineries might experience reduced emissions, not necessarily relative to current emission levels, but relative to those which would have occurred in the future had ethanol use not risen. However, to the degree that increased ethanol use reduces imports of gasoline, as opposed to the domestic production of gasoline, these reduced refinery emissions will occur overseas and not in the U.S. Therefore, we will not take any credit for reduced refinery emissions here.

Similarly, areas with MTBE production facilities might experience reduced emissions from these plants as they cease producing MTBE. However, some of these plants are likely to be converted to produce other gasoline blendstocks, such as iso-octane or alkylate. In this case, their emissions are not likely to change substantially.

The emission factors shown in Table 3.4-1 do include a credit for reduced emissions related to a reduction in the volume of non-oxygenated gasoline being distributed. These are taken directly from the GREET emission estimates for conventional gasoline production and distribution. We assumed that ethanol use will reduce gasoline use one for one on an energy basis.

3.4.1.2 Ethanol Production Emissions Received from States

The emissions from most of the steps involved in ethanol production and distributions are very diffuse (e.g., tractors plowing corn fields). However, the emissions from ethanol production plants are point sources whose emissions are often measured and tracked by local or state governments. We contacted over a dozen States in an attempt to improve our estimate of emissions from ethanol production. The results of this process are summarized below.[UUU]

We received emission estimates from 13 States for current ethanol plants with a combined capacity of 3 billion gallons per year. The emission data involved annual emission estimates for one or more years between 2001-2005. Overall, these plants represent roughly three-fourths of current ethanol capacity. The emission data cover a very wide range of plant capacities, ranging from 0.4 to 274 million gallons of ethanol per year.

The capacity-weighted average emissions of wet and dry mill ethanol plants are summarized in Table 3.4-2.

Table 3.4-2. Emissions From Ethanol Plants: State Data (g/gal ethanol)

	Wet Mills	Dry Mills
VOC	17.5	4.0
CO	15.0	1.9
NOx	18.3	5.5
PM10	8.8	2.2
SOx	24.6	7.0

As can be seen, the emissions from wet mills are much higher than those from dry mills. In general, the wet mill plants are older than the dry mills. They also involved a different set of processes and produce a different set of by-products.

The ethanol plant emissions from GREET1.6 and GREET1.7 are shown in Table 3.4-3 below.

Table 3.4-3. Emissions From Ethanol Plants: GREET (g/gal ethanol)

	Wet Mills		Dry Mills	
	GREET1.6	GREET1.7	GREET1.6	GREET1.7
VOC	6.8	2.6	6.8	2.6
CO	3.3	2.3	2.9	1.7
NOx	6.2	4.9	4.6	3.9
PM10	0.5	5.9	0.4	4.2
Sox	9.2	4.1	6.1	3.7

As can be seen from comparing the emission estimates in Tables 3.4-2 and 3.4-3, the State data indicate that the emission from wet mills are much higher than those estimated in either version of GREET. In contrast, the emission data obtained from the States for dry mills is generally consistent with the estimates in GREET1.6 and higher than those in GREET1.7. An exception to the latter are emissions of PM10, which the state data indicate are lower than the estimate in GREET1.7 and higher than that in GREET1.6.

The reasons for the differences in the State data and the estimates in GREET1.6 and GREET1.7 are not known. It is possible, particularly for wet mills, that the State estimates include the emissions from an entire geographically-defined facility which may include more operations than just corn milling. It is also possible that the estimates in GREET represent emissions from plants which would be designed today or in the future and are less representative of plants which were built over 20 years ago. This deserves further investigation. At this time, we will use the average of the State emission data as a second estimate of ethanol plant emissions, along with GREET1.7, in order to better indicate the range of possible emissions from these plants.

3.4.1.3 Selection of Ethanol Production and Distribution Emission Estimates

We have available three estimates of the emissions from ethanol plants and two estimates of the emissions from the other steps in the process of growing corn through ethanol distribution. The estimates contained in GREET1.7 represent an update of those in GREET1.6. Therefore, we will use the emission factors from GREET1.7 in lieu of those in GREET 1.6 in Chapter 4 where we estimate national emissions from ethanol production and distribution.

In addition, we develop a second estimate of these emissions by substituting the average emission factors based on the State data for the dry mill ethanol plant emissions contained in GREET1.7. While the State data represents emissions from current plants and our primary focus is future plants, it is not certain that the emissions of the two sets of ethanol plants will differ. Therefore, the use of the State data will provide a useful indication of the potential uncertainty in the GREET1.7 estimates. We chose not to use the state data for wet mills, as these emission factors are often a factor of 10 higher than those from GREET1.6 or GREET1.7. More understanding of the processes producing these emissions is needed before they can be all assigned to ethanol production. Thus, we use the GREET1.7 emission factors for wet mill ethanol production, while using the state data for dry mill ethanol production.

The two sets of estimates are shown in Table 3.4-4. In both sets of estimates, the emission factors for current ethanol plants assume an 80/20 mix of dry and wet mills, while those for future ethanol plants assume 100% dry mills.

Table 3.4-4.
Selected Emission Factors for Ethanol Production and Distribution
(g/gal ethanol)

	GREET1.7		GREET1.7 + State Data	
	Current Plants	Future Plants	Current Plants	Future Plants
VOC	1.8	1.8	3.6	3.2
CO	4.0	4.1	4.4	4.3
NOx	11.4	11.4	10.8	13.0
PM10	4.9	4.9	6.1	2.8
Sox	6.4	6.4	7.2	9.7

3.4.2 Biodiesel

Like ethanol, we base our emission factors for biodiesel production distribution on the estimates contained in the GREET model, version 1.7. Table 3.4-6 shows the emission factors associated with soybean farming, soy oil production and esterification, and biodiesel distribution. We also include emissions related to distributing the biodiesel and take credit for reduced emissions related to distributing displaced diesel fuel.

Table 3.4-5.
Well-to-Pump Emissions for Producing and Distributing Biodiesel from Soybeans
(grams per gallon biodiesel)

Pollutant	Total: Soybean Farming and Transportation	Biodiesel Production	Biodiesel Transportation	Diesel Fuel Transportation Credit	Total Emissions
VOC	2.7	34.8	0.2	-0.2	37.6
CO	10.6	2.1	0.2	-0.1	12.7
NOx	19.3	5.5	0.9	-0.6	25.1
PM10	2.6	2.2	0.0	0.0	4.8
SOx	17.6	4.1	0.1	-0.1	21.8

At the same time, areas with refineries might experience reduced emissions, not necessarily relative to current emission levels, but relative to those which would have occurred in the future had biodiesel use not risen. However, to the degree that increased biodiesel use reduces imports of diesel fuel, as opposed to the domestic production of diesel fuel, these reduced refinery emissions will occur overseas and not in the U.S.

Chapter 3: Appendix
Fuel Property Tables and Summary of Predicted Emissions Changes

Table 3A-1. CRC E-67 Study Test Fuel Properties

Inspection	Units	Fuel A	Fuel B	Fuel C	Fuel D	Fuel E	Fuel F	Fuel G	Fuel H	Fuel I	Fuel J	Fuel K	Fuel L
API Gravity	°API	62.1	59.9	57.6	61.4	56.7	60.1	57.1	60.6	57.2	56.6	59.3	54.4
Relative Density	60/60°F	0.7310	0.7393	0.7482	0.7337	0.7519	0.7387	0.7502	0.7366	0.7498	0.7525	0.7416	0.7611
DVPE	psi	7.74	7.84	7.70	7.65	7.80	7.62	7.78	7.85	7.68	7.57	7.71	7.69
Oxygenates--D 4815													
MTBE	vol %	0.03	0.03	0.13	0.03	0.11	0.08	0.13	0.09	0.16	0.13	0.16	0.16
ETBE	vol %	0.02	0.02	0.01	0.01	0.01	0.08	0.04	0.01	0.01	0.01	0.02	0.01
EtOH	vol %	0.02	5.62	10.37	0.00	10.26	0.00	10.15	0.05	5.94	5.90	0.00	10.49
O2	wt %	0.02	2.10	3.84	0.01	3.78	0.03	3.76	0.04	2.22	2.19	0.03	3.83
Sulfur Content	ppm	18.8	16.7	19.0	18.2	17.2	18.1	17.5	18.6	16.8	19.1	21.9	20.6
D 86 Distillation													
IBP	°F	94.2	107.6	104.3	88.8	106.3	94.2	103.7	94.2	100.7	102.6	93.9	106.1
5% Evaporated	°F	126.3	127.2	124.6	123.2	124.3	121.6	125.3	122.7	124.0	126.0	117.9	129.4
10% Evaporated	°F	136.0	133.2	130.5	133.3	130.5	135.0	133.2	134.0	130.2	134.4	129.7	140.0
20% Evaporated	°F	148.6	140.8	138.8	147.6	139.5	154.7	143.7	151.6	139.0	146.6	148.4	152.4
30% Evaporated	°F	163.6	154.1	146.6	164.1	147.2	177.0	152.9	173.3	150.8	175.5	174.4	158.8
40% Evaporated	°F	179.8	176.1	153.7	182.3	153.8	200.2	163.4	197.0	191.0	220.5	208.5	202.1
50% Evaporated	°F	194.7	190.9	192.7	199.5	197.7	216.8	212.2	216.3	215.9	236.6	236.1	232.7
60% Evaporated	°F	209.0	203.2	223.5	216.9	226.2	227.6	226.7	230.4	235.9	251.5	255.2	248.7
70% Evaporated	°F	224.2	219.3	245.7	237.9	259.2	238.2	237.0	245.9	260.9	271.9	279.6	273.5
80% Evaporated	°F	243.4	240.9	281.5	274.3	299.7	254.7	251.7	273.7	311.3	305.2	319.1	307.7
90% Evaporated	°F	294.3	289.8	329.2	355.0	351.7	295.0	290.7	326.9	354.2	329.2	355.5	349.1
95% Evaporated	°F	327.4	325.9	343.4	367.3	364.9	324.0	327.8	343.7	366.6	338.7	368.6	367.4
EP	°F	351.2	352.0	374.0	392.0	385.4	361.2	365.4	374.4	391.8	365.8	390.3	389.6
Recovery	vol %	97.0	97.9	97.7	97.9	97.4	97.2	96.7	98.0	97.9	97.6	98.1	97.3
Residue	vol %	1.8	1.1	1.2	0.8	1.4	1.7	1.5	1.0	1.1	1.2	1.0	1.0
Loss	vol %	1.2	1.0	1.1	1.3	1.2	1.1	1.8	1.0	1.0	1.3	0.9	1.7
Driveability Index		1082.4	1075.8	1128.0	1153.3	1165.1	1148.0	1151.2	1176.8	1211.5	1254.9	1258.2	1282.3
E200	vol %	53.6	57.6	52.1	50.6	50.6	40.0	47.4	41.7	43.1	35.2	37.6	39.4
E300	vol %	90.9	91.5	84	83.6	80.0	90.9	79.5	85.2	77.8	78.4	75.2	78.0

Table 3A-2. Summary of EPA E-67 vs. EPA Predictive Model Effects of E10 and MTBE Use Relative to CG and RFG

	Base Fuel: AAM Summer avg. non-oxy fuel	**E0:** AAM CG RVP -1 psi delta	**E0:** AAM CG RVP -2 psi delta	**E10**: AAM Summer Avg	**E10**: AAM Summer avg, T50 limited to 195ºF	**E10**: AAM Summer avg, T50 T90 O2 only for EPA model (T50=195ºF)	**11% MTBE**: Fuel props are deltas from AAM CG	**Phase 2 RFG**: Non-oxy, from 1993 region 2 class C Data, low RVP	**RFG Class C MTBE**: 1993 region 2 data, low RVP	**RFG E10**: 1993 region 2 data (L),T50 & T90 delta from AAM data, low RVP
Fuel Parameters										
RVP (psi)	8.7	7.8	6.8	9.7	9.7	8.7	8.7	6.7	6.7	6.7
T50 (ºF)	218	218	218	186	195	195	206	214	212	194
T90 (ºF)	332	332	332	325	325	325	324	325	321	322
Aromatics (vol %)	32	32	32	27	27	32	25.5	25.48	25.48	25.48
Olefins (vol %)	7.7	7.7	7.7	6.1	6.1	7.7	7.7	13.1	13.1	13.1
Oxygen (wt%)	0	0	0	3.5	3.5	3.5	2.1	0	2.1	3.5
Sulfur (ppm)	30	30	30	30	30	30	30	30	30	30
Predicted Emissions Changes										
EPA Predictive Models (% change)										
NOx	0.0	-1.0	-2.1	7.7	7.3	7.7	2.6	-1.7	2.4	6.3
NMHC	0.0	-1.0	-2.0	-7.4	-7.0	-7.5	-9.2	-7.7	-11.1	-12.9
EPA E-67 Model (% change)										
NOx	0.0	0.0	0.0	9.2	6.7	6.7	-1.9	-0.7	-2.2	8.8
NMHC	0.0	0.0	0.0	-5.7	-6.5	-6.5	-4.7	-3.2	-1.9	-7.2

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Chapter 4: National Emission Inventory Impacts

This chapter describes the methods used to develop national emissions inventories under the Renewable Fuel Standard (RFS) program. These inventories account for impacts from ethanol use, the removal of MTBE, and the resulting changes to gasoline. These inventories also account for the impacts of ethanol and biodiesel production and distribution. This chapter also presents and discusses these inventories.

4.1 Impact of Ethanol Use

This section describes the methods used to develop national emissions inventories with respect to ethanol consumption. This section also presents and discusses these inventories. These inventories reflect only emissions from vehicles and equipment operating on ethanol-blend gasoline, from both onroad and off-road sources. The off-road sources do not include nonroad diesel, locomotive, or marine applications.

4.1.1 Overview of Cases

As described in Section 2.1, we consider three cases for the future use of ethanol-blend gasoline: a Reference Case, an RFS Case, and an EIA Case. The main difference between the cases is our assumption about how much ethanol will be used and where it will go. The Reference case represents our estimate of fuel quality by county which existed in 2004 when approximately 3.5 billion gallons of ethanol were consumed nationwide. In terms of 2012 fuel consumption, about 4.0 billion gallons of ethanol is consumed nationwide in the Reference case. The RFS case assumes 6.7 billion gallons of ethanol consumption in 2012, in accordance with the requirements of the RFS mandate. The EIA case assumes 9.6 billion gallons of ethanol is used nationwide in 2012, based on projections made in the Energy Information Agency’s 2006 Annual Energy Outlook. We evaluate each case by predicting fuel quality in each county of the U.S. in 2012. This 2012 fuel matrix is then used for all inventory and air quality assessments.

While Chapter 2 discusses our methods for determining how much ethanol will go to each state in each case and how fuel properties will be affected, this section of the RIA uses those distributions to derive estimates of the impact on national emissions inventories.

4.1.2 National Emissions Inventory Estimation Procedure

Having approximated the effects of adding ethanol and removing MTBE on fuel properties (see Chapter 2), the next step was to use the EPA’s National Mobile Inventory Model (NMIM)[VVV] to calculate emissions inventories for gasoline fueled motor vehicles and nonroad equipment in years 2012, 2015, and 2020. For all three years, we ran NMIM for January and July, assuming that each was representative of winter and summer conditions, respectively. We estimate annual emission inventories by summing the two monthly inventories and multiplying by six. This was done in order to reduce the amount of time needed to actually run the model.

One additional simplification was made to shorten the time required to run NMIM for the three years, three fuel cases, two months and roughly 3100 counties in the U.S. Counties within a state with identical fuels and inspection-maintenance programs and similar temperatures were grouped together and run through NMIM as a single geographical area. The temperatures used for this area were those of the county with the highest VMT in the group. As the specific counties within a state with identical fuels sometimes changed across the three fuel cases, the groupings of counties sometimes changed across the NMIM runs of the three fuel cases. This occasionally introduced a change in the temperatures estimated for a county between fuel cases. This in turn produced a change in emissions independent of changes in fuel quality.

We evaluated the potential for this simplification to bias the projected emission impacts of the various fuel cases. Counties where RFG is sold were always modeled consistently across all three fuel cases and so are unaffected by this simplification. Counties with low RVP and 9 RVP fuel were sometimes affected. On average, the changes in emissions occurring due to a change in temperature appear to be unbiased (i.e., emissions increase as often as they decrease). Also, many of the emission impacts of changing fuel quality (e.g., exhaust VOC and NOx impact) were applied outside of the NMIM model and so are unaffected by this simplification. Since we do not present or use the emission impacts for individual counties, we believe that this simplification does not significantly impact the emission impacts presented below.

We chose 2012 as the first projection year, because it is the year of full RFS program implementation. We also chose 2015 and 2020 to illustrate how the emissions will change over time as the fleet changes. We increased ethanol consumption beyond 2012 only by volumes required to maintain the same proportion to gasoline that existed in 2012, and not by growth predicted in EIA estimates. By restricting ethanol growth in this way, the same fuel quality that existed in 2012 would apply to 2015 and 2020, which would better highlight the effects of fleet turnover.

NMIM's estimates of both onroad and nonroad emissions were "post-processed" to reflect factors not yet included in the model. For onroad emissions, the effect of fuel quality on exhaust VOC and NOx emissions contained in the model (i.e., those in MOBILE6.2) were replaced with those from the EPA Predictive Model. We further adjusted the NMIM estimates of exhaust VOC, CO and NOx emissions from onroad vehicles in a "sensitivity" analysis in order to reflect the significant degree of uncertainty which currently exists with respect to these effects. Air toxic emissions were adjusted in order to reflect changes in total exhaust VOC emissions,. Finally, the effect of ethanol on permeation VOC and benzene emissions also were added to the onroad emission estimates. This series of post-processing steps are further described in the sections below.

For nonroad emissions, the only adjustment to the NMIM estimates was to adjust air toxic emissions in the two control cases to reflect the change in the toxic fraction of VOC emissions to that estimated for onroad vehicles, as opposed to that estimated for nonroad equipment. These steps for calculating emissions inventories are described in the following sections. A summary of the models used and fundamental post-processing steps are shown in Table 4.1-1 below.

Table 4.1-1. Estimation of National Emissions Inventories: Models Used and Fundamental Post-Processing Steps

	Exhaust Emissions	Non-Exhaust Emissions
Onroad	Model: NMIM which runs MOBILE6.2. Post-processing: 1. Replace VOC and NOx fuel effects for Tier 0 vehicles from MOBILE6.2 with fuel effects from EPA Predictive Model; 2. Conduct sensitivity analysis by applying fuel effects for Tier 0 vehicles to all vehicles. 3. Adjust exhaust air toxics emissions to reflect adjustment to exhaust VOC emissions.	Model: NMIM which runs MOBILE6.2. Post-processing: 1. Add effect of ethanol on permeation emissions of VOC and benzene.
Nonroad	Model: NMIM which runs NONROAD2005 (modified to account for hose permeation). Post-processing: 1. Changes in toxic fraction of VOC emissions in two fuel control cases based on onroad estimates instead of nonroad estimates.	Model: NMIM which runs NONROAD2005 (modified to account for hose permeation). Post-processing: 1. Changes in toxic fraction of VOC emissions in two fuel control cases based on onroad estimates instead of nonroad estimates.

4.1.2.1 Onroad Emission Estimation Procedures

We ran NMIM to estimate county-specific emissions from gasoline motor vehicles for January and July in years 2012, 2015, and 2020. For each month and year combination, we ran the three onroad cases (Reference, RFS, and EIA). The NMIM model utilizes the MOBILE6.2[WWW] model to estimate motor vehicle emissions, as well as the effect of fuel quality on emissions. As discussed in Chapter 3, the EPA Predictive Model contains more recent estimates of the impact of fuel quality on exhaust VOC and NOx emissions. Therefore, we removed the impact of fuel quality on exhaust VOC and NOx emissions as estimated by MOBILE6.2 and replaced these impacts with those of the EPA Predictive Model. As also discussed in Chapter 3, MOBILE6.2 does not include the impact of ethanol on permeation emissions. Therefore, we added these emissions to those estimated by NMIM. Finally, we arrived at annual emissions estimates by summing the January and July results, then multiplying by six. The procedures for making these changes are discussed below.

4.1.2.1.1 Onroad Exhaust Emissions

MOBILE6.2 performs most of its emission estimation procedures for a non-oxygenated 8.7 RVP gasoline. The effect of differing fuel quality is represented by a set of adjustment factors, which can vary by vehicle type, model year, and whether the vehicle is properly operating or not (i.e., is a low or high emitter). Because the mix of vehicle types, model years, and low and high emitters varies by county and calendar year, it is infeasible to estimate the net impact of each fuel parameter on emissions outside of the model. In Section 3.1.1.1.2 of Chapter 3, we describe a process whereby we performed linear regressions on the exhaust emissions estimated by NMIM in order to determine the average effect of RVP, ethanol content and MTBE content on exhaust VOC and NOx emissions. Also in Section 3.1.1.1.2, we describe these same impacts using the EPA Predictive Model. We combined these fuel-emission effects with the fuel quality expected to exist in each county under each ethanol use case to estimate the adjustment which NMIM had applied to exhaust VOC and NOx emissions. This NMIM adjustment for fuel quality was removed and replaced by one based on the EPA Predictive Models. In our primary analysis, the fuel-emission effects from the EPA Predictive Models were only applied to the fraction of exhaust VOC and NOx emissions which are emitted by Tier 0 vehicles. In our sensitivity analysis, the fuel-emission effects from the EPA Predictive Models were applied to all exhaust VOC and NOx emissions.

Table 4.1-2 shows the values for “Tier 0 Fraction”; i.e., the fraction of VOC and NOx emissions from vehicles with Tier 0 emissions characteristics. Note that the fraction drops as time progress, reflecting the attrition of such vehicles in the national fleet. In the sensitivity analysis, the Tier 0 vehicle emission fraction is 1.0 for all years and pollutants.

Table 4.1-2. Fraction of In-Use Exhaust Emissions Attributable to Vehicles with Tier 0 Emissions Characteristics

Calendar Year	VOC	NOx
2012	0.339	0.162
2015	0.183	0.065
2020	0	0

After adjusting exhaust VOC and NOx according to the methods described above, we adjusted the four exhaust toxic emissions: benzene, 1,3-butadiene, formaldehyde, and acetaldehyde. MOBILE6.2 estimates exhaust toxic emissions by first estimating the fraction of exhaust VOC emissions represented by each toxic based on fuel quality. The model then applies this fraction to exhaust VOC emissions to estimate absolute emissions of air toxics. Since we adjusted exhaust VOC emissions, it was necessary to adjust exhaust toxic emissions, as well, by the ratio of the change in exhaust VOC emissions.

As described in Section 3.1.1.1.2 of Chapter 3, carbon monoxide emissions were also adjusted. The following equation illustrates the CO adjustment:

$$\begin{matrix}\text{Adj.}\\ \text{CO}\end{matrix} = \begin{matrix}\text{NMIM}\\ \text{CO}\end{matrix} \times \left(1+(\text{Etoh Vol\% x Etoh Mkt Shr} + \text{MTBE Vol\% x MTBE Mkt Shr x } 0.5454) \times \text{CO Adj. Factor}\right)$$

4.1.2.1.2 Onroad Non-Exhaust Emissions

The only adjustment to the non-exhaust emission estimates from NMIM was to add county-specific estimates of the increase in permeation emissions due to ethanol use. In Section 3.1.1.3 of Chapter 3, we determined that a 10 vol% ethanol blend increased permeation emissions by 0.8 grams per day at 95 F. We also concluded there that permeation emissions double with every increase in temperature of 18 °F. Because of this temperature relationship, permeation effects were only accounted for in the July emission estimate since emissions during the winter months could be at least four times lower, and thus negligible.

Permeation emissions occur whether a vehicle is being used or is parked. Therefore, the average hourly emission factor in each county in July is determined by adjusting the 0.8 gram per day emission rate for the average fuel tank temperature occurring in that hour of the day in each county in July and multiplying by the market share of E10 fuel in that county. Total monthly emissions in each county were determined by summing across hours of the day, multiplying by 31 days and multiplying by the number of vehicles estimated to reside in that county.

The average fuel tank temperature is a function of the average ambient temperature at that hour of the day, adjusted to account for the increase in fuel tank temperature for those vehicles which are operating or which are still cooling down from operating. We obtain estimates of these latter two factors from EPA's Draft MOVES2006 model.[XXX] These are shown in Table 4.1-3. The fuel tank temperature of vehicles which have been parked some time tend to lag the ambient temperature both when the latter is rising and falling. We assume here that the fuel tank temperature of these parked vehicles is equal to the ambient temperature, which is true on average for the day.

Table 4.1-3. Increase in Fuel Tank Temperature Relative to Ambient

Hour of the Day	Vehicles Operating or in Hot Soak	Average Tank Temperature Rise (F)
Midnight	2.6%	10.0
1:00 AM	2.8%	6.9
2:00 AM	1.2%	6.1
3:00 AM	0.9%	4.9
4:00 AM	0.8%	3.1
5:00 AM	2.6%	3.0
6:00 AM	6.6%	3.7
7:00 AM	12.3%	4.6
8:00 AM	14.0%	3.5
9:00 AM	10.0%	3.8
10:00 AM	11.1%	3.8
11:00 AM	12.5%	4.9
Noon	15.6%	4.8
1:00 PM	16.0%	5.5
2:00 PM	17.2%	6.6
3:00 PM	21.0%	7.7
4:00 PM	23.7%	8.6
5:00 PM	28.5%	8.3
6:00 PM	30.0%	8.8
7:00 PM	25.7%	9.2
8:00 PM	18.7%	8.3
9:00 PM	13.5%	7.6
10:00 PM	10.6%	8.0
11:00 PM	7.8%	8.4

The total number of gasoline vehicles in the U.S. in 2004 is estimated to be 228 million.[YYY] We increased this figure by 1.9% per year[53] to derive estimates of the gasoline vehicle fleet in 2012, 2015 and 2020. This produced estimates for the fleet of gasoline vehicles in the U.S. of 265, 281 and 308 million vehicles in 2012, 2015 and 2020, respectively. These vehicles were allocated to each county based on the county-specific distribution of national VMT by gasoline vehicles contained in NMIM.

As described in Section 3.1.1.3 of Chapter 3, we estimate that benzene represents 3% of the increased VOC permeation emissions due to ethanol use. Thus, we added this 3% to the non-exhaust emissions of benzene estimated by NMIM.

4.1.2.2 Nonroad Emissions

NMIM is capable of utilizing any one of a series of EPA's NONROAD emission models. We chose to use the NONROAD2005[ZZZ] model to estimate emissions from nonroad equipment here, as it reflects EPA's latest estimates of emission factors for nonroad equipment. EPA has also recently developed a set of emission factor inputs for the NONROAD model which include the effect of ethanol on permeation emissions from a number of types of nonroad equipment (see Chapter 3).

For the proposed rule inventories, the NONROAD model was not able to select ethanol related emission factors based on the fuel quality inputs to the model. It was therefore necessary to run NMIM for two extreme ethanol use cases (no ethanol use and 100% ethanol use) and use those results to estimate emissions for the five ethanol use cases which were the focus of the proposed rule.

For the final rule, NONROAD model capabilities were updated to account for oxygenate effects. Therefore, we were able to run NMIM (which runs NONROAD) using the same fuel property inputs that were used for onroad emissions inventories. This eliminated the need to interpolate between the "No Oxygen" and "All Oxygen" NONROAD runs that were needed for the proposal.

For nonroad toxic exhaust emissions, the toxic emissions factors for nonroad equipment are based on very limited data. In EPA's recent final rule which implemented new Mobile Source Air Toxic (MSAT) standards, we adjusted the fraction of nonroad VOC emissions represented by the various air toxics contained in NMIM for a reduction in fuel benzene content with those estimated for the same fuel change by MOBILE6.2 for onroad motor vehicles. This was done because of the very limited amount of nonroad emission test data which both varied fuel quality and measured toxics emissions. We take the same approach here. We begin with the estimate of nonroad toxic emissions from NMIM for the Reference Case. Then, any change in the toxics fraction of nonroad VOC emissions due to a change in fuel quality predicted by NMIM is replaced by the change in the toxics fraction of onroad VOC emissions due to the same

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[53] Annual growth rate in gasoline consumption on an energy basis per EIA Annual Energy Outlook, 2006 (therefore it applies regardless of future ethanol use scenario). Assumes constant annual mileage per vehicle over this timeframe.

change in fuel quality predicted by MOBILE6.2. This adjustment is illustrated in the following equation:

$$\text{Adjusted Nonroad Toxic Emissions} = \text{NMIM Toxic Emissions} \times \frac{\text{NMIM VOC Emissions (RFS or EIA case)}}{\text{NMIM VOC Emissions (Reference case)}} \times \frac{\dfrac{\text{MOBILE6.2 Toxic Emissions (RFS or EIA Case)}}{\text{MOBILE6.2 VOC Emissions (RFS or EIA Case}}}{\dfrac{\text{MOBILE6.2 Toxic Emissions (Reference Case)}}{\text{MOBILE6.2 VOC Emissions (Reference Case)}}}$$

4.1.3 National Emissions Inventory Projections

4.1.3.1 Emission Inventories: Primary Analysis

This section provides the national emissions inventories for the primary case analyses. Criteria pollutant inventories are included, along with a brief discussion of the trends. A short discussion of air toxics inventories is also included. See Tables 4A-1 through 4A-7 in the Chapter 4 Appendix for complete primary-case inventories on air toxics and criteria pollutants, as well as the percent changes in inventories from the Reference case.

Table 4.1-4 shows ethanol impacts on VOC inventories for each of the three cases of renewable fuel use in years 2012, 2015, and 2020. In any given year, the data suggest that total VOC emissions will increase as ethanol use increases. The largest increase is seen in the EIA case, where the increase is about 1% of the Reference case inventory.

Our analysis indicates that this increase is a result of VOC non-exhaust emissions, such as those from evaporation or permeation. While VOC exhaust emissions decrease, they do not decrease enough to counteract the increase from non-exhaust emissions.

Table 4.1-4.
National VOC Emissions from Gasoline Vehicles and Equipment:
Reference Case Inventory and Change in Inventory for Control Cases (Tons/Year)

Primary Case	Tons/Year		
Total	**2012**	**2015**	**2020**
Reference	5,882,000	5,569,000	5,356,000
RFS Case (Change)	18,000	25,000	34,000
EIA Case (Change)	43,000	49,000	58,000
On-Road	**2012**	**2015**	**2020**
Reference	3,417,000	3,269,000	3,244,000
RFS Case (Change)	10,000	16,000	23,000
EIA Case (Change)	32,000	36,000	42,000
Non-Road	**2012**	**2015**	**2020**
Reference	2,465,000	2,300,000	2,112,000
RFS Case (Change)	8,000	9,000	11,000
EIA Case (Change)	11,000	13,000	16,000

Table 4.1-5 shows ethanol impacts on CO inventories for each of the three cases of renewable fuel use in years 2012, 2015, and 2020. In any given year, data suggest that total CO emissions will decrease as ethanol use increases. The largest reduction is seen in the EIA case; this decrease is still less than 3% of the Reference inventory.

Table 4.1-5.
National CO Emissions from Gasoline Vehicles and Equipment:
Reference Case Inventory and Change in Inventory for Control Cases (Tons/Year)

Primary Case	Tons/Year		
Total	**2012**	**2015**	**2020**
Reference	55,022,000	53,702,000	53,949,000
RFS Case (Change)	-483,000	-473,000	-460,000
EIA Case (Change)	-1,366,000	-1,329,000	-1,286,000
On-Road	**2012**	**2015**	**2020**
Reference	37,656,000	36,171,000	35,723,000
RFS Case (Change)	-45,000	-39,000	-19,000
EIA Case (Change)	-359,000	-321,000	-252,000
Non-Road	**2012**	**2015**	**2020**
Reference	17,366,000	17,531,000	18,226,000
RFS Case (Change)	-438,000	-434,000	-441,000
EIA Case (Change)	-1,007,000	-1,008,000	-1,034,000

Table 4.1-6 shows ethanol impacts on NOx inventories for each of the three cases of renewable fuel use in years 2012, 2015, and 2020. In any given year, the data suggest that total NOx emissions will increase as ethanol use increases. The largest increase is seen in the EIA case, which is around 2% of the Reference inventory.

Our analysis also indicates that nonroad NOx emissions increase much greater than onroad emissions. While onroad inventories increase less than one percent in control cases, nonroad inventories increase up to 11% in the EIA case.

Table 4.1-6.
National NOx Emissions from Gasoline Vehicles and Equipment: Reference Case Inventory and Change in Inventory for Control Cases (Tons/Year)

Primary Case	Tons/Year		
Total	**2012**	**2015**	**2020**
Reference	2,487,000	2,059,000	1,695,000
RFS Case (Change)	23,000	18,000	17,000
EIA Case (Change)	40,000	33,000	32,000
On-Road	**2012**	**2015**	**2020**
Reference	2,240,000	1,797,000	1,407,000
RFS Case (Change)	9,000	3,000	0
EIA Case (Change)	13,000	4,000	0
Non-Road	**2012**	**2015**	**2020**
Reference	247,000	262,000	288,000
RFS Case (Change)	14,000	15,000	17,000
EIA Case (Change)	27,000	29,000	32,000

Table 4.1-7 shows ethanol impacts on air toxic emissions for each of the three cases of renewable fuel use in 2012.

For all air toxics shown, the most extreme changes occur in the EIA case. The data suggest that, in 2012, total benzene emissions will decrease by about 4% due to decreases in both onroad and nonroad emissions. Total 1,3-butadiene emissions decrease by less than 2% due to decreases in both onroad and nonroad emissions. Total formaldehyde emissions decrease by up to 1.5%. Total acetaldehyde emissions increase by as much as 36% due to increases in both onroad and nonroad emissions.

Generally, the trends in 2015 and 2020 parallel those of 2012 and are shown in the appendix to this chapter. Benzene maintains a drop of up to about 6% with increased ethanol use. Formaldehyde remains fairly flat, ranging from a 0.5% increase to a 1.2% decrease. Acetaldehyde maintains an increase of as much as 36.5%. Finally, 1,3-butadiene remains fairly flat, ranging from no change to a 0.5% increase.

Again, we emphasize that the toxics inventories are based on very limited data, especially when it comes to emissions from nonroad equipment.

Table 4.1-7.
National Toxic Emissions from Gasoline Vehicles and Equipment in 2012: Reference Case Inventory and Change in Inventory for Control (Tons/Year)

Primary Case	Benzene	1,3-Butadiene	Formaldehyde	Acetaldehyde
Total				
Reference	178,000	18,900	40,400	19,900
RFS Case (Change)	-3,200	-200	-600	3,400
EIA Case (Change)	-7,200	-300	-200	7,100
Onroad				
Reference	124,100	12,000	29,900	15,500
RFS Case (Change)	-2,300	-200	-600	2,400
EIA Case (Change)	-5,400	-200	-300	5,400
Nonroad				
Reference	53,900	6,900	10,500	4,400
RFS Case (Change)	-900	0	0	1,000
EIA Case (Change)	-1,800	-100	100	1,700

4.1.3.2 Emission Inventories: Sensitivity Analyses

This section provides the national emissions inventories for the sensitivity case analyses. Criteria pollutant inventories are included, along with a brief discussion of the trends. See Tables 4A-1 through 4A-7 in the Chapter 4 Appendix for complete sensitivity-case inventories on air toxics and criteria pollutants, as well as the percent changes in inventories from the reference case.

Table 4.1-8 shows ethanol impacts on VOC inventories for each of the three cases of renewable fuel use in years 2012, 2015, and 2020. Where the primary analysis showed total VOC emissions increasing with ethanol use in all cases, the sensitivity analysis shows that total VOC emissions decrease. Onroad emissions decrease in all cases, while nonroad emissions increase to the same extent as under the primary analysis.

Table 4.1-8.
National VOC Emissions from Gasoline Vehicles and Equipment: Reference Case Inventory and Change in Inventory for Control Cases (Tons/Year)

Sensitivity Case	Tons/Year		
Total	**2012**	**2015**	**2020**
Reference	5,834,000	5,510,000	5,281,000
RFS Case (Change)	-20,000	-23,000	-27,000
EIA Case (Change)	-4,000	-10,000	-17,000
On-Road	**2012**	**2015**	**2020**
Reference	3,369,000	3,210,000	3,169,000
RFS Case (Change)	-28,000	-32,000	-38,000
EIA Case (Change)	-15,000	-23,000	-33,000
Non-Road	**2012**	**2015**	**2020**
Reference	2,465,000	2,300,000	2,112,000
RFS Case (Change)	8,000	9,000	11,000
EIA Case (Change)	11,000	13,000	16,000

Table 4.1-9 shows ethanol impacts on CO inventories for each of the three cases of renewable fuel use in years 2012, 2015, and 2020. In any given year, the data suggest that total CO emissions will decrease as ethanol use increases. The onroad vehicle CO emission reductions increase by roughly a factor of three compared to the primary analysis. This increases the overall CO emissions reduction from about 3% in the primary case to 4% in the sensitivity case.

Table 4.1-9.
National CO Emissions from Gasoline Vehicles and Equipment: Reference Case Inventory and Change in Inventory for Control Cases (Tons/Year)

Sensitivity Case	Tons/Year		
Total	**2012**	**2015**	**2020**
Reference	54,315,000	52,998,000	53,183,000
RFS Case (Change)	-692,000	-676,000	-676,000
EIA Case (Change)	-1,975,000	-1,929,000	-1,937,000
On-Road	**2012**	**2015**	**2020**
Reference	36,949,000	35,467,000	34,957,000
RFS Case (Change)	-254,000	-242,000	-235,000
EIA Case (Change)	-968,000	-921,000	-903,000
Non-Road	**2012**	**2015**	**2020**
Reference	17,366,000	17,531,000	18,226,000
RFS Case (Change)	-438,000	-434,000	-441,000
EIA Case (Change)	-1,007,000	-1,008,000	-1,034,000

Table 4.1-10 shows ethanol impacts on NOx inventories for each of the three cases of renewable fuel use in years 2012, 2015, and 2020. In any given year, the data suggest that total NOx emissions will increase as ethanol use increases. The largest increase is seen in the EIA case, where the increase in total emissions is as high as 4.6% of the reference inventory. As in

the primary analysis, nonroad NOx emissions increase much greater than onroad emissions. While onroad inventories increase up to 3.5%, nonroad inventories increase upwards of 11.1% in the EIA case.

Table 4.1-10.
National NOx Emissions from Gasoline Vehicles and Equipment:
Reference Case Inventory and Change in Inventory for Control Cases (Tons/Year)

Sensitivity Case	Tons/Year		
Total	**2012**	**2015**	**2020**
Reference	2,519,000	2,087,000	1,717,000
RFS Case (Change)	68,000	57,000	48,000
EIA Case (Change)	106,000	91,000	79,000
On-Road	**2012**	**2015**	**2020**
Reference	2,272,000	1,825,000	1,429,000
RFS Case (Change)	54,000	42,000	31,000
EIA Case (Change)	79,000	62,000	47,000
Non-Road	**2012**	**2015**	**2020**
Reference	247,000	262,000	288,000
RFS Case (Change)	14,000	15,000	17,000
EIA Case (Change)	27,000	29,000	32,000

Table 4.1-11 shows ethanol impacts on air toxic emissions for each of the five cases of renewable fuel use in 2012. The impacts in 2015 and 2020 are shown in the Appendix to this chapter.

Table 4.1-11.
National Toxic Emissions from Gasoline Vehicles and Equipment in 2012:
Reference Case Inventory and Change in Inventory for Control (Tons/Year)

Sensitivity Case	**Benzene**	**1,3-Butadiene**	**Formaldehyde**	**Acetaldehyde**
Total				
Reference Case	175,700	18,600	39,600	19,500
RFS Case (Change)	-5,000	-400	-1,100	3,000
EIA Case (Change)	-9,400	-600	-700	6,600
Onroad				
Reference Case	121,800	11,700	29,100	15,100
RFS Case (Change)	-4,100	-400	-1,100	2,000
EIA Case (Change)	-7,600	-500	-800	4,900
Nonroad				
Reference Case	53,900	6,900	10,500	4,400
RFS Case (Change)	-900	0	0	1,000
EIA Case (Change)	-1,800	-100	100	1,700

As in the primary analysis, the most extreme changes in the sensitivity analysis tend to occur in the EIA case.

The data suggest that, in 2012, total benzene emissions will decrease by as much as 5.4% due to decreases in both onroad and nonroad emissions. Total formaldehyde emissions decrease by up to 2.8%. Nonroad formaldehyde emissions tend to remain relatively flat, while onroad emissions decrease. Total acetaldehyde emissions increase by as much as 34% due to increases in both onroad and nonroad emissions. Total 1,3-butadiene emissions decrease by about 3%.

4.1.3.3 Local and Regional VOC and NOx Emissions (Summer 2015)

We also estimate the percentage change in VOC, NOx, and CO emissions from gasoline fueled motor vehicles and equipment in those areas which actually experienced a significant change in ethanol use. Specifically, we focused on areas where the market share of ethanol blends was projected to change by 50 percent or more. We also focused on summertime emissions, as these are most relevant to ozone formation as discussed in Chapter 5. We modeled 2015 because the ozone Response Surface Model (RSM) used for air quality modeling (also discussed in Chapter 5) is based upon a 2015 emissions inventory, though we would expect similar results in 2012. Finally, we developed separately estimates for: 1) RFG areas, including the state of California and the portions of Arizona where their CBG fuel programs apply, 2) low RVP areas (i.e., RVP standards less than 9.0 RVP, and 3) areas with a 9.0 RVP standard. This set of groupings helps to highlight the emissions impact of increased ethanol use in those areas where emission control is most important.

Table 4.1-12 presents our primary analysis estimates of the percentage change in VOC, NOx, and CO emission inventories for these three types of areas when compared to the 2015 reference case. Note that the analyses here is very similar to that described in Section 5.1, with the exception that Table 4.1-12 below reflects 50-state emissions (instead of 37 eastern states) and excludes diesel emissions.

Table 4.1-12.
Change in July 2015 Emissions from Gasoline Vehicles and Equipment in Counties Where Ethanol Use Changed Significantly – Primary Analysis

Ethanol Use	RFS Case	EIA Case
	RFG Areas	
Ethanol Use	Down	Up
VOC	0.8%	2.3%
NOx	-3.4%	1.6%
CO	6.1%	-2.6%
	Low RVP Areas	
Ethanol Use	Up	Up
VOC	4.2%	4.6%
NOx	6.2%	5.7%
CO	-12.5%	-13.7%
	Other Areas (9.0 RVP)	
Ethanol Use	Up	Up
VOC	3.6%	4.6%
NOx	7.3%	7.0%
CO	-6.4%	-6.0%

As expected, increased ethanol use tends to increase NOx emissions. The increase in low RVP and other areas is greater than in RFG areas, since the RFG in the RFG areas included in this analysis all contained MTBE. Also, increased ethanol use tends to increase VOC emissions, indicating that the increase in non-exhaust VOC emissions exceeds the reduction in exhaust VOC emissions. This effect is muted with RFG due to the absence of an RVP waiver for ethanol blends. See Chapter 2 for a discussion of how ethanol levels will change at the state-level.

Table 4.1-13 presents the percentage change in VOC, NOx, and CO emission inventories under our sensitivity analysis (i.e., when we apply the emission effects of the EPA Predictive Models to all motor vehicles).

Table 4.1-13.
Change in July 2015 Emissions from Gasoline Vehicles and Equipment in Counties Where Ethanol Use Changed Significantly – Sensitivity Analysis

Ethanol Use	RFS Case	EIA Case
	RFG Areas	
Ethanol Use	Down	Up
VOC	-1.0%	1.0%
NOx	-0.9%	5.6%
CO	7.3%	-3.0%
	Low RVP Areas	
Ethanol Use	Up	Up
VOC	3.4%	3.7%
NOx	10.4%	10.8%
CO	-15.0%	-16.4%
	Other Areas (9.0 RVP)	
Ethanol Use	Up	Up
VOC	3.0%	3.9%
NOx	10.8%	11.0%
CO	-9.0%	-8.9%

Directionally, the changes in VOC and NOx emissions in the various areas are consistent with those from our primary analysis. The main difference is that the increases in VOC emissions are smaller, due to more vehicles experiencing a reduction in exhaust VOC emissions, and the increases in NOx emissions are larger.

4.2 Impact of Biodiesel Use

As discussed in Chapter 1, biodiesel use totaled 25 million gallons in 2004 and is projected to increase to 300 million gallons in 2012. Total diesel fuel use in onroad diesels in 2004 was roughly 39.4 billion gallons and is expected to grow to 47.5 billion gallons per year by 2012.[54] The volumes of biodiesel produced thus represent 0.06% and 0.6% of onroad diesel fuel

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[54] Based on linear interpolation between estimate for 2001 from Table 7.1.2-1 and that for 2014 from Table 7.1.3-4, both from the 2010 Nonroad FRM Final RIA, EPA420-R-04-007, May 2004, available in EPA Docket OAR-2003-0012.

consumption in 2004 and 2012, respectively. Given the very small contribution of biodiesel to the pool of diesel fuel, the nationwide emission impacts of biodiesel are expected to be similarly small for the foreseeable future. As a result, we have not included biodiesel emission impacts in our emission inventory estimates for this rule.

We do intend to investigate these impacts in the future, however. As stated in Chapter 3, the 2002 EPA report entitled "A Comprehensive Analysis of Biodiesel Impacts on Exhaust Emissions" concluded that biodiesel fuels improved PM, CO and HC emissions of diesel engines while slightly increasing their NOx emissions. Nevertheless, these conclusions remain controversial due to conflicting results from different studies. As a result, preparations are being made to launch a test program with stakeholder participation to further investigate the emission impacts of biodiesel.

4.3 Impact of Renewable Fuel Production and Distribution

4.3.1 Ethanol

In Chapter 2, we estimated that 3.5 billion gallons of ethanol was produced for use in motor fuel in 2004, which comprises our estimate of fuel quality for the base case . Maintaining fuel quality, but increasing fuel volume to that expected in 2012,[55] ethanol use would increase to 3.9 billion gallons. The increases in emissions associated with ethanol production and distribution under the RFS and EIA cases are, thus, determined relative to the emissions associated with producing and distributing 3.9 billion gallons of ethanol.

We describe the emissions associated with producing and distributing ethanol on a per gallon basis in Chapter 3.4.1. There, we compare emissions factors from DOE's GREET model, versions 1.6 and 1.7, as well as estimates of ethanol plant emissions obtained from the States. We decided there to use two emission estimates here, one from GREET1.7, and the other from GREET1.7 augmented by the State estimates for ethanol plant emissions. Here, we simply multiply those emission factors by the volume of ethanol being used in each scenario. Table 4.3-1 shows estimates of annual emissions expected to occur nationwide due to increased production of ethanol. It should be noted that emissions in the base case assume a 80/20 mix of dry mill and wet mill facilities. New plants (and thus, the emission increases) assume 100% dry mil facilities.

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[55] EIA projects gasoline demand of 16.93 and 18.84 quadrillion Btu in 2004 and 2012, respectively. This represents overall growth between these two years of 11.3%.

Table 4.3-1.
Annual Emissions Nationwide from Ethanol Production and Transportation: 2012
(tons per year)

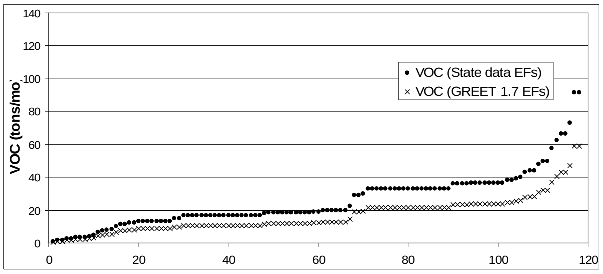
	GREET1.7			GREET1.7 + State Data		
	Base Case	RFS Case	EIA Case	Base Case	RFS Case	EIA Case
	Emissions	Increase in Emissions		Emissions	Increase in Emissions	
VOC	8,000	5,000	11,000	14,000	10,000	20,000
NOx	17,000	13,000	26,000	18,000	14,000	27,000
CO	49,000	35,000	72,000	56,000	40,000	81,000
PM10	21,000	15,000	30,000	12,000	9,000	18,000
SOx	27,000	20,000	41,000	42,000	30,000	61,000

As can be seen, the potential increases in VOC and NOx emissions from ethanol production and transportation are of the same order of magnitude as those from ethanol use. Generally, ethanol plants are not located in ozone non-attainment areas, so the ozone impact of the increased VOC and NOx emissions should be minimal.

According to our estimates, almost 120 counties throughout the nation are constructing new ethanol plants, expanding existing plants, or planning construction for future plants. The increases in ethanol production across these counties range from as low as 2 million gallons per year for modest expansions, to over 270 million gallons per year due to the construction of entirely new facilities. To estimate the potential increase in VOC and NOx emissions associated with these plants, whether construction is planned or underway, we apply the ethanol production emission factors (EFs) derived from state data as well as those found in GREET 1.7. See Chapter 3.4 for a discussion of the emission factors related to ethanol production and plant emissions.

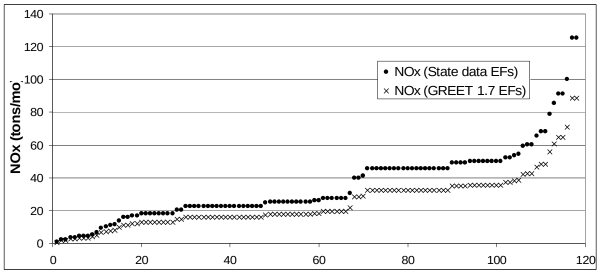
The ethanol production emission factors are applied to the increase in the volume of ethanol production expected in each of the counties. Figures 4.3-1 and 4.3-2 illustrate potential increases in future monthly VOC and NOx emissions, respectively, in counties that can expect a growth in ethanol production. The emissions reflect plants operating for one month at 90% capacity. In each figure, the distribution of counties is presented in order from the lowest-to-highest increase in ethanol production volume. The figures show results based upon both state-based emission factors and GREET 1.7 emission factors.

Figure 4.3-1.
Monthly VOC Emissions in Counties Expecting an Increase in Ethanol Production



Distribution of Counties
(in order of increasing ethanol production)

Figure 4.3-2.
Monthly NOx Emissions in Counties Expecting an Increase in Ethanol Production



Distribution of Counties
(in order of increasing ethanol production)

As the figures indicate, most counties will see an increase of less than 40 tons/month VOC and less than 60 tons/month NOx, according to the distribution based upon the state data emission factors. The average emissions are about 26 tons/month VOC and 35 tons/month NOx using state data, and about 17 tons/month VOC and 25 tons/month NOx using GREET 1.7 emission factors. However, average VOC and NOx emissions increase to about 61 tons/month and 83 tons/month, respectively, in the 10% of counties expecting largest increases in ethanol production. The average emissions for the remaining 90% of counties is about 21 tons/month VOC and 29 tons/month NOx. For both VOC and NOx, emissions estimates are about 35% less when using the GREET 1.7 emission factors.

4.3.2 Biodiesel

In Chapter 1, we estimated that 25 million gallons of biodiesel were produced for use in motor fuel in 2004. Based on growth in overall diesel fuel demand between 2004 and 2012,[56] this would represent the equivalent of 30 million gallons of biodiesel in 2012 for our reference case. Here, we estimate the increase in emissions which will occur with an increase in biodiesel production and distribution from 30 million gallons to 300 million gallons per year.

We describe the emissions associated with producing and distributing biodiesel on a per gallon basis in Chapter 3. Here, we simply multiply those emission factors by the volume of biodiesel being used in each scenario. Table 4.3-2 shows estimates of annual emissions expected to occur nationwide due to increased production of biodiesel.

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[56] EIA projects gasoline demand of 16.93 and 18.84 quadrillion Btu in 2004 and 2012, respectively. This represents overall growth between these two years of 11.3%. Source: Annual Energy Outlook 2006, DOE/EIA-0383(2006), Reference Case Table 2, available in docket EPA-HQ-OAR-2005-0161.

Table 4.3-2.
Annual Emissions Nationwide from Biodiesel Production and Transportation: 2012 (tons per year)

	Reference Inventory: 28 mill gal biodiesel per year	Increase in Emissions: 300 mill gal biodiesel per year
VOC	1,400	14,000
NOx	1,500	15,000
CO	800	8,000
PM10	50	500
SOx	250	2,500

As can be seen, the potential increases in emissions from biodiesel production and transportation are of the same order of magnitude as those from biodiesel use, with the exception of CO emissions. Generally, biodiesel plants are not located in ozone non-attainment areas, so the ozone impact of the increased VOC and NOx emissions should be minimal.

4.4 Total Emission Impacts of Renewable Fuel Production and Use

Tables 4.4-1 and 4.4-2 combine the VOC, CO and NOx emission impacts for ethanol use from Section 4.1 and renewable fuel production and distribution from Section 4.3. Table 4.4-1 includes the emission impacts from gasoline vehicles and equipment under our primary analysis and renewable fuel production and distribution from GREET1.7. Table 4.4-2 includes the emission impacts from gasoline vehicles and equipment under our sensitivity analysis and renewable fuel production and distribution from GREET1.7 augmented with the State data for ethanol production plants. Emissions from renewable fuel production and distribution in 2012 were increased by 1.9% per year to account for growth in gasoline and diesel fuel demand.

Table 4.4-1.
National Emissions from Gasoline Vehicles and Equipment and Renewable Fuel Production and Distribution: Primary Case and GREET1.7 (Tons/Year)

	Tons/Year		
VOC Emissions	**2012**	**2015**	**2020**
Reference	5,891,000	5,578,513	5,366,368
RFS Case (Change)	33,000	41,969	51,584
EIA Case (Change)	63,000	71,311	83,496
CO Emissions	**2012**	**2015**	**2020**
Reference	3,467,000	3,321,850	3,301,600
RFS Case (Change)	50,000	58,337	69,232
EIA Case (Change)	108,000	116,446	130,856
NOx Emissions	**2012**	**2015**	**2020**
Reference	2,483,000	2,319,026	2,132,736
RFS Case (Change)	33,000	36,482	39,952
EIA Case (Change)	38,000	42,596	48,256

Table 4.4-2.
National Emissions from Gasoline Vehicles and Equipment and Renewable Fuel Production and Distribution: Sensitivity Case and GREET1.7/State Data (Tons/Year)

	Tons/Year		
VOC Emissions	**2012**	**2015**	**2020**
Reference	5,849,000	5,525,855	5,298,280
RFS Case (Change)	-1,000	-746	-3,656
EIA Case (Change)	25,000	22,824	18,864
CO Emissions	**2012**	**2015**	**2020**
Reference	3,426,000	3,270,249	3,234,664
RFS Case (Change)	16,000	15,622	13,992
EIA Case (Change)	70,000	67,959	66,224
NOx Emissions	**2012**	**2015**	**2020**
Reference	2,484,000	2,320,083	2,133,888
RFS Case (Change)	34,000	37,539	41,104
EIA Case (Change)	50,000	55,280	62,080

Chapter 4: Appendix

Table 4A-1. VOC Emission Inventories under Various Ethanol Use Cases

Primary	Tons/Year			Change from Reference (tons)			% Change from Reference		
Total	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	5,882,000	5,569,000	5,356,000	--	--	--	--	--	--
RFS Case	5,900,000	5,594,000	5,390,000	18,000	25,000	34,000	0.3%	0.4%	0.6%
EIA Case	5,925,000	5,618,000	5,414,000	43,000	49,000	58,000	0.7%	0.9%	1.1%
On-Road	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	3,417,000	3,269,000	3,244,000	--	--	--	--	--	--
RFS Case	3,427,000	3,285,000	3,267,000	10,000	16,000	23,000	0.3%	0.5%	0.7%
EIA Case	3,449,000	3,305,000	3,286,000	32,000	36,000	42,000	0.9%	1.1%	1.3%
Non-Road	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	2,465,000	2,300,000	2,112,000	--	--	--	--	--	--
RFS Case	2,473,000	2,309,000	2,123,000	8,000	9,000	11,000	0.3%	0.4%	0.5%
EIA Case	2,476,000	2,313,000	2,128,000	11,000	13,000	16,000	0.4%	0.6%	0.8%

Sensitivity	Tons/Year								
Total	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	5,834,000	5,510,000	5,281,000	--	--	--	--	--	--
RFS Case	5,814,000	5,487,000	5,254,000	-20,000	-23,000	-27,000	-0.3%	-0.4%	-0.5%
EIA Case	5,830,000	5,500,000	5,264,000	-4,000	-10,000	-17,000	-0.1%	-0.2%	-0.3%
On-Road	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	3,369,000	3,210,000	3,169,000	--	--	--	--	--	--
RFS Case	3,341,000	3,178,000	3,131,000	-28,000	-32,000	-38,000	-0.8%	-1.0%	-1.2%
EIA Case	3,354,000	3,187,000	3,136,000	-15,000	-23,000	-33,000	-0.4%	-0.7%	-1.0%
Non-Road	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	2,465,000	2,300,000	2,112,000	--	--	--	--	--	--
RFS Case	2,473,000	2,309,000	2,123,000	8,000	9,000	11,000	0.3%	0.4%	0.5%
EIA Case	2,476,000	2,313,000	2,128,000	11,000	13,000	16,000	0.4%	0.6%	0.8%

Table 4A-2. CO Emission Inventories under Various Ethanol Use Cases

Primary	Tons/Year			Change from Reference (tons)			% Change from Reference		
Total	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	55,022,000	53,702,000	53,949,000	--	--	--	--	--	--
RFS Case	54,539,000	53,229,000	53,489,000	-483,000	-473,000	-460,000	-0.9%	-0.9%	-0.9%
EIA Case	53,656,000	52,373,000	52,663,000	-1,366,000	-1,329,000	-1,286,000	-2.5%	-2.5%	-2.4%
On-Road	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	37,656,000	36,171,000	35,723,000	--	--	--	--	--	--
RFS Case	37,611,000	36,132,000	35,704,000	-45,000	-39,000	-19,000	-0.1%	-0.1%	-0.1%
EIA Case	37,297,000	35,850,000	35,471,000	-359,000	-321,000	-252,000	-1.0%	-0.9%	-0.7%
Non-Road	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	17,366,000	17,531,000	18,226,000	--	--	--	--	--	--
RFS Case	16,928,000	17,097,000	17,785,000	-438,000	-434,000	-441,000	-2.5%	-2.5%	-2.4%
EIA Case	16,359,000	16,523,000	17,192,000	-1,007,000	-1,008,000	-1,034,000	-5.8%	-5.7%	-5.7%

Sensitivity	Tons/Year								
Total	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	54,315,000	52,998,000	53,183,000	--	--	--	--	--	--
RFS Case	53,623,000	52,322,000	52,507,000	-692,000	-676,000	-676,000	-1.3%	-1.3%	-1.3%
EIA Case	52,340,000	51,069,000	51,246,000	-1,975,000	-1,929,000	-1,937,000	-3.6%	-3.6%	-3.6%
On-Road	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	36,949,000	35,467,000	34,957,000	--	--	--	--	--	--
RFS Case	36,695,000	35,225,000	34,722,000	-254,000	-242,000	-235,000	-0.7%	-0.7%	-0.7%
EIA Case	35,981,000	34,546,000	34,054,000	-968,000	-921,000	-903,000	-2.6%	-2.6%	-2.6%
Non-Road	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	17,366,000	17,531,000	18,226,000	--	--	--	--	--	--
RFS Case	16,928,000	17,097,000	17,785,000	-438,000	-434,000	-441,000	-2.5%	-2.5%	-2.4%
EIA Case	16,359,000	16,523,000	17,192,000	-1,007,000	-1,008,000	-1,034,000	-5.8%	-5.7%	-5.7%

Table 4A-3. NOx Emission Inventories under Various Ethanol Use Cases

Primary	Tons/Year			Change from Reference (tons)			% Change from Reference		
Total	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	2,487,000	2,059,000	1,695,000	--	--	--	--	--	--
RFS Case	2,510,000	2,077,000	1,712,000	23,000	18,000	17,000	0.9%	0.9%	1.0%
EIA Case	2,527,000	2,092,000	1,727,000	40,000	33,000	32,000	1.6%	1.6%	1.9%
On-Road	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	2,240,000	1,797,000	1,407,000	--	--	--	--	--	--
RFS Case	2,249,000	1,800,000	1,407,000	9,000	3,000	0	0.4%	0.2%	0.0%
EIA Case	2,253,000	1,801,000	1,407,000	13,000	4,000	0	0.6%	0.2%	0.0%
Non-Road	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	247,000	262,000	288,000	--	--	--	--	--	--
RFS Case	261,000	277,000	305,000	14,000	15,000	17,000	5.7%	5.7%	5.9%
EIA Case	274,000	291,000	320,000	27,000	29,000	32,000	10.9%	11.1%	11.1%

Sensitivity	Tons/Year			Change from Reference (tons)			% Change from Reference		
Total	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	2,519,000	2,087,000	1,717,000	--	--	--	--	--	--
RFS Case	2,587,000	2,144,000	1,765,000	68,000	57,000	48,000	2.7%	2.7%	2.8%
EIA Case	2,625,000	2,178,000	1,796,000	106,000	91,000	79,000	4.2%	4.4%	4.6%
On-Road	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	2,272,000	1,825,000	1,429,000	--	--	--	--	--	--
RFS Case	2,326,000	1,867,000	1,460,000	54,000	42,000	31,000	2.4%	2.3%	2.2%
EIA Case	2,351,000	1,887,000	1,476,000	79,000	62,000	47,000	3.5%	3.4%	3.3%
Non-Road	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	247,000	262,000	288,000	--	--	--	--	--	--
RFS Case	261,000	277,000	305,000	14,000	15,000	17,000	5.7%	5.7%	5.9%
EIA Case	274,000	291,000	320,000	27,000	29,000	32,000	10.9%	11.1%	11.1%

Table 4A-4. Benzene Emission Inventories under Various Ethanol Use Cases

Primary	Tons/Year			Change from Reference (tons)			% Change from Reference		
Total	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	178,000	175,400	179,900	--	--	--	--	--	--
RFS Case	174,800	164,800	178,200	-3,200	-10,600	-1,700	-1.8%	-6.0%	-0.9%
EIA Case	170,800	169,100	174,200	-7,200	-6,300	-5,700	-4.0%	-3.6%	-3.2%
On-Road	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	124,100	124,200	130,600	--	--	--	--	--	--
RFS Case	121,800	122,600	129,400	-2,300	-1,600	-1,200	-1.9%	-1.3%	-0.9%
EIA Case	118,700	119,400	126,100	-5,400	-4,800	-4,500	-4.4%	-3.9%	-3.4%
Non-Road	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	53,900	51,200	49,300	--	--	--	--	--	--
RFS Case	53,000	42,200	48,800	-900	-9,000	-500	-1.7%	-17.6%	-1.0%
EIA Case	52,100	49,700	48,100	-1,800	-1,500	-1,200	-3.3%	-2.9%	-2.4%

Sensitivity	Tons/Year								
Total	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	175,700	172,700	176,500	--	--	--	--	--	--
RFS Case	170,700	168,000	171,900	-5,000	-4,700	-4,600	-2.8%	-2.7%	-2.6%
EIA Case	166,300	163,600	167,200	-9,400	-9,100	-9,300	-5.4%	-5.3%	-5.3%
On-Road	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	121,800	121,500	127,200	--	--	--	--	--	--
RFS Case	117,700	117,500	123,100	-4,100	-4,000	-4,100	-3.4%	-3.3%	-3.2%
EIA Case	114,200	113,900	119,100	-7,600	-7,600	-8,100	-6.2%	-6.3%	-6.4%
Non-Road	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	53,900	51,200	49,300	--	--	--	--	--	--
RFS Case	53,000	50,500	48,800	-900	-700	-500	-1.7%	-1.4%	-1.0%
EIA Case	52,100	49,700	48,100	-1,800	-1,500	-1,200	-3.3%	-2.9%	-2.4%

Table 4A-5. Acetaldehyde Emission Inventories under Various Ethanol Use Cases

Primary	Tons/Year			Change from Reference (tons)			% Change from Reference		
Total	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	19,900	20,000	21,100	--	--	--	--	--	--
RFS Case	23,300	23,400	24,700	3,400	3,400	3,600	17.1%	17.0%	17.1%
EIA Case	27,000	27,300	28,800	7,100	7,300	7,700	35.7%	36.5%	36.5%
On-Road	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	15,500	15,800	17,000	--	--	--	--	--	--
RFS Case	17,900	18,300	19,800	2,400	2,500	2,800	15.5%	15.8%	16.5%
EIA Case	20,900	21,500	23,300	5,400	5,700	6,300	34.8%	36.1%	37.1%
Non-Road	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	4,400	4,200	4,100	--	--	--	--	--	--
RFS Case	5,400	5,100	4,900	1,000	900	800	22.7%	21.4%	19.5%
EIA Case	6,100	5,800	5,500	1,700	1,600	1,400	38.6%	38.1%	34.1%

Sensitivity	Tons/Year								
Total	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	19,500	19,500	20,400	--	--	--	--	--	--
RFS Case	22,500	22,400	23,400	3,000	2,900	3,000	15.4%	14.9%	14.7%
EIA Case	26,100	26,100	27,200	6,600	6,600	6,800	33.8%	33.8%	33.3%
On-Road	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	15,100	15,300	16,300	--	--	--	--	--	--
RFS Case	17,100	17,300	18,500	2,000	2,000	2,200	13.2%	13.1%	13.5%
EIA Case	20,000	20,300	21,700	4,900	5,000	5,400	32.5%	32.7%	33.1%
Non-Road	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	4,400	4,200	4,100	--	--	--	--	--	--
RFS Case	5,400	5,100	4,900	1,000	900	800	22.7%	21.4%	19.5%
EIA Case	6,100	5,800	5,500	1,700	1,600	1,400	38.6%	38.1%	34.1%

Table 4A-6. Formaldehyde Emission Inventories under Various Ethanol Use Cases

Primary	Tons/Year			Change from Reference (tons)			% Change from Reference		
Total	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	40,400	40,100	41,400	--	--	--	--	--	--
RFS Case	39,800	39,600	41,200	-600	-500	-200	-1.5%	-1.2%	-0.5%
EIA Case	40,200	40,100	41,600	-200	0	200	-0.5%	0.0%	0.5%
On-Road	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	29,900	30,100	32,000	--	--	--	--	--	--
RFS Case	29,300	29,700	31,800	-600	-400	-200	-2.0%	-1.3%	-0.6%
EIA Case	29,600	30,100	32,200	-300	0	200	-1.0%	0.0%	0.6%
Non-Road	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	10,500	10,000	9,400	--	--	--	--	--	--
RFS Case	10,500	9,900	9,400	0	-100	0	0.0%	-1.0%	0.0%
EIA Case	10,600	10,000	9,400	100	0	0	1.0%	0.0%	0.0%

Sensitivity	Tons/Year								
Total	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	39,600	39,200	40,300	--	--	--	--	--	--
RFS Case	38,500	38,100	39,200	-1,100	-1,100	-1,100	-2.8%	-2.8%	-2.7%
EIA Case	38,900	38,400	39,500	-700	-800	-800	-1.8%	-2.0%	-2.0%
On-Road	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	29,100	29,200	30,900	--	--	--	--	--	--
RFS Case	28,000	28,200	29,800	-1,100	-1,000	-1,100	-3.8%	-3.4%	-3.6%
EIA Case	28,300	28,400	30,100	-800	-800	-800	-2.7%	-2.7%	-2.6%
Non-Road	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	10,500	10,000	9,400	--	--	--	--	--	--
RFS Case	10,500	9,900	9,400	0	-100	0	0.0%	-1.0%	0.0%
EIA Case	10,600	10,000	9,400	100	0	0	1.0%	0.0%	0.0%

Table 4A-7. 1,3-Butadiene Emission Inventories under Various Ethanol Use Cases

Primary	Tons/Year			Change from Reference (tons)			% Change from Reference		
Total	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	18,900	18,500	19,100	--	--	--	--	--	--
RFS Case	18,700	18,600	19,100	-200	100	0	-1.1%	0.5%	0.0%
EIA Case	18,600	18,500	19,100	-300	0	0	-1.6%	0.0%	0.0%
On-Road	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	12,000	12,000	12,800	--	--	--	--	--	--
RFS Case	11,800	12,000	12,800	-200	0	0	-1.7%	0.0%	0.0%
EIA Case	11,800	12,000	12,800	-200	0	0	-1.7%	0.0%	0.0%
Non-Road	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	6,900	6,500	6,300	--	--	--	--	--	--
RFS Case	6,900	6,600	6,300	0	100	0	0.0%	1.5%	0.0%
EIA Case	6,800	6,500	6,300	-100	0	0	-1.4%	0.0%	0.0%

Sensitivity	Tons/Year								
Total	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	18,600	18,200	18,700	--	--	--	--	--	--
RFS Case	18,200	18,000	18,300	-400	-200	-400	-2.2%	-1.1%	-2.1%
EIA Case	18,000	17,800	18,200	-600	-400	-500	-3.2%	-2.2%	-2.7%
On-Road	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	11,700	11,700	12,400	--	--	--	--	--	--
RFS Case	11,300	11,400	12,000	-400	-300	-400	-3.4%	-2.6%	-3.2%
EIA Case	11,200	11,300	11,900	-500	-400	-500	-4.3%	-3.4%	-4.0%
Non-Road	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	6,900	6,500	6,300	--	--	--	--	--	--
RFS Case	6,900	6,600	6,300	0	100	0	0.0%	1.5%	0.0%
EIA Case	6,800	6,500	6,300	-100	0	0	-1.4%	0.0%	0.0%

Chapter 5: Air Quality Impacts

5.1 Ozone

We performed ozone air quality modeling simulations for the eastern United States using the ozone Response Surface Model (RSM) to estimate the effects of the projected changes in emissions from gasoline vehicles and equipment. The ozone RSM is a screening-level air quality modeling tool that allows users to quickly assess the estimated air quality changes over the modeling domain. The ozone RSM is a model of a full-scale air quality model and is based on statistical relationships between model inputs and outputs obtained from the full-scale air quality model. In other words, the ozone RSM uses statistical techniques to relate a response variable to a set of factors that are of interest, e.g., emissions of precursor pollutants from particular sources and locations. The following section describes the modeling methodology, including the development of the multi-dimensional experimental design for control strategies and implementation and verification of the RSM technique. Additional detail is available in the Air Quality Modeling Technical Support Document (AQMTSD) that was drafted for the Mobile Source Air Toxics Rule Proposal (published March 29, 2006).[AAAA]

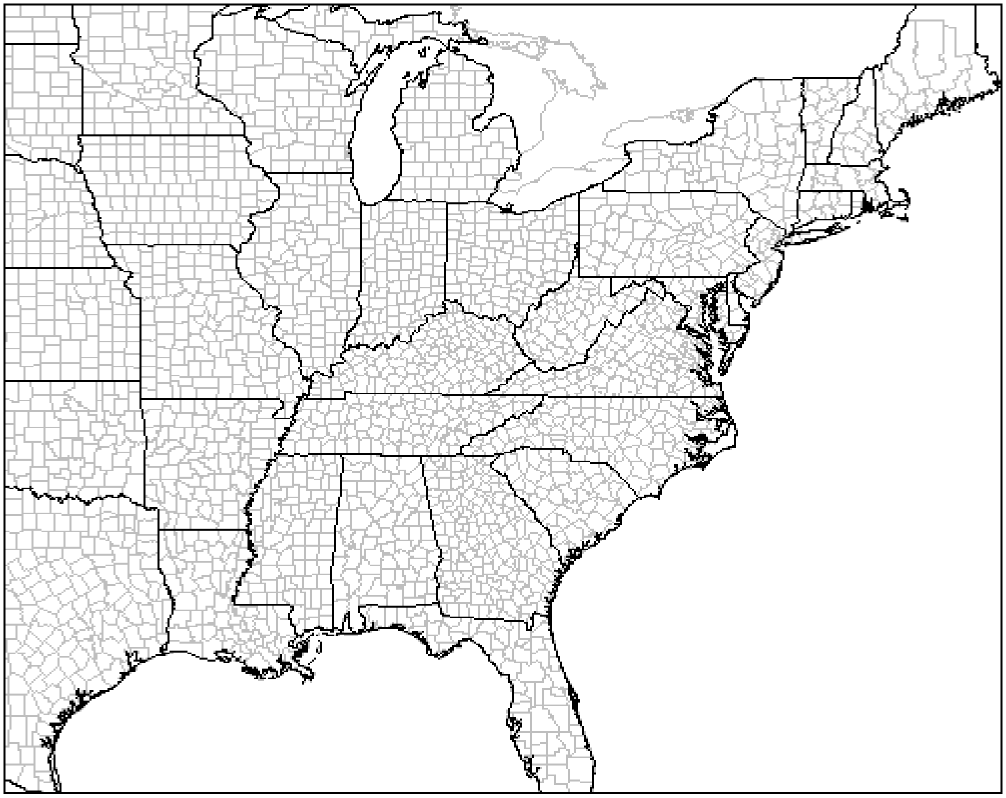
The foundation for the ozone response surface metamodeling analyses was the CAMx modeling done in support of the final Clean Air Interstate Rule (CAIR). The CAIR modeling is fully described in the CAIR Air Quality Modeling Technical Support Document, but a brief description is provided below.[BBBB] The modeling procedures used in the CAIR analysis (e.g., domain, episodes, meteorology) have been used for several EPA rulemaking analyses over the past five years and are well-established at this point.

The ozone RSM uses the 2015 controlled CAIR emissions inventory as its baseline, assuming future fuel quality remains unchanged from pre-Act levels, which serves as the baseline for the analysis of the final RFS standards.[CCCC] We then compare these baseline emissions to the emissions which would have occurred in the future if fuel quality had remained unchanged from pre-Act levels to those which will occur with fuel quality reflecting the increased renewable fuel use projected in the future. This approach differs from that traditionally taken in EPA regulatory impact analyses. Traditionally, we would have compared future emissions with and without the requirement of the Act. However, as described in Chapter 1, we expect that total renewable fuel use in the U.S. in 2012 to exceed 7.5 billion gallons even in the absence of the Renewable Fuel Standard (RFS). Thus, a traditional regulatory impact analysis would have shown no impact on emissions or air quality.

The modeling simulations that comprised the metamodeling were conducted using CAMx version 3.10. It should be noted that because the ozone RSM is built from CAMx air quality model runs, it therefore has the same strengths and limitations of the underlying model and its inputs. CAMx is a non-proprietary computer model that simulates the formation and fate of photochemical oxidants including ozone for given input sets of meteorological conditions and emissions. The gridded meteorological data for three historical episodes were developed using the Regional Atmospheric Modeling System (RAMS), version 3b.[DDDD] In all, 30 episode days were modeled using frequently-occurring, ozone-conducive, meteorological conditions from the summer of 1995. Emissions estimates were developed for the evaluation year (1995) as well as a future year (2015).

The CAMx model applications were performed for a domain covering all, or portions of, 37 States (and the District of Columbia) in the Eastern U.S., as shown in Figure 5.1-1. The domain has nested horizontal grids of 36 km and 12 km. However, the output data from the metamodeling is provided at a 12 km resolution (i.e., cells from the outer 36 km cells populate the nine finer scale cells, as appropriate). Although the domain of the ozone RSM is the 37 Eastern states, the expanded use of ethanol in fuel is expected to occur nationwide. Chapter 4 describes the nationwide inventory impacts associated with the F standards.

Figure 5.1-1. Map of the CAMx Domain Used for RFS Ozone Metamodeling



The ozone RSM used for assessing the air quality impacts of expanded ethanol use in fuel was developed broadly to look at various control strategies with respect to attaining the 8-hour ozone NAAQS. The experimental design for the ozone RSM covered three key areas: type of precursor emission (NOx or VOC), emission source type (i.e., onroad vehicles, nonroad vehicles, area sources, electrical generating utility (EGU) sources, and non-utility point sources), and location in or out of a 2015 model-projected residual ozone nonattainment area. This resulted in a set of 14 emissions factors.

The 14 emission factors were randomly varied and used as inputs to CAMx. The experimental design for these 14 factors was developed using a Maximin Latin Hypercube method. Based on a rule of thumb of 10 runs per factor, we developed an overall design with

140 runs (a base case plus 139 control runs). The range of emissions reductions considered within the metamodel ranged from 0 to 120 percent of the 2015 CAIR emissions. This experimental design resulted in a set of CAMx simulations that serve as the inputs to the ozone response surface metamodel.

To develop a response surface approximation to CAMx, we used a multidimensional kriging approach, implemented through the MIXED procedure in SAS. We modeled the predicted changes in ozone in each CAMx grid cell as a function of the weighted average of the modeled responses in the experimental design. A response-surface was then fit for several ozone metrics, namely the ozone design value, the 1-hour maximum value, the 24-hour average value and the average ozone level between 9 am and 5 pm. The effect of changes in VOC and NOx emissions on ozone was estimated in each grid cell covered by the model for each ozone metric except the ozone design value. The ozone design value is the mathematically determined pollutant concentration at a particular monitoring site that must be reduced to, or maintained at or below the National Ambient Air Quality Standard to assume attainment. The 8-hour ozone design value is the 3-year average of the fourth-highest daily maximum 8-hour average ozone concentrations measured at each monitor within an area over each year, which must not exceed 0.08 ppm (85 ppb, considering round-off). Thus, ozone design values only exist for grid cells which contain ozone monitoring stations and where ozone attainment has been an issue. Ozone design values have been developed for 525 of the 2696 counties in the 37 state region. of the 31 these The specific ozone design values used in this analysis are those for 2001, which represent the average of the ozone design values determined for three, three-year periods (1999-2001, 2000-2002, and 2001-2003). Validation was performed and is summarized in the Mobile Source Air Toxics rule Air Quality Modeling Technical Support Document. The validation exercises indicated that the ozone RSM replicates CAMx response to emissions changes very well for most emissions combinations and in most locations.

The ozone RSM limits the number of geographically distinct changes in VOC and NOx emissions which can be simulated. Emissions from motor vehicles and nonroad equipment can be varied separately. Distinct percentage changes in either the motor vehicle or nonroad inventories can also be applied in ozone nonattainment and attainment areas. However, distinct emission impacts cannot be simulated in various ozone nonattainment areas (e.g., Chicago and Houston or New York and Kansas City). This limits our ability to simulate the impact of increased ethanol use in a couple of ways. First, ethanol use is not geographically uniform across the U.S., either currently or in the future. Thus, the emission impacts resulting from changes in ethanol use also varies geographically. Second, the emission impacts of ethanol use are not uniform. Ethanol use in RFG and other areas which do not grant ethanol blends a 1.0 psi RVP waiver will not experience as much of an increase in VOC emissions with increased ethanol use as areas which grant ethanol blends an RVP waiver. Third, the impacts of new ethanol plants will be even more geographically focused. The Ozone RSM cannot generally be applied to model the emission impacts from such local sources for a couple of reasons. One, the location of new ethanol plants is difficult to predict in many cases. Two, the impact of these plants on local emissions can be very large in percentage terms given the absence of a lot of other industrial activity. The Ozone RSM was designed to represent the ozone impact of the same change in VOC or NOx emissions across a broad region (e.g., all attainment areas). Therefore, it cannot be used to model the impact of a large change in one county's emissions without also assuming the same change in the upwind county's emissions. As not every county will contain a new ethanol plant, the assumptions inherent in the Ozone RSM do not match the situation of a new individual point source, such as an ethanol plant.

We developed a methodology which would best approximate the impact of changes in local emissions on the ozone level in each local area, while maintaining as much of the impact of ozone transport from other areas as possible given the above mentioned limitations. We do this by running the ozone RSM twice for each scenario and drawing the resultant ozone impact from the run which best matched the emission impact expected in a particular local area, considering both the change in emissions modeled for that particular local area, as well as that occurring in upwind areas.

First, as mentioned above, ethanol use is expected to change dramatically in some areas, but not at all in others. Averaging the emission impacts across these two types of areas and estimating the associated ozone impact would be very misleading. No area would be likely to experience the ozone impact predicted. Some areas would experience a much greater impact, while others would experience no impact. Therefore, the first step in using the Ozone RSM to predict the ozone impacts related to the RFS is to estimate the change in VOC and NOx emissions in those areas ethanol blend market share changed significantly. As was done in the analysis of local emission impacts presented in Section 4.1.3.3 above, we defined a significant change in ethanol blend market share as a change of 50% or more. This focuses the change in emissions in those areas where the change is likely to occur.

As discussed in Chapters 3 and 4, the effect of ethanol use on emissions differs depending on the baseline fuel quality and the applicable RVP standards. In particular, ethanol use has significantly different impacts on emissions in RFG, low RVP and 9 RVP areas. Therefore, in order to better predict the ozone impact likely to occur in specific areas, we estimate the change in VOC and NOx emissions separately for RFG, low RVP and 9 RVP areas (per above, only for those areas in each case where ethanol blend market share changed by 50% or more).

The Ozone RSM only covers the 37 easternmost states in the U.S. Therefore, we limited the calculation of VOC and NOx emission impacts to only those states. The Ozone RSM was developed with the year 2015 as the default year. Since we develop most of our impacts of the RFS for the year 2012 and 2015, we chose to run the Ozone RSM for, 2015. The Ozone RSM is designed to accept emission changes in terms of total onroad and total nonroad sources, respectively, and both emission categories include diesels. Therefore, we included estimates of VOC and NOx emissions from diesel vehicles and equipment in 2015 in our calculation of the emission impacts. These diesel emissions do not change between the various RFS scenarios. However, they do reduce the effective percentage change in VOC and NOx emissions which is projected to occur. Overall, these analyses are very similar to those described in Section 4.1.3.3 above, with the exceptions of the limitation to 37 states and the inclusion of diesel emissions. The results of these calculations are shown in Table 5.1-1.

Table 5.1-1.
Emission Inputs to Ozone Modeling: Change in Total Mobile Sources Emissions in 37 Eastern States where Ethanol Use Changes Significantly, July 2015 (percent change)

		VOC				NOx			
		On Road		Non Road		On Road		Non Road	
		Attain. (9 RVP)	Non-Attain.	Attain. (9 RVP)	Non-Attain.	Attain. (9 RVP)	Non-Attain.	Attain. (9 RVP)	Non-Attain.
Primary Analysis									
RFS	**RFG**	7.5%	-1.2%	1.5%	1.8%	0.2%	0.1%	3.0%	-1.9%
	LRVP	7.5%	8.9%	1.5%	1.7%	0.2%	0.2%	3.0%	3.3%
EIA	**RFG**	8.2%	1.7%	2.3%	2.4%	0.2%	0.1%	3.2%	0.7%
	LRVP	8.2%	9.3%	2.3%	2.0%	0.2%	0.2%	3.2%	3.3%
Sensitivity Analysis									
RFS	**RFG**	6.0%	-5.3%	1.5%	1.8%	2.9%	1.7%	3.0%	-1.9%
	LRVP	6.0%	7.0%	1.5%	1.7%	2.9%	3.5%	3.0%	3.3%
EIA	**RFG**	6.6%	-1.2%	2.3%	2.4%	3.0%	2.2%	3.2%	0.7%
	LRVP	6.6%	7.4%	2.3%	2.0%	3.0%	3.6%	3.2%	3.3%

Our category of 9 RVP areas is very similar to the set of attainment areas in the Ozone RSM. Therefore, the application of the emission impacts expected in 9 RVP areas in the Ozone RSM was straightforward. However, both RFG and low RVP areas together generally comprise the set of nonattainment areas in the Ozone RSM. As seen in Table 5.1-1, the expected emission impacts of the various RFS scenarios differ significantly depending on whether the area has RFG or low RVP fuel. Both sets of emission impacts could not be run in the Ozone RSM at the same time. Therefore, we ran the Ozone RSM twice. The first run applied the emission impacts estimated for RFG areas to the ozone nonattainment areas in the Ozone RSM and applied the emission impacts for 9.0 RVP areas to the ozone attainment areas in the Ozone RSM. This run should produce satisfactory projections of ozone impacts for all areas except those areas with low RVP, as well as those areas where ethanol use is not expected to change.

The second run applied the emission impacts estimated for Low RVP areas to the ozone nonattainment areas in the Ozone RSM and applied the emission impacts for 9.0 RVP areas to the ozone attainment areas in the Ozone RSM. This run should produce satisfactory projections of ozone impacts for all areas except those areas with RFG, as well as those areas where ethanol use is not expected to change.

For both runs of the Ozone RSM, we set the predicted change in ozone to zero in those counties not expected to experience a significant change in ethanol use. This ignores any impact from ozone transport from other areas where ethanol use did change. However, we believe that the ozone impacts due to transport are much smaller than those associated with changes in local emissions. This is particularly true in this case, where the percentage change in emissions would be the same in both the local and upwind areas.

We merged the results of the two runs by attributing ozone impacts from each county according to their nonattainment designation and fuel type. For non-attainment areas, this choice was obvious. Non-attainment counties with RFG programs were assigned the ozone impacts from the first run (i.e., the run where the changes in VOC and NOx emissions were the average of those observed for RFG areas). Non-attainment counties with Low RVP programs were assigned the ozone impacts from the second run (i.e., the run where the changes in VOC and NOx emissions were the average of those observed for Low RVP areas). For attainment areas (i.e., 9 RVP areas), the results of either run could be used, as both runs of the Ozone RSM applied the same emission changes to attainment areas. Thus, the local emission impacts would be identical in the two Ozone RSM runs. Ozone transport is also likely identical for the vast majority of these counties, given that they are likely downwind from other attainment area counties. The only difference occurs if an attainment area is downwind of a RFG or Low RVP area. For a nationwide analysis such as this one, we were not able to determine for each attainment area whether a potential upwind area was more likely to be an RFG or Low RVP area. Therefore, we chose to use the ozone impacts results from the first Ozone RSM run of the model (i.e., where the emission impacts for RFG areas were applied to ozone nonattainment areas) for all attainment areas. We chose this run because RFG areas tend to have the higher ozone levels than Low RVP areas and thus, would be more likely to affect areas downwind. We present the ozone impacts of increased ethanol use resulting from this methodology in the following section.

5.1.1 Ozone Response Surface Metamodel Results

This section summarizes the results of our modeling of ozone air quality impacts in the future with and without the expanded use of ethanol in fuel. The impact of increased ethanol use on the 8-hour ozone design values in 2015 are presented in Table 5.1-2. The changes presented in Table 5.1-2 are for those counties with 2001 modeled design values.[57] The Chapter 5 Appendix presents the impacts of increased ethanol use on a number of alternative measures of ambient ozone concentration.

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[57] 2001 design values were calculated as an average of the 1999-2001, 2000-2002 and 2001-2003 design values at each monitoring site. Please see the Air Quality Modeling Technical Support Document for the final Clean Air Interstate Rule for additional information.

Table 5.1-2.
Impact of Increased Ethanol Use on 8-hour Ozone Design Values in 2015 (ppb)

	RFS Case	EIA Case
Primary Analysis		
Minimum Change	-0.015	0.000
Maximum Change	0.329	0.337
Average Change Across 37 States	0.057	0.079
Population-Weighted Change Across 37 States	0.052	0.056
Average Change Where Ethanol Use Changed Significantly States	0.153	0.181
Population-Weighted Change Where Ethanol Use Changed Significantly States	0.154	0.183
Sensitivity Analysis		
Minimum Change	-0.115	0.000
Maximum Change	0.624	0.549
Average Change Across 37 States	0.111	0.142
Population-Weighted Change Across 37 States	0.092	0.096
Average Change Where Ethanol Use Changed Significantly States	0.300	0.325
Population-Weighted Change Where Ethanol Use Changed Significantly States	0.272	0.315

As can be seen, ozone levels generally increase with increased ethanol use. This is likely due to the projected increases in both VOC and NOx emissions. Some areas do see a small decrease in ozone levels. In our primary analysis, where exhaust emissions from Tier 1 and later onroad vehicles are assumed to be unaffected by ethanol use, the population-weighted increase in ambient ozone levels is 0.052-0.056 ppb. Since the 8-hour ambient ozone standard is 0.08 ppm (85 ppb), this increase represents about 0.06 percent of the standard, a very small percentage[58]. While small, this figure includes essentially zero changes in ozone in areas where ethanol use did not change. When we focus just on those areas where the market share of ethanol blends changed by 50 percent or more, the population-weighted increase in ambient ozone levels rises to 0.154-0.183 ppb. This increase represents about 0.2 percent of the standard.

In our sensitivity analysis, where exhaust emissions from Tier 1 and later onroad vehicles are assumed to respond to ethanol like Tier 0 vehicles, the population-weighted increase in ambient ozone levels across the entire 37 state area is slightly less than twice as high, or 0.092-0.096 ppb. This increase represents about 0.11 percent of the standard. When we focus just on those areas where the market share of ethanol blends changed by 50 percent or more, the population-weighted increase in ambient ozone levels rises to 0.272-0.315 ppb. This increase represents about 0.35 percent of the standard.

For the primary analysis, we also present the counties with the largest increases in the ozone design value. Table 5.1-3 presents the county level ozone design value impacts of the RFS case, while Table 5.1-4 presents the same information for the EIA case. It is important to note that the results of this ozone response surface metamodeling exercise is meant for screening-level purposes only and does not represent the results that would be obtained from

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[58] Appendix I of 40 CFR Part 50.

full-scale photochemical ozone modeling. It is also important to note that the ozone RSM results indicate that the counties which are projected to experience the greatest increase in ozone design values are generally counties that are projected to have ambient concentrations well below the 0.08 ppm ozone standard in the 2015 baseline.

Table 5.1-3. RFS Case, Primary Analysis: 2015 Ozone Response Surface Metamodeling Results[a] for Counties with Largest Increases in Ozone 8hr Design Value (ppb) Due to Increased Use of Ethanol

State Name	County Name	2015 Baseline (Post-CAIR)[b]	2015 RFS Case	Effect of Expanded Ethanol Use (ppb)	2015 Population
Arkansas	Crittenden Co	78	78.3289	0.3	53,852
Ohio	Geauga Co	82.5	82.7972	0.3	108,600
Ohio	Mahoning Co	74.7	74.9943	0.3	248,545
Indiana	Lake Co	80.7	80.9929	0.3	490,796
Ohio	Medina Co	72	72.2909	0.3	187,686
Ohio	Summit Co	77.4	77.6901	0.3	557,892
Maine	York Co	77.6	77.8825	0.3	210,006
Ohio	Stark Co	71.7	71.9707	0.3	384,672
Ohio	Clinton Co	75.7	75.9705	0.3	50,635
Louisiana	West Baton Rouge Parish	77.4	77.6685	0.3	23,202
Louisiana	Livingston Parish	76.6	76.8656	0.3	141,807
Illinois	Cook Co	81.1	81.3605	0.3	5,362,932
Indiana	Shelby Co	76.2	76.4587	0.3	47,904
Ohio	Knox Co	71.4	71.6541	0.3	62,138
Alabama	Mobile Co	68	68.2514	0.3	430,341
Louisiana	Jefferson Parish	77.1	77.351	0.3	512,963

[a] The Ozone RSM is meant for screening-level purposes only and does not represent results that would be obtained from full-scale photochemical ozone modeling. In particular, the model does not account for changes in CO emissions or VOC reactivity, both of which should decrease with increased ethanol use and directionally reduce ozone. in areas where ozone formation is VOC-limited.

[b] The Clean Air Interstate Rule (CAIR) modeling is fully described in the CAIR Air Quality Modeling Technical Support Document (Docket EPA-HQ-OAR-2005-0036).

Table 5.1-4. EIA Case, Primary Analysis:
2015 Ozone Response Surface Metamodeling Results for Counties with Largest Increases in Ozone 8hr Design Value (ppb) Due to Increased Use of Ethanol

State Name	County Name	2015 Baseline (Post-CAIR)[c]	2015 EIA Case	Effect of Expanded Ethanol Use (ppb)	2015 Population
Ohio	Geauga Co	82.5	82.8369	0.3	108,600
Ohio	Clinton Co	75.7	76.0218	0.3	50,635
Ohio	Mahoning Co	74.7	75.0213	0.3	248,545
Arkansas	Crittenden Co	78	78.3204	0.3	53,852
Ohio	Summit Co	77.4	77.7175	0.3	557,892
Mississippi	Adams Co	67.2	67.5164	0.3	33,495
Ohio	Stark Co	71.7	72.0153	0.3	384,672
Indiana	Shelby Co	76.2	76.5115	0.3	47,904
Maine	York Co	77.6	77.902	0.3	210,006
New York	Wayne Co	71.6	71.8926	0.3	103,846
Texas	Travis Co	69.4	69.6912	0.3	1,022,772
Ohio	Medina Co	72	72.2909	0.3	187,686
Maine	Hancock Co	76.8	77.0904	0.3	55,606
Maine	Kennebec Co	64.9	65.1903	0.3	122,363
Louisiana	Livingston Parish	76.6	76.8883	0.3	141,807
Louisiana	West Baton Rouge Parish	77.4	77.6869	0.3	23,202
Louisiana	Lafourche Parish	72.7	72.984	0.3	95,881
Mississippi	Warren Co	56.2	56.4827	0.3	52,075
Michigan	Huron Co	71.9	72.1766	0.3	37,530
Ohio	Franklin Co	77	77.2716	0.3	1,181,578
Ohio	Trumbull Co	80	80.2713	0.3	227,546
Louisiana	Jefferson Parish	77.1	77.3707	0.3	512,963
Florida	Pinellas Co	62.3	62.5639	0.3	998,864
Ohio	Delaware Co	72.1	72.3606	0.3	149,341
Ohio	Knox Co	71.4	71.6579	0.3	62,138
Florida	Duval Co	50.6	50.8568	0.3	895,678
Indiana	Marion Co	74.6	74.8565	0.3	889,645
Indiana	Madison Co	72.9	73.1564	0.3	140,575
Massachusetts	Middlesex Co	75.8	76.0564	0.3	1,498,849
Michigan	Oakland Co	79.2	79.4542	0.3	1,355,671
Pennsylvania	Beaver Co	70.5	70.7528	0.3	184,649
New York	Monroe Co	74.3	74.5521	0.3	754,405
Mississippi	Harrison Co	69.3	69.5517	0.3	216,926

There are a number of important caveats concerning our estimated ozone impacts using the Ozone RSM. The Ozone RSM does not account for changes in CO emissions. As shown in Chapter 4, ethanol use should reduce CO emissions significantly, directionally reducing ambient ozone levels in areas where ozone formation is VOC-limited. Accounting for the reduction in CO emissions in NOx-limited areas, however, may have little impact on the ozone impact of ethanol use.

The Ozone RSM also does not account for changes in VOC reactivity. With additional ethanol use, the ethanol content of VOC should increase. Ethanol is less reactive than the average VOC. Therefore, this change should also reduce ambient ozone levels in a way not addressed by the Ozone RSM. Again, like the impact of reduced CO emissions, this effect applies to those areas where ozone formation is VOC-limited. Another limitation is the RSM's inability to simulate the spatial distribution of emission impacts associated with the standard. Instead, we are forced to make simplifying assumptions about the geographic uniformity of RFS emissions impacts, explained above. The caveats and limitations associated with the RSM highlight the fact that it should only be used as a screening-level tool to characterize broad trends associated with changes in different source categories of ozone precursors.

Finally, our application of the Ozone RSM here does not include the impact of emissions from new ethanol plants. Directionally, this will increase ozone levels in the vicinity of the new plant. As discussed in Chapter 4, the overall VOC and NOx emission impacts of new ethanol plants are only slightly lower than the emission impacts resulting from increased use of ethanol in vehicles and equipment. Given the concentrated nature of these impacts, the ozone impacts of these new plants should be a focus of further study in the future.

Keeping these limitations in mind, the expanded use of ethanol will impact the national emissions inventory of precursors to ozone, such as VOCs and NOx, as described in Chapter 4. Exposure to ozone has been linked to a variety of respiratory effects including premature mortality, hospital admissions and illnesses resulting in school absences. Ozone can also adversely affect the agricultural and forestry sectors by decreasing yields of crops and forests.

The Wisconsin Department of Natural Resources (DNR) recently performed a similar study of the impact of increased ethanol use on ozone.[EEEE] They estimated that the conversion of gasoline outside of RFG areas in Wisconsin to E10 blends would increase ozone in these areas on the order of 1 ppb to as much as 2 ppb. (RFG areas in Wisconsin already contain 10 vol% ethanol.) This ozone increase was due to the predicted increase in NOx emissions associated with ethanol use, since the non-RFG areas in Wisconsin are generally NOx limited for ozone formation.

The Wisconsin DNR estimated the ozone impact for calendar year 2003 and assumed that all vehicles experience the increase in NOx emissions. Thus, their results are more comparable to our sensitivity analysis, than our primary analysis. For the two increased ethanol use scenarios, our sensitivity analysis projects increased ozone levels for several Wisconsin counties of 0.35-40 ppb. Because the Wisconsin DNR analyzed calendar year 2003 emissions and air quality, their base emission levels are much higher than those estimated here for the year 2015. Emission standards applicable to new vehicles and equipment are continually reducing emissions over time. Per the emission models used here and by the State of Wisconsin (NONROAD and MOBILE6), the effect of fuel quality is generally estimated in terms of a percentage change in the base emission level. As emissions from vehicles and equipment decrease over time, the absolute impact of fuel quality changes decreases at the same rate. Thus, the absolute emission changes predicted here for 2015 could easily be a factor of two lower than those predicted by

Wisconsin for 2003. This is likely the primary cause of the difference in the two sets of projected ozone impacts.

We received a comment from the Missouri Department of Natural Resources on the ozone impact analysis performed for the NPRM which expressed a concern that our approach of zeroing out the ozone impact in areas which did not experience a significant change in ethanol use had the effect of ignoring the impact of ozone transport due to increased ethanol use in upwind areas. This comment is correct. In a national analysis such as this one, it is not practical to go through over 3100 counties to determine which counties might have not experienced a change in ethanol use in a particular ethanol use case, but is downwind of an area which did. Still, the issue is a potentially relevant one and of reasonable interest particularly to those tasked with air quality management.

In an attempt to approximate the impact of ozone transport from areas which did experience a change in ethanol use on ozone in areas which did not, we performed one additional run of the Ozone RSM. This additional run applied the changes in VOC and NOx emissions estimated above for attainment areas from our sensitivity analysis for the EIA case to emissions in attainment areas, and applied no change in emissions in non-attainment areas. We then compared the resulting ozone levels to those from the base case, focusing on the difference in ozone levels in non-attainment areas. Emissions in non-attainment areas were the same in both cases (no change from the base case). Thus, the difference in ozone levels in non-attainment areas should only be due to changes in emissions and ozone levels in upwind attainment areas.

The results of this comparison indicated that, in terms of the 8-hour ozone design value, ozone levels in non-attainment areas (i.e., RFG or Low RVP areas) decreased by 0.03 ppb. Thus, the average impact due to ozone transport is a reduction in ozone in downwind areas. However, the standard deviation in the ozone impact was 0.05 ppb, indicating that a significant number of areas experienced an increase, though most experienced a decrease. This is not surprising given that ozone in some attainments areas is VOC limited and may be decreasing in this fuel case, while others are NOx limited and may be increasing. The maximum ozone reduction was 0.17 ppb, while the maximum increase was 0.12. More precise local atmospheric dispersion modeling will be needed in order to estimate this type of impact for specific non-attainment areas.

In summary, we estimate that the measurable changes in VOC and NOx which are a result of increased ethanol use will, on average, result in small increases in ambient ozone formation. As we discussed above, the ozone modeling results in a net increase in the average population weighted ozone design value metric measured within the modeled domain (37 Eastern states and the District of Columbia). In Appendix A, we also present the impacts of increased ethanol use on a number of alternative measures of ambient ozone concentration. We acknowledge, however, that to the extent it occurs, increased future levels of ambient concentrations of ozone related to the increased use of ethanol may result in detrimental health and welfare effects due to ozone.

5.2 Particulate Matter

5.2.1 Impact of Changes in Direct PM Emissions

The amount of data evaluating the impact of ethanol and MTBE blending on direct emissions of PM from gasoline-fueled vehicles is extremely limited, as discussed in Chapter 3. Most studies do not test PM emissions from vehicles fueled with unleaded gasoline, because the level of PM emissions from properly operating vehicles is usually very low, less than 0.1 g/mi.

Two studies indicate that the addition of ethanol might reduce direct PM emissions from gasoline vehicles[FFFF],[GGGG]. However, both studies were performed under wintertime conditions and one at high altitude. One of the studies only consisted of three vehicles. The available data indicate that ethanol blending might reduce exhaust PM emissions under very cold weather conditions (i.e., 0 F or less), particularly at high altitude. There is no indication of PM emission reductions at higher temperatures or under warmed up conditions. Thus, the data are certainly too limited to support a quantitative estimate of the effect of ethanol on PM emissions.

5.2.2 Potential Impact of Changes in Secondary PM Formation

In addition to being emitted directly from a combustion source, fine particles can be formed through a series of chemical reactions in the atmosphere when SO_2, NOx, and VOC oxidize or otherwise react to form a wide variety of secondary PM. For example, SO_2 oxidizes to SO_3 and sulfuric acid and NOx oxidizes to NO_3 and nitric acid which, in turn, react with ammonia in the atmosphere to form ammonium sulfate and ammonium nitrate. Particles generated through this gas to particle conversion are referred to as secondary aerosols (SA) and represent a significant portion of ambient fine particulate matter. Studies have shown that as much as 70% of the total organic carbon in urban particulate matter can be attributed to secondary organic aerosol (SOA) formation although the amount can also be less.[HHHH] Secondary PM tends to form more in the summer with higher temperatures and more intense sunlight.

Source-receptor modeling studies conducted in the Los Angeles area is 1993 by Schauer et al[IIII] indicate that as much as 67% of the fine particulate matter collected could not be attributed to primary sources. The authors concluded that much of this unidentifiable organic matter is secondary organic aerosol formed in the atmosphere. This is consistent with previous studies conducted by Turpin and Huntzicker in 1991 who concluded that 70% of the total organic carbon in urban PM measurements made in southern California can be attributed to SOA.

Gas phase VOCs are oxidized by OH, NO_2, peroxyacetylnitrate (PAN), and ozone in the atmosphere, but their propensity to condense in the particle phase is a function of two factors: volatility and reactivity. To accumulate as an aerosol, a reaction product must first be formed in the gas phase at a concentration equal to its saturation concentration. This requirement will not be met if the relevant gas-phase reactions of the VOC are too slow or if the vapor pressure of the reaction product is higher than the initial concentration of its VOC precursor.[JJJJ] Limited data for reaction rate constants determined both experimentally and estimated by structural relationships are available in the published literature. However, the atmospheric chemistry behind SOA reaction rates and the estimated aerosol yield is highly complex and carries with it a great deal of uncertainty. Research in this area is ongoing and thus the capacity to quantitatively model SOA formation is not yet a straightforward process.

In general, all reactive VOC are oxidized by OH or other compounds. Additionally, alkenes, cycloalkenes, and other olefinic compounds can react with ozone and NO_2 to form secondary aerosols. In fact, ozone is responsible for nearly all the SOA formation from olefins, while OH plays little or no role at all (Grosjean and Seinfeld, 1989; Izumi and Fukuyama, 1990). Many VOC, however, will never form secondary organic aerosol under atmospheric conditions regardless of their reactivity. This is because the products of reactions of these compounds have vapor pressures that are too high to form aerosols at atmospheric temperatures and pressures. These include all alkanes and alkenes with up to 6 carbon atoms, benzene and many low-molecular weight carbonyls, chlorinated compounds and oxygenated solvents (Grosjean, 1992).

The VOC that have the greatest propensity to form SOA include aromatic hydrocarbons (such as toluene but even including benzene), higher molecular weight olefins and cyclic olefins, and higher molecular weight paraffins. Kleindienst et al suggest that a high fraction of SOA is due to aromatic hydrocarbon precursors. Furthermore, “aromatic products having a single alkyl group on the aromatic ring were found to represent a ‘high-yield’ family (e.g., toluene, ethylbenzene); compounds having multiple methyl groups (e.g., m-xylene, 1,2,4-trimethylbenzene) were found to represent a ‘low-yield’ family” (Kleindienst, 269). All of the above mentioned VOC precursors are important either because there are large amounts of these particular VOC emitted per day, or because a large fraction of the VOC reacts, or a combination of the two. Based on VOC emissions inventory data collected in the Los Angeles area, the most important aerosol precursors (in the LA area using 1982 VOC emissions inventories) are listed in Table 5.2-1 below:

Table 5.2-1.
Predicted In Situ SOA Formation
During a Smog Episode in Los Angeles

VOC Functional Group	kg emitted daily*	Secondary PM Produced (kg)*	% yield
Aromatics	223985	3061	1.37
Olefins			
Alkenes	31163	608	1.95
Cyclic Olefins	3220	144	4.47
Terpenes	6000	626	10.43
Paraffins			
Alkanes	140493	368	0.26
Cycloalkanes	37996	96	0.25

*Source: Grosjean et al, 1992

These predictions are a function of input data collected in the Los Angeles area, and assume ambient levels of [ozone] = 100 ppb, $[OH]=1.0\times10^6$ molecules/cm^3, and [NO3]=0 with 6 hours of reaction time. Aromatics are the largest functional group in terms of the absolute quantities of VOC emitted daily, and thus they eventually form the most SOA. Likewise, many high molecular weight paraffins (alkanes) form SOA on a significant scale simply because their emissions are high. However, the relative fraction of paraffins that react is less than that of aromatics in smog chamber experiments simulating SOA formation in the atmosphere. For olefins, the alkenes exhibit a combination of both relatively high emissions, and a high fraction of VOC reacted to form SOA. Cyclic olefins, in contrast, are emitted in relatively low levels, but a high fraction of these VOC react and the end result is a proportionally higher SOA yield than with the alkenes. Lastly, there are several “miscellaneous” compounds and terpenes that are emitted on a relatively small scale (in southern California), but that produce a substantial amount of secondary organic aerosol.

Researchers at EPA recently completed a field study in the Raleigh/Durham area of North Carolina that investigated the contribution of various sources to ambient PM 2.5 concentrations.[KKKK] In the study they identified toluene as an SOA precursor. They estimate that mobile sources contribute nearly 90% of the total toluene emissions in that region based on a chemical mass balance approach. At the same time, however, SOA attributable to non-fuel-related VOC (i.e., biogenic emissions) was found to be an even larger contributor to SOA (i.e., toluene was not likely the dominant source of SOA in this area). This study is currently undergoing peer review and will be published shortly. Qualitatively, however, this information is still quite useful since the study identifies a contributing source of SOA that is attributable almost entirely due to mobile sources.

VOC reaction rates increase with increasing ambient temperature and sunlight intensity, so the level of SOA formed is much higher in summer than in winter. Even in the more temperate coastal climates of southern CA, studies have found the summertime concentration of SOA calculated through Chemical Mass Balance models show SOA formation to be anywhere from 2 – 5 times higher in summer than winter. In a study conducted at both urban and rural locations in the southeastern United Sates, the concentration of SOA in the summer and early fall was roughly 2-3 times that of colder months[LLLL].

As mentioned in Chapters 2 and 3, the addition of ethanol should reduce aromatics in gasoline, which will in turn reduce the aromatics emitted in the exhaust. However, quantifying the emission reduction is not possible at this time due to a lack of speciated exhaust data for newer vehicles running on ethanol blends. In addition, increased NOx emissions resulting from the increased use of ethanol could increase the formation of nitrate PM.

Based on the following, we believe that it is likely that the decrease in secondary PM from organic aromatic hydrocarbons is likely to exceed the increase in secondary nitrate PM. In 1999, NOx emissions from gasoline-fueled vehicles and equipment comprised about 20% of national NOx emissions from all sources[MMMM]. In areas where ethanol use increases dramatically, NOx emissions from gasoline-fueled vehicles and equipment increases roughly 5-10%. This is roughly equivalent to a 1-2% increase in NOx emissions nationwide.

In contrast, gasoline-fueled vehicles and equipment comprised over 60% of all national gaseous aromatic VOC emissions[59]. In areas where ethanol use increases dramatically, fuel

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aromatic content decreases by about 4 vol% in the summertime, averaged across conventional gasoline and RFG. This represents about a 15% reduction from a base level of around 27 vol%. Assuming a proportional relationship between fuel aromatics and aromatic emissions, this represents about a 24% reduction in aromatic emissions nationwide.

In most urban areas, ambient levels of excess summer carbonaceous PM (a reasonable estimate of secondary organic PM) tend to exceed those of secondary nitrate PM. Thus, directionally, it appears likely that a net reduction in ambient PM levels will result from increased ethanol use. However, this should be considered a rough comparison at this time. A more precise comparison will have to await the incorporation of secondary organic aerosol formation into models, such as CMAx.

The research to facilitate this incorporation is currently underway. EPA ORD scientists are currently carrying out a wide variety of laboratory studies to refine the SOA chemistry mechanisms for use in the next version of the CMAQ model, which is expected to be completed in 2007 and submitted for peer review. This information should be available in time for the comprehensive study of the Act's fuel requirements which is due in 2009.[60]

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[59] Based on internal analyses of emissions inventories.

[60] Subject to funding.

Chapter 5: Appendix

Table 5A-1. 2015 Ozone Response Surface Metamodeling Summary Statistics for the RFS Rule[a,]; Primary Scenario

8hour Design Value (ppb)		
Statistic	**RFS Scenario**	**EIA Scenario**
Minimum Change	-0.015	0.000
Maximum Change	0.329	0.337
Average Change	0.057	0.079
Standard Deviation	0.086	0.100
Population-Weighted Change	0.052	0.056
24hr Average (ppb)		
Statistic	**RFS Scenario**	**EIA Scenario**
Minimum Change	-0.168	-0.162
Maximum Change	0.197	0.074
Average Change	0.008	0.013
Standard Deviation	0.018	0.021
Population-Weighted Change	0.014	0.013
1hr Maximum (ppb)		
Statistic	**RFS Scenario**	**EIA Scenario**
Minimum Change	-0.104	-0.094
Maximum Change	0.213	0.180
Average Change	0.015	0.024
Standard Deviation	0.033	0.040
Population-Weighted Change	0.029	0.033
Average 9-to-5 (ppb)		
Statistic	**RFS Scenario**	**EIA Scenario**
Minimum Change	-0.107	-0.097
Maximum Change	0.203	0.141
Average Change	0.012	0.019
Standard Deviation	0.027	0.031
Population-Weighted Change	0.022	0.024
Average 10-to-3 (ppb)		
Statistic	**RFS Scenario**	**EIA Scenario**
Minimum Change	-0.108	-0.107
Maximum Change	0.207	0.149
Average Change	0.012	0.019
Standard Deviation	0.027	0.032
Population-Weighted Change	0.023	0.024

[a] Note that the statistics presented here represent ethanol use changes across the entire 37-state ozone RSM domain.

Table 5A-2. 2015 Ozone Response Surface Metamodeling Summary Statistics for the RFS Rule[a]; Sensitivity Scenario

8hour Design Value (ppb)		
Statistic	**RFS Scenario**	**EIA Scenario**
Minimum Change	-0.115	0.000
Maximum Change	0.624	0.549
Average Change	0.111	0.142
Standard Deviation	0.158	0.170
Population-Weighted Change	0.092	0.096
24hr Average (ppb)		
Statistic	**RFS Scenario**	**EIA Scenario**
Minimum Change	-0.181	-0.173
Maximum Change	0.184	0.142
Average Change	0.015	0.024
Standard Deviation	0.034	0.041
Population-Weighted Change	0.025	0.028
1hr Maximum (ppb)		
Statistic	**RFS Scenario**	**EIA Scenario**
Minimum Change	-0.150	-0.133
Maximum Change	0.498	0.346
Average Change	0.027	0.043
Standard Deviation	0.060	0.072
Population-Weighted Change	0.052	0.062
Average 9-to-5 (ppb)		
Statistic	**RFS Scenario**	**EIA Scenario**
Minimum Change	-0.177	-0.163
Maximum Change	0.400	0.260
Average Change	0.022	0.034
Standard Deviation	0.049	0.057
Population-Weighted Change	0.040	0.046
Average 10-to-3 (ppb)		
Statistic	**RFS Scenario**	**EIA Scenario**
Minimum Change	-0.182	-0.167
Maximum Change	0.431	0.273
Average Change	0.022	0.035
Standard Deviation	0.050	0.058
Population-Weighted Change	0.041	0.047

[a] Note that the statistics presented here reflect the impact of ethanol use changes across the entire eastern U.S. 37-state ozone RSM domain.

Chapter 6: Lifecycle Impacts on Fossil Energy and Greenhouse Gases

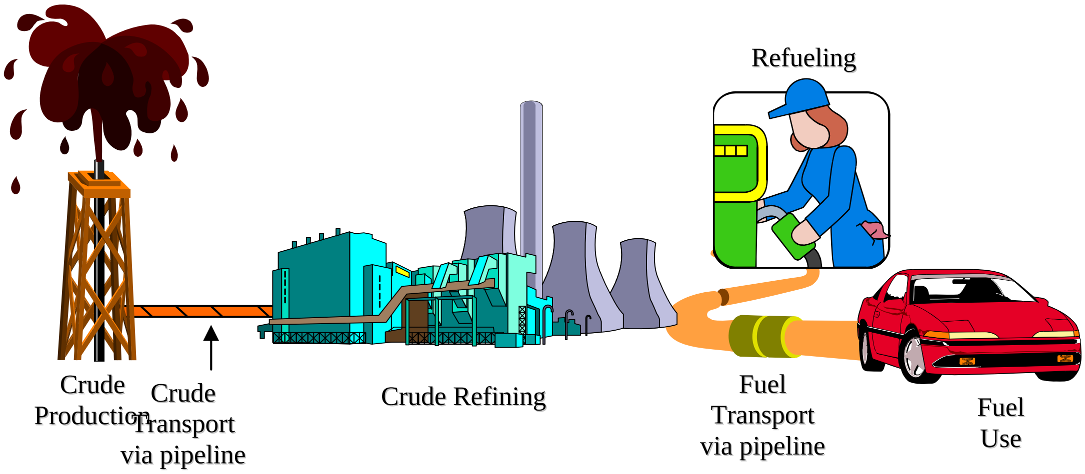
6.1 Lifecycle Modeling

Lifecycle modeling accounts for the energy and emissions from a production process. It incorporates the material aspects, input and output, of each step in a product system. This method helps to identify key processes and emission sources and facilitates comparisons between processes, consumption of natural resources, pollutant generation and environmental burden. It is important to note that lifecycle modeling typically provides only general comparisons, based on industry-wide estimates and assumptions; it does not reflect general equilibrium impacts, such as effects on input markets. The results of this type of analysis are highly dependent upon the input data used, the variables considered, and the assumptions made. Nevertheless, within these limitations, it can be an extremely useful tool for evaluating some of the environmental impacts of products and processes.

For transportation fuels, lifecycle modeling considers all steps in the production of the fuel. This includes production of the fuel feedstock, transportation of the fuel feedstock to a processing facility, fuel processing, and distribution of the fuel to the retail outlet. If the analysis considers only the finished product, it is sometimes called a ‘well-to-pump’ analysis; if the fuel combustion emissions are included, it can be called a ‘well-to-wheel’ analysis. While both approaches have advantages, in this work we have considered ‘well-to-wheel’ impacts. However, we are not addressing the issues of vehicle technology and energy efficiency, since we are making the assumption that the vehicle issues will not be affected by the presence of renewable fuels (i.e., efficiency of combusting one Btu of renewable fuel is equal to the efficiency of combusting one Btu of conventional fuel).

To put this type of analysis into perspective, consider the example of gasoline. The fuel feedstock is crude oil. The lifecycle analysis accounts for the energy used to extract the oil from the ground and any associated emissions, such as the natural gas that is flared at the well head. Next you evaluate transportation of the crude oil to the refinery. If it is domestic crude oil, it may be delivered by pipeline and/or barge. The analysis takes into account national trends for domestic oil transportation, and apportions energy used and emissions generated to each type of transportation. For foreign crude oil, the energy and emissions from ocean tankers is included, with an estimate of the average distance traveled by these tankers. Next is an estimation of the energy use and emissions from the refinery. Because gasoline is not the only product produced at the refinery, only a portion of the energy and emissions is allocated to gasoline production. There are different methods for making this allocation, based on the value of the co-products or an engineering assessment of the energy use and emissions from the various units in the refinery. You then evaluate the energy use and emissions from transporting the gasoline to market, via pipeline and truck, based on national average distances. Finally, vehicle energy use and emissions are estimated. Figure 6.1-1 illustrates this process.

Figure 6.1-1: Lifecycle Production Process, 'Well-to-Wheel', for Gasoline



Lifecycle modeling has been a useful tool in evaluating the environmental benefits of various alternative transportation fuels. It allows the replacement fuel to be fairly compared against the conventional transportation fuels – gasoline and diesel fuel. There have been several significant lifecycle analyses of transportation fuels done in the last decade. The lifecycle analysis done for this Renewable Fuel Standard (RFS) program uses a model developed by the Department of Energy (DOE) Argonne National Laboratory (ANL) called the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model. EPA has reviewed and modified GREET somewhat to reflect the data and assumptions appropriate for the RFS. These modifications are discussed further in section 6.1.2.

6.1.1 Scope of the Lifecycle Analysis

An important step in conducting a lifecycle analysis is to define the scope of the study. Varying results can be obtained depending on the scope identified. The scope of the analysis includes (1) the goal (2) the system boundaries (3) what flows are considered (4) temporal considerations and (5) modeling tools used. Each of these components is examined in the following sections.

6.1.1.1 Goal

The goal of this analysis is to determine the GHG emission and fossil fuel impact of the increased use of renewable fuels. This analysis is based on comparing future scenarios representing an increased percentage of the overall transportation sector fuel pool coming from renewable fuels compared to a reference case with the percentage of renewable fuels use at current levels. This implies that our future scenarios assume renewable fuels are displacing their petroleum based counterparts and causing less to be used. This RIA reflects increases in ethanol production of 85% and 150% respectively from the baseline. As this analysis is compared to a reference case we are only interested in the savings of the new or marginal renewable fuels used.

We have evaluated the absolute savings (e.g., tons of GHG emissions) as well as determining what percentage these absolute savings are in terms of overall transportation sector and economy wide emissions and energy use.

6.1.1.2 System Boundaries

The lifecycle analysis for the relevant activities identified in the GREET model is conducted without any regard to the geographic attributes of where emissions or energy use occurs. While the primary emphasis of a rulemaking analysis is typically to examine the domestic implications of a rulemaking, the lifecycle analysis of this final rule represent global reductions in GHG emissions and energy use, not just those occurring in the U.S. For example, under a full lifecycle assessment approach, the savings associated with reducing overseas crude oil extraction and refining are included here, as are the international emissions associated with producing imported ethanol. This assumes that for every gallon of gasoline that's not imported into the US, the corresponding quantity of crude oil is not extracted or processed to make this gasoline regardless where the extraction or production takes place. This type of modeling does not allow for behavioral changes that may be occur, called "rebounding effect," discussed later.

There are two important caveats to this analysis, both dealing with secondary impacts that may result internationally due to the expanded use of renewable fuels within the United States. The first caveat is the emissions associated with international land use change. Due to decreasing corn exports some changes to international land use may occur, for example, as more crops are planted in other regions to compensate for the decrease in crop exports from the U.S. While the emissions associated with domestic land use change are well understood and are included in our lifecycle analysis, we did not include the potential impact on international land use and any emissions that might directly result. Our currently modeling capability does not allow us to assess what international land use changes would occur or how these changes would affect greenhouse gas emissions. For example, we would need to know how international cropping patterns would change as well as farming inputs and practices that might affect emissions assessment. The second caveat results from the assumption of reduced petroleum imports. It is commonly presumed in economic analyses that demand for a normal good (i.e., oil) will increase as price decreases. A world wide reduction of oil price that could result from reduced U.S. imports can reduce the cost of producing transportation fuel which in turn would tend to reduce the price consumers would have to pay for this fuel. To the extent fuel prices are decreased, demand and consumption would tend to increase; this impact of reduced cost of driving is sometimes referred to as a "rebound effect." Such a greater consumption would presumably result in an increase in greenhouse gas emissions as consumers would drive more. These increased emissions would in part offset the emission benefits otherwise accounted for this rule[61]. It is important to note that GREET does not model behavioral changes that may affect prices of relevant commodities and goods which through various feedback loops ultimately energy use. The model does not include a general equilibrium approach that examines how a shock (whether economic, technical or legal) affects not only the sector of interest but also other sectors and the economy as a whole.[62] While such impacts of U.S. actions are important to

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[61] The extent to which this offset would occur would depend on sensitivity of demand to price.

understand, we have not have fully considered and quantified the rebound effects of this renewable fuel standard. Nevertheless, such impacts remain an important consideration for future analysis.

The system boundaries for this study encompass both the renewable fuels lifecycle stages as well as their petroleum based counterparts. Table 6.1-1 shows the lifecycle stages considered for each fuel.

Table 6.1-1. Lifecycle Stages Included in Analysis

Corn Ethanol	Cellulosic Ethanol	Biodiesel	Petroleum-Based Gasoline	Petroleum-Based Diesel Fuel
Corn Farming	Biomass Farming	Soybean Farming	Crude Oil Extraction	Crude Oil Extraction
Corn Transport	Biomass Transport	Soybean Transport	Crude Oil Transport	Crude Oil Transport
		Soybean Crushing		
Ethanol Production	Ethanol Production	Biodiesel Production	Refining	Refining
Ethanol T&D	Ethanol T&D	Biodiesel T&D	Gasoline T&D	Diesel Fuel T&D
Ethanol Tailpipe Emissions	Ethanol Tailpipe Emissions	Biodiesel Tailpipe Emissions	Gasoline Tailpipe Emissions	Diesel Fuel Tailpipe Emissions

The boundaries around each lifecycle stage include the emissions and energy use associated with that operation as well as upstream components that feed into it. For example, the corn farming stage includes emissions from fuel used in tractors as well as from producing and transporting the fertilizer used in the field. Electricity production emissions are included in almost all of the stages shown. These components typically have the biggest impact on the results. We did not include for example, energy and emissions associated with producing the steel and concrete used to construct the ethanol plants or petroleum refineries.

As other lifecycle studies of renewable fuels have included an expanded set of system boundaries, a sensitivity analysis was performed that includes the energy use and the emissions associated with producing farm equipment, and is described in section 6.1.2.7.

A potentially important system boundary affect, however, could be changes in land use. This is particularly the case for GHGs if new land (e.g., rainforest land) must first be cleared in order to grow the biofuel feedstocks. This lifecycle analysis is conducted without any regard to the geographic attributes of where emissions or energy use occurs. The benefits of this final rule represent global reductions in GHG emissions and energy use, not just those occurring in the U.S. For example, the savings associated with reducing overseas crude oil extraction and refining are included here, as are the international emissions associated with producing imported ethanol. One exception to this is the emissions associated with international land use change. Due to decreasing corn exports and modest decreases in soybean exports, there may be some

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[62] Since GREET is not a behavioral model, it cannot assess any economic efficiency implications associated with increased ethanol production. Analyzing these implications would be important for future ethanol rulemakings.

additional corn and soybean acres planted internationally to meet world demand. The emissions associated with domestic land use change are included in our lifecycle analysis but international land use change was not as it was outside the scope of our agriculture sector analysis. However, if emissions from international land use change were included it would lower the overall benefits of this rule. This is an area we will continue to examine for future analysis.

6.1.1.3 Environmental Flows Considered

One issue that has come to the forefront in the assessment of the environmental impacts of transportation fuels relates to the effect that the use of such fuels could have on emissions of greenhouse gases (GHGs). The combustion of fossil fuels has been identified as a major contributor to the increase in concentrations of atmospheric carbon dioxide (CO_2) since the beginning of the industrialized era, as well as the build-up of trace GHGs such as methane (CH_4) and nitrous oxide (N_2O). This lifecycle analysis evaluates the impacts of increased renewable fuel use on greenhouse gas emissions.

The relative global warming contribution of emissions of various greenhouse gases is dependant on their radiative forcing, atmospheric lifetime, and other considerations. For example, on a mass basis, the radiative forcing of CH_4 is much higher than that of CO_2, but its effective atmospheric residence time is much lower. The relative warming impacts of various greenhouse gases, taking into account factors such as atmospheric lifetime and direct warming effects, are reported on a 'CO_2-equivalent' basis as global warming potentials (GWPs). The GWPs used in this analysis were developed by the UN Intergovernmental Panel on Climate Change (IPCC) as listed in their Third Assessment Report[63], and are shown in Table 6.1-2.

Table 6.1-2.
Global Warming Potentials for Greenhouse Gases

Greenhouse Gas	GWP
CO_2	1
CH_4	23
N_2O	296

Greenhouse gases are measured in terms of CO_2-equivalent emissions, which result from multiplying the GWP for each of the three pollutants shown in the above table by the mass of emissions for each pollutant. The sum of impacts for CH_4, N_2O, and CO_2, yields the total effective GHG impact.

The impact increased volumes of renewable fuels use has on GHG emissions (in terms of CO_2-eq.) as well as for only CO_2 emissions which represent a subset of the overall GHG emissions, is considered in this analysis. The impact increased volumes of renewable fuels use has on fossil energy (in terms of Btus) is also considered. Fossil energy use includes energy

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[63] IPCC "Climate Change 2001: The Scientific Basis", Chapter 6; Intergovernmental Panel on Climate Change; J.T. Houghton, Y. Ding, D.J. Griggs, M. Noguer, P.J. van der Linden, X. Dai, C.A. Johnson, and K. Maskell, eds.; Cambridge University Press. Cambridge, U.K. 2001. http://www.grida.no/climate/ipcc_tar/wg1/index.htm

associated with coal, natural gas, and petroleum products. Fossil energy use is strongly linked with CO_2 and GHG emissions and is an important consideration when looking at overall sustainability.

Petroleum energy use is a subset of fossil energy use and is the major contributor to overall transportation sector energy use. Petroleum energy use is also linked to CO_2 and GHG emissions but also has impacts on national energy concerns such as dependence on foreign sources of petroleum. Therefore, petroleum energy was also considered separately in this analysis and examined in terms of overall energy use, as well as in terms of petroleum imports avoided through the increased use of renewable fuels.

6.1.1.4 Time Frame and Volumes Considered

The results presented in this analysis represent a snapshot in time. They represent annual GHG and fossil fuel savings in the year considered, in this case 2012.

Consistent with the renewable fuel volume scenarios described in Chapter 2, our analysis of the GHG and fossil fuel consumption impacts of renewable fuel use was conducted using three volume scenarios. The first scenario was a reference case representing 2004 renewable fuel production levels, projected to 2012. This scenario provided the point of comparison for the other two scenarios. The other two renewable fuel scenarios for 2012 represented the RFS program requirements and the volume projected by EIA.

In both the RFS and EIA scenarios, we assumed that the biodiesel production volume would be 0.303 billion gallons based on an EIA projection. Furthermore, the Energy Act requires that 250 million gallons of cellulosic ethanol be produced starting in the year 2013, for both scenarios we assume that 250 million gallons of ethanol that qualify for cellulosic credit will be produced in 2012. The remaining renewable fuel volumes in each scenario would be ethanol made from corn and imports. The import volume is based on EIA's projections for the percent of total ethanol volume supplied by imports in 2012. The total volumes for all three scenarios are shown in Table 6.1-3.

Table 6.1-3. Volume Scenarios in 2012 (billion gallons)

	Reference Case	RFS Case	EIA Case
Corn-ethanol	3.947	5.985	8.758
Cellulosic ethanol	0.0	0.25	0.25
Biodiesel	0.030	0.303	0.303
Ethanol imports	0.0	0.436	0.630
Total volume	3.977	6.974	9.941

As we are comparing against a reference case, we are only interested in the emissions and energy savings associated with new or marginal renewable fuels production that comes on-line after 2004 (the baseline assumed for the reference case).

6.1.1.5 Model Used

The lifecycle model used in the evaluation of the impacts of the RFS program is the fuel-cycle model developed by DOE's Argonne National Laboratory. For this work, EPA used the most recent version of this model, GREET 1.7 (November 10, 2006 release). GREET, a multi-dimensional spreadsheet model, is one of the most widely used model of this type for transportation fuels. It has been reviewed, used, and referenced by a wide variety of analysts, including General Motors, National Corn Growers Association, several fuel industry organizations, and a wide variety of academic institutions. It is the most comprehensive and user-friendly model of its type. It has been under development for over 10 years, with input from EPA, USDA, DOE laboratories, and industry representatives. The model addresses the full lifecycle for an exhaustive number of alternative transportation fuels and automotive technologies. For these reasons, EPA felt it was the best tool for evaluating the energy and emission impacts of the RFS program.

The GREET model has been developed to calculate per-mile energy use and emission rates of various combinations of vehicle technologies and fuels for both fuel cycles and total energy cycles. The model actually consists of three components: GREET 1.x, which calculates fuel cycle energy use and emissions, GREET 2.x, which calculates light-duty vehicle cycle energy use and emissions, and GREET 3.x, which calculates heavy-duty vehicle cycle energy use and emissions. All discussion here refers to GREET 1.7, the most recent version of the fuel component of GREET.

To estimate fuel cycle energy use and emissions, GREET first estimates energy use and emissions for a given upstream stage. The model then combines the energy use and emissions from all upstream stages for a fuel cycle, to estimate total upstream fuel cycle energy use and emissions. Inputs are national-average energy usage rates, efficiencies and emission factors for each stage. The model calculates total energy use, fossil energy use, and emission rates for the regulated pollutants and greenhouse gases, reported as grams per mile or grams per million Btu. These results allow comparison of transportation fuels, based on energy use and/or emissions.

One of the main comments we received on our lifecycle approach was that our sole reliance on the GREET model should be avoided, given other models are available. There are several other models that have been developed for conducting renewable fuels lifecycle analysis. For example, researchers at the Energy and Resources Group (ERG) of the University of California Berkeley have developed the ERG Biofuel Analysis Meta-Model (EBAMM) and Mark Delucchi at the Institute of Transportation Studies of the University of California Davis has developed the Lifecycle Emissions Model (LEM). There are also other non-fuel specific lifecycle modeling tools that can be used to perform renewable fuel lifecycle analysis. The main differences in these models are with input assumptions used as described below.

Several studies have been released recently making use of these other models and showing different results than we find in the analysis done for this rule. For example, whereas GREET estimates a net GHG reduction of about 22% for corn ethanol compared to gasoline, the previously cited works by Farrell et al. utilizing the EBAMM show around a 13% reduction. While there may be small differences in the models in terms of emissions and energy uses associated with ancillaries (e.g., emissions to produce fertilizer, electricity, etc.) the main difference in results is not due to model used but assumptions on scope and input data used.

For example, most studies focus on average or current ethanol production which uses a current mix of wet and dry mill ethanol production and use of coal and natural gas as process energy. In contrast, we consider new or marginal ethanol production which implies a higher portion of more efficient dry mill production and mix of process fuels. Other studies also typically base ethanol and farm energy use on historic data while we are assuming a state of the art dry milling plant and most current farming energy use data. Assumptions concerning land use change CO_2 emissions and agriculture related GHG emissions could also have an impact on overall results. Other studies also differ in the environmental flows considered. For example, Delucchi[NNNN] uses different types of greenhouse gases and GWPs compared to those used in this analysis as shown in Table 6.1-2 to determine GHG emissions.

Other researchers have performed lifecycle analysis of renewable fuels not specifically focused on GHG emissions. One result that has been debated recently is the net energy balance of corn-based ethanol fuel. Some analysts have suggested that there is actually a negative energy balance for corn ethanol, meaning that it takes more fossil energy to produce the ethanol than is contained in the resulting fuel, making it an unattractive transportation fuel. While we do not believe this is an appropriate metric to use when examining renewable fuels, as discussed in Section 6.2.3, it is still useful in examining the range of lifecycle results. Two studies Pimental (2003)[64] and Patzek (2005), [65] concluded that the energy balance is negative. . Many other researchers, however, have criticized that work as being based on out-dated farming and ethanol production data, including data not normally considered in lifecycle analysis for fuels, and not following the standard methodology for lifecycle analysis in terms of valuing co-products. Furthermore, several recent surveys have concluded that the energy balance is positive, although they differ in their numerical estimates.[66,67,68] Authors of the GREET model have also concluded that the lifecycle amount of fossil energy used to produce ethanol is less than the amount of energy in the ethanol itself. Based on our review of all the available information, and the results of our own analysis, we also believe that the energy balance is positive.

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[64] Pimentel, David “Ethanol Fuel: Energy Balance, Economics, and Environmental Impacts are Negative”, Vol. 12, No 2, 2003 International Association for Mathematical Geology, Natural Resources Research

[65] Pimentel, D.; Patzek, T. "Ethanol production using corn, switchgrass, and wood; biodiesel production using soybean and sunflower." Nat. Resour. Res. 2005, 14 (1), 65-76.

[66] Hammerschlag, R. "Ethanol's Energy Return on Investment: A Survey of the Literature 1990 - Present." Environ. Sci. Technol. 2006, 40, 1744 - 1750.

[67] Farrell, A., Pelvin, R., Turner, B., Joenes, A., O’Hare, M., Kammen, D., “Ethanol Can Contribute to Energy and Environmental Goals”, Science, 1/27/2006, Vol 311, 506-508.

[68] Hill, J., Nelson, E., Tilman, D., Polasky, S., Tiffany, D., “Environmental, economic, and energetic costs and benefits of biodiesel and ethanol biofuels”, Proceedings of the National Academy of Sciences, 7/25/2006, Vol. 103, No. 30, 11206-11210.

The differences found by different studies and models used emphasize the importance of the input data and methodology when using lifecycle analysis. It also shows how dependent this type of analysis is on the assumptions made throughout the model. Based on differences in scopes and input data considered between these other studies and what we defined in this analysis, we believe the differences in results that are seen are reasonable and the values we are obtaining from our use of the GREET model are acceptable for this analysis.

6.1.2 Modifications to GREET

EPA chose to use GREET 1.7 to evaluate the lifecycle impacts of the RFS program. GREET 1.7 is the most recently released version of the GREET model. However, this version of the model does not reflect the potential impacts on transportation fuel industries as a result of the RFS program. In addition, for this regulation our intent was to evaluate the impact of incremental renewable fuel production resulting from the RFS program and not a current industry average. Therefore, EPA has modified some of the input variables and assumptions made in the GREET model. The renewable fuels considered in this analysis were modeled as being produced from the following feedstocks and processes:

- Corn Ethanol:
  - Wet Milling
    - Mix of coal and natural gas as process fuel
  - Dry Milling
    - Natural gas as process fuel
    - Coal as process fuel
    - Biomass as process fuel

- Cellulosic Ethanol:
  - Hybrid Poplar Feedstock
    - Fermentation route
  - Switchgrass Feedstock
    - Fermentation route
  - Corn Stover Feedstock
    - Fermentation route
  - Forest Waste Feedstock
    - Gasification route

- Biodiesel:
  - Soybean Oil Feedstock
    - Transesterification route
  - Yellow Grease Feedstock
    - Transesterification route

These feedstocks and processes were primarily based on what was available in the GREET model with some minor modifications as described below. However, there are other pathways for producing renewable fuels not covered here, for example different feedstocks for cellulosic ethanol production (e.g., MSW) as well as different process for the feedstocks considered, like gasification of switchgrass and production of soybean oil diesel fuel through hydrotreating.

Furthermore, the lifecycle analysis used for this rulemaking is based on averages of the different renewable fuels modeled. For example, the GHG emission and fossil energy savings associated with increased use of corn ethanol are calculated based on a mix of process fuels, assuming a certain projected mix of each process fuel as outlined below. While this method may not exactly represent the reductions associated with a given gallon of renewable fuel, it is reasonable for the purpose of this analysis which is to determine the impact of the total increased volume of renewable fuels used.

We recognize that different feedstocks and processes will each have unique characteristics when it comes to lifecycle GHG emissions and energy use. However, we understand that other feedstocks and processes as well as differences in other parts of the renewable fuel lifecycle will impact the savings associated with their use and this is the focus of ongoing work at the agency.

GREET is subject to periodic updates by ANL, each of which results in some changes to the inputs and assumptions that form the basis for the lifecycle estimates of emissions generated and energy consumed. These updates generally focus on those input values for those fuels or vehicle technologies that are the focus of ANL at the time. As a result there are a variety of other inputs related to ethanol and biodiesel that may not have been updated in some time. In the context of the analysis of the RFS and EIA scenarios, we determined that some of the GREET input values that were either based on outdated information or did not appropriately reflect market conditions under a renewable fuels mandate should be examined more closely, and updated if necessary.

Since the analysis done for the NPRM, several changes have been made to the GREET model, some as part of periodic updates ANL had planned and some as part of an interagency agreement between ANL and EPA to investigate a variety of GREET input values. A summary of the changes is as follows:

- Included CO_2 emissions from corn farming lime use
- Updated the corn farming fertilizer use inputs
- Added cellulosic ethanol production from corn stover and forest waste
- Modeled biomass as a process fuel source in corn ethanol dry milling

In addition to the changes above we also examined and updated other GREET input assumptions for corn ethanol and biodiesel production. A summary of the GREET input values we investigated and modified is given below. We also examined several other GREET input values, but determined that the default GREET values should not be changed for a variety of reasons as discussed in the following sections. These included corn and ethanol transport distances and modes and byproduct allocation methods. Our investigation of these other GREET input values are discussed more fully below. The current GREET default factors for these other inputs were included in the analysis for this final rule.

We did not investigate the input values associated with the production of petroleum-based gasoline or diesel fuel in the GREET model for this final rule. However, the refinery modeling discussed in Chapter 7 will provide some additional information on the process energy requirements associated with the production of gasoline and diesel under a renewable fuels mandate. We will use information from this refinery modeling in future analysis to determine if any GREET input values should be changed.

A summary of the GREET corn ethanol input values we investigated for this final rule is given below.

6.1.2.1 Wet Mill versus Dry Mill Ethanol Plants

As described in Chapter 1, the two basic methods for producing ethanol from corn are dry milling and wet milling. In the dry milling process, the entire corn kernel is ground and fermented to produce ethanol. The remaining components of the corn are then dried for animal feed (dried distillers grains with solubles, or DDGS). In the wet milling process, the corn is soaked to separate the starch, used to make ethanol, from the other components of the corn kernel. Wet milling is more complicated and expensive than dry milling, but it produces more valuable products (ethanol plus corn syrup, corn oil, and corn gluten meal and feeds). The majority of ethanol plants in the United States are dry mill plants, which produce ethanol more simply and efficiently.

While other lifecycle models often base the mix of wet and dry milling on existing plants, for this analysis, we are only interested in marginal ethanol production. We expect most new ethanol plants will be dry mill operations. That has been the trend in the last few years as the demand for ethanol has grown, and our analysis of ethanol plants under construction and planned for the near future has verified this. Our analysis of production plans, as outlined in Chapter 1, indicates that essentially all new ethanol production will be from dry mill plants (99%).

6.1.2.2 Coal versus Natural Gas in Ethanol Plants

The type of fuel used within the ethanol plant for process energy to power the various components that are used in ethanol production (dryers, grinders, heating, etc.) can vary among ethanol plants. The type of fuel used has an impact on the energy usage, efficiency, and emissions of the plant, and is primarily determined by economics. Most new dry mill plants built in the last few years have used natural gas. However, some new plants are using coal. For these cases, EPA is promoting the use of combined heat and power, or cogeneration, in ethanol plants to improve plant energy-efficiency and to reduce air emissions. This technology, in the face of increasing natural gas prices, may make coal a more attractive energy source for new ethanol plants.

GREET default factors represent the average percentage of fuel use for the entire industry, and may not reflect the recent growth in the industry. Therefore, we based our fuel mix assumptions on the review of plants under construction and those planned for the near future outlined in Chapter 1. Our analysis indicates that coal will be used as process fuel for approximately 14% of the new dry mill under construction and planned ethanol production volume capacity. This is the value we used in GREET for our analysis of dry milling ethanol production fuel mix.

As opposed to typical dry mill plants, corn wet mill ethanol plants can use a mix of process fuel sources at the same plant. For the 1% of additional ethanol production from wet mills, the GREET model defaults of 40% coal and 60% natural gas process fuel was used in this analysis.

As described below, the ethanol production stage of the lifecycle typically represents the stage where the largest amount of fossil fuel energy is consumed and where the impact on lifecycle emissions is the greatest. Therefore, the type of process fuel used in ethanol production will have a significant impact on the fuel's lifecycle GHG results. For example, our analysis indicates that ethanol produced in a coal fired dry mill plant would not have any GHG benefits as compared to petroleum gasoline. Given that the relative prices of natural gas and coal could change over time, and thus change the percentage of each used in ethanol production, our analysis of fuels used in plants under construction and those planned for the future would need to be reevaluated for future work.

6.1.2.3 Ethanol Plant Process Efficiency

For the corn-to-ethanol fuel cycle, the largest amount of fossil fuel energy consumed occurs at the ethanol production plant. The energy use at a dry mill plant using natural gas was based on the model developed by USDA which was documented in a peer-reviewed journal paper on cost modeling of the dry-grind corn ethanol process.[OOOO] This model was modified by EPA for use in the cost analysis of this rulemaking described in Chapter 7. GREET inputs are total energy use per gallon of ethanol produced. The USDA model predicts the annual thermal (natural gas) and electricity demand shown in Table 6.1-4.

Table 6.1-4.
Annual Energy Use at Dry Mill Ethanol Plant

Energy Input	Value
Purchased Electricity (MWh/yr.)	41,308
Natural Gas (mmBtu/yr.)	1,617,094
Output	
Ethanol (mmgal/yr.)	50

Electricity energy use was converted from MWh to Btu based on a conversion of 3,410 btu/kWh. The primary energy used to produce electricity is accounted for in the GREET model. Table 6.1-5 shows the GREET input used for natural gas process fuel dry milling plants in this analysis.

Table 6.1-5.
GREET Inputs for Corn Ethanol
Natural Gas Dry Mill Energy Use

Total Energy Use (mmBtu/gal.)	35,159
% electricity	8.0%

Energy requirements for a coal fired ethanol plant are different from a natural gas fired plant. Typically coal boilers are slightly less efficient than natural gas boilers. Furthermore additional electricity is required for coal storage and handling as compared to natural gas. Additionally a large portion of the energy at an ethanol plant is due to drying the DDGS. A natural gas plant utilizes natural gas driers for this process while a coal fired plant would use steam dryers, the efficiency loss of converting coal to steam represents additional thermal energy required at a coal fired plant vs. a natural gas one.

Most other lifecycle models assume the same energy efficiency for both coal and natural gas ethanol plants, however, for this analysis, it was assumed that a coal plant would require 15%[69] more electricity demand due to coal handling and have a 13% increase in thermal demand for steam dryers as compared to the natural gas fueled plant. The increase in thermal demand was based on breaking out the drying energy in the USDA process model and assuming the same amount of energy would be produced by 78% efficient coal boilers. Table 6.1-6 shows the GREET input used for coal process fuel dry milling plants in this analysis.

Table 6.1-6.
GREET Inputs for Corn Ethanol
Coal Dry Mill Energy Use

Total Energy Use (mmBtu/gal.)	40,079
% electricity	8.1%

The Energy Act also allows ethanol made from non-cellulosic feedstocks to receive cellulosic ethanol production volume credit if 90 percent of the process energy used to operate the facility is derived from a renewable source. In the context of our cost analysis, we have assumed that 250 million gallons of corn ethanol will be produced using 90 percent or more biomass energy and receive the cellulosic ethanol volume credit. Further discussion of this issue can be found in Chapter 1.

For the lifecycle analysis we considered the case where a corn ethanol dry mill plant utilized biomass as a fuel source. For this case the same amount of fuel and purchased electricity energy per gallon as a coal powered plant was assumed. This assumption is based on the biomass plant having more fuel handling than a natural gas plant and producing steam for DDGS drying.

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[69] Baseline Energy Consumption Estimates for Natural Gas and Coal-based Ethanol Plants - The Potential Impact of Combined Heat and Power (CHP), Prepared for: U.S. Environmental Protection Agency Combined Heat & Power Partnership, Prepared by: Energy and Environmental Analysis, Inc., July 2006.

As discussed in section 6.2.3, CO_2 emissions from combustion of biomass are not assumed to increase net atmospheric CO_2 levels. Therefore, CO_2 emissions from biomass combustion as a process fuel source are not included in the lifecycle GHG inventory of the ethanol plant. The fossil energy use and GHG emissions from producing the electricity used at the plant are included.

For the 1% of corn ethanol produced from wet milling, the GREET process energy use default of 49,950 Btu/gallon of ethanol produced by the wet milling process was used in the analysis.

6.1.2.4 Corn Transport Distances

Corn transport distances selected for use in this analysis are 100 miles round trip. Corn used in the ethanol production process is assumed to travel from corn fields to ethanol production facilities in a two-step process; first, corn is transported from outlaying farms to centrally-located collection facilities, such as county elevators. Second, this corn is transported from the collection facilities to the ethanol production facilities. The first leg of the corn transport process is assumed to be a 20-mile round trip and the second leg is assumed to be an 80-mile round trip. These assumptions coincide with those used in GREET[PPPP] Version 1.7 and GREET Version 1.5.

Corn transport data is limited, however; Graboski[70] found that the average one-way hauling distance for corn from fields to county elevators was 7.5 miles and from county elevators to ethanol processing facilities was 49.7 miles for an effective average round-trip corn transport distance of 74.6 miles. Similarly, Gervais and Baumel[QQQQ] found that average one-way corn transport distances for the 1994-1995 Iowa growing season was 37.2 miles for semi-trucks (35.8%), 4.9 miles for wagons (33.3%), and 9.1 miles for single and tandem axel vehicles (30.9%). Several Minnesota corn mills indicated that the maximum radius of supply for their mills was 65 to 80 miles (values apparently cited in the same study).

The available data on corn transport distances does not provide a clear indication that the default values in GREET are unreasonable. Therefore, we retained the GREET default values for our analysis. This assumes that the land use pattern (where corn is planted) and the plant location decisions by ethanol plants will not change significantly. We believe this is reasonable for the fuel volumes considered. This is an area we will continue to examine for future analysis.

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[70] The authors assume that the corn payload weight is equal to the transport vehicle weight, that the vehicle returns empty, and the effective average round-trip vehicle distance can be estimated as being one and a half times the one-way travel distance (1.5 times 49.7 miles = 74.6 miles); Graboski, 2002, *Fossil Energy Use in the Manufacture of Corn Ethanol*, Colorado School of Mines, (Prepared for the National Corn Growers Association).

6.1.2.5 Ethanol Transportation Distances and Modes

The default values in GREET for ethanol transportation and modes are shown in Table 6.1-7. These values correspond to numbers in a USDA study on the energy balance of corn ethanol.[RRRR]

Table 6.1-7. GREET Ethanol Transportation Input Data

Mode	Plant to Terminal		Terminal to Station	
	%	Distance (miles)	%	Distance (miles)
Rail	40%	800	0%	
Barge	40%	520	0%	
Truck	20%	80	100%	30

The GREET default values are consistent with the analysis we performed on ethanol distribution infrastructure. Chapter 1 of this document discusses current ethanol transportation and distribution and indicates that if ethanol facilities are located within 100-200 miles of a terminal, trucking is preferred. Rail and barge are used for longer distances. Pipelines are not currently used to transport ethanol and are not projected to play a role in ethanol transport in the future time frame considered.

We also discuss in Chapter 1 future ethanol transportation and distribution needs based on the increased amounts of renewable fuels used as a result of this rule. We concluded that most new ethanol capacity will not have river access. In addition, at least one new ethanol plant slated for production that does have river access is planning to move its ethanol to market via rail so most new ethanol freight volumes will be handled by rail and that ethanol transport by inland waterway will remain constant.

A recent USDA Cost of Ethanol Production report also provides information on ethanol distribution distances and modes.[SSSS] The report includes 2002 data from a survey of 21 dry mill ethanol plants. The survey collected data on modes and distances traveled for ethanol transport from the facilities. The report concluded that 46 percent of the ethanol produced at the surveyed plants in 2002 was shipped by truck an average one way distance of 93 miles, with a range of 30 to 250 miles. The remaining 54 percent of ethanol produced was shipped by rail an average one way distance of 1,163 miles, with a range of 800 to 2,500 miles. However, this data is for a subset of existing plants where, for example, there is no barge transportation listed, and also does not take into account the increased demand for ethanol projected by this rule.

Comparing the GREET default values to these other sources indicates that the GREET defaults values for percent of ethanol transported by rail may be low. However, due to lack of precise data on future ethanol transportation by mode, we concluded that the current GREET default values for percent of ethanol transported by mode are appropriate for the RFS analysis.

The GREET default values for miles shipped by mode fall within the range of values listed in the USDA survey data of existing plants. The USDA survey data indicate higher than average transportation distances; however the data is not comprehensive enough, only representing a small fraction of total and projected ethanol production capacity, thus not warranting a change to the default GREET values. Therefore, the default values shown in Table 6.1-7 were used in this analysis. This is an area we will continue to examine for future analysis.

6.1.2.6 Biodiesel Transportation Distances and Modes

The default values in GREET for biodiesel transportation and modes are shown in Table 6.1-8.

Table 6.1-8. GREET Biodiesel Transportation Input Data

Mode	**Plant to Terminal**		**Terminal to Station**	
	%	Distance (miles)	%	Distance (miles)
Barge	8%	520	0%	
Pipeline	63%	400	0%	
Rail	29%	800	0%	
Truck	0%		100%	30

The GREET default assumptions for mode of biodiesel transportation are not consistent with the analysis we performed on biodiesel distribution infrastructure. The distribution infrastructure discussion in Chapter 1 of this document indicates pipelines are not currently used to transport biodiesel and are not projected to play a role in biodiesel transport in the future time frame considered.

Therefore, GREET default factors for biodiesel transportation from plant to terminal were modified to remove pipeline transport. The percent of biodiesel shipped by barge and rail were increased in the same proportion as the current percentage split. The result was 22% of biodiesel shipped by barge and 78% shipped by rail. The GREET default distances for biodiesel rail and barge transport as well as terminal to station assumptions are consistent with ethanol transportation and distribution assumptions and were used in this analysis.

6.1.2.7 Corn Yield and Related Inputs

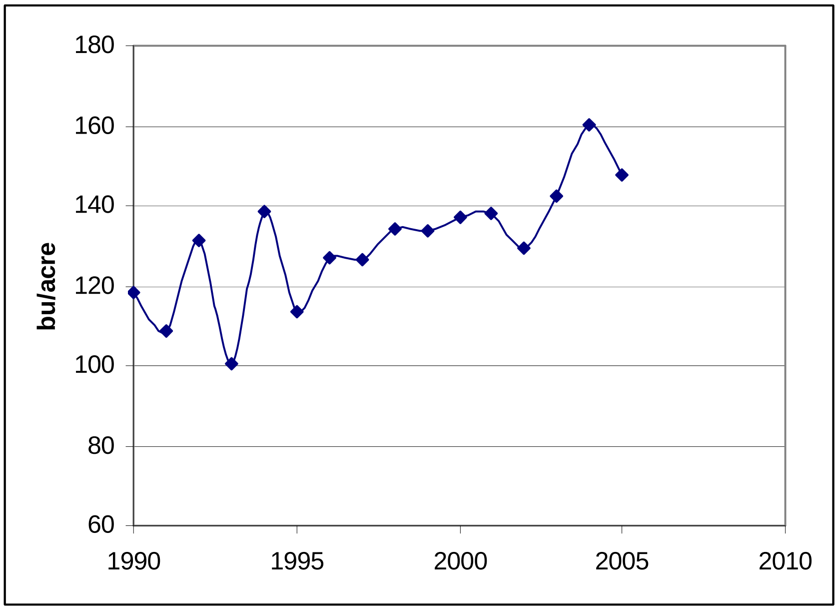
GREET includes a collection of energy use and material inputs to corn farming per bushel (bu) of corn produced. Several corn farming input data parameters and default values were updated from the version of GREET used for the NPRM to the version used in the FRM analysis. The current GREET corn farming input data default values are shown in Table 6.1-9.

Table 6.1-9. GREET Corn Farming Input Data

Input Parameter	Default Value
Energy Use for Corn Farming	22,500 Btu/bu
- Energy use from diesel fuel	38.3%
- Energy use from gasoline	12.3%
- Energy use from natural gas	21.5%
- Energy use from LPG	18.8%
- Energy use from purchased electricity	9.0%
Nitrogen Fertilizer (as N)	420 g/bu
Phosphate Fertilizer (as P_2O_5)	149 g/bu
Potash Fertilizer (as K_2O)	174 g/bu
Lime (as $CaCO_3$)	1,202 g/bu
Herbicide Use:	8.1 g/bu
Insecticide Use:	0.68 g/bu

The default GREET input values for corn farming shown in Table 6.1-9 are based in part on farm energy use and material inputs per acre divided by an assumed corn yield in bu/acre. Therefore, while corn yield is not a direct input in GREET, it is a critical part of the calculation of corn energy and material input requirements. Although corn yields have been generally rising over time, see Figure 6.1-2, the annual variation is volatile.

Figure 6.1-2. U.S. Average Corn Yield[TTTT]



We examined data on farm energy use, material input, and yield data to determine if the GREET default values needed to be updated. The lifecycle modeling conducted for the RFS program is based on future predictions. Unfortunately, no good projections of future energy use associated with corn farming are available. USDA does list projections for corn yield. The 2012 projected U.S. average corn yield is 158.5 bu/acre.[UUUU] Historic data on corn farming energy use is available from the following USDA information sources.

- The USDA Agricultural Resource Management Survey (ARMS) provides data from selected States on fuel, electricity, natural gas, and seed corn used per acre on the farm and activities of moving farm products to initial storage facilities.
- The USDA National Agricultural Statistics Service (NASS) produces annual data on crop production including yields per acre and total production of corn by state.

USDA NASS data on corn yields and production values are provided annually. However, the three most recent years of the ARMS data and specifically the costs-of-production portion of the survey dedicated to corn are 1991, 1996, and 2001[71]. Table 6.1-10 lists corn farming energy input data for the three years of the ARMS study.

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[71] Use of historic farming energy use may not be representative of current practice. Higher energy prices relative to the years considered here could lead to farmers adopting practices that lower overall energy use.

Table 6.1-10. Farm Energy Use Data per Acre

Input	Units	9-State Weighted Average Values			
		1991	1996[a]	2001	3 Yr. Avg.
Seed	bu/acre	1.51	1.50	1.69	1.57
Energy:					
- Diesel	Gallons/acre	7.81	9.80	6.40	8.01
- Gasoline	Gallons/acre	3.42	3.07	1.65	2.71
- LPG	Gallons/acre	3.86	7.25	5.10	5.41
- Electricity	kWh/acre	32.72	79.38	38.22	50.11
- Natural Gas	Cubic ft/acre	284.73	208.12	207.09	233.31
Total Energy Use	mmBtu/acre	2.12	2.71	1.78	2.20

[a] High energy use in the 1996 survey is due to increased corn drying requirements. See the discussion below.

Although USDA corn data is available for every state that produces corn, the data documented in Table 6.1-10 is for nine major corn producing States: Illinois, Indiana, Iowa, Minnesota, Nebraska, Ohio, Michigan, South Dakota, and Wisconsin. In 2005, these nine States accounted for 80 percent of U.S. corn production. In 2001 these nine States represented 92 percent of U.S. ethanol production, and based on our analysis outlined in Chapter 1 are projected to represent 82 percent of ethanol production in 2012. The data in Table 6.1-10 are weighted based on corn production data for each of the nine States from the NASS. The total energy use values listed in Table 6.1-10 were calculated by converting fuel use to Btu based on the lower heating values of the fuels as listed in the GREET model. These estimates may be biased downward if the corn production attributable to the incremental increase in ethanol production will occur on less productive land than was used in the 1991-2001 period, when corn prices were lower than they are projected to be in this analysis. Also, as corn production expands due to expanded ethanol production, it may increasingly take place in dryer climates that may increase irrigation demand and result in different yields. This is an area we will continue to examine for future analysis.

The ARMS surveys include information on energy use and also on dollars spent by farmers on custom work. This custom work includes farmers contracting outside services for corn drying, planting, fertilizing and harvesting. The cost of custom work includes machine overhead, fuel charges, and labor costs. Therefore, there is some energy use associated with the dollars spent on fuel used in custom work. It was assumed that 10% of custom work cost was spent on fuel[VVVV]. This fuel cost was assumed to be split between LPG and diesel fuel in the same percentage as reported energy use for each state. Cost was converted to gallons based on price paid by farmers for LPG and diesel fuel in each of the survey years[WWWW]. Custom work energy use is included in Table 6.1-10.

It can be seen from Table 6.1-10 that there is substantial variation in the three years of energy use survey data. Several factors can influence corn farming energy use. For example, it was reported that 1991 was a dry year, lowering the moisture content of the corn crop and thus requiring less energy to dry the corn, whereas the 1996 crop was reported to have a higher moisture content and thus require more energy to dry resulting in the high energy use values for

1996. Farm diesel use is also dependent on tillage type and soil conditions, wetter soil requiring more diesel use, and decreased tillage requirements (e.g., no till) reducing diesel use.[XXXX]

To project corn farming fuel use in 2012, the average energy use from the three years of survey data were taken, in terms of energy per acre. As energy use is somewhat weather related and it is impossible to confidently predict future conditions, it was felt that the three years of historic data represented a good mix of high and low energy use years. The average energy use in terms of Btu/acre was divided by the projected corn yield in 2012 of 156.9 bu/acre. This is the USDA projected corn yield adjusted to account for seed corn energy use as shown in Table 6.1-10. The seed use shown in Table 6.1-10 accounts for seed corn energy use. We assumed that growing seed corn requires 4.7 times the energy and material inputs to grow than corn[YYYY,ZZZZ]. The result was 14,036 Btu of energy needed to produce a bushel of corn, which was used in GREET for this analysis.

The GREET default values for corn farming material inputs were updated from the values in the NPRM version. GREET defaults were based on historic data provided from the following USDA sources.

- The USDA National Agricultural Statistics Service (NASS) produces annual reports listing quantities of fertilizers and chemicals used per acre of corn.
- The USDA Economic Research Service (ERS) produces an Agricultural Resources and Environmental Indicators report that has data on lime used per acre of corn.

The USDA sources provide average material use data per harvested acre of corn. The GREET defaults are based on the assumption that material input use per acre will be flat from 2005 into the future. The 2005 values are based on a three year average of 2003 through 2005 data. Data on inputs per acre are divided by projected corn yields to get GREET defaults in terms of g/bushel of corn. While these values are felt to be reasonable to be used in this analysis, the agency cautions that these estimates are based on the historical record while the incremental corn production attributable to expanded ethanol production may occur on less productive land than was used historically. As a result, these estimates may be biased downward, resulting in over-estimates of ethanol displacement indices.

Another potential input to corn farming is the energy and emissions associated with producing farm equipment. As described in Section 6.1.1.2, this input is considered outside the system boundaries of our lifecycle analysis. However, the latest version of GREET has an option to include energy use and emissions associated with producing farm equipment in the corn ethanol lifecycle results. We performed a sensitivity analysis on expanding the corn production system to include farm equipment production to determine the impact it has on the overall results of our analysis.

It was found that including farm equipment production energy use and emissions increases ethanol lifecycle energy use and GHG emissions and decreases the corn ethanol displacement index by approximately 1 percent. Furthermore, to be consistent in the modeling if system boundaries are expanded to include production of farming equipment they should also be expanded to include producing other material inputs to both the ethanol and petroleum lifecycles.

For example, this expansion of system boundaries would include the energy use and emissions associated with producing concrete and steel used in the petroleum refinery[72]. The net effect of this would be a slight increase in both the ethanol and petroleum fuel lifecycle results and a smaller or negligible effect on the comparison of the two.

The corn farming material and energy use used in the lifecycle analysis is based on producing and average bushel of corn. There are differences associated with variations in corn yield, inputs required for existing land vs. land converted to crops, etc. Furthermore, there are ripple effects associated with increased corn used for ethanol that could have GHG emission implications, ranging from changes in manure management to the acres of rice grown. One such effect is CO_2 associated with land use change which is examined in the following section. Other effects and variations in corn farming will be examined as part of future analysis.

6.1.2.8 CO_2 from Land Use Change

Farming practices could potentially release carbon stored in soil as CO_2 emissions. If non-cropland (e.g., pastureland, Conservation Reserve Program (CRP) land) is converted to crop production, carbon sequestered in the soil and existing cover could be released. The agricultural sector modeling work done for this rulemaking examined the issue of land use change due to increases in renewable fuel production and use. The agricultural sector modeling results indicate that, compared to the 2012 Reference Case, approximately two and a half million acres will come out of CRP land as a result of increased renewable fuel production. Not all of these two million acres will go directly into corn production used to produce ethanol. However, the entire amount of CO_2 emissions from the CRP land use change is attributable to the increased amount of ethanol produced, as without the increased demand for corn there would be no change in CRP land. The agricultural modeling results also indicated a reduction in U.S. corn exports and a modest decline in U.S. soybean exports which could impact crop production in other countries. However, we did not consider impacts on non-U.S. land use that might result from decrease in U.S. exports of corn and soybeans.

The GREET model has a default factor for CO_2 from land use change that was included in the NPRM analysis. This factor was updated based on the results of the agricultural sector modeling mentioned above and included in the final rulemaking lifecycle analysis. The CO_2 emissions from land use change used in the final rulemaking represent approximately 1% of total corn ethanol lifecycle GHG emissions. However, this value could be more significant if increased amounts of renewable fuels are used.

The issue of CO_2 emissions from land use change associated with converting forest or CRP land into crop production for use in producing renewable fuels is an important factor to consider when determining the overall sustainability of renewable fuel use. While the analysis described above is indicating that this rulemaking will not cause a significant change in land use, this is an area we will continue to research for any future analysis.

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[72] The expansion of system boundaries would apply to existing refineries as ethanol is assumed to replace gasoline from existing production.

6.1.2.9 Ethanol Production Yield

Modern ethanol plants are now able to produce more than 2.7 gallons of ethanol per bushel of corn compared with less than 2.4 gallons of ethanol per bushel of corn in 1980. The development of new enzymes continues to increase the potential ethanol yield. We used a value of 2.71[73] gal/bu in our analysis, which may underestimate actual future yields. However, this value is consistent with the ethanol model developed by USDA described in Section 6.1.2.2 and was used in the cost modeling of corn ethanol discussed in Chapter 7.

6.1.2.10 Byproduct Allocation

There are a number of by-products made during the production of ethanol. In lifecycle analyses, the energy consumed and emissions generated by an ethanol plant must be allocated not only to ethanol, but also to each of the by-products. There are a number of methods that can be used to estimate by-product allocations. These include methods based on the economic value of each by-product, or on energy usage, based on engineering analysis of the actual processes related to each product. The method preferred by EPA is called the displacement method. This method most accurately accounts for these by-products by calculating the lifecycle emissions of the products that will be displaced by them. In this method the lifecycle emissions of the displaced product are calculated and subtracted from the ethanol lifecycle. The ethanol receives a credit for the lifecycle emissions of whatever product is displaced, since a quantity of that product is no longer needed and is displaced by the ethanol by-products.

For example, the DDGS produced by an ethanol dry mill plant is a replacement for corn and soybean animal feed. We based the amount of DDGS produced by an ethanol dry mill plant on the USDA model used in the cost analysis work of this rulemaking. That model predicted 6.21 dry lb. of DDGS per gallon of ethanol produced. As per the agricultural sector modeling done for this rulemaking, we assumed that this DDGS displaces 50% corn and 50% soybean meal on a mass basis. So the lifecycle emissions of producing 3.1 lb. of corn and 3.1 lb. of soybean meal were calculated and subtracted from the lifecycle emissions associated with producing a gallon of ethanol.

By-products from the ethanol wet milling process include corn gluten meal and corn gluten feed that are assumed to displace corn production, as well as corn oil that is assumed to displace soybean oil. Ethanol produced from cellulosic feedstock through the fermentation route is assumed to produce excess electricity as a by-product, from onsite combustion of lignin. This excess electricity is assumed to displace electricity from the grid. The fermentation process used to produce ethanol in corn wet and dry milling and cellulosic ethanol production also produces CO_2 as a by-product. This CO_2 could be sold to an organization that specializes in cleaning and pressurizing it for use in the food industry for example to carbonate beverages, to manufacture dry ice, and to flash freeze meat. While CO_2 could potentially displace other sources of CO_2 production, this was not considered in our analysis and no value was associated with this CO2 co-product.

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[73] All yield values presented represent pure ethanol production (i.e. no denaturant).

The displacement method for by-product allocation is the default for the GREET model. EPA supports that approach and continues to use that method in this analysis. However, other researchers have used different allocation methods in their ethanol fuel cycle studies. We evaluated one of these other methods used by USDA in a recent ethanol energy balance report[AAAAA] to determine the impact this assumption has on the overall results of the analysis. The method used by USDA was to split the energy use and emissions of corn agriculture and ethanol production between the ethanol and co-products. The lifecycle analysis results were then based on only the ethanol portion. A process simulation was used to allocate the energy used in the ethanol plant to ethanol and by-products. Using this approach they determined that on average 59 and 64 percent of the energy used in dry and wet mills respectively is used to produce ethanol. The remaining energy is used for the production of by-products. Therefore, for dry mill ethanol production only 59 percent of the plant energy use and associated emissions were allocated to the ethanol lifecycle. Corn production energy use and emissions were allocated based on the starch content of the corn, assumed to be 66 percent of corn kernel weight. So, only 66 percent of the energy and emissions used to produce corn were allocated to the ethanol lifecycle.

Use of the process energy based allocation method reduces ethanol lifecycle energy use and GHG emissions by approximately 30 percent compared to the displacement allocation approach. This indicates that ethanol lifecycle analysis results are extremely sensitive to the choice of allocation method used. However, as mentioned above, EPA feels that the displacement allocation method is the most reasonable and is the preferred method to use. This decision is supported by international lifecycle assessment standards which indicate that whenever possible the product system should be expanded to include the additional functions related to the co-products[BBBBB].

6.1.2.11 Biodiesel Production

Two scenarios for biodiesel production were considered, one utilizing soybean oil as a feedstock and one using yellow grease.

For the soybean oil scenario, the energy use and inputs for the biodiesel production process were based on a model developed by NREL and used by EPA in the cost modeling of soybean oil biodiesel, as discussed in Chapter 7.

The GREET model does not have a specific case of biodiesel production from yellow grease. Therefore, as a surrogate we used the soybean oil based model with several adjustments. For the yellow grease case, no soybean agriculture emissions or energy use was included. Soybean crushing was still included as a surrogate for yellow grease processing (purification, water removal, etc.). Also, due to additional processing requirements, the energy use associated with producing biodiesel from yellow grease is higher than for soybean oil biodiesel production. As per the cost modeling of yellow grease biodiesel discussed in Chapter 7, the energy use for yellow grease biodiesel production was assumed to be 1.72 times the energy used for soybean oil biodiesel.

The biodiesel lifecycle results were based on a 50% / 50% split between soybean oil and yellow grease biodiesel production based on EIA's AEO 2006 projections for biodiesel produced from the different feedstocks.

6.2 Methodology

As outlined in the scoping discussion, the goals of this analysis are to both examine the total GHG and fossil fuel reductions of increased renewable fuel use in absolute tons and gallons and to compare these reductions to the U.S. transportation sector and nationwide GHG emissions and fossil fuel use. The output of the GREET model can be used directly to calculate tons of GHG and gallons of petroleum reduced. However, these results are not entirely consistent with transportation sector and nationwide emissions inventories which are based on slightly different assumptions concerning fuel heating values and carbon content. As a result we could not use GREET directly to estimate the nationwide impacts of replacing some gasoline and diesel with renewable fuels.

To be consistent between our modeling of savings and overall sector inventories, we used GREET instead to generate comparisons between renewable fuels and the petroleum-based fuels that they displace. These comparisons allowed us to develop displacement indexes which represent the percent of lifecycle GHGs or fossil fuel reduced when a Btu of renewable fuel replaces a Btu of gasoline or diesel. In this way GREET was used to generate percent reductions and not absolute values. These percent reductions or displacement values were then applied to the same gasoline and diesel fuel inventories used to generate transportation sector and nationwide inventories. This ensured that savings and sector wide inventories in terms of absolute values were calculated in a consistent manner.

In order to estimate the impacts of increased use of renewable fuels on fossil energy and greenhouse gases, we first determined how much gasoline and diesel would be replaced as a result of this rule. We then combined lifecycle percent reductions from GREET with lifecycle inventories and petroleum consumption values for gasoline and diesel fuel use to get the amounts of fossil energy and greenhouse gases reduced. For example, to estimate the impact of corn-ethanol use on GHGs, these factors were combined in the following way:

$$S_{\text{GHG,corn ethanol}} = R_{\text{corn ethanol}} \text{ x } LC_{\text{gasoline}} \text{ x } DI_{\text{GHG,corn ethanol}}$$

where:

$S_{\text{GHG,corn ethanol}}$ = Lifecycle GHG emission reduction over the reference case associated with use of corn ethanol (million metric tons of GHG)

$R_{\text{corn ethanol}}$ = Amount of gasoline replaced by corn ethanol on an energy basis (Btu)

LC_{gasoline} = Lifecycle emissions associated with gasoline use (million metric tons of GHG per Btu of gasoline)

$DI_{\text{GHG,corn ethanol}}$ = Displacement Index for GHGs and corn ethanol, representing the percent reduction in gasoline lifecycle GHG emissions which occurs when a Btu of gasoline is replaced by a Btu of corn ethanol

Variations of the above equation were also generated for impacts on all four endpoints of interest (fossil fuel consumption, petroleum consumption emissions of CO_2, and emissions of GHGs) as well as all three renewable fuels examined (corn-ethanol, cellulosic ethanol, and biodiesel). These values are then compared to the total U.S. transportation sector and nationwide inventories of fossil energy and greenhouse gases to get the overall impacts of the rule.

In this regard, the impact on overall transportation sector GHG emissions due to the increased use of renewable fuels can be described mathematically as follows:

$$\text{TSector}_{\text{%,GHG}} = \frac{S_{\text{GHG,corn ethanol}} + S_{\text{GHG,cell ethanol}} + S_{\text{GHG,biodiesel}}}{\text{TSector}_{\text{GHG}}}$$

where:

$\text{TSector}_{\text{%,GHG}}$ = Percent reduction in overall transportation sector GHG emissions resulting from the use of renewable fuels (%)

$S_{\text{GHG,corn ethanol}}$ = Lifecycle GHG emission reduction over the reference case associated with use of corn ethanol (million metric tons of GHG)

$S_{\text{GHG,cell ethanol}}$ = Lifecycle GHG emission reduction over the reference case associated with use of cellulosic ethanol (million metric tons of GHG)

$S_{\text{GHG,biodiesel}}$ = Lifecycle GHG emission reduction over the reference case associated with use of biodiesel (million metric tons of GHG)

$\text{TSector}_{\text{GHG}}$ = Overall transportation sector GHG emissions in 2012 (million metric tons of GHG)

We used the same approach to estimate fossil energy, petroleum energy, and CO_2 reductions in the transportation sector. We also used the same approach to estimate nationwide reductions.

Section 6.2.1 describes how we estimated the amount of gasoline and diesel fuel replaced as modeled for this rule. Section 6.2.2 describes the lifecycle emissions and energy associated with gasoline and diesel fuel use. In Section 6.2.3 below, we outline how we generated displacement indexes using GREET. Section 6.2.4 outlines how we developed the overall transportation sector and nationwide fossil energy and greenhouse gas emissions.

6.2.1 Modeling Scenarios

In general, the volume fraction (R) in the equation above represents the amount of conventional fuel no longer consumed – that is, displaced – as a result of the use of the replacement renewable fuel. Thus R represents the incremental amount of renewable fuel used under each of our renewable fuel volume scenarios, in units of Btu. We make the assumption that vehicle energy efficiency will not be affected by the presence of renewable fuels (i.e., efficiency of combusting one Btu of ethanol is equal to the efficiency of combusting one Btu of gasoline).

As described in Section 6.1.1.4, our analysis of the GHG and fossil fuel consumption impacts of renewable fuel use was conducted using three volume scenarios. The total volumes for all three scenarios are shown in Table 6.1-3. For the purposes of calculating the R values, we assumed the ethanol volumes shown in Table 6.1-3 are 5% denatured, and the ethanol volumes were adjusted down to represent pure (100%) ethanol. The adjusted volumes were then converted to total Btu using the appropriate volumetric energy content values (76,000 Btu/gal for ethanol, and 118,000 Btu/gal for biodiesel).

Since the impacts of increased renewable fuel use were measured relative to the 2012 reference case, the value of R actually represented the incremental amount of renewable fuel between the reference case and each of the two other scenarios. The results are shown in Table 6.2-1. The results shown in Table 6.2-1 are direct reductions in fuel use and do not represent lifecycle savings.

Table 6.2-1.
Direct Conventional Fuel Replaced in 2012 (quadrillion Btu)

	RFS Case	EIA Case
Gasoline Replaced by Corn Ethanol	0.147	0.347
Gasoline Replaced by Cellulosic Ethanol	0.018	0.018
Diesel Fuel Replaced by Biodiesel	0.032	0.032
Gasoline Replaced by Ethanol Imports	0.031	0.045
Total Energy	0.229	0.443

6.2.2 Lifecycle Impacts of Conventional Fuel Use

In order to determine the lifecycle impact that increased renewable fuel volumes may have on any particular endpoint (fossil fuel consumption or emissions of GHGs), we also needed to know the conventional fuel inventory on a lifecycle basis. Since available sources of GHG emissions are provided on a direct rather than a lifecycle basis, we converted these direct emission and energy estimates into their lifecycle counterparts.

To do this, we used GREET to develop multiplicative factors for converting direct (vehicle-based) emissions of GHGs, or direct (vehicle-based) consumption of petroleum, into full lifecycle factors. GREET output was used to generate the conversion factors shown in Table 6.2-2.

Table 6.2-2.
Direct (wheel only) Conversion Factors to Well-to-Wheel (lifecycle) Emissions or Energy Use

	Gasoline	Diesel
Petroleum	1.11	1.10
Fossil fuel	1.22	1.21
GHG	1.26	1.25
CO_2	1.23	1.21

The factors in Table 6.2-2 were applied to gasoline and diesel fuel inventories of emissions or energy consumption at the consumer level (i.e. direct emissions or energy) to convert them into alternative inventories representing full lifecycle contributions.

The direct petroleum energy for gasoline and diesel fuel is just the energy content of the fuels used. Consistent with U.S. EPA National Inventory calculations[CCCCC], we converted energy use values for gasoline and diesel fuel to direct CO_2 emissions by multiplying by a carbon content coefficient, a carbon oxidation factor, and converting the resulting carbon emissions into CO_2. The CO_2 emissions were then scaled up by assuming a fraction increase to the CO_2 emissions to account for non-CO_2 GHGs (CH_4 and N_2O). The fraction increase was based on the U.S. EPA National Inventory 2004 values for both CO_2 and total GHG emissions. Table 6.2-3 shows the total lifecycle petroleum and GHG emissions associated with direct use of a Btu value of gasoline or diesel fuel. These values represent factor LC in the equation described above.

Table 6.2-3.
Lifecycle Emissions and Energy (LC Values)

	Gasoline	Diesel
Petroleum (Btu/Btu)	1.11	1.10
Fossil fuel (Btu/Btu)	1.22	1.21
GHG (Tg-CO_2-eq/QBtu)	99.4	94.5
CO_2 (Tg-CO_2/QBtu)	94.2	91.9

6.2.3 Displacement Indexes

In order to permit a quantitative evaluation of the degree to which a renewable fuel reduces lifecycle fossil fuel consumption or GHG emissions, several metrics have been developed. Three of the most prominent metrics are shown in Table 6.2-4.

Table 6.2-4. Metrics Used to Measure Lifecycle Impacts of Renewable Fuels

Metric	Calculation
Net energy balance	Renewable energy out - fossil energy in
Energy efficiency	Fossil energy in ÷ renewable energy out (or alternatively renewable energy out ÷ fossil energy in)
Displacement index	% reduction in emissions or energy compared to the fuel that it replaces

Of these metrics, we believe the displacement index is the most appropriate to use as it compares the renewable fuel to the petroleum fuel it is displacing. The net energy balance and energy efficiency approaches only consider the renewable fuel itself and do not account for the fact that the use of renewable fuels result in decreased use of petroleum fuels and thus provide misleading results.

As an example, if 81,000 Btu of fossil fuels were required to make, transport, and store one gallon of ethanol, then the energy efficiency would be calculated as follows:

Energy efficiency = 81,000 Btu/gal ÷ 76,000 Btu/gal = 1.07

This result would imply that ethanol cannot be labeled "renewable," since one gallon of ethanol contains less energy than was required to make that one gallon. However, the use of ethanol may still reduce overall lifecycle fossil fuel use even in this case. If, for example, 18,000 Btu of fossil fuels were required to make one ethanol-equivalent gallon of gasoline (i.e. 76,000 Btu of gasoline), then a total of 94,000 Btu of fossil fuel energy would be consumed whenever 76,000 Btu of gasoline energy was combusted in a conventional vehicle. Since 81,000 Btu is less than 94,000 Btu, the use of ethanol would result in less fossil fuel consumption than the use of gasoline, even though the energy efficiency is greater than 1.0. The 81,000 Btu of fossil energy required to produce the ethanol includes lifecycle energy. The energy content of the ethanol (76,000 Btu) itself is not considered fossil energy and therefore not included in the comparison with gasoline calculation above. Thus, even in cases where the net energy balance of a renewable fuel is negative or has energy efficiency less than 1.0[74], there may still be an overall reduction in lifecycle fossil fuel use (and associated GHG emissions) due to decreased petroleum fuel use.

Therefore, studies that rely on the energy balance metric and conclude for example that the net energy balance of corn ethanol is negative, or the energy efficiency is less than 1.0, making it an unattractive transportation fuel, are not capturing the full implications of the use of the fuel and are providing misleading results.

Because of this potential for the net energy balance and energy efficiency metrics to provide misleading information, for our analysis of this rule we have chosen to use the displacement index. The displacement index provides the most direct measure of the impacts of replacing conventional gasoline or diesel with a renewable fuel, and is also better suited to describing impacts of renewable fuel use on fossil fuel consumption and GHGs.

The displacement index (DI) represents the percent reduction in GHG emissions or fossil fuel energy brought about by the use of a renewable fuel in comparison to the conventional gasoline or diesel that the renewable fuel replaces. The formula for calculating the displacement index depends on which fuel is being displaced (i.e. gasoline or diesel), and which endpoint is of interest (e.g. petroleum energy, GHG). For instance, when investigating the CO_2 impacts of ethanol used in gasoline, the displacement index is calculated as follows:

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[74] A net energy balance of zero, or an energy efficiency of 1.0, would indicate that the full lifecycle fossil fuels used in the production and transportation of ethanol are exactly equal to the energy in the ethanol itself.

$$DI_{CO2} = 1 - \frac{\text{lifecycle } CO_2 \text{ emitted for ethanol in g/Btu}}{\text{lifecycle } CO_2 \text{ emitted for gasoline in g/Btu}}$$

The units of g/Btu ensure that the comparison between the renewable fuel and the conventional fuel is made on a common basis, and that differences in the volumetric energy content of the fuels is taken into account. The denominator includes the CO_2 emitted through combustion of the gasoline itself in addition to all the CO_2 emitted during its manufacturer and distribution. The numerator, in contrast, includes only the CO_2 emitted during the manufacturer and distribution of ethanol, not the CO_2 emitted during combustion of the ethanol.

The combustion of biomass-based fuels, such as ethanol from corn and woody crops, generates CO_2. However, in the long run the CO_2 emitted from biomass-based fuels combustion does not increase atmospheric CO_2 concentrations, assuming the biogenic carbon emitted is offset by the uptake of CO_2 resulting from the growth of new biomass[DDDDD]. As a result, CO_2 emissions from biomass-based fuels combustion are not included in their lifecycle emissions results and are not used in the CO_2 displacement index calculations shown above. Net carbon fluxes from changes in biogenic carbon reservoirs in wooded or crop lands are accounted for separately in the GREET model.

When calculating the GHG displacement index, however, the CH_4 and N_2O emitted during biomass-based fuels combustion are included in the numerator. Unlike CO_2 emissions, the combustion of biomass-based fuels does result in net additions of CH_4 and N_2O to the atmosphere. We assume that combustion CH_4 and N_2O emissions are not offset by carbon uptake of renewable biomass production. As shown in Table 6.1-2, CH_4 and N_2O emissions contribute to the total GHG impact. Therefore, combustion CH_4 and N_2O emissions are included in the lifecycle GHG emissions results for biomass-based fuels and are used in the GHG displacement index calculations.

Using GREET, we calculated the lifecycle values for energy consumed and GHGs produced for corn-ethanol, cellulosic ethanol, and soybean-based biodiesel, as well as the gasoline and diesel fuel that would be displaced. For both renewable and conventional fuels, we summed the lifecycle results for both the feedstock and the fuel. The results are shown in Table 6.2-5.

Table 6.2-5. Output from GREET Used to Develop Displacement Indexes

	Units	Gasoline[a]	Corn ethanol	Corn ethanol (biomass fuel)	Cellulosic ethanol	L S Diesel	Biodiesel
Well-to-Pump							
Fossil energy	Btu/mmBtu	224,133	742,411	290,324	88,973	207,008	464,594
Petroleum energy	Btu/mmBtu	107,298	90,771	88,896	91,977	98,656	96,539
CO_2	g/mmBtu	17,893	56,275	26,089	-71	16,629	28,468
CO_2-eq	g/mmBtu	20,435	75,219	43,043	6,427	19,134	31,193
End point combustion							
Fossil energy	Btu/mmBtu	1,000,000	0	0	0	1,000,000	0
Petroleum energy	Btu/mmBtu	1,000,000	0	0	0	1,000,000	0
CO_2 combustion[b]	g/mmBtu	76,419	74,755	74,755	74,755	77,570	79,388
Fossil CO_2 combustion		76,419	0	0	0	77,570	0
CO_2-eq combustion[c]	g/mmBtu	79,015	2,596	2,596	2,596	77,669	99

[a] Volume-weighted average of conventional gasoline (65%), RFG blendstock (25%), and CaRFG blendstock (10%).

[b] Based on carbon content of the fuel.

[c] Includes Fossil CO_2, CH_4, and N_2O tailpipe emissions. CH_4 and N_2O emissions based on assuming an increase over CO_2 emissions, the percent increase is from the U.S. EPA National Inventory for CO_2 and GHG emissions from on-road sources.

We used the values from the table above to calculate the displacement indexes. The results are shown in Table 6.2-6.

Table 6.2-6. Displacement Indexes Derived from GREET

	Corn ethanol	Corn ethanol (biomass fuel)	Cellulosic ethanol	Imported ethanol	Biodiesel
$DI_{Fossil\ Fuel}$	39.3%	76.3%	92.7%	69.0%	61.5%
$DI_{Petroleum}$	91.8%	92.0%	91.7%	92.0%	91.2%
DI_{GHG}	21.8%	54.1%	90.9%	56.0%	67.7%
DI_{CO2}	40.3%	72.3%	100.1%	71.0%	69.8%

The displacement indexes in this table represent the impact of replacing a Btu of gasoline or diesel with a Btu of renewable fuel. Thus, for instance, for every Btu of gasoline which is replaced by corn ethanol, the total lifecycle GHG emissions that would have been produced from that Btu of gasoline would be reduced by 21.8 percent. For every Btu of diesel which is replaced by biodiesel, the total lifecycle petroleum energy that would have been consumed as a result of burning that Btu of diesel fuel would be reduced by 91.2 percent.

Consistent with the cost modeling done for this rule, for the 2012 cases we assume the “cellulosic” ethanol volume is actually produced from corn utilizing a biomass fuel source at the ethanol production plant. The displacement index for that fuel as shown in Table 6.2-6, is used in the calculation of reductions.

The displacement index for imported ethanol in all cases is based on an average of corn and cellulosic ethanol. While not exclusively, we anticipate much imported ethanol to be primarily sugarcane based ethanol. There currently is no sugarcane ethanol lifecycle values included in GREET. The GHG emissions when producing sugarcane ethanol differs from corn ethanol in that the GHG emissions from growing sugarcane is likely different than for growing a equivalent amount of corn to make a gallon of ethanol, the process of turning sugar into ethanol is easier and therefore less energy intensive (which typically translates into lower GHG) and, importantly, we understand that at least some of the ethanol produced in Brazil uses the bagasse from the sugarcane itself as a process fuel source. We know from our analysis that using a biomass source for process energy greatly improves the GHG benefit of the renewable fuel. These factors would result in sugarcane ethanol having a greater GHG benefit per gallon than corn ethanol, certainly where natural gas or coal is the typical process fuel source used. Conversely, sugarcane ethanol production does not result in a co-product such as distillers grain as in the case of corn ethanol. In our analyses, accounting for co-products significantly improved the GHG displacement index for corn ethanol. Furthermore, there would be additional transportation emissions associated with transporting the imported ethanol to the U.S. as compared to domestically produced ethanol. Developing a technically rigorous lifecycle estimate for energy needs and GHG impacts for sugarcane ethanol is not a simple task and was not available in the timeframe of this rulemaking. Considering all of the differences between imported and domestic ethanol, for this rulemaking, we assumed imported ethanol would be predominately from sugarcane and have estimated DI’s approximately mid-way between the DI’s for corn ethanol and DI’s for cellulosic ethanol. We are continuing to develop a better understanding of the lifecycle energy and GHG impacts of producing ethanol from sugarcane and other likely feedstocks of imported ethanol for any future analysis.

6.2.4 Transportation Sector and Nationwide Inventories

For our analysis described above, we need estimates of transportation sector and nationwide fossil energy and GHG emissions to determine the percent reduction impacts of the program (e.g., $\mathrm{TSector}_{\mathrm{GHG}}$ factor in the equation above). These inventories are direct not lifecycle and are needed for 2012 to compare to the projected renewable fuel savings in 2012.

6.2.4.1 Fossil Fuel Inventory

The transportation sector and nationwide fossil fuel inventory is just the energy content of the fuels used. Fossil fuel use in the transportation sector includes gasoline and diesel as well as other petroleum fuels, such as residual oil and LPG. It also includes other fossil energy use in the form of natural gas and the fossil portion of electricity used. Inherent with the assumptions on the amounts of renewable fuels use projected to 2012, there are also assumed values for gasoline and diesel fuel use. Values for energy use of the different transportation fuels other than gasoline and diesel (e.g., jet fuel, natural gas, etc.) were taken directly from the 2006 Annual Energy Outlook.

The nationwide fossil fuel inventory includes petroleum, natural gas, and coal energy use. The direct fossil fuel inventory values are shown in Table 6.2-7.

Table 6.2-7. Direct Fossil Fuel Inventories (QBtu)

	2012
Nationwide	94.53
Transportation Sector	31.41

6.2.4.2 Petroleum Inventory

As with fossil energy, the transportation sector and nationwide petroleum inventory is just the energy content of the fuels used. The transportation sector petroleum inventory includes gasoline and diesel as well as other petroleum fuels, such as residual oil and LPG.

The nationwide petroleum inventory includes petroleum use in the transportation sector as well as other sectors. The direct petroleum inventory values are shown in Table 6.2-8.

Table 6.2-8. Direct Petroleum Inventories (QBtu)

	2012
Nationwide	43.87
Transportation Sector	30.47

6.2.4.3 CO_2 Inventories

We calculated direct CO_2 emissions for the transportation sector in 2012 by applying carbon emissions factors to the projected amount of fuels used in those years.

Direct CO_2 emissions from the transportation sector as a whole are calculated in the same way as direct gasoline and diesel emissions are calculated as described in Section 6.2.2. We converted energy use values for transportation sector fuels to direct CO_2 emissions by multiplying by a carbon content coefficient, a carbon oxidation factor, and converting the resulting carbon emissions into CO_2. Emissions from electricity use in the transportation sector (rail) are calculated based on the U.S. average mix of fossil fuels used to generate electricity.

Consistent with the EPA inventory report we made an adjustment to diesel fuel, jet fuel and residual oil use to subtract out the emissions associated with bunker fuel. The AEO values include the energy use of bunker fuels, but the emissions of these fuels are not considered part of the U.S. transportation sector emissions. This adjustment was done by decreasing emissions of diesel fuel, jet fuel, and residual oil by the portion of emissions associated with bunker fuels as determined in the EPA inventory report.

Direct nationwide CO_2 emissions are also calculated in the same way applying factors for all fossil fuels used as reported by the 2006 Annual Energy Outlook. This type of analysis results in a small understatement of total Nationwide CO_2 emissions as it does not capture other industrial sources of CO_2 emissions for example CO_2 emissions from calcinations of limestone in the cement industry. However, there are no projections of these other emissions sources for 2012, and they are a relatively small part of total Nationwide CO_2 emissions, representing only 6% of total CO_2 emissions in 2004 according to the EPA National Inventory values. Therefore, while impacts of increased renewable fuel use as a percent of nationwide CO_2 emissions may be slightly overestimated the impacts on results are not thought to be significant. The results of direct CO_2 emission calculations are shown in Table 6.2-9.

Table 6.2-9. CO_2 Direct Inventories (Tg CO_2)

	2012
Nationwide	6,406
Transportation Sector	2,108

6.2.4.4 GHG Inventories

Projections for direct GHG emissions can not be calculated directly from the energy projections as was done for CO_2. The approach to estimating CO_2 emissions from mobile combustion sources varies significantly from the approach to estimating non-CO_2 GHG emissions (CH_4 and N_2O emissions). While CO_2 can be reasonably estimated by applying an appropriate carbon content and fraction of carbon oxidized factor to the fuel quantity consumed, CH_4 and N_2O emissions depend largely on the emissions control equipment used (e.g., type of catalytic converter) and vehicle miles traveled. Emissions of these gases also vary with the efficiency and vintage of the combustion technology, as well as maintenance and operational practices. Due to this complexity, a much higher level of uncertainty exists in the estimation of CH_4 and N_2O emissions from mobile combustion sources, compared to the estimation of CO_2 emissions.

Projections for direct transportation sector and nationwide GHG emission are done by assuming a fraction increase to the CO_2 emissions to account for non-CO_2 GHGs. The fraction increase was based on the U.S. EPA National Inventory 2004[EEEEE] values for both CO_2 and total GHG emissions. This same increase is applied to 2012 CO_2 values. Table 6.2-10 shows the fraction increase values for GHGs over CO_2 emissions calculated from the U.S. EPA National Inventory report.

Table 6.2-10. U.S. National Inventory 2004 CO_2 and GHG Inventories

	CO_2 (Tg-CO_2)	**GHG (Tg-CO_2–eq.)**	**Fraction Increase**
Nationwide	5,988	7,074	1.1807
Transportation Sector	1,860	1,960	1.0538

The results of direct GHG emission calculations are shown in Table 6.2-11.

Table 6.2-11. GHG Direct Inventories (Tg CO_2-eq.)

	2012
Nationwide	7,564
Transportation Sector	2,222

6.3 Impacts of Increased Renewable Fuel Use

We used the methodology described above to estimate impacts of increased use of renewable fuels on consumption of petroleum and fossil fuels and also emissions of CO_2 and GHGs. This section describes our results.

6.3.1 Fossil Fuels and Petroleum

We used the S equation in Section 6.2 to estimate the reduction associated with the increased use of renewable fuels on lifecycle fossil fuel and petroleum consumption. These values are then compared to the total U.S. transportation sector and nationwide inventories to get a percent reduction. The estimates are presented in Tables 6.3-1 and 6.3-2.

Table 6.3-1.
Estimated Fossil Fuel Impacts of Increased Use of Renewable Fuels in 2012,
In Comparison to the Reference Case

	RFS Case	EIA Case
Reduction (quadrillion Btu)	0.15	0.27
Percent reduction in Transportation Sector Energy Use	0.48 %	0.85 %
Percent reduction in Nationwide Energy Use	0.16 %	0.28 %

Table 6.3-2.
Estimated Petroleum Impacts of Increased Use of Renewable Fuels in 2012, In Comparison to the Reference Case

	RFS Case	**EIA Case**
Reduction (billion gal)	2.0	3.9
Percent reduction in Transportation Sector Energy Use	0.82 %	1.60 %
Percent reduction in Nationwide Energy Use	0.57 %	1.11 %

6.3.2 Greenhouse Gases and Carbon Dioxide

We used the S equation in Section 6.2 to estimate the reduction associated with the increased use of renewable fuels on lifecycle emissions of CO_2. These values are then compared to the total U.S. transportation sector and nationwide emissions to get a percent reduction. The estimates are presented in Table 6.3-3.

Table 6.3-3.
Estimated CO_2 Emission Impacts of Increased Use of Renewable Fuels in 2012, In Comparison to the Reference Case

	RFS Case	**EIA Case**
Reduction (million metric tons CO_2)	11.0	19.5
Percent reduction in Transportation Sector Emissions	0.52 %	0.93 %
Percent reduction in Nationwide Emissions	0.17 %	0.30 %

Carbon dioxide is a subset of GHGs, along with CH_4 and N_2O as discussed above. It can be seen from Table 6.2-6 that the displacement index of CO_2 is greater than for GHGs for each renewable fuel. This indicates that lifecycle emissions of CH_4 and N_2O are higher for renewable fuels that for the conventional fuels replaced. Therefore, reductions associated with the increased use of renewable fuels on lifecycle emissions of GHGs are lower than the values for CO_2. The estimates for GHGs are presented in Table 6.3-4.

Table 6.3-4.
Estimated GHG Emission Impacts of Increased Use of Renewable Fuels in 2012, In Comparison to the Reference Case

	RFS Case	EIA Case
Reduction (million metric tons CO_2-eq.)	8.0	13.1
Percent reduction in Transportation Sector Emissions	0.36 %	0.59 %
Percent reduction in Nationwide Emissions	0.11 %	0.17 %

6.4 Implications of Reduced Imports of Petroleum Products

6.4.1 Impacts on Imports of Petroleum Products

To assess the impact of the RFS program on petroleum imports, the fraction of domestic consumption derived from foreign sources was estimated using results from the AEO 2006. We describe in this section how fuel producers might change their levels and mix of imports in response to a decrease in fuel demand.

We compared the levels and mix of imports in the AEO reference case with the AEO low macroeconomic growth case and AEO high oil price case. The latter two cases reflect different assumptions by EIA regarding economic growth and world oil prices, respectively. The net effect for both cases is a reduction in domestic petroleum consumption compared to the AEO reference case. The changes in the level and mix of imports were examined, given a reduction in petroleum consumption similar to the amount estimated in the RFS for 2012 (0.25 to 0.49 Quads). Note that the EIA has conducted three separate analyses of Congressional bills which included earlier forms of the renewable fuel standard. These separate analyses however were based on earlier AEO versions and, in some instances, considered numerous provisions in addition to an RFS which collectively affected world oil prices and domestic oil consumption.

Thus, we did not directly use these earlier analyses, rather opting to use only the results in the AEO 2006 cases, as discussed above, to assess the RFS impacts on imports.

Comparison of the AEO 2006 reference case against the low macroeconomic growth case allowed us to evaluate how a decrease in domestic petroleum demand might affect the mix of imported finished products, imported crude oil, and domestic production. Note that the world price of crude oil remains the same between the AEO low macroeconomic growth and reference cases. Comparison of the two cases show that with an initial decrease in petroleum consumption (approximately 300,000 barrels per day or 0.61 Quads, higher than 2012 values), net imports will account for approximately 95% of the reductions on an energy basis.[FFFFF] These net imports include imports of crude oil or petroleum products minus exports of crude oil or petroleum products.[GGGGG] Both reduced domestic crude production and natural gas plant liquids account for most of the remainder. Note that for all levels of reduced petroleum demand, domestic crude production appears to account for less than 5% of the change. In addition, the reductions shown here do not reflect any rebound effect that may occur. Out of the initial reductions in net petroleum imports, imported finished products account for almost all the reductions. As domestic petroleum demand is reduced even further (over 860,000 barrels per day), approximately 50% of the reductions come from imported finished products, 44% from imported crude oil, and the remainder from reduced domestic, natural gas plant liquid (NGL) production, and exports.

Under the low macroeconomic growth case assumptions, imported finished products are initially reduced presumably because they represent the higher marginal cost source for refineries versus imported crude oil. Refineries may prefer to refine crude oil as opposed to importing finished products because of the higher margins involved with the former and the potentially more optimum use of refining capacity. Crude oil, as an international commodity, will be purchased at the market price by refineries. Thus, while crude oil from abroad may be produced more cheaply than domestic production sources, refineries that purchase from either source will pay the international market price for that specific grade of crude oil based on specific gravity and sulfur content plus the cost of transport to the U.S.

Note that there is uncertainty in quantifying how refineries will change their mix of sources with a decrease in petroleum demand, particularly at the levels estimated for the RFS. Changes in world oil price from the reference case could also significantly alter the mix of sources from which refineries choose. For example, a comparison between the AEO high price case and the reference case (under a decrease in petroleum consumption of 0.64 Quads) shows that 80% of the reductions (on an energy basis) come from reductions in net petroleum imports, while the remaining 20% comes from reductions in domestic production. As petroleum consumption is reduced even further, reductions in net petroleum imports make up an even greater percentage. For the reductions in net petroleum imports, imports of finished products are observed to actually increase while imports of crude oil decrease even more.

We believe that the actual refinery response might range between these two AEO cases, so that net import reductions could compose 80-95% of the reductions in petroleum demand for 2012. The split between the changes in imports of finished products versus crude oil are more uncertain. Discussions with EIA suggest the split could be close to 50-50. Thus, we believe the range could be between these two estimates (nearly all to 50% finished product). For the purposes of this RIA, we show values for the case where net import reductions come entirely from imports of petroleum products, with an example shown below.

By using the petroleum reduction levels as discussed in 6.3.2 of the RIA and comparing these to the AEO 2006 results, we estimate that 95% of the lifecycle petroleum reductions will be met through reductions in net petroleum imports. Table 6.4-1 shows the reductions in net petroleum imports estimated for the RFS program. We expect that these import reductions will be met almost exclusively from finished petroleum products rather than from crude oil, for the reasons given above and consistent with the results of the AEO 2006 low macroeconomic growth case. As an example calculation, we apportioned 95% of the total reductions in gasoline and diesel to displaced finished product imports. By 2012, imports of finished products are estimated to be reduced by 123,000 and 240,000 barrels per day, respectively, for the RFS and EIA cases. We compare these reductions in imports against the AEO projected levels of net petroleum imports. The range of reductions in net petroleum imports are estimated to be between 0.9 to 1.7%.

Table 6.4-1. Net reductions in Imports in 2012

	RFS Case	EIA Case
Reduction in finished products[a] (barrels per day)	123,000	240,000
Percent reduction[b]	0.89%	1.73%

[a] Net reductions relative to 2012 reference case

[b] Compared to AEO2006 projections for 2012 reference case

6.4.2 Impacts on Import Expenditures

The reductions in petroleum imports were discussed in Section IX.D of the preamble. As noted in the preamble, we calculate the change in expenditures on petroleum imports and ethanol imports assuming this would not result in any other changes in consumer behavior that would be reflected in fuel use. 95% of all reductions in petroleum imports were calculated to be from finished petroleum products rather than crude oil, as discussed in the prior section. The economic savings in petroleum product imports was calculated by multiplying the reductions in gasoline and diesel imports by their corresponding price. According to the EIA, the price of imported finished products is the market price minus domestic local transportation from refineries and minus taxes.[HHHHH] An estimate was made by using the AEO 2006 wholesale gasoline, distillate, and ethanol price forecasts for the specific analysis years. The current ethanol import tariff of $0.54/gallon placed on countries outside the Caribbean and Central America is not included in the import expenditures, since the tariff revenue collected would remain in the U.S.

As an example calculation, the RFS case is expected to yield a reduction of 2.0 billion gallons of gasoline in the year 2012. 95% of these reductions, or 1.9 billion gallons, are expected to come from imports of finished gasoline. Thus, the domestic refining sector would avoid purchases of 1.9 billion gallons of gasoline and diesel at the wholesale price. According to the AEO 2006, the end-user prices of gasoline and diesel are forecasted to be $2.01 per gallon and $1.98 per gallon respectively. Minus federal taxes, state taxes, and distribution costs, the wholesale prices of gasoline and diesel forecasted in the AEO 2006 are $1.376 and $1.382 per gallon, respectively (2004$). Note that the AEO wholesale prices were used for this calculation, as opposed to the gasoline and diesel production costs in Chapter 7 of the RIA, to stay consistent with the other AEO results used herein. The avoided petroleum payments abroad thus total $2.6 billion in 2012 as shown in Table 6.4-2. The additional ethanol import expenditures, using the same approach, is estimated to be $0.7 billion in 2012. The net avoided expenditures in imports is thus the difference, or $1.9 billion in 2012 as shown in Table 6.4-2.

We compare these avoided petroleum import expenditures against the projected value of total U.S. net exports of all goods and services economy-wide. Net exports is a measure of the difference between the value of exports of goods and services by the U.S. and the value of U.S. imports of goods and services from the rest of the world. For example, according to the AEO 2006, the value of total import expenditures of goods and services exceeds the value of U.S. exports of goods and services to the rest of the world by $695 billion for 2006 (for a net export level of minus $695 billion) and by $383 billion for 2012 (for a net export level of minus $383 billion).[75] In Table 6.4-2, we compare the avoided expenditures in imports versus the total value of U.S. net exports of goods and services for the whole economy for 2012. Note that changes to corn exports, discussed in Chapter 8 of the RIA, are also included in the calculation of net exports. Relative to the 2012 projection, the avoided import expenditures due to the RFS would represent 0.4 to 0.7% of economy-wide net exports.

Table 6.4-2.
Avoided Import Expenditures ($2004 billion)

Cases	AEO Total Net Exports	Expenditures on Petroleum Imports	Expenditures on Ethanol Imports	Decreased Corn Exports	Net Expenditures on Imports	Percent of Total Net Exports
RFS Case	- $383 (year 2012)	- $2.6	+ $0.7	+ $0.6	- $1.4	0.4%
EIA Case		- $5.1	+ $1.0	+ $1.3	- $2.8	0.7%

6.5 Energy Security Implications of RFS

6.5.1 Background

One of the effects of increased use of renewable fuels in the U.S. from the RFS is that it diversifies the energy sources in making transportation fuel. A potential disruption in supply reflected in the price volatility of a particular energy source carries with it both financial as well as strategic risks. These risks can be reduced to the extent that diverse sources of fuel energy reduce the dependence on any one source. This reduction in risks is a measure of improved energy security.

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[75] For reference, the U.S. Bureau of Economic Analysis (BEA) reports that the 2005 import expenditures on energy-related petroleum products totaled $235.5 billion (2004$) while petroleum exports totaled $13.6 billion – for a net of $221.9 billion in expenditures. Net petroleum expenditures made up a significant fraction of the $591.3 billion current account deficit in goods and services for 2005 (2004$). (http://www.bea.gov/)

At the time of the proposal, EPA stated that an analysis would be completed and estimates provided in support of this rule. In order to understand the energy security implications of the RFS, EPA has worked with Oak Ridge National Laboratory (ORNL), which has developed approaches for evaluating the social costs and energy security implications of oil use. In a new study produced for the RFS, entitled "*The Energy Security Benefits of Reduced Oil Use, 2006-2015*," ORNL has updated and applied the method used in the 1997 report "*Oil Imports: An Assessment of Benefits and Costs*", by Leiby, Jones, Curlee and Lee.[76],[77] While the 1997 report including a description of methodology and results at that time has been used or cited on a number of occasions, this updated analysis and results have not been available for full public consideration. Since energy security will be a key consideration in future actions aimed at reducing our dependence on oil, it is important to assure estimates of energy security impacts have been thoroughly examined in a full and open public forum. Since the updated analysis was only recently available, such a thorough analysis has not been possible. Therefore, EPA has decided not to rely on the results of this report for the purposes of this rulemaking. Rather, we are including it as part of the record of this rulemaking and are inviting further public analysis and consideration of both this particular report and other perspectives on how to best quantify energy security benefits. To facilitate that additional consideration, we highlight below some of the key aspects of this particular analysis.

The approach developed by ORNL estimates the incremental benefits to society, in dollars per barrel, of reducing U.S. oil imports, called “oil premium.” Since the 1997 publication of this report, changes in oil market conditions, both current and projected, suggest that the magnitude of the oil premium has changed. Significant driving factors that have been revised include: oil prices, current and anticipated levels of OPEC production, U.S. import levels, the estimated responsiveness of regional oil supplies and demands to price, and the likelihood of oil supply disruptions. For this analysis, oil prices from the EIA's AEO 2006 were used. Using the "oil premium" approach, estimates of benefits of improved energy security from reduced U.S. oil imports from increased use of renewable fuels are calculated.

In conducting this analysis, ORNL considered the full economic cost of importing petroleum into the U.S. The full economic cost of importing petroleum into the U.S. is defined for this analysis to include two components in addition to the purchase price of petroleum itself. These are: (1) the higher costs for oil imports resulting from the effect of U.S. import demand on the world oil price and OPEC market power (i.e., the so called "demand" or "monoposony" costs); and (2) the risk of reductions in U.S. economic output and disruption of the U.S. economy caused by sudden disruptions in the supply of imported oil to the U.S. (i.e., macroeconomic disruption/adjustment costs).

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[76] Leiby, Paul N., Donald W. Jones, T. Randall Curlee, and Russell Lee, *Oil Imports: An Assessment of Benefits and Costs*, ORNL-6851, Oak Ridge National Laboratory, November, 1997.

[77] The 1997 ORNL paper was cited and its results used in DOT/NHTSA’s rules establishing CAFE standards for 2008 through 2011 model year light trucks. See DOT/NHTSA, Final Regulatory Impacts Analysis: Corporate Average Fuel Economy and CAFE Reform MY 2008-2011, March 2006.

1. Effect of Oil Use on Long-Run Oil Price, U.S. Import Costs, and Economic Output

The first component of the full economic costs of importing petroleum into the U.S. follows from the effect of U.S. import demand on the world oil price over the long-run. Because the U.S. is a sufficiently large purchaser of foreign oil supplies, its purchases can affect the world oil price. This monopsony power means that increases in U.S. petroleum demand can cause the world price of crude oil to rise, and conversely, that reduced U.S. petroleum demand can reduce the world price of crude oil. Thus, one consequence of decreasing U.S. oil purchases due to increased use of renewable fuel is the potential decrease in the crude oil price paid for all crude oil purchased.

2. Short-Run Disruption Premium From Expected Costs of Sudden Supply Disruptions

The second component of the external economic costs resulting from U.S. oil imports arises from the vulnerability of the U.S. economy to oil shocks. The cost of shocks depends on their likelihood, size, and length, the capabilities of the market and U.S. Strategic Petroleum Reserve (SPR), the largest stockpile of government-owned emergency crude oil in the world, to respond, and the sensitivity of the U.S. economy to sudden price increases. While the total vulnerability of the U.S. economy to oil price shocks depends on the levels of both U.S. petroleum consumption and imports, variation in import levels or demand flexibility can affect the magnitude of potential increases in oil price due to supply disruptions. Disruptions are uncertain events, so the costs of alternative possible disruptions are weighted by disruption probabilities. The probabilities used by the ORNL study are based on a 2005 Energy Modeling Forum[78] synthesis of expert judgment and are used to determine an expected value of disruption costs, and the change in those expected costs given reduced U.S. oil imports.

3. Costs of Existing U.S. Energy Security Policies

The last often-identified component of the full economic costs of U.S. oil imports is the costs to the U.S. taxpayers of existing U.S. energy security policies. The two primary examples are maintaining a military presence to help secure stable oil supply from potentially vulnerable regions of the world and maintaining the SPR to provide buffer supplies and help protect the U.S. economy from the consequences of global oil supply disruptions.

U.S. military costs are excluded from the analysis performed by ORNL because their attribution to particular missions or activities is difficult. Most military forces serve a broad range of security and foreign policy objectives. Attempts to attribute some share of U.S. military costs to oil imports are further challenged by the need to estimate how those costs might vary with incremental variations in U.S. oil imports. Similarly, while the costs for building and maintaining the SPR are more clearly related to U.S. oil use and imports, historically these costs

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[78] Stanford Energy Modeling Forum, Phillip C. Beccue and Hillard G. Huntington, “An Assessment of Oil Market Disruption Risks,” Final Report, EMF SR 8, October, 2005.

have not varied in response to changes in U.S. oil import levels. Thus, while SPR is factored into the ORNL analysis, the cost of maintaining the SPR is excluded.

As stated earlier, we have placed the report in the docket of this rulemaking for the purposes of inviting further consideration. However, the results of that report have not been used in quantifying the impacts of this rule.

Chapter 7: Estimated Costs of Renewable Fuels, Gasoline and Diesel

This section describes our methodology for estimating the cost impacts of increased production, distribution, and blending of renewable fuels, including corn and cellulosic ethanol and biodiesel. Detailed information is given on expected changes to the nation's fuel distribution system, as well as changes in refining processes that will likely occur as larger volumes of ethanol are blended into gasoline. The impact of subsidies is also addressed.

7.1 Ethanol

This subsection provides a description of the analysis we conducted for estimating the cost of corn and cellulosic ethanol. Our analysis indicates that corn ethanol will cost $1.32 per gallon to produce (2004 dollars) in 2012. We also estimated that using cellulosic feedstock, the production costs for ethanol would be approximately $1.65 per gallon (2004 dollars). By 2012 this cellulosic cost may decline with breakthroughs and advances in technology. Based on reports from a variety of sources and discussions we held with members of academia as well as those directly involved in the industry, we believe several hurdles still have to be overcome in the production of large volumes of cellulosic derived ethanol. However, it appears that good progress continues to be made and we remain optimistic that cellulosic ethanol will become increasingly important in the future.

7.1.1 Corn Ethanol

Of the new ethanol production capacity expected to be built, according to Section 1.2.2 of this RIA, less than three percent combined is expected to be produced from cellulosic feedstocks or in plants that differ significantly from dry mill corn ethanol plants. Several plants will be able to utilize other starchy feedstocks besides corn, such as milo, barley, wheat, and sorghum. However, corn is the primary feedstock, and therefore, the following analyses will focus on dry mill starch ethanol production.

7.1.1.1 Engineering and Construction Requirements for Corn Ethanol Plants

To meet the RFS Case goal of 6.7 billion gallons per year (Bgal/y) of ethanol in 2012 from the October 2006 capacity of 5.2 Bgal/yr, 1.5 Bgal/yr of additional capacity will have to be constructed.[79] If we consider that it is likely that at least 9.6 Bgal/yr of actual ethanol capacity will come on-line by 2012 (EIA Case), the annual capacity increase is 4.4 Bgal/yr. Our industry characterization work considering plants that are either under construction or are planned to be constructed in the next 2-3 years suggests the average new plant size will be 81 million gallons per year (MMgal/yr) (including a small number of expansions).

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[79] For details on current and expected ethanol capacity, refer to Section 1.2 of this RIA. Note that volumes considered cellulosic are also included here, since we believe that virtually all near-term cellulosic ethanol production will be from starch-based feedstocks that meet the alternative definition in the Act (discussed further in Section 7.1.1.2).

Based on conversations with representatives from design-build firms working in this field, as well as material from public sources, each new plant requires design engineering work lasting about six months followed by construction lasting 12-14 months before plant startup is possible, resulting in a total project timeline of 18-20 months. The design phase for a basic 50 MMgal/yr plant is expected to require the attention of about 12 engineers full time, and the construction phase will employ an average of about 125-150 workers each day. To correlate these figures with requirements for an 81 MMgal/yr plant, the number of construction personnel (150) were scaled proportionally, while the number of engineering personnel were assumed to be constant.

These figures provide a basis for estimating the personnel requirements of the total volume needed to meet the expected volumes. Over the six-year build-up period, a maximum of 970 construction workers and 30 engineers would be required on a monthly basis for the RFS case, while for the EIA case, these numbers increase to 2,328 and 75, respectively.

These figures simply estimate the number of workers required at the final assembly stage of the plant, and do not capture many more personnel hours that will go into designing and constructing vessels, pipe fittings, control systems, and other pieces of equipment that will be installed and brought online by the plant construction crews. A report produced by one consultant suggested that expansion of the ethanol industry was responsible for more than 65,000 construction jobs in 2005.[IIIII]

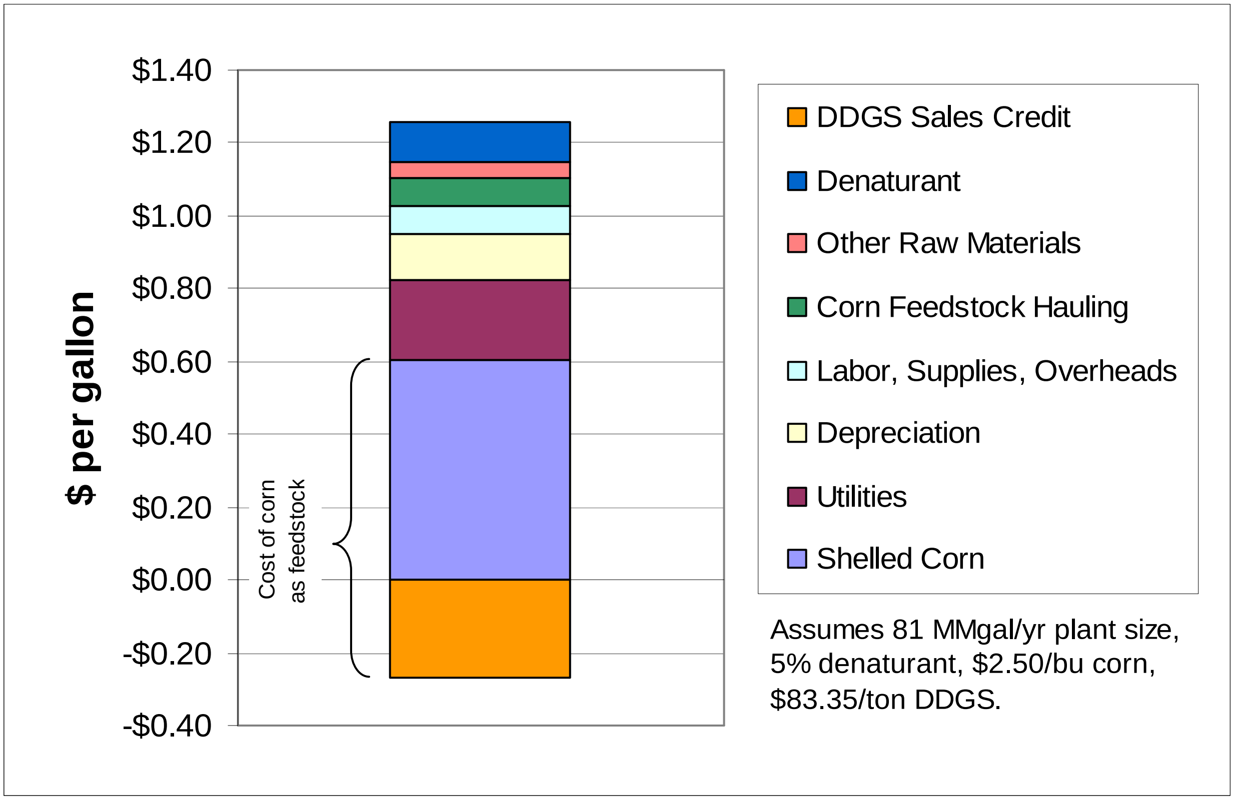
7.1.1.2 Corn Ethanol Production Costs

Corn ethanol costs for our work were estimated using a model developed by USDA that was documented in a peer-reviewed journal paper on cost modeling of the dry-grind corn ethanol process.[JJJJJ] It produces results that compare well with cost information found in surveys of existing plants.[KKKKK]

The USDA model is for a 40 MMgal/yr corn plant producing ethanol with a primary co-product of distillers dried grains with solubles (DDGS). The ethanol yield used in the model is 2.87 gallons per bushel with 5.0% gasoline denaturant. The model is based on work done in chemical process simulation software to generate equipment sizes, stream flowrates, and material and energy balances. These results were then put together with feedstock, energy, and equipment cost information in a spreadsheet format to arrive at a final per-gallon cost estimate. Although the model is current in terms of technology, yields, and capital estimates, we made some modifications to allow estimation of costs for ethanol plants of different sizes and operating under different energy and feedstock prices. We believe that these updates, in combination with the industry and supplier surveys done by USDA in developing the model, result a reasonable estimate for projected ethanol production costs.

We estimate an average corn ethanol production cost of $1.26 per gallon in 2012 (2004 dollars) for the RFS case and $1.32 per gallon for the EIA case. The cost of ethanol production is most sensitive to the prices of corn and the primary co-product, DDGS. Utilities, capital, and labor expenses also have an impact, although to a lesser extent. Corn feedstock minus DDGS sale credit represents about 48% of the final per-gallon cost, while utilities, capital and labor comprise about 19%, 9%, and 6%, respectively. For this work, we used corn and DDGS price projections generated by the Forestry and Agricultural Sector Optimization Model, which is described in Chapter 8.1.1 of this RIA. Corn and DDGS prices are given there in Table 8.1-1. Figure 7.1-1 shows the cost breakdown for production of a gallon of ethanol. Note that this production model does not account for the cost to pelletize or ship the DDGS. Those costs are external and are expected to increase the price of DDGS an end user located far from the plant. More details are given in Section 8.1.1 where the FASOM model is discussed.

Figure 7.1-1.
Cost Breakdown of Corn Ethanol Production (2004$).



Assumes 81 MMgal/yr plant size, 5% denaturant, $2.50/bu corn, $83.35/ton DDGS.

The ability to address plant scaling in the model was accomplished by applying an engineering scaling factor to all plant equipment. In past rulemakings involving modifications to refineries we have used a material scaling factor of 0.65. This factor is applied as an exponent to the ratio of the new size to the original size, the result of which is then multiplied by the original capital cost. However, there is information suggesting that a general factor may be considerably higher for ethanol plants. Based on a recent journal publication, a factor of 0.84 was used in this work.[LLLLL] With this factor, the model indicates that the change in per-gallon production cost due to economies of scale is very small over the range of typical plant sizes, on the order of $0.02 between 40 and 100 MMgal/yr. In this analysis we used an average new plant size of 81 MMgal/yr, derived from our industry characterization work in Chapter 1.

We also added functions to estimate the per-gallon cost impact of coal combustion as a process energy source rather than natural gas. Our industry characterization work suggests that about 14% of ethanol production from new plants being constructed will use coal for the process energy source, so the effect on average costs is relatively small. Capital cost used for an 81 MMgal/yr gas-fired plant was $99 million (2004$). For the coal system versus natural gas, additional requirements were estimated at $45 million in capital for the same size plant, as well as one additional operator per shift and 10% additional electric utility use. These figures should be considered conservative estimates, and were based on information from press releases as well as a conversation with staff of a company that designs and builds ethanol plants. Additionally, we adjusted the thermal efficiency of coal combustion processes downward by 13% relative to natural gas, and electricity consumption upward by 10% to reflect operational differences in the processes.[MMMMM] Using this information in the model, the cost savings is about $0.04 per gallon of ethanol for a coal-fired plant compared to natural gas firing. The results presented here are a weighted average of coal and gas production costs (using 14% coal).

Under the Energy Act, starch ethanol can be counted as cellulosic if at least 90% of the process energy is derived from animal wastes or other waste materials.[NNNNN] It is expected that the vast majority of the 250 million gallons per year of cellulosic ethanol production required by 2013 will be made using this provision. While we have been unable to develop a detailed production cost estimate for ethanol from corn which meets cellulosic criteria, we assume that the costs will not be significantly different from conventionally produced corn ethanol. We believe this is reasonable because to the extent that these processes are utilized, we expect them to be in locations where the very low or zero cost of the feedstock or biogas itself will likely offset the costs of hauling the material and the additional capital for handling and combusting it. In addition, because the quantity of ethanol produced using these processes is still expected to be a relatively small fraction of the total ethanol demand, the sensitivity of the overall analysis to this assumption is also very small.

In general, energy prices used in the model were taken from historical EIA data for 2004 and scaled according the ratios of 2004-2012 price forecasts published in the Annual Energy Outlook 2006. [OOOOO,PPPPP] The prices used in the modeling are shown in Table 7.1-2. Several sensitivity cases were run using the model, and the results are shown in Table 7.1-3. Input values in this table were chosen to give a significant margin around current and anticipated future prices.

Table 7.1-2.
Energy Prices Used for Ethanol Cost Modeling for 2012 (2004$)

Natural Gas[a] **$/MMBtu**	**Coal**[a] **$/MMBtu**	**Electricity**[a] **$/kWh**	**Natural Gasoline**[b] **$/gal**
6.16	1.94	0.044	1.36

[a] Historical data based on averages for Iowa, Illinois, Minnesota, and Nebraska

[b] Natural gasoline (or natural gas liquids) is the typical denaturant used in ethanol production, since it is cheaper than finished gasoline. The price used was based on its value being 20 cents per gallon below wholesale gasoline.

Table 7.1-3.
Energy and Feedstock Price Sensitivities (2004$)

Natural Gas = $6.00/MMBtu			Natural Gas = $12.00/MMBtu		
Corn $/bu	**DDGS $/ton**	**Ethanol $/gal**	**Corn $/bu**	**DDGS $/ton**	**Ethanol $/gal**
$2.00	$50.00	$1.18	$2.00	$50.00	$1.35
	$100.00	$1.02		$100.00	$1.19
	$150.00	$0.86		$150.00	$1.03
$2.50	$50.00	$1.36	$2.50	$50.00	$1.52
	$100.00	$1.20		$100.00	$1.36
	$150.00	$1.04		$150.00	$1.20
$3.00	$50.00	$1.53	$3.00	$50.00	$1.70
	$100.00	$1.37		$100.00	$1.54
	$150.00	$1.21		$150.00	$1.38
$3.50	$50.00	$1.71	$3.50	$50.00	$1.87
	$100.00	$1.55		$100.00	$1.71
	$150.00	$1.39		$150.00	$1.55
$4.00	$50.00	$1.88	$4.00	$50.00	$2.04
	$100.00	$1.72		$100.00	$1.88
	$150.00	$1.56		$150.00	$1.72
$5.00	$50.00	$2.23	$5.00	$50.00	$2.39
	$100.00	$2.07		$100.00	$2.23
	$150.00	$1.91		$150.00	$2.07
$6.00	$50.00	$2.58	$6.00	$50.00	$2.74
	$100.00	$2.42		$100.00	$2.58
	$150.00	$2.26		$150.00	$2.42

7.1.2 Cellulosic Ethanol

7.1.2.1 How Ethanol Is Made from Cellulosic Feedstocks

It is not clear when the first processes to produce ethanol from cellulosic biomass were discovered. While ethanol produced from starch can be traced historically to ancient times, cellulosic derived ethanol appears to have been investigated in the 1800's. Until recently, the demand for fuel ethanol has been somewhat limited, and not sufficient to support a cost-competitive, commercial process to convert cellulose into ethanol.

With the increasing demand for fuel ethanol during the past few years, good progress has been made toward producing ethanol from cellulosic feedstocks. Interest in ethanol has continued to grow, initially fostered in part from EPA's reformulated gasoline (RFG) regulations that required such gasoline to contain a minimum of 2 percent oxygen by weight in the fuel. This minimum oxygen requirement has recently been revoked by EPA in response to the Energy Act, which revised the Clean Air Act requirement for oxygen in RFG. The Renewable Fuel Standard (RFS) continues to create a demand for ethanol. Likewise, there is an additional incentive to produce cellulosic ethanol because the Energy Act mandates that, starting in 2013, renewable fuels used in gasoline must include.

There is a wide variety of government and renewable fuels industry research and development programs dedicated to improving our ability to produce renewable fuels from cellulosic feedstocks. There are at least three completely different approaches to producing ethanol from cellulosic biomass, sometimes referred to as "platforms". The first is based on what NREL refers to as the "sugar platform,"[80] which refers to pretreating the biomass, then hydrolyzing the cellulosic and hemicellulosic components into sugars, and then fermenting the sugars into ethanol. Corn grain is a nearly ideal feedstock for producing ethanol by fermentation, especially when compared with cellulosic biomass feedstocks. Corn grain is easily ground into small particles, following which the exposed starch which has α-linked saccharide polymers is easily hydrolyzed into simple, single component sugar which can then be easily fermented into ethanol. By comparison, the biomass lignin structure must be either mechanically or chemically broken down to permit hydrolyzing chemicals and enzymes access to the saccharide polymers. The central problem is that the cellulose/hemicellulose saccharide polymers are β-linked which makes hydrolysis much more difficult. Simple microbial fermentation used in corn sugar fermentation is also not possible, since the cellulose and hemicellulose (6 & 5 carbon molecules, respectively) have not been able to be fermented by the same microbe. We discuss various pretreatment, hydrolysis and fermentation technologies, below. The second and third approaches have nothing to do with pretreatment, acids, enzymes, or fermentation. The second is sometimes referred to as the "syngas" or "gas-to-liquid" approach; we will call it the "Syngas Platform." Briefly, the cellulosic biomass feedstock is steam-reformed to produce syngas which is then converted to ethanol over a Fischer-Tropsch catalyst. The third approach uses plasma technology.

Technologies that are currently being developed may solve some of the problems associated with producing cellulosic ethanol. Specifically, one problem, mentioned previously, with cellulosic feedstocks is that the hydrolysis reactions produce both glucose, a six-carbon sugar, and xylose, a five-carbon sugar (pentose sugar, $C_5H_{10}O_5$; sometimes called "wood sugar"). Early conversion technology required different microbes to ferment each sugar. Recent research has developed better cellulose hydrolysis enzymes and ethanol-fermenting organisms.[81] Now, glucose and xylose can be co-fermented—hence, the terminology, weak-acid enzymatic hydrolysis and co-fermentation. In addition, at least one group is researching the use of recently developed genome modifying technology to produce a variety of new or modified enzymes and microbes that show promise for use in a process known as weak-acid, enzymatic-prehydrolysis [82]

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[80] *Enzyme Sugar Platform (ESP), Project Next Steps National Renewable Energy,* Dan Schell, FY03 Review Meeting; Laboratory Operated for the U.S. Department of Energy by Midwest Research Institute • B NREL, Golden, Colorado, May 1-2, 2003; U.S. Department of Energy by Midwest Research Institute • Battelle • Bechtel

[81] "Purdue yeast makes ethanol from agricultural waste more effectively." Purdue News, June 28, 2004; Writer: Emil Venere, (765) 494-4709, venere@purdue.edu; source: Dr. Nancy Ho, (765) 494-7046, nwyho@ecn.purdue.edu.

[82] *DOE Genomics: GTL Roadmap, Systems Biology for Energy and Environment,* U.S. Department of Energy, Office of Science, Office of Biological and Environmental Research, Office of Advanced Scientific Computing Research, Germantown, MD 20874-1290, August 2005; DOEGenomesToLife.org/roadmap; downloadable as whole or in sections.

7.1.2.2 Difficulties in Estimating Capital and Operating Costs for New or Pioneer Process Plants

Many years ago the petroleum and chemical process industries learned that it can be financially problematic to scale-up a bench or laboratory scale process to a full commercial sized operation. There are simply too many process variables that act one way at a batch rate of one- or two-gallons per day, or even 100-gallons per day, but then act a completely different way in a continuous, 70,000 gallon per day operation. Under these, admittedly somewhat extreme expectations, there is also absolutely no reasonable way to optimize a process. We expect that at least pilot or demonstration size projects will be necessary before a fully commercial sized, reasonably optimized plant can be constructed.

The petroleum and chemical process industries have also learned that if a different feedstock, with similar, but at the same time sufficiently different characteristics, becomes available, it is nearly always necessary to make several pilot plant runs before the feedstock in introduced into the process. There are a wide variety of potential cellulosic feedstocks, such as switch grass, forest thinnings, municipal waste, wood chips, and corn stover (corn stalks). The physical characteristics of these materials, such as size, composition, and density vary widely. As a result, there could be significant differences in the process configurations, as well as differences in the enzyme “cocktails” required to hydrolyze and convert each of them into ethanol. Compositional and density variations may require different reactor residence times for each feedstock, which will impact throughput. Many of the process streams will actually be slurries of the feedstock. It is also quite likely that each slurry stream will have its own flow and compositional characteristics. The flow characteristics of any slurry, under real operating conditions, must be well understood in order to properly design an optimum system. Additionally, valve and pump types, sizes, and materials of construction, as well as line sizes and configurations, may vary. Apart from the various process issues, questions also remain regarding which of the feedstocks is actually the best in terms of ethanol yield per dollar.

Consequently, we believe a good deal more process data is necessary before a reasonably accurate cost to design, engineer, and build a commercial scale cellulosic based ethanol plant can be expected. At the present time, there is only one cellulosic ethanol plant in North America (Iogen[QQQQQ] a privately held company, based in Ottawa, Ontario, Canada). On February 28, 2007, however, the Department of Energy (DOE) announced that it will provide grants of up to $385 billion for six biorefinery projects over the next four years. These facilities are expected to produce more than 130 million gallons of celluloic ethanol per year. As additional information on these future facilities are made available, EPA will have more information on process design from which we will better be able to project production costs for cellulosic ethanol.

Although the industry seems to be moving down several different pathways, one of the more mature process being tested and improved uses dilute acid enzymatic prehydrolysis with simultaneous saccharification (enzymatic) and co-fermentation. Because there is more publicly available information about this process, the model we used incorporates this type of process to estimate the cost of producing ethanol from corn stover. We chose corn stover because it is ubiquitous and because of the likelihood it will eventually be used as a feedstock.

In 1999, the National Renewable Energy Laboratory (NREL) published a report outlining its work with the USDA to design a computer model of a plant to produce ethanol from hardwood chips.[RRRRR] Although the cellulosic model was originally prepared for hardwood chips, it was meant to serve as a modifiable-platform for ongoing research using cellulosic biomass as feedstock to produce ethanol. Their long-term plan was that various indices, costs, technologies, and other factors would be regularly updated.

NREL modified the model in order to compare the cost of using corn-grain with the cost of using corn stover to produce ethanol. We used the corn stover model from the second NREL/USDA study for this analysis. Because there are no operating plants that could potentially provide real world process design, construction, and operating data for processing cellulosic ethanol, NREL had originally considered modeling the plant based on assumptions associated with a pioneer plant. Such assumptions would likely result in costs significantly higher than corn ethanol plants due to the higher level of uncertainty in both the design and engineering as well as the final construction and operating costs. The literature indicates that such models often underestimate actual costs since the high performance assumed for pioneer process plants is generally unrealistic.

The NREL analysis assumed that the corn stover plant was an N^{th} generation plant, built after the industry had been well enough established to provide verified costs. The corn stover plant was normalized to the corn kernel plant, e.g., placed on a similar basis. Additional costs for risk financing, longer start-ups, and other costs associated with first-of-a-kind or pioneer plants were not included in the study.[SSSSS] It is also reasonable to expect the cost of cellulosic ethanol will be higher than corn ethanol because of the complexity of the cellulose conversion process. During the recent past, process improvements and other advancements in corn production have considerably reduced the cost of producing corn ethanol. We also believe it is realistic to assume that cellulose-derived ethanol process improvements will be made and that one can likewise reasonably expect that as the industry matures, the cost of producing ethanol from cellulose will also decrease.

7.1.2.3 Methods, Data Sources, and Assumptions

For our analysis, we used the spreadsheet model that NREL developed for its comparison of the costs of producing ethanol from corn grain and corn stover.[83] We believe NREL’s approach was reasonable and well thought out. They also had an outside engineering firm validate their work, to the extent possible. The Delta-T Corporation (Delta-T) assisted in preparing, reviewing, and estimating costs for the process design. Delta-T worked with NREL process engineers to review all the process design and equipment costs (with the exclusion of wastewater treatment and the burner-boiler system, which were reviewed by Merrick Engineering and Reaction Engineering, Inc., respectively). For the plant areas that are actively

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[83] The first, woodchip-plant study was designed to produce 52.2 million gallons of ethanol per year from about 2,200 tons per day (350 operating days per year; 15 days for downtime, including turn-around) of woodchips. The second study normalized the original woodchip plant into the corn stover plant to produce 25 million gallons of ethanol per year (about 1,235 wet tons per day), in 1999 dollars. The adjustments included feedrate and feedstock volume and cost adjustments; equipment sizes with adjustments to capital and installation costs, and the cost of capital, labor, and process chemicals, including denaturant.

being investigated under DOE programs (e.g., prehydrolysis, cellulase enzyme production, and simultaneous saccharification and co-fermentation), Delta-T used the results of the DOE sponsored research to identify process design criteria and equipment requirements. These were used as a basis for sizing and costing major equipment components in the facility. The results of Merrick Engineering's work on wastewater treatment and REI's work on the burner/boiler were also included.[TTTTT] The NREL model used the Aspen Plus™ process simulator to calculate the flows and the heat and material balances for the process. We decided to use the NREL spreadsheet corn stover model, as is, since we did not have access to the Aspen Plus™ model nor to all the input. Rather, we left the feedrate, yields, and streams flows as they were, but adjusted equipment capital and installation costs, and utility, chemical, and labor costs to 2004 dollars. We used the same indices used by NREL to update their corn stover study; however, we used actual costs and indices for 2004 where possible. For example, in their 2000 calculations, NREL had extrapolated the Chemical Engineering Plant Cost Index and the Chemical Cost Index through 2012. However, we used actual 2004 data rather than the extrapolated data.

We did not change the corn stover cost. Several issues remain to be settled regarding the amount of stover that should be left in place and how it should be gathered, baled, and shipped. We found cost ranges of from $25 per dry ton to $45 per dry ton. For purposes of this analysis we used the $35 per dry ton that NREL assumed in its analysis.

For the analysis, we calculated the annual production cost in dollars per gallon of fuel ethanol. The annual production cost includes equipment straight-line depreciation for the life of the plant (10 years), and variable costs, labor, supplies and overhead, minus any by-product credits. Gasoline for denaturant and diesel for bulldozers to move the stover were projected into 2012 prices using IEA's AEO 2006[UUUUU] report. The market selling price minus the annual production cost is the before-tax profit. We calculated variable operating costs using NREL's best estimate of quantities of chemicals and additives based on their laboratory work. NREL calculated fixed costs using industry standards for percentages of direct labor (indirect labor was 40% of direct labor and overhead was 60% of total labor); other operating supplies, insurance, etc. totaled 3.25% of total installed cost. According to the analysis three major cost categories made up the majority of the total production cost: feeds stock – 31.2%; fixed costs – 23.8%; and depreciation (reflects installed capital cost of equipment) – 33.8%.

As previously stated, several feedstock issues remain to be settled, not least being which of the many available feedstocks will be the best or most efficient. We chose an average cost of $35 per dry ton; we don't believe the cost will rise and as a result of the research that is currently under way, there is reason to expect it to come down a little. On the other hand, several researchers have indicated switch grass may be better than corn stover; others point to forest wastes, etc. In the end, the best feedstock will likely be the one that is readily available and close to the plant; gathering, baling, and hauling continue to be important issues that will definitely impact the viability of a feedstock. Equipment cost reductions may have a significant impact on future costs. For example, there appear to be reasons to expect significant savings from purchasing enzymes rather than growing them onsite. Another issue that remains to be investigated is whether a particular kind of feedstock can be processed using one type of technology while a different kind may require the use of a completely different technology.

7.1.2.4 Results and Discussion

Given the limitations we've already discussed, and perhaps others, we determined that it would have cost approximately $1.65 in 2012 (2004 dollars) to produce a gallon of ethanol using corn stover as a cellulosic feedstock.

The provisions offering grants and shared financing included in Title XV of the Energy Act[VVVVV] will likely encourage process development work to generate the necessary construction and operating cost estimates. We assume the results produced by the above referenced NREL study are accurate and reasonable given the state of our current knowledge.

7.2 Biodiesel and Renewable Diesel Production Costs

7.2.1 Overview of Analysis

We based our estimate for the cost to produce biodiesel on the use of USDA's, NREL's and EIA's biodiesel computer models, along with estimates from engineering vendors that design biodiesel plants. Biodiesel fuel can be made from a wide variety of virgin vegetable oils such as canola, corn oil, cottonseed, etc. though, the operating costs (minus the costs of the feedstock oils) for these virgin vegetable oils are similar to the costs based on using soy oil as a feedstock, according to an analysis by NREL[84]. Biodiesel costs are therefore determined based on the use of soy oil, since this is the most commonly used virgin vegetable feedstock oil, and the use of recycled cooking oil (yellow grease) as a feedstock. Production costs are based on the process of continuous transesterification, which converts these feedstock oils to esters, along with the ester finishing processes and glycerol recovery. The models and vendors data are used to estimate the capital, fixed and operating costs associated with the production of biodiesel fuel, considering utility, labor, land and any other process and operating requirements, along with the prices for feedstock oils, methanol, chemicals and the byproduct glycerol.

The USDA, NREL and EIA models are based on a medium sized biodiesel plant that was designed to process raw degummed virgin soy oil as the feedstock. Additionally, the EIA model also contains a representation to estimate the biodiesel production cost for a plant that uses yellow grease as a feedstock. In the USDA model, the equipment needs and operating requirements for their biodiesel plant were estimated through the use of process simulation software. This software determines the biodiesel process requirements based on the use of established engineering relationships, process operating conditions and reagent needs. To substantiate the validity and accuracy of their model, USDA solicited feedback from major biodiesel producers. Based on responses, they then made adjustments to their model and updated their input prices to year 2005. The NREL model is also based on process simulation software, though the results are adjusted to reflect NREL's modeling methods, using prices based on year 2002. The origin of the EIA model is not known, though it is based on 2004 prices. The output for all of these models was provided in spreadsheet format. We also use engineering vendor

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[84] NREL Presentation "U.S. Biodiesel Feedstock Supply" June 2004.

estimates as another source to generate soy oil and yellow grease biodiesel production costs. These firms are primarily engaged in the business of designing biodiesel plants.

The production costs are based on a 10 million gallon per year biodiesel plant located in the Midwest using feedstock oils and methanol, which are catalyzed into esters and glycerol by use of sodium hydroxide. Because local feedstock costs, distribution costs, and biodiesel plant type introduce some variability into cost estimates, we believe that using an average plant to estimate production costs provides a reasonable approach. Therefore, we simplified our analysis and used costs based on an average plant and average feedstock prices since the total biodiesel volumes forecasted are not large and represent a small fraction of the total projected renewable volumes.

The models and vendor estimates are further modified to use input prices for feedstocks, byproducts and energy that reflect the effects of the fuels provisions in the Energy Act. In order to capture a range of production costs, we generated cost projections from all of the models and vendors. We present the details on these estimates later in this section.

For soy oil biodiesel production, based on the USDA model, we estimate a production cost of $2.06 per gallon in 2004 and $1.89 per gal in 2012 (in 2004 dollars). With the NREL model, we estimate soy oil biodiesel production costs of $2.28 and $2.11 per gallon in 2004 and 2012, respectively, which is slightly higher than the USDA results. The EIA model generated soy oil based costs of $2.33 and $ 2.15/gal, while the engineering vendor's costs averaged $2.27 and $2.09/gal, in years 2004 and 2012, respectively.

For yellow grease derived biodiesel, we used the EIA and vendor estimates and generated a range of costs, as discussed later. The total production costs ranged from $1.24 to $1.60/gal in 2004, and from $1.11 to $1.56 for year 2012.

Table 7.2-1.
Summary of Production Costs for Biodiesel made from Soy Oil, per Gallon (2004 cents)

	Total Production Cost	Subsidized Production Cost	Feed	Capital	Reagent and Chemicals	Labor	Energy/Utilities
USDA	189	89	156	11.3	12.7	5.0	4.8
NREL	211	111	165	17.0	17.0	6.0	7.4
EIA	215	115	161	14.4	NA	NA	16.0
PSI-Lurgi	220	120	174	18.8	12.6	8.2	5.5
Superior Process Technologies	224	124	175	11.7	16.5	7.6	5.0

Table 7.2-2.
Summary of Production Costs for Biodiesel made from Yellow Grease, per Gallon (2004 cents)

	Total Production Cost	Subsidized Production Cost	Feed	Capital	Reagent and Chemicals	Labor	Energy/Utilities
EIA	138	88	80	14.4	NA	NA	16.9
Superior Process Technologies	167	117	114	14.7	18.3	8.7	9.0

With the current Biodiesel Blender Tax Credit Program, producers using virgin vegetable oil stocks receive a one dollar per gallon tax subsidy while yellow grease producers receive 50 cents per gallon, reducing the net production cost to a range of 89 to 115 c/gal for soy oil and 61 to 106 c/gal for yellow greased derived biodiesel fuel in 2012. This compares favorably to the projected wholesale diesel fuel prices of 138 cents per gallon in 2012, signifying that the economics for biodiesel are positive under the effects of the blender credit program, though the tax credit program will expire in 2008 if it is not extended. Congress may later elect to extend the blender credit program, though, following the precedence used for extending the ethanol blending subsidies. Additionally, the Small Biodiesel Blenders Tax credit program and state tax and credit programs offer some additional subsidies and credits, though the benefits are modest in comparison to the Blender's Tax credit.

7.2.2 Inputs to and Results of USDA's Model

We used USDA's biodiesel model as a source to generate an estimate for the cost to produce biodiesel fuel. The model is in spreadsheet format with inputs in 2005 dollars, and contains all of the capital and operating costs for a plant to produce 10 million gallons per year of biodiesel fuel.

7.2.2.1 Feedstock Costs

Feedstock prices are the largest component in generating production costs for biodiesel fuel. For soy oil prices, we used prices based on USDA's 2006 Outlook, which has forecasted soy oil prices considering production of biodiesel under EPAct 2005. USDA's Outlook is a national forecasting analysis that models the effects of demand for farm products and farm product prices for soy beans, soy bean oil, corn and other farm commodities. The 2006 Outlook estimated soy oil prices considering the demand of soy oil derived biodiesel fuel at approximately 160 MM gallons per year in 2006 and 312 MM gallons a year in 2007[85]. This is in close proximity to EIA's soy oil derived biodiesel volume projection of 135 MM gals and 265 MM gals in 2006 and 2007, respectively. We therefore used the soy oil prices from USDA's Outlook to determine biodiesel production costs. The USDA does not forecast yellow grease prices, so we assumed that yellow grease feedstocks costs would maintain the same relative historical pricing differential to virgin soy oil. In the past, some analysis has shown that yellow

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[85] Per USDA phone discussion 6/22/06

grease has sold for about half the price of soy oil[86]. The resulting feedstock costs to make a gallon of biodiesel under projected volumes for RFS are in Table 7.2-3.

Table7.2-3.
Projected Prices of Feedstock (2004 Dollars per Gallon)

Marketing Year	Soy Oil[a]	Yellow Grease
2004	1.71	0.86
2012	1.56	0.78

[a]Production of Biodiesel assumed to consume 7.42 lbs of soy oil per gallon. USDA prices in 2012 are adjusted to 2004 dollars to account for inflation, using GDP index of 109.7 in year 2004 and 130.8 in year 2012.

7.2.2.2 Capital Costs

For capital costs we used USDA's total installed capital cost of $10.66 MM for a 10 MM gallon per year plant. This estimate was determined by the USDA, using a detailed analysis to generate costs for equipment needs, installation, land, engineering and construction work, buildings, utility needs, contingencies, startup costs etc. The USDA model is based on 2005 dollars, so we adjusted the numbers to 2004 values using the GDP index. Per the USDA method, the total installed capital costs on a per gallon basis was amortized on a 10 year straight line depreciation rate using a facility dependent cost of 10 percent times the capital costs. Maintenance charges, insurances and facility supply costs were also calculated as percentages of the capital. The total of all of these are equal to 16 cents per gallon.

7.2.2.3 Operating Costs

The total operating expenses were 20 and 18 c/gal for a soy based biodiesel plant in 2004 and 2012, respectively. The operating cost included a 4 cent per gallon offset from sale of the glycerol product at a price of 5 cents/lb. The operating costs include values for utilities, feed reagents, manpower and were based on the USDA's model. The components of the operating costs are discussed below.

7.2.2.4 Utility and Labor Costs

We estimated utility costs using energy requirements from USDA's model and adjusted the inputs to match the energy and electricity prices for the Midwest, using prices from EIA's AEO. The cost for steam was estimated using the price of natural gas. Each pound of steam was produced from heating water, which required 810 British Thermal Units (BTUs) per pound of steam. Additionally, the steam costs are estimated assuming that the BTUs to make steam are increased by a factor of two, to account for steam distribution efficiency losses, treatment of boiler water to prevent fouling, maintenance and other miscellaneous costs. The utility requirements per gallon of biodiesel and energy prices are presented in Tables 7.2-4 and 7.2-5

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[86] Energy Information Administration NEMS Petroleum Marketing Model Documentation page J-2

Table 7.2-4.
Utility Requirements per Gallon Biodiesel[a]

Medium Pressure Steam, lbs	4.0
Electricity, kWh	0.10
Cooling Tower Water, lbs	96.1

[a] Utilities per USDA model from the production of biodiesel from soy oil.

Table 7.2-5.
Midwest Energy Prices per Year (in 2004 $)

Year	2004	2012
Electricity, $/kWh	0.046	0.044
Natural gas, $/MM BTU	7.16	6.16

Labor costs include the salaries and benefits for personnel to operate a biodiesel plant. This was estimated in the USDA model, though the labor costs were in 2005 dollars, which we adjusted to 2004 dollars using the GDP price index. The resulting labor costs are 5 cents per gallon of produced biodiesel fuel.

7.2.2.5 Chemical Reagents

Another operating expense, the production of biodiesel also requires the use of chemicals and chemical reagents, as these act as a catalyst in the transesterification process. Additionally, methanol is required as it is the feedstock that is chemically combined with soy oil and yellow grease during the transesterification process, yielding the biodiesel product. The amount of chemicals and methanol required to make a gallon of biodiesel are listed in Table 7.2-6.

Table 7.2-6.
Reagent Requirements

Reagent	Annual Requirement, lbs per gallon
Water	0.0323
Hydrochloric acid	0.0185
Methanol	0.8006
Sodium Methoxide	0.0231
Sodium Hydroxide	0.0031

For the prices of chemical reagents, we used prices that were supplied in USDA's 2005 model and adjusted them to 2004 dollars. Additionally, since we have no forecasting mechanism we assumed that the chemical reagent prices remained unchanged in 2012.

However, we estimated methanol prices, as the cost for this feedstock is a significant component of the total operating costs. For our analysis, we generated values by use of a correlation that calculates methanol's price as a function of the price of natural gas[87]. In 2004 and 2012, using Midwest natural gas prices, we estimated methanol prices of 13.1 and 11.6 cents per pound, respectively. All other chemical prices, we assumed were constant over time and are in Table 7.2-7.

Table 7.2-7.
Reagent Prices (in 2004 $)

Reagent	**Prices, $/lb**
Hydrochloric acid	0.167
Sodium Methoxide	1.358
Sodium Hydroxide	0.273

7.2.2.6 Glycerol Byproduct

The feedstock cost credit for the glycerin by product in our modeling work was 5 cents per pound, based on recent pricing trends, assuming that additional glycerol generated from expansion of biodiesel production will continue to keep prices low. The model, like many biodiesel plants, produces a crude 80% glycerin stream, which is usually sold to glycerin refiners for purification. In the past, crude glycerin has sold for around $0.15 / pound. Because of the increase in biodiesel production around the world, however, the crude glycerin market has become saturated and the price is now around $0.05 / pound. As more biodiesel capacity comes on line, this price may very well drop further, though other markets for the use of glycerol are likely to develop because glycerol is a platform chemical used throughout industry. We assumed that the current glycerin pricing environment will continue in the future. For our cost estimation, the byproduct glycerin was sold at 5 cents per pound, reflecting current saturated market and low pricing conditions. The income from sale of the byproduct glycerin lowered biodiesel production costs by 2 percent and 4 percent for soy oil and yellow grease derived biodiesel fuel, respectively.

The total biodiesel production costs derived using the USDA's model are summarized in Table 7.2-8

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[87] Per EIA paper "MTBE Production Economics" Tancred C. M. Lidderdale, methanol price cents per gallon = 15.79 + 0.099 *natural gas price ($ per million BTU)

Table7.2-8.
Projected Production Costs for Biodiesel by Feedstock per Gallon (2004 Dollars)

Marketing Year	Soy Oil
2004	2.06
2012	1.89

7.2.3 Inputs to and Results of NREL's Biodiesel Model

We used NREL's biodiesel model as another source to generate an estimate for the cost to produce biodiesel fuel. Similar to the USDA's model, the NREL biodiesel model also represents a continuous transesterification process that uses sodium hydroxide and methanol to convert soy oil to biodiesel and which has the finishing processes for biodiesel and glycerol. The model is in spreadsheet format, and contains all of the capital and operating costs for a plant to produce 10 million gallons per year of biodiesel fuel. We again simplified our analysis, and used the NREL model to estimate production costs for an average biodiesel plant that makes 10 MM gallon per year. To make the results directly comparable to USDA's model, we used energy costs in the Midwest, and based the analysis on production of soy oil derived biodiesel.

Based on the results of the NREL model, we estimate that the total production costs to make soy oil derived biodiesel fuel are $2.28 and $2.11 per gallon for years 2004 and 2012, respectively. This is 22 cents more per gallon than the estimate derived from USDA's model. The components that make up our NREL estimate are discussed in the sections that follow.

7.2.3.1 Feedstock Costs

The feedstock costs increase because the NREL model assumes 7.87 pounds of soy oil are required to make a gallon of biodiesel fuel. This is slightly higher than the pounds required by the USDA model, though the difference may be due to each model being based on soy oils with differing chemical structures, i.e. more esters, differing densities. The higher amount of soy oil required by the NREL model raises the production costs for biodiesel by about 10 cents per gallon for feedstock costs alone, versus the USDA model. The feedstock costs are summarized in Table7.2-9.

Table7.2-9.
Projected Prices of Feedstock (2004 Dollars per Gallon)

Marketing Year	Soy Oil
2004	181.0
2012	165.2

7.2.3.2 Capital Costs

The total capital cost in the NREL model account for all of the costs for building a plant, including but not limited to the expenses for equipment, tanks, installation costs, engineering, tanks, construction, land and site development, start up and permitting charges. These costs do not account for expenses incurred from maintenance, insurance and taxes, however. The total capital coats for a plant are $14.8 million in 2002 dollars, which we adjusted to 2004 dollars using the GDP price index. The capital costs were amortized assuming a seven percent return on investment, resulting in a cost of 17 cents per gallon. All of the economic factors used for amortizing the capital costs are summarized in Table 7.2-10.

Table 7.2-10.
Economic Factors Used in Deriving the Capital Cost Amortization Factor

Amortization Scheme	Depreciation Life	Economic and Project Life	Federal and State Tax Rate	Return on Investment (ROI)	Resulting Capital Amortization Factor
Societal Cost	10 Years	15 Years	0%	7%	0.11

7.2.3.3 Operating Costs

The total operating costs are 31 and 30 cents per gallon for years 2004 and 2012, respectively. These costs are not directly comparable to those from the USDA model, as fixed operating cost are included in the operating costs for the NREL model, while the USDA model accounts for fixed costs in the capital estimate. The operating cost for the NREL analysis includes items for utilities, reagents, manpower, insurance, taxes, general administration and maintenance costs, though do not account for capital costs. Additionally, the sale of the glycerol byproduct (80% strength) generated income of 4 cents per gallon of produced biodiesel, using glycerol price of 5 cents per pound. The cost associated with insurance, taxes, general administration and supplies incur a cost of 2.4 cents per gallon of biodiesel. The remaining components of operating costs for the NREL modeling analysis are discussed below.

7.2.3.4 Utility and Labor

The utility costs were estimated using the energy requirements in the NREL model along with the same prices for energy, steam and electricity, as those used in our USDA analysis. The utility requirements per gallon of biodiesel fuel are listed in Table 7.2-11

Table 7.2-11.
Utility Requirements per Gallon of Biodiesel

Natural Gas, SCF	2.0
Medium Pressure Steam, lbs	3.2
Electricity, kWh	0.1
Cooling Tower Water, lbs	8.3

The NREL model accounts for the salaries of 4 employees per shift to run and maintain the plant. In addition to salaries for these personnel, the labor expenses also accounted for employee fringe benefits and the cost for a plant supervisor. The resulting labor costs are 6 cents for each gallon of biodiesel.

7.2.3.5 Chemical Reagents

The NREL model also requires the use of the same chemicals and chemical reagents that are used in the USDA model. The amount of chemical reagents in the NREL model, however, reflect the use of diluted hydrochloric acid (HCl) and sodium methoxide for the biodiesel production process. Hydrochloric acid is listed as being at 33 percent strength, which we assumed also applied to the strength of sodium methoxide, since the amount of HCl in the model is reflective of about one third the value of the USDA's model. For the chemical and reagents prices, we used the same pricing values as those in our USDA modeling analysis. The resulting total chemical and reagent costs on a per gallon basis are about 17 cents for each gallon of biodiesel fuel produced. All of the required chemicals and reagents for the production of biodiesel are presented on an undiluted basis in Table 7.2-12.

Table 7.2-12.
Reagent Requirements

Reagent	**Annual Requirement, lbs per gallon**
Water	3.4646
HCl[a]	0.0098
Methanol	0.6037
$NAOCH_3$[a]	0.0338
Sodium Hydroxide	0.1901

[a] HCl is Hydrochloric acid, $NAOCH_3$ is sodium methoxide.

The total biodiesel production costs derived from the NREL model are summarized in Table 7.2-13.

Table 7.2-13.
Projected Production Costs for Biodiesel by Feedstock per Gallon
(2004 dollars)

Marketing Year	**Soy Oil**[a]
2004	2.28
2012	2.11

[a] Production consumes 7.87 lbs of soy oil per gallon of biodiesel. USDA prices in 2012 are adjusted to 2004 dollars to account for inflation, using GDP index of 109.7 in year 2004 and 130.8 in year 2012.

7.2.4 EIA NEMS Model for Biodiesel

We also estimated production costs using the biodiesel plant representation in EIA's NEMS model. This biodiesel model is in spreadsheet format and has the aggregated cost components for an average soy oil and yellow grease based biodiesel plant. We could not locate written documentation that describes the basis for these models, though we will assume for our analysis that it represents an average biodiesel plant.

EIA's model requires 7.65 lbs/gal of soy oil and yellow grease feedstock to produce a gallon of biodiesel fuel. Using the oil feedstock costs as discussed in section 7.2.2.1, feed stock costs for soy oil are $1.76/gal and $1.61/gal for 2004 and year 2012, respectively, while yellow grease feedstock costs are $0.88/gal and $0.80/gal for years 2004 and 2012, respectively.

The EIA model does not provided specific individual cost components for biodiesel production, though it does have an estimate for total energy, operating and capital costs for both plant types. Capital costs are estimated at 14.4 cents/gal in 2004 for both plant types, which we assumed contains all of costs associated with building a plant, along with the depreciation and capital payoff costs. The energy costs are provided in the model on an aggregated basis and do not contain the individual amounts of natural gas, electricity and steam used by a plant. The model, though, has the total energy needs in year 2004, which are 13.7 c/gal for soy oil and 14.5 cents/gal for yellow grease. For 2012, we determined the energy costs by adjusting the 2004 aggregate energy cost by the EIA projected price change of natural gas in the Midwest from 2004 to 2012, resulting in an energy cost of 16.0 and 16.9 cents/gal for soy oil and yellow grease, respectively. All of the other operating costs are represented by an aggregate number, which in year 2004 is 32.6 and 34.5 cent/gal for soy oil and yellow grease, respectively. This cost represents all of the operating costs not associated with energy and capital requirements. For our analysis, we assume that this cost does not change in 2012. We used a glycerin price of 5 c/lb, which generates income and offsets operating cost by 4 c/gal.

The net production cost for yellow greases (minus feedstock costs) is about 3 c/gal more than the net production cost for soy based biodiesel, indicating the extra cost incurred for the yellow grease process. The resulting total production cost are presented in Table 7.2-14

Table7.2-14.
Projected Production Costs for Biodiesel by Feedstock per Gallon
(2004 Dollars)

Marketing Year	**Soy Oil[a]**	**Yellow Grease**
2004	2.33	1.47
2012	2.15	1.38

[a]Production consumes 7.65 lbs of soy oil per gallon of biodiesel. USDA prices in 2012 are adjusted to 2004 dollars to account for inflation, using GDP index of 109.7 in year 2004 and 130.8 in year 2012.

7.2.5 Vendor Production Estimates for Biodiesel

We used engineering vendor estimates as another source to generate the cost to produce biodiesel fuel. For this, we used engineering details from two firms, Superior Technologies and PSI-Lurgi Engineering Inc. These engineering vendors are engaged in the business of designing, constructing and building biodiesel plants. The biodiesel production processes provided by these firms are also based on the continuous transesterification process, using sodium hydroxide and methanol to convert soy oil and yellow grease to biodiesel, along with the finishing processes for biodiesel and glycerol, similar to the other models. The vendors generated estimates of the total cost to build and operate a biodiesel plant, providing the requirements for the equipment, energy, capital and operating. We adjusted these estimates to a 2004 year costs basis for comparative purposes, and used energy costs in the Midwest.

The vendor estimates we used for PSI-Lurgi are those listed in the report “Economic Feasibility of Producing Biodiesel in Tennessee” [88]. The biodiesel plant in this analysis was sized for soy oil feedstock, based on a 13 MM gallon per year plant, which we assumed is directly comparable to the 10 MM gallon plant used in the USDA, NREL and EIA models. In making this comparison, we relied on a report[89] from Superior Process Technologies to generate the production costs to make biodiesel from soy oil and yellow grease. This report has the various cost components for a 10 MM gallon per year plant.

The total soy oil based biodiesel production cost estimate for year 2004 is $2.20/gal and $2.34/gal for PSI-Lurgi and Superior Technology, respectively with an average cost of $2.27/gal. For 2012, we project the soy oil production cost from both vendors would average approximately $2.09 gal. The Superior Technology’s yellow grease biodiesel production cost is $1.66/gal in 2004.

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[88] “Economic Feasibility of Producing Bio-diesel in Tennessee” AIM-AG Agri-Industry Modeling & Analysis Group, 2002

[89] Superior Process Technologies, “ Biodiesel Plant Economics and Process Description”, 8/18/06

7.2.5.1 PSI-Lurgi estimate of Biodiesel Costs

The feedstock costs assume that 7.569 pounds of soy oil are required to make a gallon of biodiesel fuel. The resulting feedstock cost is 174.1 cents/gal for year 2004 . We adjusted all other cost items in the PSI estimate from a 2002 year to 2004 basis, scaling by the relative change of GDP, though the costs for reagent needs and utilities are adjusted using the methods as discussed in the following sections.

7.2.5.2 Capital Costs

The total capital cost provided in the estimate account for all of the costs for building a plant, though excluding maintenance costs, similar to the capital requirements in the NREL model. The total capital coats for a plant are $19.7 million in 2004 dollars, which we adjusted from 2002 dollars. The capital costs were amortized assuming a seven percent return on investment, resulting in an annualized cost of 16.7 cents per gallon. The economic factors used for amortizing the capital costs are the same as those listed in Table 7.2-8.

7.2.5.3 Operating Costs

The total operating costs are 29 cents per gallon for year 2004, excluding capital charges. The cost associated with insurance, taxes and general administrations is 7.3 cents per gallon, while the cost for maintenance is 2 cents/gal. The sale of the glycerol byproduct at 80% strength generates incomes of 4 cents per gallon of produced biodiesel, assuming a glycerol price of 5 cents per pound. The remaining components of operating costs are discussed below.

7.2.5.4 Utility and Labor

The utility costs were estimated using the energy requirements presented in Table 3.1 of the report, along with the same prices for energy, steam and electricity, as those used in our 2004 model analysis. The total utility requirements are 5.5 cents per gallon. The utility requirements per gallon of biodiesel fuel are listed in Table 7.2-15.

Table 7.2-15.
Utility Requirements per Gallon of Biodiesel

Natural Gas, SCF	0
Medium Pressure Steam, lbs	3.92
Electricity, kWh	0.093
Cooling Tower Water, lbs	200.7

The PSI-Lurgi estimate accounts for the salaries of 4 employees per shift to run and maintain the plant. In addition to salaries for these personnel, the labor expenses also accounted for employee fringe benefits. The resulting labor costs are 6.3 cents for each gallon of biodiesel. In addition to these costs, the SG&A expenses are estimated at 6.3 c/gal.

7.2.5.5 Chemical Reagents

The PSI-Lurgi estimate also requires the same chemicals and chemical reagents in the USDA/NREL models. We assumed that the hydrochloric acid and the sodium methoxide used in the PSI estimate is 33% strength, as the prices listed in the study are reflective of being on a diluted basis. We also assumed that the price for the amount of caustic soda required is on an undiluted basis. We adjusted the prices for the chemical and reagents using the 2004 year pricing values used in our USDA/NREL modeling analysis, though the price of phosphoric acid was adjusted using the GDP index. The resulting total chemical and reagent costs on a per gallon basis are about 12.6 cents for each gallon of biodiesel fuel produced. All of the required chemicals and reagents for the production of biodiesel are presented on an undiluted basis in Table 7.2-16.

Table 7.2-16.
Reagent Requirements

Reagent	Annual Requirement, lbs per gallon
Water	1.666
HCl[a]	0.026
Methanol	0.700
$NAOCH_3$[a]	0.038
Caustic Soda / Sodium Hydroxide	0.04
Phosphoric Acid	0.013

[a] HCl is Hydrochloric acid, $NAOCH_3$ is sodium methoxide.

The total soy oil based biodiesel production costs derived from the PSI-Lurgi are $2.20 dollars in year 2004.

7.2.6 Superior Process Technologies Estimate

The Superior feedstock costs assume that 7.60 pounds of soy oil and yellow grease are required to make a gallon of biodiesel fuel, which results in a feedstock cost of 175 cents/gal for year 2004 for soy oil and 87.5 c/gal for yellow grease, using the feedstock costs in section 7.2.2.1. We adjusted all other cost items in the Superior estimate from a 2006 year to 2004 basis, adjusting the cost by the relative change of GDP, though the costs for reagent needs and utilities are adjusted using the methods as discussed below.

7.2.6.1 Capital Costs

The total capital coats for a soy oil based plant are $10.7 million, while the costs for a yellow grease plant are $13.4 million, in 2004 dollars. These costs are inclusive of the amount needed for a new plant, which is similar to the other biodiesel estimates. The capital costs were amortized assuming a seven percent return on investment, resulting in a cost of 11.7 cents per gallon and 14.7 cents per gallon for a soy oil and yellow grease based plant, respectively.

7.2.6.2 Operating Costs

The total operating costs, excluding capital charges are 47 and 64 cents per gallon for soy oil and yellow grease plants in year 2004, respectively. Insurance, taxes, rent and local taxes incur a cost of about 6 and 7 cents per gallon, for soy oil and yellow grease, respectively. The costs for maintenance, plant overhead costs and supplies account for about 16.0 and 21.5 cents/gal, for soy oil and yellow grease. The sale of the glycerol byproduct at 80% strength generates incomes of 4 cents per gallon of produced biodiesel, assuming glycerol price of 5 cents per pound. The remaining components of operating costs are discussed below.

7.2.6.3 Utility and Labor

The overall utility costs were provided, though the specific amounts of natural gas, electricity were not provided for the 10 MM gallon plant. We adjusted the Superior utility cost estimate from a 2006 year to a 2004 year basis, using the relative price change of natural gas and electricity, assuming that natural gas supplies 90 percent of the energy, and electricity supplies the remaining 10 percent. The resulting energy requirement is 5.0 and 8.6 cents per gallon, for soy oil and yellow grease, respectively.

The estimate accounts for personnel cost to run and maintain the plant, including laboratory, plant supervisory and administration costs. The overall labor costs on a 2004 year basis are 7.6 and 12.8 cents for each gallon of biodiesel, for soy oil and yellow grease, respectively.

7.2.6.4 Chemical Reagents

The Superior vendor estimate also requires the same chemicals and chemical reagents as used in the USDA/NREL models and Tennessee study. The total chemical reagent cost from Superior on a 2006 year reagent pricing basis is 18.1 and 20.1 c/gal, respectively for soy and yellow grease plants. Superior provided the prices for each of the chemicals, though the specific amounts of each chemical were not provided for the soy oil based estimate. We therefore, adjusted the total chemical reagent cost to a 2004 year basis, assuming the demands for reagent as documented in the PSI-Lurgi estimate. The resulting reagent costs on a 2004 year basis are 16.5 and 18.3 cents/gal, for soy oil and yellow grease. The Superior prices for the required chemicals and reagents are presented in Table 7.2-17.

Table 7.2-17.
Superiors Reagent Prices

Reagent	**Dollar / lb**
$NAOCH_3$ [a] (25% solution)	0.50
HCl [a] (32%)	0.091
Methanol	0.146
Phosphoric Acid (75%)	0.42
Caustic Soda / Sodium Hydroxide (50%)	0.14

[a] HCl is Hydrochloric acid, $NAOCH_3$ is sodium methoxide.

The total resulting biodiesel production costs derived from Superior Process description and engineering estimate is $2.34 and $ 1.66 per gallon for soy oil and yellow grease derived biodiesel respectively, in year 2004. Yellow greases net production cost (minus feedstock costs) are about 20 c/gal more than the net production cost for soy based biodiesel.

7.2.7 Yellow Grease Production Costs

Yellow grease's production cost is higher than soy oil produced biodiesel fuel, due to the extra capital and operating costs required to remove contaminants in the grease feedstock. In the prior sections, the EIA and Superior analysis indicated that the yellow grease production cost for biodiesel is higher than the production cost based on use of soy oil, excluding the feedstock costs. The EIA analysis showed that yellow grease's production cost is 3 c/gal higher, while the Superior results showed that the yellow grease's production cost is about 20 c/gal higher than soy oil production costs. Both of these provide a measurement of the extra production costs (excluding feedstock) associated with making biodiesel from yellow grease versus soy oil.

In this section, we use the EIA and Superior results to generate yellow grease costs as inputs to the models, adjusting the soy oil production costs to reflect the extra cost for producing yellow grease. We assume the same feedstock costs for yellow grease as those listed in section 7.2.2.1, and that it takes 7.6 lbs of yellow grease to produce a gallon biodiesel fuel. Table 7.2-18, contains the resulting yellow grease production costs based on the EIA and Superior analyses.

Table 7.2-18.
Yellow Grease Costs Based on EIA and Superior Results

	EIA 2004	**Superior 2004**	**EIA 2012**	**Superior 2012**
USDA, c/gal	124	141	111	128
NREL, c/gal	138	155	131	148
EIA, c/gal	143	160	132	149
Vendor avg, c/gal	142	159	139	156
Average	136.8	153.8	128.3	145.2

We averaged all of the yellow grease results, and generated an average production cost of \$1.45/gal in 2004 and \$1.37/gal in 2012 for yellow grease derived biodiesel.

7.2.8 Biodiesel Blending Credit Programs

There are numerous credit and incentive programs that encourage the blending of biodiesel. These programs reimburse blenders and producers for adding biodiesel to transport diesel fuel, which acts to lower the production costs and makes the production of biodiesel more economically competitive with petroleum derived diesel fuel. There are several federal/nationwide biodiesel credit programs that offer subsidies for blending or use of biodiesel as a transport diesel fuel which are discussed below.

The Commodity Credit Commission Bio-energy Program is an existing program that expires at the end of fiscal year 2006, though due to a funding shortfall the program will terminate on July 31, 2006. This program was administered by the USDA and pays biodiesel producers grants when the economics to produce biodiesel are poor. The stipend is determined based on available funding and the volume of renewable fuel that can receive the credit. For historical purposes, the payments in 2004 and 2005 averaged about 107 and 50 c/gal of fuel produced, respectively. For the first half of 2006, the credit on a per gallon basis is reduced further, as the payment is diluted by increased production volume of fuels available to receive the credit.

The Energy Act extended the Biodiesel Blenders Tax Credit program to the end of year 2008. This program was created under the American Jobs Creation Act of 2004 which created an excise tax credit that can be claimed by anyone who blends biodiesel into transport diesel fuel. Under this program, blenders may claim a credit against the applicable federal motor fuels excise tax for blends containing biodiesel. According to IRS guidelines, the credit may be claimed by anyone who adds biodiesel into diesel fuel at a level greater than 0.1 percent in the final blend. The full credit for biodiesel made from virgin vegetable oils and animal fats is $1.0 per gallon, while biodiesel derived from recycled grease receives 50 cents/gallon. A blender with more excise tax credits than taxes owed can receive a refund from the IRS. Additionally, under the current program, imported biodiesel and fuel made from imported feedstocks can also receive the credit.

The Income Tax Credit Alternative is a program that is also available. This program does not require any blending of biodiesel, though it does offers allow a similar excise tax credit as in the blenders tax credit program. The excise tax can only be taken against actual income, however, which makes the program less economically attractive than the blenders' credit program.

The Energy Act also created the Small Biodiesel Blenders Tax credit program. Under this program, a credit of 10 c/gal is available to small producers who make biodiesel fuel from virgin vegetable oils. This stipend is limited to companies with annual production volumes less than 60 MM gallons per year, using the aggregated capacity from all production sites for an individual company. The maximum payment per company is capped at $15 MM per year and the program is set to expire at the end of year 2008.

In addition to the federal programs, there are state and local programs that offer state fuel tax exemptions, tax credits, and incentives that are more modest.

7.3 Distribution Costs

7.3.1. Ethanol Distribution Costs

There are two components to the costs associated with distributing the volumes of ethanol necessary to meet the requirements of the Renewable Fuels Standard (RFS): 1) the capital cost of making the necessary upgrades to the fuel distribution infrastructure system, and 2) the ongoing additional freight costs associated with shipping ethanol to terminals. The most comprehensive study of the infrastructure requirements for an expanded fuel ethanol industry was conducted for the Department of Energy (DOE) in 2002.[wwwww] This study provides the foundation for our estimates of the capital costs associated with upgrading the distribution infrastructure system as well as the freight costs to handle the increased volume of ethanol needed in 2012.   Distribution costs are evaluated here for the RFS and EIA cases.

7.3.1.1 Capital Costs to Upgrade the Ethanol Distribution System

The 2002 DOE study examined two cases regarding the use of renewable fuels. The first case assumed that 5.1 Bgal/yr of ethanol would be used in 2010, and the second case assumed that 10 Bgal/yr of ethanol would be used in 2015. We interpolated between these two cases to provide the foundation for our estimate of the capital costs to support the use of 6.67 Bgal/yr of ethanol in 2012 (the RFS case). The 10 Bgal/yr case from the DOE study was used as the foundation to estimate the capital costs under the EIA case. For both the 6.67 Bgal/yr and 9.64 Bgal/yr cases, we adjusted the results from the DOE study to reflect a 3.9 Bgal/yr 2012 ethanol use baseline. Table 7.3-1 contains our estimates of the infrastructure changes and associated capital costs for the two ethanol use scenarios examined in today's rule.[90]

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[90] These capital costs will be incurred incrementally during the period of 2007-2012 as ethanol volumes increase. For the purpose of this analysis, we assumed that all capital costs will be incurred in 2007.

Table 7.3-1.
Ethanol Distribution Infrastructure Capital Costs
Relative to a 3.9 Billion Gallon per Year Reference Case

	RFS Case (6.67 Bgal/yr)	EIA Case (9.64 Bgal/yr)
New Terminal Blending Systems for Ethanol		
Number of terminals	243	515
Capital cost	$73,044,000	$154,530,000
New Ethanol Storage Tanks at Terminals		
Number of tanks	168	370
Capacity	1,526,000 barrels	3,415,000 barrels
Capital cost	$21,939,000	$48,803,000
Terminal Storage Tanks Converted to Ethanol		
Number of tanks	44	83
Capacity	319,000 barrels	592,000 barrels
Capital cost	$931,000	$1,739,000
Terminals Using Ethanol for the First Time[a]		
Number of terminals	212	453
Capital cost	$4,238,000	$9,065,000
New Rail Delivery Facilities at Terminals		
Number of terminals	42	76
Capital cost	$14,869,000	$27,127,000
Retail Facilities Using Ethanol for First Time[a]		
Number of retail facilities	33,600	74,820
Capital cost	$19,824,000	$44,146,000
New Tractor Trailer Transport Trucks		
Number of Trucks	209	435
Capital Costs	$24,027,000	$50,075,000
New Barges		
Number of new barges	11	23
Capital cost	$21,475,000	$43,204,000
New Rail Cars		
Number of new rail cares	2,024	3,491
Capital cost	$172,012,000	$296,729,000
Total Capital Costs	$352,361,000	$675,418,000
Capital Costs Attributed to Terminal and Retail (i.e. fixed) Facilities	$134,847,000	$285,410,000
Capital Costs Attributed to Mobile Facilities (tank trucks, rail cars, & barges)	$217,514,000	$390,008,000

[a] Terminal and retail facilities using ethanol for the first time will need to make various modifications to ensure the compatibility of their systems with ethanol.

Our estimated capital costs in this final rule differ from those in the proposal for several reasons. First, the volume for the RFS case was updated to reflect the fuel rule provisions. Second, we adjusted our estimate of capital costs from those in the proposal to reflect an increase in the cost of rail tank cars and barges since the DOE study was conducted. Third, we are assuming a 30 percent increase in the reliance on rail versus marine transport over that projected in the DOE study. The 2002 DOE study estimated that 53 percent of the increase in ethanol volume shipped between PADDs would be carried by barge and 47 percent by rail. For the purposes of this analysis, we assumed that 30 percent of the increased volume in ethanol shipments that were projected to be carried by barge in the DOE study would instead be carried by rail. This equates to 37 percent of the increase in ethanol shipments being carried by barge and 63 percent by rail. To provide a conservatively high estimate of the potential economic impact, we assumed that this shift translates into a 30 percent increase in rail infrastructure costs. This incorporates the increased cost to prepare additional terminals to receive ethanol by rail, and to provide a sufficient number of additional rail tank cars for ethanol transport. The actual increase in rail infrastructure costs may be somewhat lower given improvements in the efficiency of ethanol transport by rail.

Amortized over 15 years at a 7 percent cost of capital, the total capital costs (of $352,361,000 under the RFS case and 675,418,000 under the EIA case) equates to an annual cost of approximately $38,687,000 under the RFS case and $74,157,000 under the EIA case. This translates to approximately 1.4 cents per gallon of new ethanol volume under the RFS case and 1.2 cents per gallon under the EIA case. Under both cases, approximately 0.5 cents per gallon is attributed to mobile facilities and the remainder to fixed facilities.

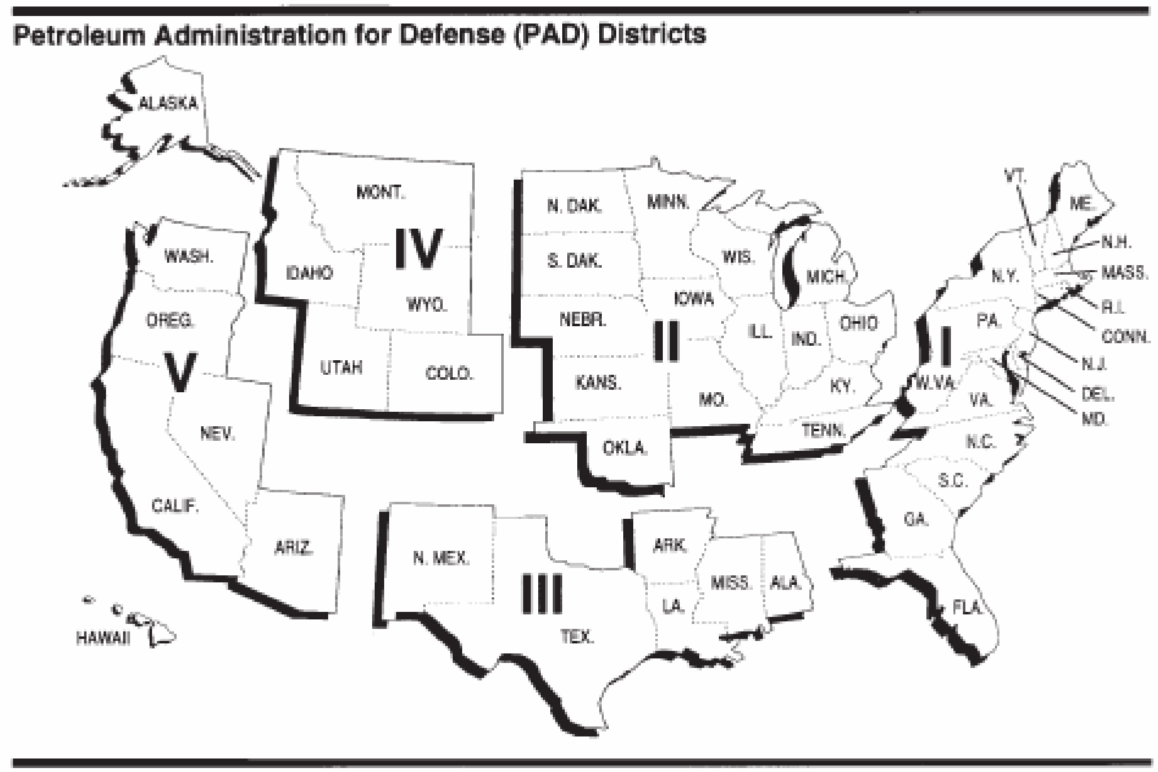
7.3.1.2 Ethanol Freight Costs

The 2002 DOE study contains estimated ethanol freight costs for each of the 5 PADDs. These estimated costs are summarized in the following Table 7.3-2.[XXXXX] A map of the PADDs is contained in Figure 7.3-1.

Table 7.3-2.
Estimated Ethanol Freight Costs from the 2002 DOE Study

PADD	5.1 billion gallons per year (cents per gallon)	10.0 billion gallons per year (cents per gallon)
1	11.1	7.2
2	4.3	2.4
3	6.6	5.8
4	4.7	7.4
5	12.7	10.7
National Average	7.7	5.7

Figure 7.3-1.
PAD District Definitions.

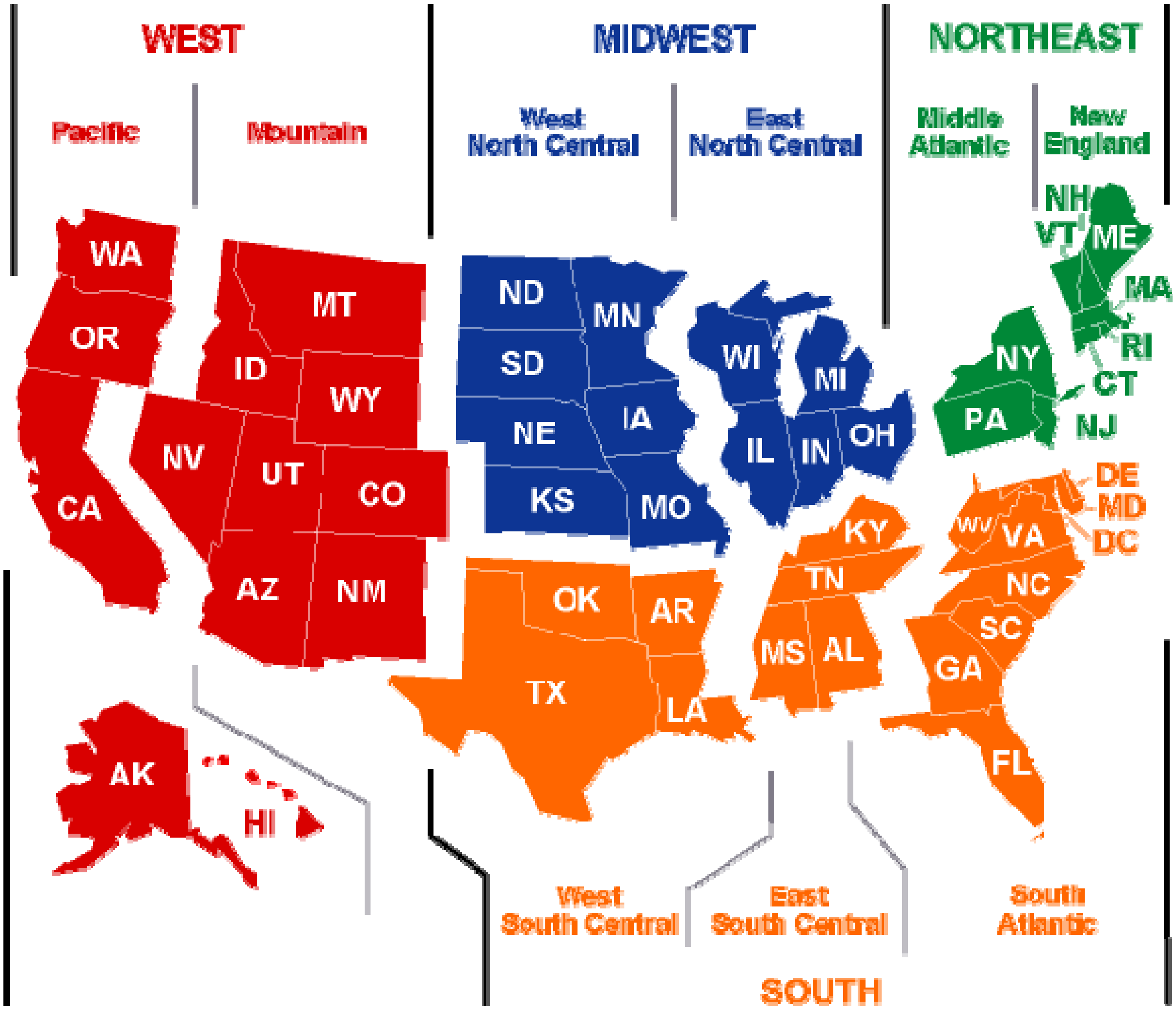


The Energy Information Administration (EIA) translated the cost estimates from the 2002 DOE study to a census division basis.[YYYYY] A summary of the resulting (EIA) ethanol distribution cost estimates are contained in the following Table 7.3-3. A map of the census divisions is contained in Figure 7.3-2.

Table 7.3-3.
EIA Estimated Ethanol Freight Costs
(derived from the 2002 DOE Study)

Census Division		Freight Cost (cents per gallon)
From	To	
East North Central	New England	9.8
East North Central	Middle Atlantic	9.8
East North Central	East North Central	4
East North Central	South Atlantic	9.8
East North Central	East South Central	4.7
East North Central	Pacific	14.0
West North Central	New England	11.4
West North Central	Middle Atlantic	11.4
West North Central	East North Central	4
West North Central	West North Central	4
West North Central	South Atlantic	11.4
West North Central	East South Central	4.7
West North Central	West South Central	4.7
West North Central	Mountain	4.5
West North Central	Pacific	13.0

Figure 7.3-2.
Census Divisions



We took the EIA projections and translated them into State-by-State ethanol freight costs. For the purposes of this analysis, all ethanol was assumed to be produced in the East and West North Central Census Divisions (corresponding closely to PADD 2). We believe that this is a reasonable approach because the cost of shipping corn feedstock from PADD 2 to ethanol plants located outside of PADD 2 will typically negate any potential reduction in freight cost from reduced shipping distances for ethanol or dried distiller grains. The vast majority of ethanol plants planned for outside of PADD 2 are projected to begin operation using corn supplied from PADD 2.[91] Many have stated plans to transition to local feedstocks. However, we believe that such a transition will typically not be accomplished within the timeframe considered by this

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[91] Hawaii is a special case because plants potentially located there will use local feedstocks from their initial start up date.

analysis (i.e. 2012). Other local considerations may provide a unique cost advantage to locating a plant outside of PADD 2. One such consideration might be that if by locating a plant outside of PADD 2 the ethanol producer could avoid the need to dry the distiller grains it produces and sell the wet distiller grains to a local market. Although this might result in a significant cost savings, it is unclear the extent to which this will be possible given the short shelf life of wet distiller grain (~3 days). Also, any potential cost savings might be offset by the relatively lower price that can be negotiated for wet versus dry distiller grains. In any event, there is insufficient data at this time to evaluate the extent to which such local conditions may result in an advantage in lower freight costs for ethanol plants outside of PADD 2. Further, our projection of where new ethanol production plants might be located indicates that only 10 percent of production capacity could be located outside of PADD 2. Thus, any potential freight cost advantage that might be enjoyed by such plants would not likely have a significant impact on our national analysis. Furthermore, to the extent that the location of ethanol plants outside of PADD 2 imparts a savings in ethanol distribution costs, this would suggest that our estimates of ethanol freight costs in this rule are conservatively high.

Ethanol consumed within census divisions belonging to PADD 2 was assumed to be transported by truck, while distribution outside of these areas was assumed to be by rail, ship, and/or barge. A single average distribution cost for each destination census division was generated by weighting together the 2012 freight costs given for each mode in both source census divisions according to their volume share. These cents per gallon figures were first adjusted upward by 10 percent to reflect the increased cost of transportation fuels used to ship ethanol since the 2002 DOE study, and then additional adjustments were applied to some individual states based on their position within the census division. In the case of Alaska and Hawaii, differences in ethanol delivery prices from the mainland were inferred from gasoline prices.

For some states, different freight costs for ethanol supplied to large hub terminals versus small satellite terminals was estimated. The reasoning behind this is that large shipments of ethanol shipped from the Midwest by barge, ship, and/or unit train will often be initially unloaded at hub terminals for further distribution to satellite terminals. In cases where redistribution from a hub to a satellite terminal doesn’t take place, the volume of ethanol shipped directly from the producer to a lesser volume (“satellite”) terminal will also incur a higher freight rate than ethanol shipped to a larger-volume “hub” terminal. The largest adjustment was applied to the Rocky Mountain States since they are generally large in area and additional expense is required to transport freight through higher elevations and rugged terrain. Smaller adjustments were applied to states that are smaller, flatter, or have access by navigable waterways. The states to which an adjustment was not applied were generally in the Midwest or were so small as to not warrant different distribution costs. Given the large number of ethanol plants in the Midwest, we do not believe that there are substantial differences in the cost of distributing ethanol with that area.

We made several adjustments in our estimates of ethanol freight costs from those in the proposal. First, the differential cost of shipping ethanol to satellite terminals versus hub terminals was increased to better reflect the additional costs incurred in either redistributing the ethanol from a hub to a satellite terminal, or of shipping ethanol directly from the producer to the satellite terminal in a lesser volume. The estimated additional freight cost of shipping ethanol to satellite terminals versus hub terminals is contained in the following Table 7.3-4.

Table 7.3-4.
Additional Freight Cost to Deliver Ethanol to a Satellite Terminal Compared to a Hub Terminal

States	cents per gallon
OH	2
AL, AR, FL, GA, KY, LA, MD, ME, MS, NC, NH, NY, OK, OR, PA, SC, TN, VA, VT, WA, WV	4
AK, AZ, CO, ID, NM, NV, TX, UT, WY	5

Another change that we made from the proposal was with respect the volume of ethanol we estimated would be delivered to hub versus satellite terminals. The proposal assumed a 50/50 spit. For this final rule, we project that all of the ethanol volume blended into reformulated gasoline would be used in urban areas served by hub terminals. The percentage of ethanol blended into conventional gasoline that is used in an urban area (and hence delivered to a hub terminal) versus that used in a rural area (and hence delivered to a satellite terminal) was based on our analysis of the percentage of vehicle miles traveled in urban versus rural areas.[92]

The final change from the proposal pertains to our consideration of the cost of shipping ethanol from the production plant to the rail head / marine terminal either for large volume shipment by unit train or marine shipment to hub terminals, or for shipment at single car rates via multiple-product trains directly to satellite terminals. Our review of current ethanol freight rates conducted in response to a comment on the proposed rule indicates that we did not adequately account for this added cost in the proposal. Chicago is a primary ethanol gathering point from producers for further distribution. A 4 cent per gallon conveyance fee is charged to account for delivery of ethanol from the production plant gate to the Chicago Board of Trade delivery point for taking ethanol. This includes train shipments, loading costs, and other miscellaneous fees. Based on this information, we have added 4 cents per gallon to our ethanol freight estimates.

Our estimates of the State-by-State ethanol freight costs under the RFS and EIA cases are contained in Tables 7.3-5 and 7.3-6. National and PADD average freight costs under both the RFS and EIA cases are contained in Table 7.3-7. We are assuming that these freight costs do not include the costs associated with the recovery of capital for the distribution facility changes that are necessary to accommodate the increased volume of ethanol. This may tend to overstate distribution costs to some extent because some capital recovery may be incorporated into the 4 cent per gallon conveyance fee. The inclusion of rail tank car lease fees also suggests that these estimated freight costs may be conservatively high given that rail car lease fees incorporate a capital recovery and profit margin.

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[92] See Chapter 2 of this RIA for additional discussion of our estimate of the percentage of ethanol that will be used in urban versus a rural areas

Table 7.3-5.
State-by-State Ethanol Freight Costs

State	PADD	Ethanol Freight Cost*: (cents per gallon)			
		Hub Terminal	Satellite Terminal	Average Freight Cost**	
				RFS Case	EIA Case
Connecticut	1	15.4	15.4	15.4	15.4
Maine	1	17.4	21.4	20.0	20.0
Massachusetts	1	15.4	15.4	15.4	15.4
New Hampshire	1	16.4	16.4	16.4	16.4
Rhode Island	1	15.4	15.4	15.4	15.4
Vermont	1	16.4	16.4	NA***	16.4
New Jersey	1	15.4	15.4	15.4	15.4
New York	1	15.4	19.4	15.4	15.7
Pennsylvania	1	12.4	16.4	13.8	13.7
Delaware	1	15.4	15.4	15.4	15.4
District of Columbia	1	15.4	15.4	NA***	15.4
Florida	1	12.4	16.4	14.0	14.0
Georgia	1	15.4	19.4	NA***	17.4
Maryland	1	15.4	15.4	NA***	15.4
North Carolina	1	15.4	19.4	NA***	NA***
South Carolina	1	15.4	19.4	NA***	NA***
Virginia	1	15.4	19.4	NA***	15.4
West Virginia	1	15.4	19.4	NA***	NA***
Illinois	2	4.4	4.4	4.4	4.4
Indiana	2	5.4	5.4	5.4	5.4
Michigan	2	6.4	6.4	6.4	6.4
Ohio	2	5.4	7.4	6.6	6.6
Wisconsin	2	4.4	4.4	4.4	4.4
Iowa	2	3.4	3.4	3.4	3.4
Kansas	2	4.4	4.4	4.4	4.4
Minnesota	2	4.4	4.4	4.4	4.4
Missouri	2	4.4	4.4	4.4	4.4
Nebraska	2	4.4	4.4	4.4	4.4
North Dakota	2	5.4	5.4	5.4	5.4
South Dakota	2	4.4	4.4	4.4	4.4
Kentucky	2	6.2	10.2	7.1	7.3
Tennessee	2	6.2	10.2	8.7	8.7
Oklahoma	2	8.3	12.3	NA***	11.1

* Freight rates from PADD 2 production facilities

** Hub and satellite freight rates were volume weighted to arrive at an average freight rate.

*** No significant ethanol use. See Chapter 2 of this RIA regarding our estimates of where ethanol will be used.

Table 7.3-5.
State-by-State Ethanol Freight Costs (continued)

State	PADD	Ethanol Freight Cost*: (cents per gallon)			
		Hub Terminal	Satellite Terminal	Average Freight Cost**	
				RFS Case	EIA Case
Alabama	3	11.2	15.2	14.0	14.0
Mississippi	3	10.2	14.2	13.9	13.9
Arkansas	3	11.3	16.3	15.0	15.0
Louisiana	3	11.3	15.3	13.8	13.8
Texas	3	14.3	19.3	14.3	16.0
New Mexico	3	16.4	21.4	19.0	19.6
Colorado	4	14.4	19.4	NA***	17.0
Idaho	4	19.4	24.4	NA***	22.8
Montana	4	17.4	22.4	21.8	21.8
Utah	4	17.4	22.4	NA***	20.5
Wyoming	4	16.4	21.4	NA***	20.8
Arizona	5	19.4	24.4	20.3	20.5
Nevada	5	20.4	25.4	21.1	22.3
Alaska	5	45.5	50.5	NA***	NA***
Hawaii	5	40.5	40.5	NA***	40.5
Oregon	5	20.5	24.5	20.5	20.5
Washington	5	20.5	24.5	21.9	21.9
California	5	20.5	20.5	20.5	20.5

* Freight rates from PADD 2 production facilities.
** Hub and satellite freight rates were volume weighted to arrive at the average freight rate.
*** No significant ethanol use. See Chapter 2 of this RIA regarding our estimates of where ethanol will be used.

Table 7.3-6.
National and PADD Average Ethanol Freight Costs

	Ethanol Freight Cost* (cents per gallon)	
	RFS Case	EIA Case
National Average	11.3	11.9
PADD 1	14.9	15.1
PADD 2	5.1	5.3
PADD 3	14.6	15.2
PADD 4	21.8	19.8
PADD 5 excluding AK & HI	20.6	20.7
PADD 5 including AK & HI	20.6	22.1

* Freight rates from PADD 2 production facilities.

The national average ethanol freight cost of 11.3 cents per gallon under the RFS case and 11.9 cents per gallon under the EIA case translates to an annual freight cost for the additional volume of ethanol used in 2012 of $313,123,000 and $678,300,000 respectively. Adding in the annualized capital costs, results in a total annual ethanol distribution cost of 351,810,000 or 12.7 cents per gallon under the RFS case and $752,457,000 or 13.1 cents per gallon under the EIA case.[93]

7.3.2 Biodiesel Distribution Costs

The volume of biodiesel used by 2012 under the RFS is estimated at 300 million gallons per year. The 2012 reference case against which we are estimating the cost of distributing the additional volume of biodiesel needed to meet the requirements of the RFS is 30 million gallons.[94]

The capital costs associated with distribution of biodiesel are higher per gallon than those associated with the distribution of ethanol due to the need for storage tanks, blending systems, barges, tanker trucks and rail cars to be insulated and in many cases heated during the winter months.[95] In the proposal, we estimated that that these capital costs would be approximately $50,000,000. We adjusted our estimate of these capital costs for this final rule based on additional information regarding the cost to install the necessary storage and blending equipment at terminals and the need for additional rail tank cars for biodiesel.[96] We now estimate that handling the increased biodiesel volume will require a total capital cost investment of $145,500,000 which equates to about 6 cents per gallon of new biodiesel volume.[97]

In the proposal, we estimated that the freight costs for ethanol adequately reflect those for biodiesel as well. In response to comments, we sought additional information regarding the freight costs for biodiesel. This information indicates that freight costs for biodiesel are typically 30 percent higher than those for ethanol which translates into an estimate of 15.5 cents per gallon for biodiesel freight costs.[98]

Including the cost of capital recovery for the necessary distribution facility changes, we estimate the cost of distributing biodiesel to be 21.5 cents per gallon.

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[93] All capital costs were assumed to be incurred in 2007 and were amortized over 15 years at a 7 percent cost of capital.

[94] See Chapter 1 of this RIA regarding the 2012 reference case.

[95] See Chapter 1.3 of the Regulatory Impact Analysis associated with today's rule for a discussion of the special handling requirements for biodiesel under cold conditions.

[96] Information on biodiesel facility costs was obtained from a number of biodiesel blenders on the condition that the specific source of such information would not be identified. Biodiesel rail tank cars typically have a capacity of 25,500 gallons as opposed to 30,000 gallons for an ethanol tank car. Thus, additional tank cars are need to transport a given volume of biodiesel relative to the same volume of ethanol.

[97] Capital costs will be incurred incrementally over the period of 2007-2012 as biodiesel volumes increase. For the purpose of this analysis, all capital costs were assumed to be incurred in 2007 and were amortized over 15 years at a 7 percent cost of capital.

[98] This is based on our review of publicly available biodiesel and ethanol freight rates from CSX and BNSF rail at www.csx.com and www.bnsf.com , on information regarding the lease rates for biodiesel versus ethanol freight cars considering the smaller size of biodiesel tank cars, and on discussions with biodiesel distributors. The estimated ethanol freight costs were increased by 30 percent to arrive at the estimate of biodiesel freight costs.

7.4 Gasoline and Diesel Blendstock Costs

The previous sections of this chapter have presented estimates of the cost of producing and distributing ethanol and biodiesel. In this section, we summarize the results of refinery modeling conducted by Jacobs Consultancy under contract to EPA. Jacobs's used the Haverly Linear Programming (LP) model to conduct the analysis. This model is widely used by the refining industry, consultants, engineering firms and government agencies to analyze refinery economics, refinery operations, fuel quality changes, refinery capital investments, environmental changes and demand changes. The Haverly model uses Jacobs's Refining Process Technology Database to represent refining operations

The modeling was conducted to analyze the effect of the increased renewable fuel use on the production costs and composition of the nation's gasoline and diesel fuel. The refinery modeling output described in this section includes the changes in volumes and capital investments as well as the resulting capital and fixed operating costs, the variable costs, and the total of all these costs. The costs are expressed in 2006 dollars and capital costs are amortized at 7% before tax return on investment (ROI). The costs for the RFS and EIA cases are expressed incremental to the reference case. We first report the results of the RFS case, followed by the results of the EIA case.

7.4.1 Description of Refinery Modeling Cases Modeled

The modeling cases were set up to analyze the RFS and EIA cases described in Chapter 2. The primary renewable fuel modeled was ethanol in gasoline, while considering a fixed production amount of biodiesel as projected by EIA in 2012. Along with the increased use of renewable fuels, the analyses for the RFS and EIA cases both include the elimination of the RFG oxygen content standard and the resulting removal of MTBE from the U.S. gasoline market. These scenarios both assume the current Mobile Source Air Toxics standard (MSAT1) is in place. The effects of the MSAT2 standard are modeled in that rulemaking which has just recently been made final.

Jacobs conducted a Linear Programming (LP) modeling analysis of the refining industry for the various RFS scenarios using a model developed by Haverly's LP technology. The modeling was set up to analyze the extent to which ethanol will be used in CG versus RFG by region and the resulting effects on gasoline composition. The refining industry was modeled based on five aggregate complex refining regions, representing PADD's 1, 2, 3, 4 & 5 together minus California and California separately. All of the PADDS were modeled simultaneously together in the LP model, in order to balance and meet the national gasoline and fuel demands.

7.4.1.1 RVP

The analysis modeled summer and winter seasons, with all gasoline types including California RFG, Federal RFG, 7.0, 7.8 RVP controlled areas and 9.0 CG. The control cases consisted of the minimum renewable fuel volume as specified by EPAct and discussed in Chapter 2 and the 2006 AEO projection of 9.6 billion gallons of ethanol per year in 2012.

Winter gasoline RVP levels were adjusted higher than EPA data, to account for refiner RVP reporting inaccuracies from use of the complex model in the winter season. (Some refiners reported lower RVP levels than actually produced, as the complex model has a fixed upper reporting limit of 8.8 in the winter season.)

7.4.1.2 Base case (2004)

The base case was established by modeling fuel volumes for 2004. Information was based on process capacities from Oil and Gas Journal, EIA data and gasoline emissions and property data from EPA. Fuel property data for this base case was built off of 2004 refinery batch reports provided to EPA; however, the base case assumed sulfur standards based on gasoline data in 2004, not with fully phased in of Tier 2 gasoline standards at the 30 ppm level. In addition we assumed the phase-in of 15 ppm sulfur standards for highway, nonroad, locomotive and marine diesel fuel. The supply/demand balance for the U.S. was based on gasoline volumes from EIA and the California Air Resources Board (CARB). Our decision to use 2004 rather than 2005 as the baseline year was because of the refinery upset conditions associated with the Gulf Coast hurricanes in 2005.

7.4.1.3 MSAT1 Provisions for Refinery Cases in 2012

For CG and RFG, gasoline qualities were modeled to assure Complex model Phase 2 calculations seasonal and annual compliance, taking into account the elimination of the oxygen requirement for RFG; (by PADD and California), and under MSAT1 gasoline standards. Incremental gasoline volumes above the 2004 base case volumes for each PADD were allowed to conform to less stringent toxics performance standards as allowed by the MSAT1 provisions. For this, the MSAT 1 PADD constraints were calculated using gasoline data from 1998-2000 EPA batch reports, considering that new incremental volumes of gasoline above the 1998-2000 annual average would comply with MSAT1 provisions, as predicated by EPact 2005. The following tables show the resulting conventional and RFG gasoline MSAT1 baseline constraints, which was applied to gasoline produced for the cases modeled in year 2012.

Table 7.4-1.
Conventional Gasoline MSAT 1 2012 Baseline Data

	Exhaust Toxics mg/mi*	NOx mg/mi*
PADD 1	88.33	1,440.84
PADD 2	92.79	1,432.57
PADD 3	88.79	1,438.76
PADD 4 & 5, excluding California	99.85	1,414.00

*mg/mi is milligram per mile.

Table 7.4-2.
RFG Gasoline MSAT 1 2012 Baseline Data

	Total Toxics mg/mi*	Toxics Percent Reduction
PADD 1	75.11	27.39
PADD 2	80.11	22.56
PADD 3	74.74	27.75
PADD 4 & 5, excluding California	NA	NA

*mg/mi is milligram per mile.

7.4.1.4 Reference case (2012)

The reference case was based on modeling the base case, using 2012 fuel prices, and scaling the 2004 fuel volumes to 2012 based on growth in fuel demand. In addition, we scaled MTBE and ethanol upward, in proportion to gasoline growth, and assumed the RFS program would not be in effect. For example, if the PADD 1 gasoline pool MTBE oxygen was 0.5 wt% in 2004, the reference case assumed it should remain at 0.5 wt%. Finally, we assumed the MSAT 1 standards would remain in place as would the RFG oxygen mandate. We assumed the crude slate quality in 2012 is the same as the baseline case.

7.4.1.5 Control cases (2012)

Two control cases were run for 2012. The assumptions for the control cases are summarized below:

- Control Case 1 (RFS case): 6.7 billion gallons/yr (BGY) of ethanol in gasoline; it reflects the renewable fuel mandate. In addition, it is assumed that no MTBE is in gasoline, MSAT1 is in place, the 1 psi waiver for CG containing 10 volume percent ethanol remains in effect for all states where it currently applies, the RFS is in effect, and there is no RFG oxygenate mandate.

- Control Case 2 (EIA case): Same as Control Case 1, except that the ethanol volume in gasoline is 9.6 BGY.

7.4.2 Assumptions made for Refinery Modeling

7.4.2.2 Fuels Production and Demand

The production of and demand for gasoline and other refinery fuels in the reference and control cases were based on EIA's AEO 2006 projections for year 2012 . The modeling also was set up to meet demand based on terminals' sales in each refining area, using EIA fuel sales data. The LP modeling accounted for inter-PADD transfers of finished products and gasoline blendstocks from refiners, to meet demand at terminals, based on historical transfer data from EIA, including CBOB and RBOB. Both the RFS and EIA control cases did not model any production of biodiesel fuel in fulfilling transportation diesel fuel demand.

7.4.2.3 Ethanol

The control cases were based on fixed national ethanol volumes as specified in Chapter 2. For the control cases, however, the LP modeling analysis used ethanol blending economics and ethanol distribution costs to allocate ethanol to each PADD, and to allocate ethanol use in CG and RFG grades of gasoline. Additionally, the modeling assumed that all ethanol added to gasoline is match-blended for octane by refiners in the reference and control cases, while splash blending of ethanol was assumed as appropriate for the base case using EPA gasoline data.

The price of ethanol was based on the 2004 yearly average price spread between regular conventional gasoline sold on spot market in Houston and ethanol sold on spot market on Chicago Board of Trade (CBOT). This was used to determine a Midwest ethanol production price. To derive ethanol prices for all other PADDs outside the Midwest, the Midwest ethanol production price was then adjusted for transportation costs to deliver ethanol from the Midwest to end use terminals (see section 7.3 for additional details). The price of ethanol was also adjusted to account for the 51 cent/gal rebate from the Federal subsidies, but did not account for the impact of state subsides.

The reference and control cases where modeled assuming that ethanol CG blends are entitled to the 1.0 psi RVP waiver during the summer (i.e., for all 9.0 RVP and low RVP control programs) so as to assess the impact on summertime butane removal.

7.4.2.4 Processes and Capital

All changes in refining capital was assessed at a 15% Return on Investment (ROI) after taxes, which was adjusted to 7 % ROI before taxes. Crude and other input prices were based on Jacobs' projection of refinery margins and crude prices in 2012 cases, which was also based on the historical price spreads of fuels between PADDS, using information from EIA's 2004 price information tables, Platts, and AEO 2006, see the Jacob's report for the petroleum fuel prices used in the modeling analysis.

7.4.3 Results of Refinery Modeling

7.4.3.1 Summary of Changes in Refinery Inputs and Outputs to the RFS Case

There are a number of changes in individual and overall volume for specific gasoline blendstocks between the RFS case and reference case based on the refinery model results. The changes include the increased blending of ethanol, the removal of MTBE, and the increased volumes of isooctane, isooctene and alkylate from the reuse of isobutylene formerly used to produce MTBE. The isooctane and isooctene are produced by merchant MTBE plants that formerly produced MTBE from mixed butanes, ethylene crackers, and propylene oxide plants as determined by a survey of how those plants are being converted to produce other gasoline blendstocks. The alkylate is produced from the isobutylene previously used to produce MTBE at captive (refinery-based) MTBE plants. The total volume of these gasoline blend stocks is summarized in Table 7.4-3 for both the reference case and RFS case adjusting the volume of ethanol and MTBE to reflect their gasoline energy-equivalent volumes.

Table 7.4-3.
Comparison of Ethanol, MTBE, Isooctane, Isooctene, and Alkylate Volumes by PADD for the RFS Case and Reference Case (barrels per day)

Case	Gasoline Blendstock	PADD 1	PADD 2	PADD 3	PADD 4/5	CA	USA
Reference Case	Ethanol	57,620	114,900	5,242	20,676	58,934	257,372
	MTBE	54,887	0	122,474	0	0	177,360
	Isooctane/Isooctene	200	200	200	200	200	1,000
	Gasoline-equivalent Volume	82,687	76,034	102,864	13,846	39,096	314,527
RFS Case	Ethanol	139,224	201,989	23,091	17,853	53,004	435,160
	MTBE	0	0	0	0	0	0
	Isooctane/Isooctene Alkylate from MTBE	11,042	200	212,177	200	21,484	245,103
	Gasoline-equivalent Volume	102,930	133,513	227,417	11,983	56,466	532,308
	Change in Gasoline Equivalent Volume	20,243	57,479	124,553	-1,863	17,370	217,781

As the bottom row in Table 7.4-3 shows, the gasoline-equivalent volumes for the aggregated volume of these gasoline blendstocks are expected to increase as we compare the RFS case to the reference case. It is this net increase in gasoline blendstock volume that is expected to result in a net reduction in petroleum consumption.

The addition of ethanol to wintertime gasoline, and to summertime RFG, will cause an increase of approximately 1 psi in RVP that needs to be offset to maintain constant RVP levels. An obvious means that refiners could choose to offset the increase in RVP is to reduce the butane levels in their gasoline. To some extent, the modeling results showed some occurrences of that, but it also did not report an overall increase in butane sales as a result of the increased use of ethanol.

To convert the captive MTBE over to alkylate, after the rejection of methanol, refiners will need to combine one molecule of refinery produced isobutane with the isobutylene that was the feedstock for MTBE. The use of the isobutane will reduce the RVP of the gasoline pool from which it comes, helping to offset the RVP impacts of ethanol. Also, the increased production of alkylate provides a low RVP gasoline blendstock that offsets a portion of the cracked stocks produced by the fluidized catalytic cracker unit. Other means that the refinery model used to offset the high blending RVP of ethanol includes purchasing gasoline components with lower RVP, producing more poly gasoline which has low RVP and selling more high-RVP naphtha to petrochemical sales.

In Table 7.4-4, we summarize the inputs into and gasoline outputs from the refinery model separate from the ethanol and converted MTBE blendstocks summarized above. The summary shows that crude oil and vacuum gas oil and residual fuel purchases are expected to decrease about 1 percent averaged over all the PADDs. The refinery model also estimates that the volume of purchased gasoline components will increase in most PADDs. These gasoline components include renewable blendstocks for ethanol blending (RBOB), which is a very low

RVP gasoline blendstock. A likely reason for the increased gasoline blendstock volumes over purchased crude oil purchases is that the refinery model is seeking to purchase low RVP blendstocks to offset the volatility impacts of ethanol, as opposed to having to crack crude oil which produces more volatile four carbon compounds. Table 7.4-4 also shows the volume of gasoline projected to be produced for both the RFS case and reference case. We adjusted the gasoline volume for the RFS case to reflect the same energy density of the gasoline reported for the reference case. While the national energy-adjusted gasoline production levels for RFS case are about the same as the reference case, the energy adjusted gasoline production levels vary significantly by PADD. The refineries in PADDs 1 and 2 are projected to produce more gasoline in the RFS case compared to the reference case, while the refineries in PADD 3 are projected to produce less gasoline in the RFS case.

Table 7.4-4.
Summary of Refinery Model Input and Output Volumes by PADD for the RFS Case and Reference Case (barrels per day)

Case	Crude Oil and Gasoline	PADD 1	PADD 2	PADD 3	PADD 4/5	CA	USA
Reference Case	Crude Oil	1,823,008	3,650,044	9,071,056	1,529,442	1,952,560	18,026,111
	VGO and Residual Fuel	152,467	59,552	680,329	0	27,400	919,748
	Gasoline Component Inputs	144,293	69,233	144,782	49,247	51,475	459,030
	Gasoline Volume	1,378,811	2,398,179	4,004,675	778,262	1,184,533	9,744,461
	Gasoline Energy Content	5.012	4.997	5.093	5.019	5.024	5.044
RFS Case	Crude Oil	1,762,018	3,579,232	9,071,056	1,520,709	1,952,560	17,885,576
	VGO and Residual Fuel	75,044	59,552	680,329	0	40,707	855,631
	Change in Crude oil and VGO/resid	-138,413	-70,812	0	-8,733	13,307	-204,651
	Inputs	200,272	69,233	178,080	49,247	67,146	563,979
	Change in Gasoline Component Inputs	55,979	0	33,298	0	15,672	104,949
	Gasoline	1,483,535	2,584,977	3,753,849	765,880	1,184,533	9,772,775
	Gasoline Energy Content	4.951	4.957	5.073	5.015	5.046	5.016
	Total Gasoline at Constant Energy	1,465,385	2,564,330	3,739,352	765,181	1,189,801	9,719,422
	Volume at Constant Energy	86,573	166,151	-265,323	-13,081	5,268	-25,039

The addition of ethanol, the phase out of MTBE and the reuse of former MTBE feedstocks to make other gasoline blendstocks is expected to change the capital investments that would otherwise occur if these changes were not made. Table 7.4-5 summarizes the change in refinery unit throughputs by PADD comparing the RFS case to the reference case.

Table 7.4-5.
Change in the Refinery Unit Capacities by PADD between the RFS Case and Reference Case (thousand barrels per day)

Unit or Category	PADD 1	PADD 2	PADD 3	PADD 4/5	CA	USA
Crude Tower	-61	-71	0	-9	0	-141
Vacuum Tower	-22	-32	0	-2	0	-56
Sats Gas Plant	-13	-12	6	-2	0	-21
Unsats Gas Plant	-38	-19	0	-4	3	-59
FCC DeC5 Tower	-8	-3	56	-4	-9	33
FCC	-130	-61	0	-16	2	-205
FCC Splitter	-97	-5	116	-8	3	9
Hydrocracker	0	0	0	0	-6	-6
Delayed Coker	-13	-16	0	0	3	-27
Visbreaker	0	0	0	0	-3	-3
Thermal Naphtha Splitter	-2	-2	0	0	0	-3
CRU Reformer	0	8	48	0	0	56
SRU Reformer	0	0	0	0	-4	-4
BTX Reformer	0	0	0	0	0	0
C4 Isomerization	-13	0	1	0	-2	-14
C5/C6 Isomerization	0	3	-57	15	-26	-65
HF Alkylation	0	-1	1	0	0	0
H2SO4 Alkylation	-22	0	59	-1	-3	33
Dimersol	0	0	0	-2	0	-2
Cat Poly	1	0	18	0	0	19
Isooctane	0	0	0	0	0	0
DHT - Total	0	1	22	5	-1	28
DHT 2nd RCT - Total	0	3	2	5	0	10
DHT Arom Saturation	0	0	0	0	-4	-4
NHT - Total Fd	-9	3	-13	-1	-4	-23
NHT - Isom/Thermal Fd	-9	-5	-61	0	0	-75
NHT - Reformer Fd	0	8	48	0	-4	52
CGH - Generic	-81	-34	-42	-4	0	-161
CGH - Olefin Sat'n	0	0	0	0	28	28
FCCU Fd HDT	-39	0	0	0	0	-39
LSR Splitter	-12	-32	0	0	-6	-50
LSR Bz Saturator	-6	-15	0	0	-2	-22
Reformate Saturator	-2	-24	0	0	-4	-30
SDA	0	0	0	0	0	0
MTBE	-5	0	-114	0	0	-119
TAME	0	0	0	0	0	0
Hydrogen Plant - Total BSCF	-11	1	-75	3	-27	-109
Lube Unit	0	0	0	0	0	0
Sulfur Plant	-276	-298	138	-13	81	-368
Fuel System - Fuel Oil	0	0	0	0	0	0
Fuel System - CO2 (BLb/Day)	-18	-9	-5	-1	-2	-35
Utilities - Steam (Blbs)	-22	-12	-17	0	-6	-58
Utilities - Steam Vent (Blbs)	0	0	0	0	0	0
Utilities - Power (Mwh)	-715	-226	749	1	-133	-324
Utilities - Cooling H2O (Bgal)	-213	-93	-156	-14	-27	-502

Most of the capacity throughput changes are negative, reflecting the decreased processing of crude oil and vacuum gas oil and decreased downstream refining units as projected by the refinery model. Of the negative throughput changes, the large reduced volume of the fluidized catalytic cracker is important. As discussed above, the refinery model likely chose to decrease the fluidized catalytic cracker throughput to crack less heavy hydrocarbons to light hydrocarbons, producing less four-carbon compounds to offset the volatility impacts of ethanol. There are several units which show throughput capacity increases, primarily in PADD 3. PADD 3 refineries will have a substantial loss in octane because of the removal of a substantial volume of MTBE, but the refinery model did not choose to blend much ethanol in PADD 3. Instead, the refinery model chose to make additional alkylate from the captive MTBE plants formerly operating in PADD 3, and blend in isooctene from the conversion of merchant MTBE plants. The refinery model also added some reformer capacity to make up the balance of octane loss. The refinery model added depentanizer capacity mostly in PADD 3 to enable the blending of ethanol into RFG.

Refiners can also control the gasoline production and quality by adjustments they can make to several of their refinery conversion units. Refiners can adjust the conversion of their FCC and hydrocracker units, and change the severity of their reformers. Table 7.4-6 contains the percent conversions and severities of these units.

Table 7.4-6.
Comparison of Key Refinery Unit Operations by PADD between the RFS Case and Reference Case (percent)

Case	Refinery Unit Operations	PADD 1	PADD 2	PADD 3	PADD 4/5	CA
Reference Case	FCCU Conversion	73	74	74	71	75
	Continuous Reformer Severity	99	99	97	0	0
	Semi-Regen Severity	0	0	0	94	95
	Hydrocracker Conversion	80	80	85	85	85
RFS Case	FCCU Conversion	72	74	74	71	75
	Continuous Reformer Severity	100	96	97	0	0
	Semi-Regen Severity	0	0	0	93	96
	Hydrocracker Conversion	80	80	85	85	85

The refinery model maintains the same FCC unit conversion percentage for the RFS case compared to the reference case, except for PADD 1 which showed a small decrease in FCC unit conversion. For all PADDs, hydrocracker conversion percentage remains the same. Continuous reformer severity is projected to increase slightly in PADD 1 likely because of the octane loss caused by the removal of MTBE from the RFG pool which is not completely made up by the increased ethanol volume there. In PADD 2 where a lot of ethanol is being blended, reformer severity decreases significantly from 99 RON to 96 RON. Reformer severity remains the same in PADD 3. Reformer severity is projected to increase slightly in California due to an anticipated small decrease in ethanol. Finally, reformer severity is projected to decrease slightly in PADDs 4 and 5 despite the small decrease in ethanol there.

These changes in refinery unit throughputs are associated with changes in capital investments. Table 7.4-7 summarizes the projected change in capital investments between the reference case and the RFS control case. Table 7.4-7 shows that incremental to the reference case, refiners are expected to reduce their capital investments by $5.8 billion compared to business as usual. Most of the reduction occurs in PADDs 1 and 2 where large volumes of ethanol, and other gasoline blendstocks, are expected to enter the gasoline pool. Of course, this capital cost decrease is countered by the $2.3 billion in capital costs being incurred to build new ethanol plants and put into place the distribution system required to distribute the new ethanol.

Table 7.4-7.
Comparison of Capital Expenditures by PADD between the RFS Case and Reference Case (million dollars)

	PADD 1	PADD 2	PADD 3	PADD 4/5	CA	U.S. Total
Unit	CAPEX vs Reference Case	CAPEX vs Reference Case	CAPEX vs Reference Case	CAPEX vs Reference Case	CAPEX vs Reference Case	CAPEX vs Reference Case
Crude Tower	-228.6	0.0	0.0	0.0	0.0	-228.6
Vacuum Tower	-141.4	0.0	0.0	2.6	0.0	-138.7
Sats Gas Plant	-101.2	-13.6	-1.8	2.6	-22.7	-136.8
Unsats Gas Plant	-280.1	-225.5	-2.5	-29.5	-1.0	-538.6
FCC DeC5 Tower	17.4	-52.0	54.3	-16.6	0.0	3.1
FCC	-1426.9	-1160.4	0.0	-103.8	0.0	-2691.0
FCC Splitter	-144.2	-37.0	49.5	-6.6	0.0	-138.3
Hydrocracker	0.0	0.0	0.0	0.0	0.0	0.0
H-Oil Unit	0.0	0.0	0.0	0.0	0.0	0.0
Delayed Coker	0.0	0.0	0.4	0.0	0.0	0.4
Visbreaker	-0.1	-0.1	0.0	0.0	0.0	-0.2
Thermal Naphtha Splitter	0.0	0.0	0.0	0.0	0.0	0.0
CRU Reformer	0.0	0.0	0.0	0.0	0.0	0.0
SRU Reformer	0.0	0.0	0.0	23.9	0.0	23.9
BTX Reformer	0.0	0.0	2.4	0.0	0.0	2.4
C4 Isomerization	0.0	0.0	28.9	0.0	-60.6	-31.7
C5/C6 Isomerization	0.0	0.0	0.0	153.7	0.0	153.7
HF Alkylation	0.0	0.0	0.0	0.0	0.0	0.0
H2SO4 Alkylation	-698.3	0.0	607.5	0.0	0.0	-90.9
Dimersol	0.0	0.0	0.0	-23.3	-25.0	-48.3
Cat Poly	29.0	0.0	100.3	0.0	0.0	129.3
Isooctane	0.0	0.0	0.0	0.0	0.0	0.0
DHT - Total	1.6	0.0	217.8	32.0	11.2	262.6
DHT 2nd RCT - Total	0.0	11.0	6.1	21.1	0.0	38.2
DHT Arom Saturation	0.0	0.0	0.0	0.0	0.0	0.0
NHT - Total Fd	-39.7	0.0	0.0	69.3	0.0	29.6
CGH - Generic	-472.8	-154.5	-139.5	-70.3	0.0	-837.2
CGH - Olefin Sat'n	0.0	0.0	0.0	0.0	160.5	160.5
FCCU Fd HDT	-525.0	0.0	0.0	0.0	0.0	-525.0
LSR Splitter	0.0	-47.2	0.0	0.0	0.0	-47.2
LSR Bz Saturator	-44.7	-151.7	0.0	0.0	0.4	-196.0
Reformate Saturator	-8.2	-272.4	0.0	0.0	-47.3	-328.0
Reformate Splitter	-4.4	-142.7	0.0	0.0	-8.8	-155.9
SDA	0.0	0.0	0.0	0.0	0.0	0.0
MTBE	0.0	0.0	-175.4	0.0	0.0	-175.4
TAME	0.0	0.0	0.0	0.0	0.0	0.0
Hydrogen Plant	-109.6	2.2	-196.1	-7.4	-58.3	-369.2
Lube Unit	0.0	0.0	0.0	0.0	0.0	0.0
Sulfur Plant	-1.9	-2.8	0.0	-0.1	0.1	-4.7
Merox Jet	0.0	0.0	0.0	0.0	0.0	0.0
Merox Diesel	0.0	0.0	0.0	0.0	0.0	0.0
BTX Reformer - Tower feed	0.0	0.0	0.0	0.0	0.0	0.0
BTX Reformer - Extract feed	0.0	0.0	0.0	0.0	0.0	0.0
Total Capital Costs $MM	-4,179	-2,247	552	48	-51	-5,878

7.4.3.2 Summary of Changes in Refinery Inputs and Outputs to the EIA Case

The EIA case has some similarities to the RFS case. The MTBE is still estimated to no longer be blended into gasoline, and the former MTBE feedstocks are converted over to other low-RVP gasoline blendstocks. The annual volume of ethanol blended into gasoline, however, is almost 3 billion gallons higher. This increased volume of ethanol is expected to be spread over all the PADDs, although PADD 3 is projected to absorb the most. The much increased volume of very high octane ethanol is expected to slightly reduce the consumption of the gasoline blendstocks produced from former MTBE feedstocks. The net gasoline-equivalent volume increase by ethanol and other gasoline blendstock changes is expected to be over 100 thousand barrels per day. Table 7.4-8 contains the volumes of these gasoline blendstocks by PADD.

Table 7.4-8.
Comparison of Ethanol, MTBE, Isooctane, Isooctene, and Alkylate Volumes by PADD for the EIA Case and Reference Case (barrels per day)

Case	Gasoline Blendstock	PADD 1	PADD 2	PADD 3	PADD 4/5	CA	USA
Reference Case	Ethanol	57,620	114,900	5,242	20,676	58,934	257,372
	MTBE	54,887	0	122,474	0	0	177,360
	Isooctane/Isooctene	200	200	200	200	200	1,000
	Gasoline-equivalent Volume	82,687	76,034	102,864	13,846	39,096	314,527
EIA Case	Ethanol	161,821	255,512	117,722	32,113	59,055	626,223
	MTBE	0	0	0	0	0	0
	Isooctane/Isooctene Alkylate from MTBE	11,042	200	200,119	200	17,010	228,571
	Gasoline-equivalent Volume	117,844	168,838	277,816	21,395	55,986	641,878
	Change in Gasoline Equivalent Volume	35,157	92,804	174,952	7,548	16,889	327,351

Table 7.4-9 summarizes the inputs into and gasoline outputs from the refinery model separate from the ethanol and converted MTBE blendstocks summarized in Table 7.4-12 above. Crude oil and vacuum gas oil and residual fuel purchases are expected to decrease about 1.7 percent averaged over all the PADDs. The refinery model also estimates that the volume of purchased gasoline components will increase incrementally over the RFS case. It seems that a likely reason for the increased gasoline blendstock volumes over purchased crude oil purchases is that the refinery model is seeking to purchase low RVP blendstocks to offset the volatility impacts of ethanol, as opposed to having to crack crude oil which produces more volatile four carbon compounds. Table 7.4-15 also shows the energy-adjusted volume of gasoline projected to be produced for both the RFS case and reference case. The national energy-adjusted gasoline production levels for EIA case is somewhat lower than the reference case which suggests that the crude oil savings described above are somewhat overstated. The refineries in PADDs 1 and 2 are projected to produce much more gasoline in the EIA case compared to the reference case, while the refineries in PADD 3 are projected to produce much less gasoline in the EIA case.

Table 7.4-9.
Summary of Refinery Model Input and Output Volumes by PADD
for the EIA Case and Reference Case (barrels per day)

Case	Crude Oil and Gasoline	PADD 1	PADD 2	PADD 3	PADD 4/5	CA	USA
Reference Case	Crude Oil	1,823,008	3,650,044	9,071,056	1,529,442	1,952,560	18,026,111
	VGO and Residual Fuel	152,467	59,552	680,329	0	27,400	919,748
	Gasoline Component Inputs	144,293	69,233	144,782	49,247	51,475	459,030
	Gasoline Volume	1,378,811	2,398,179	4,004,675	778,262	1,184,533	9,744,461
	Gasoline Energy Content	5.012	4.997	5.093	5.019	5.024	5.044
EIA Case	Crude Oil	1,667,893	3,539,369	9,058,059	1,528,255	1,952,560	17,746,134
	VGO and Residual Fuel	97,621	59,552	675,959	0	41,194	874,325
	Change in Crude oil and VGO/resid	-209,962	-110,675	-17,368	-1,188	13,794	-325,398
	Gasoline Component Inputs	208,809	69,233	166,023	49,247	62,913	556,224
	Change in Gasoline Component Inputs	64,516	0	21,240	0	11,438	97,194
	Gasoline	1,602,258	2,584,977	3,657,519	775,512	1,184,533	9,804,799
	Gasoline Energy Content	4.924	4.922	5.042	5.000	5.042	4.988
	Total Gasoline at Constant Energy	1,574,007	2,546,302	3,620,530	772,501	1,188,742	9,695,751
	Change in Total Gasoline Volume at Constant Energy	195,196	148,123	-384,145	-5,761	4,208	-48,710

The addition of ethanol, the phase out of MTBE and the reuse of former MTBE feedstocks to make other gasoline blendstocks is expected to change the capital investments that would otherwise occur if these changes were not made.

Table 7.4-10 summarizes the change in refinery unit throughputs by PADD comparing the EIA case to the reference case.

Table 7.4-10.
Change in the Refinery Unit Capacities by PADD between the EIA Case and Reference Case (thousand barrels per day)

Unit or Category	PADD 1	PADD 2	PADD 3	PADD 4/5	CA	USA
Crude Tower	-155	-111	-13	-1	0	-280
Vacuum Tower	-63	-50	12	4	0	-97
Sats Gas Plant	-17	-20	-20	0	1	-56
Unsats Gas Plant	-37	-28	-6	-7	3	-74
FCC DeC5 Tower	-7	0	40	-6	-9	17
FCC	-130	-90	-18	-24	3	-260
FCC Splitter	-99	0	82	-12	3	-27
Hydrocracker	0	0	0	0	-7	-7
Delayed Coker	-10	-25	-7	0	3	-39
Visbreaker	3	3	1	0	-3	3
Thermal Naphtha Splitter	-1	-3	-1	0	0	-5
CRU Reformer	-15	-19	-109	0	0	-143
SRU Reformer	0	0	0	-1	-3	-4
BTX Reformer	0	0	0	0	0	0
C4 Isomerization	-13	3	0	0	-2	-12
C5/C6 Isomerization	0	-14	-93	-3	-30	-140
HF Alkylation	0	-3	1	0	0	-2
H2SO4 Alkylation	-22	0	49	-1	-5	22
Dimersol	0	0	0	-2	3	1
Cat Poly	0	0	18	0	0	19
Isooctane	0	0	0	0	0	0
DHT - Total	-24	-3	-66	16	0	-78
DHT 2nd RCT - Total	0	-15	17	15	0	17
DHT Arom Saturation	0	0	0	0	-4	-4
NHT - Total Fd	-32	-27	-145	-1	-3	-208
NHT - Isom/Thermal Fd	-17	-7	-36	0	0	-60
NHT - Reformer Fd	-15	-19	-109	-1	-3	-147
CGH - Generic	-81	-53	26	-6	0	-114
CGH - Olefin Sat'n	0	0	0	0	29	29
FCCU Fd HDT	-39	0	0	0	0	-39
LSR Splitter	-12	-32	0	0	-6	-50
LSR Bz Saturator	-6	-15	0	1	-2	-21
Reformate Saturator	-3	-24	0	0	-5	-32
SDA	-3	0	0	0	0	-3
MTBE	-5	0	-114	0	0	-119
TAME	0	0	0	0	0	0
Hydrogen Plant - Total BSCF	-34	7	4	4	-30	-49
Lube Unit	0	23	0	0	0	23
Sulfur Plant	-340	-551	-261	-4	86	-1,070
Fuel System - Fuel Oil	0	0	0	0	0	0
Fuel System - CO2 (BLb/Day)	-20	-13	-10	-2	-2	-47
Utilities - Steam (Blbs)	-25	-12	-28	-3	-7	-75
Utilities - Steam Vent (Blbs)	0	0	0	0	0	0
Utilities - Power (Mwh)	-1,029	-582	-98	40	-168	-1,837
Utilities - Cooling H2O (Bgal)	-246	-128	-256	-24	-28	-682

Most of the capacity throughput changes are negative, reflecting the decreased processing of crude oil and vacuum gas oil and decreased downstream refining units as projected by the refinery model. Of the negative throughput changes, the reduced volume of the fluidized catalytic cracker is important. As discussed above, the refinery model likely chose to decrease the fluidized catalytic cracker throughput to crack less heavy hydrocarbons to light hydrocarbons, producing less four-carbon compounds to offset the volatility impacts of ethanol. The reduction in FCC unit throughput is relatively less for the EIA case than it was for the RFS case. There are several units which show throughput capacity increases, primarily in PADD 3. PADD 3 refineries will have a substantial loss in octane because of the removal of a substantial volume of MTBE. Unlike the RFS case, however, much of the ethanol is projected to be blended into PADD 3's gasoline pool making up for the octane loss. This can be seen in Table 7.4-15 as reformer and alkylation throughputs volumes are projected to be lower for the EIA case. The refinery model added depentanizer capacity mostly in PADD 3 to enable the blending of ethanol into RFG.

Refiners can also control the gasoline production and quality by adjustments they can make to several of their refinery conversion units. Refiners can adjust the conversion of their FCC and hydrocracker units, and change the severity of their reformers. Table 7.4-11 contains the percent conversions and severities of these units.

Table 7.4-11.
Comparison of Key Refinery Unit Operations by PADD between
The EIA Case and Reference Case (percent)

Case	Refinery Unit Operations	PADD 1	PADD 2	PADD 3	PADD 4/5	CA
Reference Case	FCCU Conversion	73	74	74	71	75
	Continuous Reformer Severity	99	99	97	0	0
	Semi-Regen Severity	0	0	0	94	95
	Hydrocracker Conversion	80	80	85	85	85
EIA Case	FCCU Conversion	72	74	74	71	75
	Continuous Reformer Severity	100	94	96	0	0
	Semi-Regen Severity	0	0	0	93	97
	Hydrocracker Conversion	80	80	85	85	85

The refinery model maintains the same FCC unit conversion percentage for the RFS case compared to the reference case, except for PADD 1 which showed a small decrease in FCC unit conversion. For all PADDs, hydrocracker conversion percentage remains the same. Continuous reformer severity is projected to increase slightly in PADD 1 despite the ethanol blended into that PADD's gasoline. In PADD 2 where a lot of ethanol is being blended, reformer severity decreases significantly from 99 RON to 94 RON. Reformer severity is projected to decrease slightly in PADD 3 due to the large volume of ethanol being blended into the gasoline in that PADD. Reformer severity is projected to decrease slightly in California due to an anticipated small increase in ethanol. Finally, reformer severity is projected to decrease slightly in PADDs 4 and 5 due to the increase in ethanol there.

These changes in refinery unit throughputs are associated with changes in capital investments. Table 7.4-12 summarizes the projected change in capital investments between the reference case and the EIA control case. Table 7.4-12 shows that incremental to the reference case, refiners are expected to reduce their capital investments by $7.3 billion compared to business as usual. Most of the reduction occurs in PADDs 1 and 2 where large volumes of ethanol, and other gasoline blendstocks are expected to enter the gasoline pool. Of course, this capital cost decrease is countered by the estimated $6.5 billion in capital costs incurred to build new ethanol plants and put into place the distribution system that the new ethanol requires.

Table 7.4-12.
Comparison of Capital Expenditures by PADD between the EIA Case and Reference Case (million dollars)

	PADD 1	PADD 2	PADD 3	PADD 4/5	CA	U.S. Total
Unit	CAPEX vs Reference Case	CAPEX vs Reference Case	CAPEX vs Reference Case	CAPEX vs Reference Case	CAPEX vs Reference Case	CAPEX vs Reference Case
Crude Tower	-453.8	0.0	0.0	0.0	0.0	-453.8
Vacuum Tower	-295.0	0.0	103.7	8.9	0.0	-182.4
Sats Gas Plant	-115.9	-13.6	-55.8	0.1	-23.4	-208.7
Unsats Gas Plant	-275.6	-261.5	-20.1	-49.6	2.5	-604.4
FCC DeC5 Tower	17.7	-58.9	50.9	-18.5	0.0	-8.8
FCC	-1426.9	-1160.4	-68.1	-331.7	0.0	-2987.1
FCC Splitter	-147.0	-48.7	46.6	-9.6	0.0	-158.7
Hydrocracker	0.0	0.0	0.0	0.0	0.0	0.0
H-Oil Unit	0.0	0.0	0.0	0.0	0.0	0.0
Delayed Coker	0.0	0.0	-185.9	0.0	0.0	-185.9
Visbreaker	7.2	6.2	0.0	0.0	0.0	13.4
Thermal Naphtha Splitter	0.0	0.0	-0.3	0.0	0.0	-0.3
CRU Reformer	0.0	0.0	0.0	0.0	0.0	0.0
SRU Reformer	0.0	0.0	0.0	-2.6	0.0	-2.6
BTX Reformer	0.0	0.0	1.8	0.0	0.0	1.8
C4 Isomerization	0.0	0.0	0.0	0.0	-60.6	-60.6
C5/C6 Isomerization	0.0	0.0	0.0	-56.6	0.0	-56.6
HF Alkylation	0.0	0.0	0.0	0.0	0.0	0.0
H2SO4 Alkylation	-715.4	0.0	497.6	0.0	0.0	-217.8
Dimersol	0.0	0.0	0.0	-17.9	7.8	-10.1
Cat Poly	4.3	0.0	114.9	0.0	0.0	119.2
Isooctane	0.0	0.0	0.0	0.0	0.0	0.0
DHT - Total	-169.8	0.0	-219.5	93.2	21.6	-274.6
DHT 2nd RCT - Total	0.0	-165.3	105.6	138.0	0.0	78.3
DHT Arom Saturation	0.0	0.0	0.0	0.0	0.0	0.0
NHT - Total Fd	-39.7	0.0	0.0	-1.9	0.0	-41.7
CGH - Generic	-471.6	-179.5	102.0	-77.1	0.0	-626.1
CGH - Olefin Sat'n	0.0	0.0	0.0	0.0	161.0	161.0
FCCU Fd HDT	-525.0	0.0	0.0	0.0	0.0	-525.0
LSR Splitter	0.0	-47.2	0.0	0.0	0.0	-47.2
LSR Bz Saturator	-44.7	-151.7	0.0	21.9	0.4	-174.0
Reformate Saturator	-19.2	-272.4	0.0	0.0	-49.9	-341.6
Reformate Splitter	-20.1	-142.7	0.0	0.0	-10.1	-172.9
SDA	0.0	0.0	0.0	0.0	0.0	0.0
MTBE	0.0	0.0	-175.4	0.0	0.0	-175.4
TAME	0.0	0.0	0.0	0.0	0.0	0.0
Hydrogen Plant	-188.5	22.9	6.6	54.2	-58.3	-163.2
Lube Unit	0.0	0.0	0.0	0.0	0.0	0.0
Sulfur Plant	-2.5	-2.8	-0.2	0.0	0.1	-5.4
Merox Jet	0.0	0.0	0.0	0.0	0.0	0.0
Merox Diesel	0.0	0.0	0.0	0.0	0.0	0.0
BTX Reformer - Tower feed	0.0	0.0	0.0	0.0	0.0	0.0
BTX Reformer - Extract feed	0.0	0.0	-0.1			
Total	-4,882	-2,476	304	-249	-9	-7,311

7.4.3.3 Adjustments to the LP Refinery Model's Cost Estimate

We made several adjustments to the costs directly estimated by the LP refinery cost model for the RFS and EIA cases which are included in the costs reported below. One adjustment made was to adjust the costs based on the ethanol prices used in the LP cost model to reflect the ethanol production costs estimated and reported above in section 7.1.1. This adjustment resulted in much lower ethanol costs to refiners because Jacobs largely based its ethanol prices on ethanol's octane costs instead of its historical price relationship to gasoline, which is much lower. We also adjusted the ethanol distribution costs from those used in the LP refinery cost study, which roughly corresponded to those used for the proposed rule cost analysis, to those estimated for the final rule as discussed above in section 7.3.1. In Table 7.4-13 we summarize the ethanol production and distribution costs used in the LP refinery cost model and those we estimated for the final rule.

Table 7.4-13
Ethanol Price and Distribution Costs used in the LP Refinery Model versus Those used for the Final Rule Cost Analysis (cents per gallon)

		Case	PADD 1	PADD 2	PADD 3	PADD 4/5 ex CA	CA
Prices used in LP Refinery Cost Model	Ethanol Price in Midwest	RFS and EIA Case	158	158	158	158	158
	Ethanol Distribution Cost	RFS and EIA Case	12	0	10	17	18
	Ethanol Price in PADD	RFS and EIA Case	170	158	168	175	176
Costs used in Final Cost Analysis	Ethanol Production Cost	RFS Case	126	126	126	126	126
		EIA Case	131	131	131	131	131
	Ethanol Distribution Cost	RFS and EIA Case	16	6.5	16	23	22
	Ethanol Cost in PADD	RFS Case	142	132.5	142	149	148
		EIA Case	147	137.5	147	154	153

Another adjustment we made to the costs directly estimated by the LP refinery cost model was to add a cost for distributing gasoline. The refinery cost model did not include distribution costs for gasoline for moving the gasoline from the refinery to the terminal. We assigned gasoline distribution costs to be 4 cents per gallon applied as a cost savings to the gasoline-equivalent volume of ethanol blended into each PADD's gasoline, since this roughly corresponded to the volume of gasoline displaced by the ethanol.

7.4.3.4 Estimated Costs

7.4.3.4.1 Estimated Costs for the RFS Case

Table 7.4-14 summarizes the costs for the RFS case excluding federal and state ethanol consumption subsidies. The costs are reported by different cost component as well as aggregated total and the per-gallon costs.[99] This estimate of costs reflects the changes in gasoline that are occurring with the expanded use of ethanol, including the corresponding removal of MTBE and reuse of MTBE feedstocks. The operating costs include the labor, utility and other operating costs and are a direct output from the refinery model. These costs are adjusted to reflect ethanol's production cost plus distribution costs instead of the ethanol prices used in the refinery cost model. The fixed costs are 3 percent of the capital costs. The costs associated with lower energy density gasoline are accounted for using the fractional change in energy density shown in Table 7.4-4, multiplied times the wholesale price of gasoline. By excluding the federal and state ethanol consumption subsidies in the table, we avoid the transfer payments caused by these subsidies that would hide a portion of the program's costs.

Table 7.4-14.
Summary of RFS Case Costs without Ethanol Consumption Subsidies
(million dollars per year and c/gal, except as noted; 2004 dollars, 7% ROI before taxes)

	RFS Case 6.7 Billion Gals Incremental to Reference Case
Capital Costs ($MM)	**-5,878**
Amortized Capital Costs ($MM/yr)	-647
Fixed Operating Cost ($MM/yr)	-178
Variable Operating Cost ($MM/yr)	-201
Lower Energy Density Gasoline ($MM/yr)	1,848
Total Cost ($MM/yr)	**823**
Capital Costs (c/gal)	-0.40
Fixed Operating Cost (c/gal)	-0.11
Variable Operating Cost (c/gal)	-0.12
Lower Energy Density Gasoline (c/gal)	1.13
Total Cost Excluding Subsidies (c/gal)	**0.50**

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[99] EPA typically assesses social benefits and costs of a rulemaking. However, this analysis is more limited in its scope by examining the average cost of production of ethanol and gasoline without accounting for the effects of farm subsidies that tend to distort the market price of agricultural commodities.

Our analysis shows that when considering all the costs associated with these fuel changes resulting from the expanded use of ethanol that these various possible gasoline use scenarios will cost the U.S. $820 million in the year 2012. Expressed as per-gallon costs, these fuel changes would cost the U.S. 0.50 cent per gallon of gasoline.

Table 7.4-15 expresses the total and per-gallon gasoline costs for the RFS case with the federal and state ethanol subsidies included. The federal tax subsidy is 51 cents per gallon for each gallon of new ethanol blended into gasoline. The state tax subsidies apply in 5 states and range from 1.6 to 29 cents per gallon. The cost reduction to the fuel industry and consumers are estimated by multiplying the subsidy times the volume of new ethanol estimated to be used in the state.

Table 7.4-15.
Estimated RFS Case Cost including Ethanol Consumption Subsidies
(million dollars per year and cents per gallon; 2004 dollars, 7% ROI before taxes)

	RFS Case 6.7 Billion Gals Incremental to Reference Case
Total Cost ($MM/yr)	823
Federal Subsidy ($MM/yr)	-1376
State Subsidies ($MM/yr)	-5
Revised Total Cost ($MM/yr)	**-558**
Per-Gallon Cost Excluding Subsidies (c/gal)	0.50
Federal Subsidy (c/gal)	-0.84
State Subsidies (c/gal)	-0.003
Total Cost Including Subsidies (c/gal)	**-0.34**

The cost including subsidies better represents gasoline’s production cost as might be reflected to the fuel industry as a whole and to consumers “at the pump” because the federal and state subsidies tends to hide a portion of the actual costs. Our analysis estimates that the fuel industry and consumers will see a 0.34 cent per gallon decrease in the apparent cost of producing gasoline for the RFS case.

7.4.3.4.2 Estimated Costs for the EIA Case

Table 7.4-16 summarizes the costs for the EIA case. The costs in this table exclude federal and state ethanol consumption subsidies. The costs are reported by different cost components as well as the aggregated total and the per-gallon costs. This estimate of costs reflects the changes in gasoline that are occurring with the much expanded use of ethanol, including the removal of MTBE and reuse of MTBE feedstocks. The operating costs include the labor, utility and other operating costs and are a direct output from the refinery model, adjusted for ethanol’s production cost at this higher volume including ethanol distribution costs. The fixed costs are 3 percent of the capital costs. The costs associated with lower energy density gasoline, as shown in Table 7.4-9, are estimated by the fractional change in energy content times the wholesale price of gasoline. The increment of the EIA case to the RFS case indicates the economic impact of the additional volume of ethanol between the two cases.

Table 7.4-16.
Summary of EIA Case Costs without Ethanol Consumption Subsidies
(million dollars per year and c/gal, except as noted; 2004 dollars, 7% ROI before taxes)

	EIA Case 9.6 Billion Gals Incremental to Reference Case	EIA Case 9.6 Billion Gals Incremental to RFS Case
Capital Costs ($MM)	**-7,311**	**-1,433**
Amortized Capital Costs ($MM/yr)	-804	-158
Fixed Operating Cost ($MM/yr)	-222	-43
Variable Operating Cost ($MM/yr)	-491	-290
Lower Energy Density Gasoline ($MM/yr)	3,255	1407
Total Cost ($MM/yr)	**1739**	**915**
Capital Costs (c/gal)	-0.49	-0.10
Fixed Operating Cost (c/gal)	-0.14	-0.03
Variable Operating Cost (c/gal)	-0.30	-0.18
Lower Energy Density Gasoline (c/gal)	1.98	0.86
Total Cost Excluding Subsidies (c/gal)	**1.06**	**0.56**

Our analysis shows that when considering all the costs associated with these fuel changes resulting from the expanded use of subsidized ethanol that these various possible gasoline use scenarios will cost the U.S. $1,740 million in the year 2012 for the EIA case. Expressed as per-gallon costs, these fuel changes would cost the U.S. about 1.1 cents per gallon of gasoline. The incremental volume of ethanol added between the RFS and EIA cases is expected to cost $915 million in the year 2012, resulting in a 0.56 cent per gallon cost.

Table 7.4-17 expresses the total and per-gallon gasoline costs for the EIA case with the federal and state ethanol subsidies included. The federal tax subsidy is 51 cents per gallon for each gallon of new ethanol blended into gasoline. The state tax subsidies apply in 5 states and range from 1.6 to 29 cents per gallon. The cost reduction to the fuel industry and consumers are estimated by multiplying the subsidy times the volume of new ethanol estimated to be used in the state.

Table 7.4-17.
Estimated EIA Case Cost including Ethanol Consumption Subsidies
(million dollars per year and cents per gallon; 2004 dollars, 7% ROI before taxes)

	EIA Case 9.6 Billion Gals Incremental to Reference Case	EIA Case 9.6 Billion Gals Incremental to RFS Case
Total Cost ($MM/yr)	1739	915
Federal Subsidy ($MM/yr)	-2865	-1489
State Subsidies ($MM/yr)	-31	-26
Revised Total Cost ($MM/yr)	**-1158**	**-600**
Per-Gallon Cost Excluding Subsidies (c/gal)	1.06	0.56
Federal Subsidy (c/gal)	-1.74	-0.90
State Subsidies (c/gal)	-0.02	-0.02
Total Cost Including Subsidies (c/gal)	**-0.71**	**-0.37**

The cost including subsidies better represents gasoline's production cost as might be reflected to the fuel industry as a whole and to consumers "at the pump" because the federal and state subsidies tends to hide a portion of the actual costs. Our analysis estimates that the fuel industry and consumers will see a 0.71 cent per gallon decrease in the apparent cost of producing gasoline for the EIA case. Incremental to the RFS case, the consumer would be expected to see a 0.37 cent per gallon price decrease "at the pump."

7.4.3.4.3 Sensitivity Cost Analyses for the RFS and EIA Cases

In Table 7.1-5 above, we presented various corn-ethanol production cost estimates based on varying corn and dried distillers grain prices. We entered a range of low and high production ethanol cost estimates from that table into our cost spreadsheet created from the output from the LP refinery cost modeling. The range of ethanol production costs that we chose represents a reasonable bound around the possible range of future ethanol production costs. This allowed us to estimate the cost of using ethanol at these other possible ethanol production costs at the ethanol volumes analyzed for the RFS and EIA cases. We present these costs in Table 7.4-18. We did not conduct sensitivity analyses around higher or lower crude oil prices.[100]

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[100] This sensitivity analysis conducted at lower and higher ethanol production costs can also be used as a surrogate for a sensitivity analysis of higher and lower crude oil prices. Analyzing a lower ethanol cost is similar to analyzing a higher crude oil price with ethanol production costs at the levels we analyzed them at which was 126 and 131 cents per gallon, and vice versa for our sensitivity analysis at the higher ethanol production cost.

Table 7.4-18.
Summary of the Sensitivity Cost Analysis at Higher and Lower Ethanol Production Costs
(Costs in 2012, 2004 dollars, 7% ROI before taxes)

Ethanol Production Cost		Units	Costs RFS Case	Costs EIA Case
0.86	Cost without Subsidies	$MM/yr	-260	-846
		c/gal	-0.16	-0.52
	Cost with Subsidies	$MM/yr	-1640	-3740
		c/gal	-1.00	-2.28
2.04	Cost without Subsidies	$MM/yr	2930	5784
		c/gal	1.79	3.53
	Cost with Subsidies	$MM/yr	1546	2890
		c/gal	0.95	1.76

7.4.4 Impact on Diesel Prices

Biodiesel fuel is added to highway and nonroad diesel fuel, which increases the volume and therefore the supply of diesel fuel and thereby reduces the demand for refinery-produced diesel fuel. In this section, we estimate the overall cost impact, considering how much refinery based diesel fuel is displaced by the forecasted production volume of biodiesel fuel. The cost impacts are evaluated considering the production cost of biodiesel with and without the subsidy from the Biodiesel Blenders Tax credit program. Additionally, the diesel cost impacts are quantified with refinery diesel prices as forecasted by Jacobs's which are based on EIA's AEO 2006.

We estimate the net effect that biodiesel production has on overall cost for diesel fuel in year 2012 using total production costs for biodiesel and diesel fuel. The costs are evaluated based on how much refinery based diesel fuel is displaced by the biodiesel volumes as forecasted by EIA, accounting for energy density differences between the fuels. The cost impact is estimated from a 2012 year basis, by multiplying the production costs of each fuel by the respective changes in volumes for biodiesel and estimated displaced diesel fuel. We further assume that all of the forecasted bio-diesel fuel volume is used as transport fuel, neglecting minor uses in the heating oil market.

For this analysis, the production costs for biodiesel fuel are based on the costs generated using the USDA, NREL, EIA and the design vendors estimates in the preceding sections. We average these results to developed costs for soy oil and yellow grease feedstocks. Additionally, the production costs are based on EIA's projection in 2012 that half of the total biodiesel volume will be made from soy oil feedstock with the remaining volume being produced from yellow grease. To these estimates, we add distribution costs of 21.5 c/gal to the biodiesel production costs, reflecting the distribution estimates derived in section 7.3.2. For the refinery diesel production costs in 2012, we used the projected wholesale national average diesel price of 160 c/gal projected by the Jacobs' pricing forecast. Distribution costs of 4 c/gal were added to the Jacobs's wholesale diesel price projection, to account for the additional costs to move diesel fuel from the wholesale market to end use terminals.

Our estimate for the reduction in refinery produced diesel fuel is based on EIA's forecast for approximately 300 MM gallons of biodiesel in 2012, along with the 2012 Reference Case year biodiesel production volume of 28 MM gallons. With this and accounting for differences in energy density between biodiesel and diesel fuel, we estimate in 2012 that the additional biodiesel production reduces the need for 250 MM gallons of refinery produced diesel fuel. Table 7.4-19 contains the energy densities used in this analysis.

Table 7.4-19.
Energy Content of Fuels per Gallon

Fuel	Lower Heating Value (BTU/gallon)
Biodiesel	117,093
Refinery Produced Diesel	128,700

For all RFS case scenarios, the net effect of biodiesel production on diesel fuel costs, including the biodiesel blenders' subsidy, is a reduction in the cost of transport diesel fuel costs by $114 MM per year, which equates to a fuel cost reduction of about 0.20 c/gal[101]. Without the subsidy, the transport diesel fuel costs are increased by $91 MM per year, or an increase of 0.16 c/gal.

7.5 Other Potential Economic Impacts

Ideally, we would prefer to assess all economic and environmental impacts of increased ethanol use and decreased fossil fuel use in a holistic manner. Such an analysis is beyond the scope of this RIA. However, we can approximate some of the impacts of increased ethanol production and use, and we can discuss other impacts qualitatively. The preceding discussion quantifies the impact of expanded use of renewable fuels on the cost of gasoline and diesel fuel. It does so by quantifying the direct costs of ethanol production, as well as the direct costs of state and federal tax subsidies for the renewable fuels, which are financed through tax payments. There are many other economic impacts associated with the use of renewable fuels and the fossil fuels they replace which go well beyond the scope of the analysis conducted for the RIA. We have not attempted to quantify all of them here. For example, increased renewable fuel production and use may have adverse impacts on surface and ground water quality and soil erosion, while decreased fossil fuel, distribution and use may have positive impacts. To quantify the economic impact associated with this would require extensive analysis of the likely responses of farmers to the increased demand for renewable fuels, the cost of actions taken to remedy the impacts, and the cost of any resulting health and welfare impacts.

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[101] Based on EIA's AEO 2006, the total volume of highway and off-road diesel fuel consumed in 2012 was estimated at 58.9 billion gallons.

Furthermore, the renewable fuel production costs assumed in our analysis do not reflect the entire cost to society associated with the production of the corn and soybean feedstocks used in their production due other state and federal agricultural policies. Direct payments, counter-cyclical payments, marketing loans, and subsidized crop insurance are all examples of policies outside of this rulemaking that impact the price of corn and soybeans that are not reflected in the production cost for ethanol and biodiesel, but do impact costs borne by consumers indirectly through taxes. Quantifying the incremental impacts of this rulemaking on the effects of these pre-existing programs would represent a significant challenge. However, the challenge is complicated even more by the direct and indirect economic support provided for the production, supply, and distribution of the fossil fuels which would be replaced by these renewable fuels. Again, any assessment of the overall costs to society for increase renewable use would have to look at the economic support provided across the entire fuel supply. Such an analysis is well beyond the scope of this RIA.

Despite our inability to fully capture all the potential impacts on the cost to society of increased renewable fuel use, two potential impacts were touched on briefly in our analysis, and these are discussed in this subsection.

Economic Impacts of Emission Changes

As discussed in Chapters 4.1 and 5.1, we estimate that there may be an increase in emissions and a corresponding small increase in ozone resulting from the expanded use of renewable fuels. Our vehicle and equipment emission estimates are highly uncertain, however, given the lack of data in particular on vehicles and engines complying with the latest standards. However, to the extent that there are emission and ozone increases resulting from the expanded use of renewable fuels, there can be a cost associated with them. In some cases, areas that see an increase in emissions resulting from renewable fuel use may be forced to take other actions to offset these emission increases. In other cases, particularly in attainment areas, the impact, while not affecting attainment, may adversely impact air quality and human health. It is difficult to provide any quantitative estimate of what the mitigation costs might be to offset emission increases, or to quantify the health impacts resulting from the air quality impacts. Not only are the emission and air quality impacts highly uncertain, but they are also very location dependent. While we have made projections on where the ethanol use may rise or fall for the purposes of estimating nationwide fuel cost impacts and potential emissions impacts, these projections are much less reliable when trying to predict specific local air quality impacts.

Despite all of the above caveats, we have attempted to provide a rough estimate of the potential national-level cost impacts; As a surrogate for additional emission control costs in nonattainment areas and potential health impacts in attainment areas, we looked at the potential health costs associated with the secondary nitrate PM resulting from the decreases in NOx emissions estimated in previous EPA rules. We note again that we actually expect an overall decrease in ambient $PM_{2.5}$ formation due to the increased use of ethanol in fuel (See Chapter 5.2).[102] Thus, we expect most areas to have lower health impact costs and certainly lower abatement costs related to PM control.

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[102] Overall, we expect that the decrease in secondary organic PM is likely to exceed the increase in secondary nitrate PM. In 2006, NO_x emissions from gasoline-fueled vehicles and equipment comprise about 37% of national NO_x

In recent rulemakings we monetized PM emission impacts, including those resulting from changes in secondarily formed $PM_{2.5}$ due to NOx emission changes. Using this information as a guide, we provide a screening-level estimate of the monetized PM-related health impacts associated with an increase in NOx emissions associated with the final rule. For this analysis, we derived a dollar-per-ton value based on recent benefits modeling conducted for the Clean Air Nonroad Diesel Rule (CAND).[zzzzz] This value ($8,000 in PM-related monetized health impacts per ton of NOx reduced) is based on air quality modeling conducted in 2004 for the CAND rule. This benefits transfer method is consistent with approaches used in other recent mobile and stationary source rules.[103] We refer the reader to the final CAND RIA for more details on this benefits transfer approach. The dollar-per-ton value represents monetized health impacts in 2015 (in year 2000 dollars).

We combined the dollar-per-ton estimate of monetized health effects with the projected 2015 emission changes presented in Table 4.4-1, which includes emissions from gasoline vehicles and equipment and renewable fuel production and distribution. We estimate that the potential $PM_{2.5}$-related monetized impact associated with NOx emissions from increased use of ethanol to be up to $290 million for the RFS control scenario, and up to $340 million for the EIA control scenario. Note that this impact is based on monetized changes in health effects, including changes in mortality risk, chronic bronchitis, nonfatal heart attacks, respiratory hospital admissions, asthma attacks, and other minor health endpoints. It is also important to point out that this value does not represent the cumulative monetized health impacts associated with the potential PM changes associated with the future use of ethanol described above.

This estimate is subject to a number of additional caveats. The dollar-per-ton values reflect specific geographic patterns of emissions reductions and specific air quality and benefits modeling assumptions which are derived from previous analyses and will not match those associated with increased ethanol use in fuel for two reasons. One, the geographical distribution of the emission sources affected by increased ethanol use differs from that addressed in the CAND rulemaking. Two, the CAND rule was national in scope and the emission reductions were spread out across the entire nation. Increased ethanol use will be very geographically focused. Many major population centers will not experience an increase in ethanol use as their fuel already contains ethanol. Care should be taken when applying these estimates to emission reductions that occur in any specific location, since the dollars-per-ton for emission reductions in specific locations may be very different than the national average. Given these caveats and the

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emissions from mobile sources. In contrast, gasoline-fueled vehicles and equipment comprise almost 90% of national gaseous aromatic VOC mobile source emissions. The percentage increase in national NO_x emissions due to increased ethanol use should be smaller than the percentage decrease in national emissions of gaseous aromatics. Finally, in most urban areas, ambient levels of secondary organic PM exceed those of secondary nitrate PM. Thus, directionally, we expect a net reduction in ambient PM levels due to increased ethanol use. However, we are unable to quantify this reduction at this time.

[103] See: Clean Air Nonroad Diesel final rule (69 FR 38958, June 29, 2004); Nonroad Large Spark-Ignition Engines and Recreational Engines standards (67 FR 68241, November 8, 2002); Final Industrial Boilers and Process Heaters NESHAP (69 FR 55217, September 13, 2004); Final Reciprocating Internal Combustion Engines NESHAP (69 FR 33473, June 15, 2004); Final Clean Air Visibility Rule (EPA-452/R-05-004, June 15, 2005); Ozone Implementation Rule (70 FR 71611, November 29, 2005).

potential decrease in ambient $PM_{2.5}$ due to the decrease in aromatic fuel content, we can not say for certain in which direction the total monetized PM-related health impact will be. In reality there may be an overall reduction in PM-related health costs, despite the increase due to increased NOx emissions.

Chapter 8: Agricultural Sector Impacts

As described in the Preamble, we used the Forest and Agricultural Sector Optimization Model (FASOM) to estimate the U.S. agricultural impacts of increasing renewable fuel volumes to 7.5 billion gallons per year (BGY) by 2012, as required by the Renewable Fuels Standard (RFS) and to 9.9 BGY, the volume of renewable fuel the Energy Information Administration (EIA) predicts for the year 2012 in the Annual Energy Outlook 2006.[104] Although these renewable fuel volumes are lower than current market predictions, these assumptions were established during the NPRM and are used throughout this FRM.

FASOM is a long term economic model of the U.S. agriculture sector that maximizes total revenues for producers while meeting the demands of consumers. Using a number of inputs, FASOM determines which crops, livestock, and processed agricultural products will be produced in the U.S. In each model simulation, crops compete for price sensitive inputs such as land and labor at the regional level. The cost of these and other inputs are used to determine the price and level of production of primary commodities (e.g., field crops, livestock, and biofuel products). FASOM also estimates prices using costs associated with the processing of primary commodities into secondary products (e.g., converting livestock to meat and dairy, crushing soybeans to soybean meal and oil). FASOM does not capture short-term fluctuations (i.e., month-to-month, annual) in prices and production, however, as it is designed to identify long term trends.[105]

FASOM uses supply and demand curves for the 11 major U.S. domestic regions,[106] which are calibrated to historic price and production data. FASOM also includes detailed supply and demand data for corn, wheat, soybeans, rice and sorghum across 37 foreign regions.[107] FASOM maintains transportation costs to all regions and then uses all of this information to determine U.S. exports to the point where prices are then equated in all markets.[108]

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[104] We analyzed the U.S. agricultural impacts of producing renewable fuels domestically after adjusting for equivalence values of cellulosic ethanol and biodiesel and projected U.S. imports. For the RFS Case, we assumed 440 million gallons of corn based ethanol will be imported, while we assumed 630 million gallons of corn based ethanol will be imported for the EIA Case. For both cases, we assume 250 million gallons of cellulosic ethanol will be produced (with a 2.5 equivalence value), and 300 million gallons of biodiesel will be produced (with a 1.5 equivalence value).

[105] FASOM calculates output in five year increments. For this analysis, 2010 and 2015 data were interpolated to estimate 2012 values.

[106] U.S. regions consist of the Pacific Northwest (West and East), Pacific Southwest, Rocky Mountains, Great Plains, Southwest, South Central, Corn Belt, Lake States, Southeast, and the Northeast.

[107] FASOM Foreign Regions include: the European Economic Community, North Central Europe, Southwest Europe, Eastern Europe, Adriatic, Eastern Mediterranean, Former Soviet Union, North Africa, East Africa, West Africa, South Africa, Red Sea, Iran, India, Taiwan, Japan, South Korea, North Korea, China, Bangladesh, Indonesia, Myanmar, Pakistan, Philippines, Thailand, Vietnam, West Asia, Southeast Asia, Australia, Caribbean, Eastern Mexico, Eastern South America, Western South America, Argentina, Brazil, Canada, Other.

8.1 Commodity Prices

8.1.1 Corn and DDGS Prices

FASOM predicts that as renewable fuel volumes increase, agricultural prices over a range of products (not just corn and soybean renewable fuel feedstocks) will increase as well. Since the principal feedstock for ethanol is corn, corn prices are anticipated to rise. For consistency, all of the dollar estimates are presented in 2004 dollars. In the RFS Case, corn prices increase to $2.50/bushel by 2012 (compared to a Reference Case price of $2.32/bushel in 2012). With the higher renewable fuels volumes in the EIA Case, corn prices rise to $2.71/bushel (2004$) by 2012. (See Table 8.1-1) To place this difference in perspective, in 2012, corn prices are about 8 percent higher in the RFS Case and 17 percent higher in the EIA Case relative to the Reference Case.[109]

Table 8.1-1. Corn and DDGS Prices in 2012

	Reference Case	RFS Case	EIA Case
Corn Price	$2.32/bushel	$2.50/bushel	$2.71/bushel
Distillers Dried Grains with Solubles (DDGS) Price	$85.55/ton	$83.35/ton	$86.15/ton

The cost of producing ethanol is dependent upon, among other factors, the price of corn and the price of related byproducts. As part of the analytical approach described in the NPRM, we used FASOM to estimate the future prices of the major ethanol production byproduct: distillers dried grains with solubles (DDGS). FASOM estimates that the price of DDGS will remain relatively constant with the renewable volume scenarios that we are examining in this rulemaking. An increase in DDGS supply is anticipated to be offset by an increase in DDGS demand as technology improves to pelletize and distribute DDGS to a wider market. DDGS prices in the U.S. in 2012 are predicted to be $83.35/ton in the RFS Case and $86.15/ton in the EIA Case. (See Table 8.1-1) Hence, the overall price of DDGS remains within 3 percent of the DDGS Reference Case price.

Note that the DDGS price given here is the price an ethanol producer would expect to receive at the plant gate. FASOM predicts a higher value for the DDGS at the place of end use,

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[108] For additional details on the FASOM model, see the report by Professor Bruce McCarl, Texas A&M University, "The Impacts of the Renewable Fuel Standard Program on the U.S. Agricultural Sector," February 2007, included in the docket.

[109] The current price of corn in the U.S. is approximately $3.50 per bushel (2004$), which is considerably higher than the FASOM prediction and is a likely a result of the fact that recent demand for corn for ethanol is higher than the currently available stocks. The model results for 2012 reflects medium-term spatial equilibrium prices, where rising demand for corn is met by rising supply -- due to increased acres planted to corn and to increased corn yields per acre. Note that while the model assumes that markets for corn and related agricultural commodities will settle at a price of $2.50 per bushel (in the RFS case) by 2012, that this may be a conservative estimate to the extent that the agricultural sector is able to adjust to the increased use of corn in ethanol production by 2012.

based on its nutritional ability to be substituted as half soy meal and half corn in animal feed. The difference between its feed value and the ethanol plant gate price is made up of the cost of handling and shipping, which may include pelletizing or other measures required to support a national commodity market for DDGS.

8.1.2 Soybean and Soybean Byproducts

FASOM predicts relatively modest changes in soybean prices as a result of the increases in the renewable fuel volumes examined in this rulemaking. In the RFS Case, soybean prices rise to $5.44/bushel (2004$) by 2012 (compared to a Reference Case price of $5.26/bushel in 2012). In the EIA Case, soybean prices rise to $5.47/bushel (2004$) by 2012. (See Table 8.1-2) Soybeans prices are expected to increase by about 3 percent (RFS Case) and 4 percent (EIA Case) relative to the Reference Case by 2012. The slightly higher prices of soybeans reflect the consequences of the higher demand for soybeans for renewable fuels as well as the slightly higher input costs (e.g., land prices). It is also expected that in medium-term the acres planted to soybeans will fall, due to increased corn plantings, which will also increase soybean prices.

Table 8.1-2. Soybean and Soybean Meal Prices in 2012

	Reference Case	**RFS Case**	**EIA Case**
Soybean Price	$5.26/bushel	$5.44/bushel	$5.47/bushel
Soybean Meal Price	$176.70/ton	$171.73/ton	$170.05/ton

Soybean meal is produced when crushing soybeans and extracting soybean oil, the primary feedstock of biodiesel in the U.S. Under the RFS scenario, FASOM estimates the price of soybean meal will decrease by about 3 percent in 2012, relative to the Reference Case.[110] (See Table 8.1-2) This decrease is slightly larger under the EIA scenario, with the price of soybean meal dropping by about 4 percent. Several factors influence the small change in soybean meal prices. First, more acres of soybeans are being planted to rotate with increased planting of corn, and this leads to increased soybean supplies. Second, increased DDGS supplies can substitute for soybean meal as a feed ingredient by reducing the soybean meal needed in feed rations using higher levels of DDGS. Third, the size of the livestock herd is smaller due to higher meat prices, reducing the demand for animal feeds overall.

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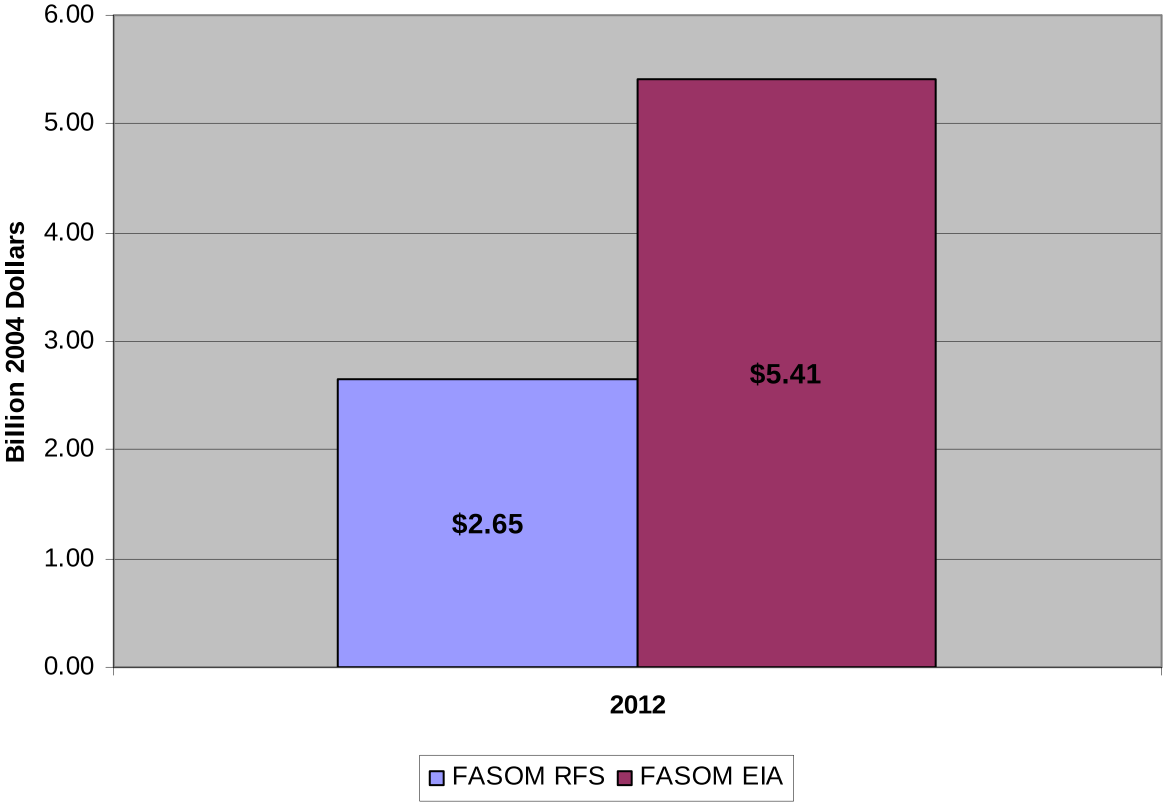
[110] The current price of soybeans in the U.S. is considerably higher than the FASOM prediction and is a likely a result of the fact that the market expects acres planted to soybeans in the short term are likely to decline due to increased corn plantings. As with the corn results,.the model reflects medium-term spatial equilibrium prices, where rising demand for corn is met by rising supply -- due to increased acres planted to corn and to increased corn yields per acre by 2012. Similarly, over time, farmers will begin to plant more soybeans in response to relatively higher short-term prices. The model expects soybean prices to reach an equilibrium price of $5.44 per bushel (in the RFS case) by 2012.

8.2 Impact on U.S. Farm Income

The increase in renewable fuel production provides a significant increase in farm income to the U.S. agricultural sector. FASOM predicts that in 2012, U.S. farm income from the sale of agricultural commodities will increase by \$2.65 billion dollars in the RFS Case and \$5.41 billion in the EIA Case. (See Figure 8.2-1) The RFS and EIA farm income changes represent roughly a 5 and 10 percent increase, respectively, in U.S. farm income from the sale of farm commodities over the Reference Case of roughly \$53 billion[111]. Most of the increase in net income is likely to be concentrated in rural areas, and may contribute to rural wealth creation.

Figure 8.2-1. Change in Net Farm Income Relative to Reference Case in 2012



8.3 Impact on Employment

Agricultural employment was not directly modeled but is likely to be very small since modern farm practices are not labor intensive and increases in production as modeled here will have negligible impact on direct farm employment. Some additional employment will result

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[111] While U.S. government farm payments are currently part of the U.S. farm income, what programs will be in place in 2012 and their impact on farm income is unclear. For our modeling, we assumed the support programs were in place in 2010 but none were in place in 2015; interpolation between 2010 and 2015 provided the assumed impact in 2012.

from ethanol plant construction and operation. 30 to 50 people per ethanol production facility seems typical.

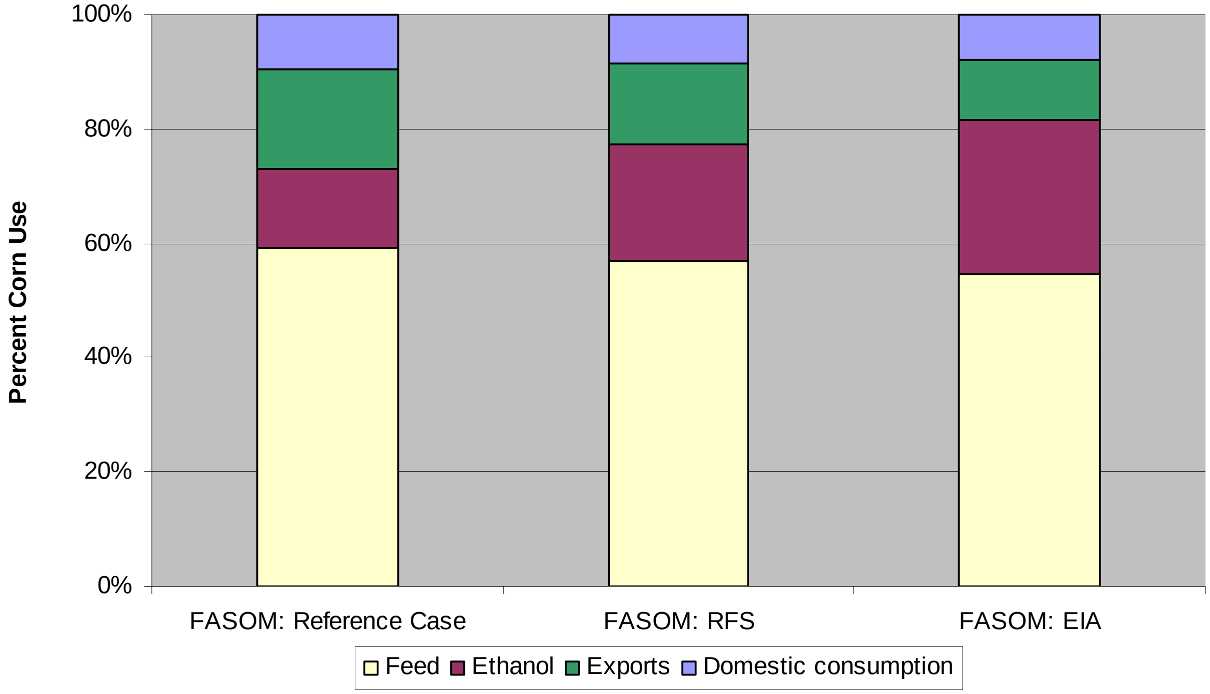
8.4 Commodity Use Change

8.4.1 Corn and Ethanol Byproducts

For this analysis, U.S. corn uses are broken down into four categories: domestic (i.e., household) consumption, ethanol production, livestock feed, and U.S. corn exports. (See Figure 8. 4-1) As the demand for corn increases to produce more renewable fuel, U.S. corn utilization patterns are expected to be altered. In 2005, approximately 13 percent of all corn produced in the U.S. was used for ethanol production. With the two renewable fuel volumes that we are examining, the percentage of corn feedstock used for renewable fuels increases significantly. By 2012, in the RFS Case, 20 percent of all corn produced in the U.S. is used to produce ethanol. In 2012, in the EIA Case, 26 percent of all corn is used to produce fuel ethanol. These estimates are similar to the percentages included in the NPRM.

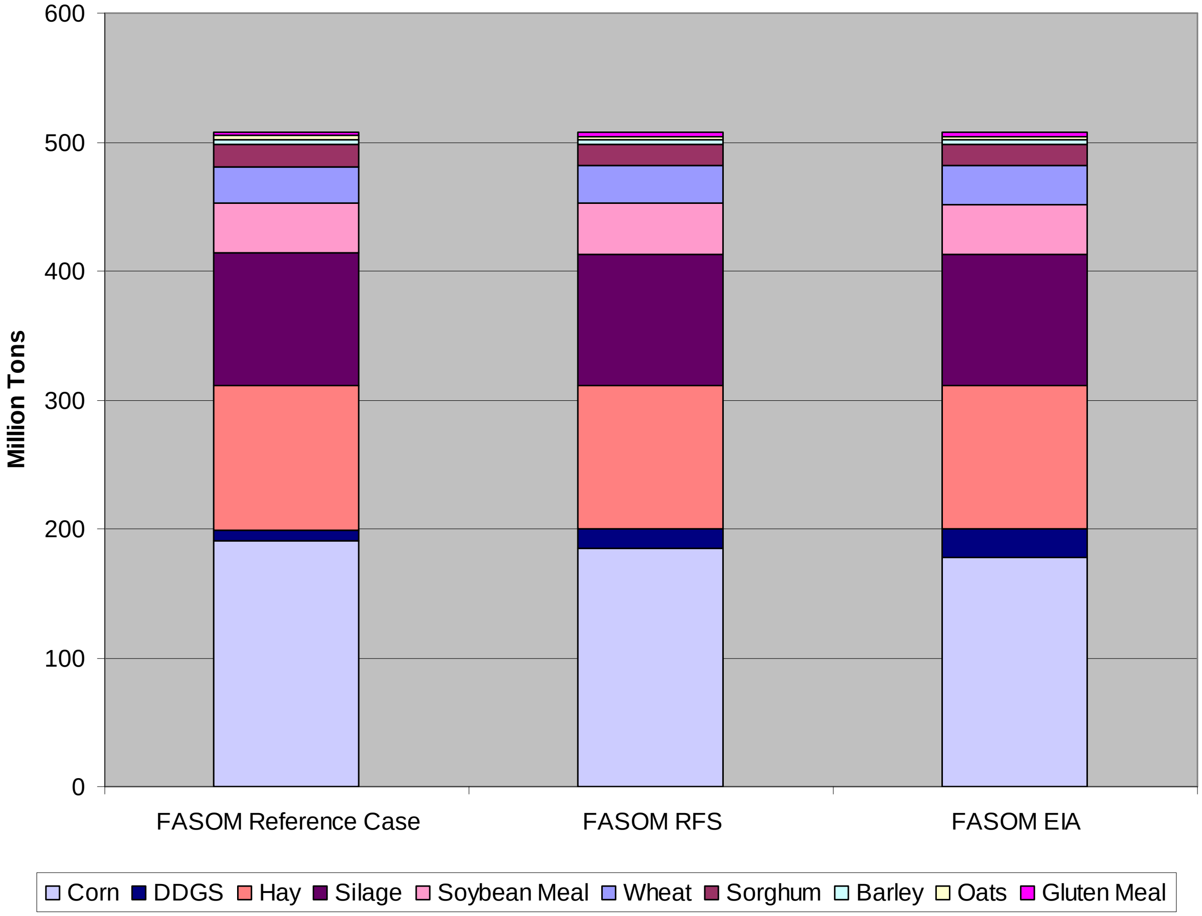
The increasing use of corn for ethanol raises the price of corn which has a direct impact on the other uses of corn. FASOM predicts higher U.S. corn prices leads to lower U.S. exports of corn. U.S. corn exports drop from about 2 billion bushels in the Reference Case to 1.6 billion bushels in the RFS Case and 1.3 billion bushels in the EIA Case by 2012. In value terms, U.S. exports of corn fall by $573 million in the RFS Case and by $1.29 billion in the EIA Case in 2012.

Figure 8.4-1. Corn Uses in 2012



Higher U.S. prices for corn due to increased demand for ethanol production results in decreased use of corn for U.S. livestock feed. The amount of corn used for livestock feeding decreases by about 320 million bushels in the RFS Case and by about 690 million bushels in the EIA Case relative to the Reference Case. Substitutes are available for corn as a feedstock, and this market is highly price sensitive. One alternate feedstock is DDGS because feed ration using increased levels of DDGS would need less corn. The relatively flat prices for DDGS predicted across all ethanol volume scenarios results from the significant increase in the demand for DDGS as a feed ingredient parallels the increase in supply of DDGS. FASOM estimates that DDGS use for livestock feeding for the RFS Case will almost double by 2012, increasing from 8.5 million tons to 15.2 million tons. Under the EIA Case, FASOM predicts that DDGS will increase to 22.2 million tons by 2012. (See Figure 8.4-2) Domestic (i.e., household) consumption of corn for food use declines slightly with the different renewable fuel volumes analyzed in this rulemaking.

Figure 8.4-2. Livestock Feed Sources in 2012



8.4.2 Soybean and Soybean Byproducts

As described previously, only a modest increase in the demand for soybeans are expected to be used to produce biodiesel in the renewable fuel scenarios analyzed in this rulemaking. Although changes in soybean uses in this analysis are limited, U.S. exports are expected to drop by 41.8 million bushels (RFS Case) and 35.6 million bushels (EIA Case). In terms of export earnings, U.S. exports of soybeans fall by $220 million in the RFS Case and by $194 million in the EIA Case in 2012.

8.5 U.S. Land Use Patterns and Land Prices

8.5.1 Corn Acreage

FASOM predicts that total production of corn in the U.S. in 2012 will be 11.9 billion bushels under the RFS Scenario and 12.1 billion bushels under the EIA Scenario (compared to 11.7 billion bushels in the Reference Case)[112]. (See Table 8.5-1) With higher renewable fuel volumes, more corn will be produced in the U.S. Increased U.S. corn production can result from two sources: greater productivity on existing acres of land devoted to corn or from "new" acres that are brought into the corn production. Much of the high quality, suitable land in the U.S. is already being used to produce corn. Improvement in the productivity of growing corn on existing U.S. land is projected to grow by roughly 1 percent annually through 2012. As a result, most of the increased demand for corn from increased use of renewable fuels will be met from increased productivity on existing acres of corn relative to the 2005 baseline year. However, corn production from new acres plays an important role in corn supply. FASOM estimates an increase in land devoted to corn production of 1.6 million acres (RFS Case) and 2.6 million acres (EIA Case) in 2012 compared to the Reference Case.

Table 8.5-1.
U.S. Corn Acres Harvested, Corn Production, and Agricultural Land Prices in 2012

	Reference Case	RFS Case	EIA Case
Corn Acres Harvested (million acres)	78.5	80.1	81.1
Total Corn Production (billion bushels)	11.7	11.9	12.1
Land Prices (percent increase relative to Reference Case)	N/A	8.4%	16.8%

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[112] FASOM includes corn equivalent feeding of by products.in the estimate for total corn production.

Higher renewable fuel volumes will have a direct impact on the value of U.S. agricultural land. As demand for corn and other farm products increases, the price of U.S. farm land will also increase. The FASOM analysis shows that in 2012, higher renewable fuel volumes increase average agricultural land prices in the U.S. by about 8 percent (RFS Case) and 17 percent (EIA Case).

8.5.2 Soybean Acreage

Increasing use of biodiesel fuel in the renewable fuel scenarios does not cause a significant change in U.S. soybean production. Soybean production stays relatively flat at 3.3 billion bushels in all three scenarios analyzed. (See Table 8.5-2) Soybean acreage increases modestly as well in the renewable fuel scenarios examined. In the RFS Case, total soybean acres are 74.6 million. For the EIA Case, total soybean acres are 74.4 million acres, compared to 73.4 million acres of soybeans in the Reference Case.

Table 8.5-2. U.S. Soybean Acres Harvested and Soybean Production in 2012

	Reference Case	RFS Case	EIA Case
Soybean Acres Harvested (million acres)	73.4	74.6	74.4
Total Soybean Production (billion bushels)	3.3	3.3	3.3

8.5.3 CRP Acreage

Current lands in the Conservation Reserve Program (CRP) total approximately 40 million acres. To qualify for inclusion in the CRP, the acres must have been at one time in active agricultural use. Farmers are paid to take these lands out of production and place them in CRP to provide environmental benefits, including limiting erosion and providing wildlife habitat. Farmers put land into the CRP voluntarily, considering among other factors the value of the land if it were to remain in agricultural production versus the amount paid under the CRP contract. The amount of government payments can change over time.

For this analysis, we have assumed current per-acre payment levels to landowners are maintained through 2012. However higher commodity prices and higher land rents associated with higher renewable fuel volumes would likely require higher CRP payments to maintain the same level of CRP enrollments. The RFS and EIA renewable fuel volumes are estimated to result in CRP withdrawals of 2.3 million and 2.5 million acres, respectively, relative to the Reference Case. Most of the CRP lands are not likely to go into corn or soybean production since much of the CRP lands tend to be marginal lands due to their location and productivity. For example, only a relatively small portion of CRP lands are in the Corn Belt. Instead, additional corn or soybeans acres will probably be planted on lands that were previously used for other crops or pasture, for example, wheat, grain, sorghum or planted forage crops. It is expected that some of the land removed from CRP will be used for these other agricultural purposes. Table 8.5-3 depicts the estimate of CRP impacts.

Table 8.5-3. CRP Acreage Changes Relative to Reference Case

	RFS Case	EIA Case
Reduction in CRP Acreage (million acres)	2.3	2.5

8.6 Fertilizer Use

Under the RFS scenario, the total amount of nitrogen applied on all farms increases by 1.2 percent, or 480,000 pounds, relative to the Reference Case in 2012. Under the EIA scenario, the total amount of nitrogen applied on all farms increases by 2 percent, or 790,000 pounds, relative to the Reference Case in 2012. (See Table 8.6-1) We note that this percent increase in fertilizer is largely accounted for by the 2 percent increase in land used for corn production and 1 percent increase in land for soybean production. The fact that the amount of nitrogen used increases at a smaller percent than the amount of land increase for corn production suggest that much of the corn production land is already in agricultural use (with fertilizer applied) and is not likely to be land newly released from CRP.

Table 8.6-1. Nitrogen and Phosphorous Use in 2012

	Reference Case	RFS Case	EIA Case
Total Nitrogen Applied (million pounds)	40.28	40.76	41.07
Total Phosphorous Applied (million pounds)	4.24	4.27	4.29

Under the RFS scenario, the total amount of phosphorous applied on all farms increases by 0.7 percent, or 30,000 pounds, relative to the Reference Case in 2012. Under the EIA scenario, the total amount of phosphorous applied on all farms increases by 1.2 percent, or 50,000 pounds, relative to the Reference Case in 2012. See Table 8.6-1.

8.7 Environmental Analysis

Although this analysis does not include a comprehensive and integrated environmental assessment of the impacts in the agricultural sector of higher renewable fuel volumes from this rulemaking, we looked at two factors directly impacted by the production of agricultural crops that may relate to environmental impacts. FASOM does estimate the amount of fertilizer used and changes in CRP land, two indicators that could be associated with water pollution.[113]

Marathon commented that it believes that EPA's assessment of environmental impacts does not consider all environmental impacts and is therefore incomplete, especially with respect to water quality impacts. As described above, our analysis predicts a modest increase in fertilizer use and modest withdrawals of CRP lands due to the higher renewable fuel volumes. While increased agricultural development would likely increase pressure on environmentally sensitive areas such as wetlands and prairie lands and rural ecosystems in general, FASOM does not represent this level of land detail in the national model and therefore cannot quantify any potential impacts on these subsets of land types. To the extent that CRP withdrawals are managed in an environmentally sustainable way, however, water pollution impacts would be minimized.

Increasing worldwide demand for biofuels and decreasing U.S. exports of feedstocks used in producing renewable fuels will likely lead to increased prices, production, and different trade patterns for renewable fuel feedstocks (i.e., corn and soybeans) in parts of the world outside of the U.S. FASOM includes the export effect as it contains supply curves for rest of world production of key agricultural products, but it does not contain a mechanism for appraising world environmental implications since FASOM is a domestic model of the U.S. agricultural sector. Therefore, this analysis focuses only on impacts of the higher renewable fuels volumes in the U.S.

8.8 U.S. Food Prices

Despite the wider use of U.S. agricultural feedstocks, principally corn, for renewable fuels, FASOM estimates only a modest increase in U.S. household food costs. Annual wholesale U.S. food costs are estimated to increase by approximately $7 per person with the RFS renewable volumes and by about $12 per person annually with the EIA renewable volumes by 2012. (See Figure 8.8-1) Agricultural costs are only a portion of ultimate household food costs so significant increases in corn prices and, to a lesser degree, soybean prices results in a much smaller relative increase in household food costs.

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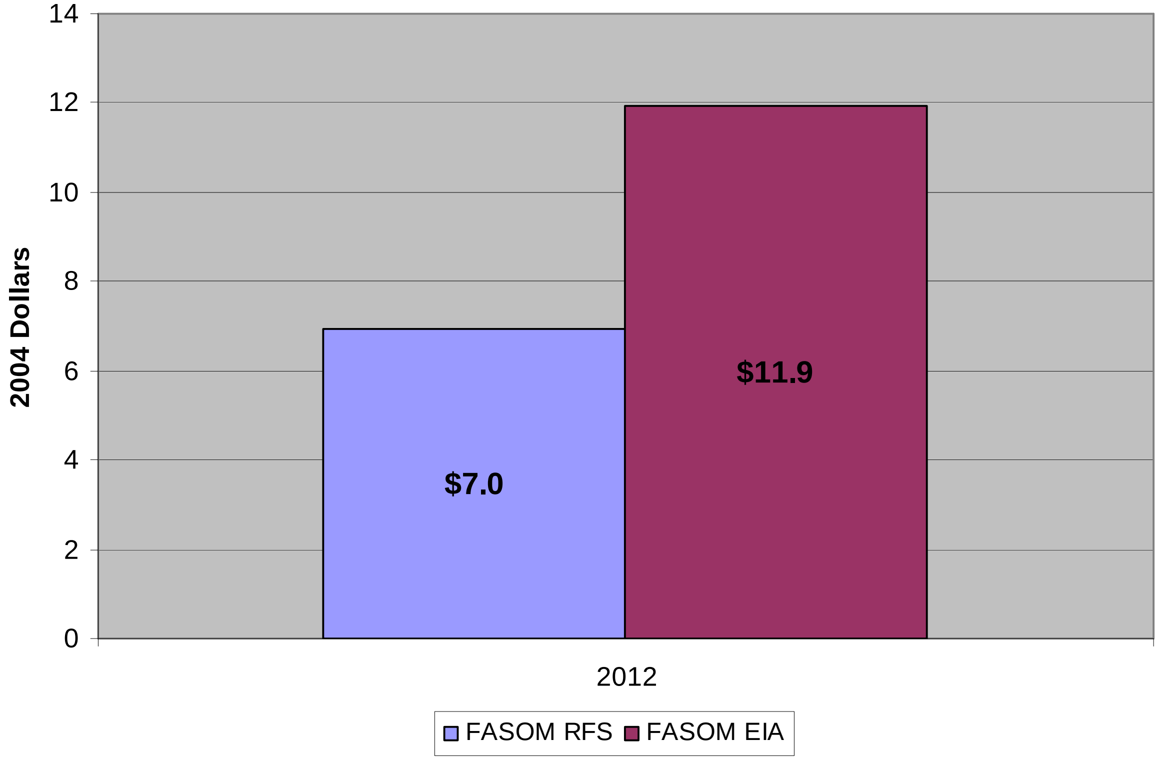
[113] The FASOM model can describe the proportion of fertilizer that potentially will affect groundwater quality and surface water quality. FASOM also details the extent to which shifts in agricultural production may affect soil erosion and carbon sequestration. In the short timeframe available, we were not able to devote significant efforts to this type of analysis, but this area of inquiry could be investigated more extensively in the future. We do note that we capture the sequestration impacts in the GREET analysis.

Figure 8.8-1. Increase in Annual Food Costs Per Person Relative to Reference Case in 2012



FASOM estimates a relatively modest increase in U.S. prices for meat and agricultural products associated with the higher renewable fuel volumes. When evaluating changes in overall U.S. food prices, FASOM uses the All Farm Products Price Index, which is a weighted average of prices received by farmers at the "farm gate" for crop and livestock products relative to the Reference Case.[114] FASOM estimates a 4 percent increase in the RFS Scenario and a 7 percent increase in the EIA Scenario in the weighted price of all farm products. (See Table 8.8-1)

To evaluate changes in U.S. meat prices, FASOM uses the All Meat Products Price Index which is a weighted average of the prices that farmers receive for meat products at the farm gate. This index is based upon changes in the weighted average of beef, pork, chicken, and turkey prices. U.S. meat prices that farmers receive in 2012 are estimated to increase by 0.3% in the RFS Case and by 1.3% in the EIA Case compared to the Reference Case.

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[114] The All Farm Products Price Index includes: cotton, corn, soybeans, wheat, sorghum, rice, oats, barley, silage, hay, sugarcane, sugar beet, potatoes, tomatoes, oranges, grapefruit, switch grass, hybrid poplar, willow, beef, cows, milk, pigs, lamb, wool, horses and mules, eggs, chicken, and turkey.

Table 8.8-1. Increase in the All Farm Products Price Index and the All Meat Products Price Index Relative to the Reference Case in 2012

	RFS Case	**EIA Case**
All Farm Products Price	3.8% increase	6.9% increase
All Meat Products Price	0.3% increase	1.3% increase

Because corn is a major component of the All Crop Price Index, a significant change in corn prices will result in a pronounced change in this index. The impact of corn price changes on the Meat Price Index will be less pronounced for two reasons. First, as corn prices rise, meat producers will modify feed rations and production systems to reduce their corn usage. Second, there will also be substitution among meats leading to higher consumption of meat from animals using less of the higher priced corn (e.g., increased production of poultry products relative to beef products).

Chapter 9: Small-Business Flexibility Analysis

This chapter presents our Small Business Flexibility Analysis (SBFA) which evaluates the potential impacts of the new standards on small entities. The Regulatory Flexibility Act, as amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Prior to issuing a proposal for this rulemaking, we analyzed the potential impacts of these regulations on those entities that we believe are small entities (see section 9.3, below). As a part of this analysis, we conducted outreach with those entities to gather information and recommendations from these entities on how to reduce the impact of the rule on small businesses.

9.1 Requirements of the Regulatory Flexibility Act

We are generally required under the Regulatory Flexibility Act (RFA) to conduct a regulatory flexibility analysis unless we certify that the requirements of a regulation will not cause a significant impact on a substantial number of small entities. The key elements of the RFA include:

- a description of and, where feasible, an estimate of the number of small entities to which the proposed rule will apply;
- the projected reporting, record keeping, and other compliance requirements of the proposed rule, including an estimate of the classes of small entities which will be subject to the requirements and the type of professional skills necessary for preparation of the report or record;
- an identification to the extent practicable, of all other relevant Federal rules which may duplicate, overlap, or conflict with the proposed rule; and,
- any significant alternatives to the proposed rule which accomplish the stated objectives of applicable statutes and which minimize any significant economic impact of the proposed rule on small entities.

The RFA was amended by SBREFA to ensure that concerns regarding small entities are adequately considered during the development of new regulations that affect them. Although we are not required by the Clean Air Act to provide special treatment to small businesses, the RFA requires us to carefully consider the economic impacts that our proposed rules will have on small entities. Specifically, the RFA requires us to determine, to the extent feasible, our rule’s economic impact on small entities, explore regulatory options for reducing any significant economic impact on a substantial number of such entities, and explain our ultimate choice of regulatory approach.

We have concluded that the final RFS rule will not have a significant impact on a substantial number of small entities. We based this conclusion on several criteria. First, the industry is expected to be overcomplying by a wide margin independent of the standard, thus causing compliance costs to be minimal. Second, the Energy Policy Act of 2005 (Energy Policy Act) already provides relief from the renewable fuels standards until 2011 for the majority of the small entities; and lastly, we are extending this relief to the remaining small entities. This is discussed further below.

9.2 Need for the Rulemaking and Rulemaking Objectives

A detailed discussion on the need for and objectives of this rule are in the preamble to the final rule. As previously stated, EPA is required to promulgate regulations implementing a renewable fuel program under Section 1501 of the Energy Policy Act, which amended the Clean Air Act by adding Section 211(o). The Energy Policy Act requires EPA to establish a program to ensure that U.S. gasoline contains specific volumes of renewable fuel for each calendar year beginning in 2006, to increase the amount of renewable fuel used in vehicles and engines in the U.S.

9.3 Description of Affected Entities

9.3.1 Definition of Small Entities

Small entities include small businesses, small organizations, and small governmental jurisdictions. For the purposes of assessing the impacts of the rule on small entities, a small entity is defined as: (1) a small business that meets the definition for business based on the Small Business Administration’s (SBA) size standards (see Table 9-1); (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field. Table 9.3.1-1 provides an overview of the primary SBA small business categories potentially affected by this regulation.

Table 9.3.1-1. Small Business Definitions

Industry	Defined as small entity by SBA if:	NAICS Codes [a]
Gasoline refiners	≤1,500 employees[115]	324110

[a] North American Industrial Classification System

9.3.2 Summary of Small Entities to Which the Rulemaking Will Apply

The refiners that are potentially affected by this proposed rule are those that produce gasoline. For our recent rulemaking “Control of Hazardous Air Pollutants from Mobile Sources”

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[115] In the Draft RIA, we also referred to a 125,000 barrels of crude per day (bpcd) crude capacity limit. This criterion was inadvertently used and is not applicable for this program (as it only applies in cases of government procurement). We note that the number of small entities remains the same whether this criterion is used or not.

(72 FR 8428, February 26, 2007), we performed an industry characterization to determine the universe of potentially affected gasoline refiners. Information about the characteristics of refiners comes from sources including the Energy Information Administration within the U.S. Department of Energy, and from Hoover's (a division of Dun and Bradstreet). The refining industry is located primarily in NAICS code 324110.

The industry characterization was then used to determine which refiners met the SBA definition of a small refiner. From the industry characterization, and further analysis following the Notice of Proposed Rulemaking (71 FR 55552, September 22, 2006), we determined that there were 15 gasoline refiners (owning 16 refineries) that met the definition of a small refiner. It should be noted that because of the dynamics in the refining industry (e.g., mergers and acquisitions), the actual number of refiners that ultimately qualify for small refiner status could be different from this estimate.

Title XV the Energy Policy Act provides, at Section 1501(a)(2) [42 U.S.C. 7545(o)(9)(A)-(D)], special provisions for "small refineries", which includes a temporary exemption from the standards until calendar year 2011. Further, the Energy Policy Act states that EPA must use the definition of "small refinery" and apply the special provisions provided for small refineries in the RFS program. The Energy Policy Act defines the term "small refinery" as "…a refinery for which the average aggregate daily crude oil throughput for a calendar year…does not exceed 75,000 barrels."

A small refinery (as defined by the Energy Policy Act) is very different from a small <u>refiner</u> (as defined in SBA's regulations at 13 CFR 121.201). Per 13 CFR 121.201, and as stated above in Table 9-1, a small refiner is a small business that employs less than or equal to 1,500 employees. A small <u>refinery</u>, per the Energy Policy Act, is a small-capacity refinery and could be owned by a larger refiner that exceeds the criterion specified in SBA's small entity definition; whereas small refiners generally only own a few (and more often than not, only one) refineries.

In our analysis of the potentially affected small refiners, we found that 42 refineries met the Energy Policy Act's definition of a small refinery. Of these, we determined that 13 of these refineries were owned by small refiners. Therefore, 12 of the 15 small refiners owned refineries that also met the Energy Policy Act's definition of a small refinery. As a result, we believe that all but three small refiners would automatically be granted relief by implementing the provisions specified in the Energy Policy Act.

9.4 Issues Raised By Public Comments

During the public comment period we received numerous comments regarding various aspects of the proposed rule, including our proposed small refiner provisions. The following section provides a summary of the comments that we received on our proposed provisions. More information on these comments can be found in the Final Summary and Analysis of Comments, which is a part of the rulemaking record.

9.4.1 Extension of the Small Refinery Exemption to Small Refiners

Commenters that supported the provision extending the small refinery exemption to small refiners generally stated that they believe that a small refiner exemption is necessary as those entities that would qualify as small refiners are generally at an economic disadvantage due to their company size – whereas the Energy Policy Act only recognizes facilities, based on the size of each location. These commenters also stated that they have concerns with the cost and the availability of credits under the RFS program, and believe that provisions for small refiners are necessary to help mitigate any significant adverse economic impact on these entities.

Commenters that opposed the provision commented that they believe that EPA exceeded its discretionary authority, that there appears to be no basis on which the Agency can legitimately expand this statutory exemption to add small refiners, and that Congress "clearly did not intend that the exemption be broadened to also include small refiners." One commenter also stated that it does not believe that small refiner provisions are necessary because the RFS program does not require costly capital investments like previous fuel regulations.

9.4.2 Application Deadline

We proposed that refiners would need to apply for the small refinery exemption, and that the exemption would be effective 60 days after receipt of the application by EPA (unless EPA notifies the applicant that the application was not approved or that additional documentation is required). We received comments on this provision in which commenters stated that requiring small refinery applications was inconsistent with the language set out in the Energy Policy Act. The commenters stated that the Energy Policy Act intended that small refineries would automatically receive the small refinery exemption upon the effective date of the standard, and that these parties should not be considered obligated parties in 2007 even if they do not submit a small refinery application.

9.4.3 Provisions for Foreign Small Refineries and Refiners

For consistency with prior gasoline-related fuel programs, we also proposed to extend the RFS small refinery (and small refiner) exemption to foreign refiners, and we requested comment on this provision. We received some comments in which commenters stated that they believe that there is no reason to extend the small refinery exemption to these refiners. One commenter even stated that it believed that such an allowance would be unlawful.

9.4.4 Other

We received some comments which stated that EPA needed to clarify whether or not exempt small refineries (and small refiners) could separate a RIN simply by owning a batch of fuel. We also received a comment which stated that it was not clear in the proposed rule whether or not small refineries (and small refiners) blending ethanol at a terminal or any location without formally opting into the program could separate RINs.

9.5 Related Federal Rules

Other current and proposed Federal rules that are related to this rule are: the Mobile Source Air Toxics (MSAT2) rule (72 FR 8428, February 26, 2007), the Tier 2 Vehicle/Gasoline Sulfur rulemaking (65 FR 6698, February 10, 2000), and the fuel sulfur rules for highway diesel (66 FR 5002, January 18, 2001) and nonroad diesel (69 FR 38958, June 29, 2004).

9.6 Projected Reporting, Recordkeeping, and Other Compliance Requirements

For any fuel control program, EPA must have the assurance that refiners meet the applicable standards. Thus, requirements are imposed to ensure that compliance obligations are met.

The recordkeeping, reporting and compliance provisions of this program are fairly consistent with those currently in place for our other 40 CFR part 80 fuel programs, including the highway and nonroad diesel and MSAT regulations. These provisions include:

- Registration (the registration numbers will also be used in the RINs)
- Submission of annual reports summarizing a refiner’s annual gasoline production and a demonstration of its compliance with the renewable fuels standard and submission of annual reports detailing and tracking a refiner’s RINs; EPA’s Central Data Exchange will be used for report submissions
- Recordkeeping will consist of the retention of all compliance documents (such as Product Transfer Documents and all reports submitted to EPA) for at least five years

For a more detailed discussion of these provisions, please see section IV of the preamble to this final rule.

9.7 Steps to Minimize Significant Economic Impact on Small Entities

As stated above, we conducted outreach to a number of stakeholders that met the definition of a small entity to gain feedback and advice on the needs of small businesses and potential challenges that these entities may face. The feedback that we received from these entities as a result of these meetings was used during the development of the proposed rule for developing regulatory alternatives to mitigate the impacts of the rulemaking on small businesses. General concerns raised by these entities were the potential difficulty and costs of compliance with the upcoming standards given the other fuel compliance requirements that the fuel refining industry is subject to. Below we discuss the regulatory flexibility alternatives and provisions which are being finalized in this action.

While we do not believe that the RFS program with just the statutorily-prescribed temporary relief for small refineries would have a significant economic impact on a substantial number of small entities, we continue to believe that some refiners, due to their size, generally face greater challenges compared to larger refiners. These refiners generally have greater difficulty in raising and securing capital for investing in capital improvements and in competing for engineering resources and projects. This rulemaking does not require that refiners make capital improvements, however there are still costs associated with meeting the standard. Thus, we find it appropriate to extend the small refinery temporary exemption, as set out in the Energy Policy Act, to small refiners. Under this exemption, any gasoline produced at a refinery owned by a small refiner will not be counted in determining the renewable fuel obligation of a refiner until January 1, 2011; further, the small refiner may exclude gasoline produced at its refineries from its compliance calculations. Beginning in 2011, refineries owned by small refiners will be required to meet the same renewable fuel obligation as all other refineries.

Past fuels rulemakings have included a provision that, for the purposes of the regulatory flexibility provisions for small entities, a refiner must also have an average crude capacity of no more than 155,000 barrels of crude per day (bpcd). To be consistent with these previous rules, we are finalizing in this rule that refiners that meet this criterion (in addition to having no more than 1,500 total corporate employees) will be considered small refiners for the purposes of the regulatory flexibility provisions for RFS program. Further, the refiner must have produced gasoline at its refineries by processing crude oil through refinery processing units. We are also finalizing that eligibility will be based on 2004 data.

We agree with statements from commenters that the Energy Policy Act did in fact intend to provide the small refinery exemption without the need for the submission of small refinery applications, and that these parties should receive the exemption upon the effective date of the rule. We also believe that this should be the case for small refiners as well. Therefore, we are finalizing that small refiners will also receive the exemption immediately upon the effective date of the rule. However, to ensure that only those refiners who meet the criteria above receive this exemption, we believe that it is necessary for refiners to verify that they do in fact meet the criteria. Therefore, these refiners will also be required to submit a verification letter showing that they meet the criteria for qualification as a small refiner for the regulatory flexibility provisions. This letter will be similar to the small refiner status applications required under other EPA fuel programs (and must contain all the required elements specified at §80.1142 of the regulations), except the letter will not be due prior to the program. Small refiner status verification letters for this rule that are later found to contain false or inaccurate information will be void as of the effective date of this rule. Small refiners who subsequently do not meet all of the RFS program's regulatory flexibility qualification criteria (i.e., cease producing gasoline by processing crude oil, employ more than 1,500 people, or exceed the 155,000 bpcd crude oil capacity limit) as a result of a merger with or acquisition of or by another entity, are disqualified as small refiners, except in the case of a merger between two previously approved small refiners. As in other EPA programs, where such disqualification occurs, the refiner must notify EPA in writing no later than 20 days following the disqualifying event.

We are finalizing the proposed provision allowing foreign refiners to apply for a small refinery or small refiner exemption under the RFS program. The Energy Policy Act definition of "small refinery" is not limited to domestic facilities, and we believe that we have the discretion to apply the definition of small refinery, and the similar relief that we are providing to small refiners, to foreign producers. We believe that this provision is necessary for consistency with prior fuel programs (anti-dumping, MSAT, and the fuel sulfur rules) which allowed foreign refiners to receive such exemptions. Under this provision, gasoline produced at approved foreign small refineries, and by approved foreign small refiners, will be exempt from the RFS standard such that obligated parties (importers or blenders) would not count these volumes towards their renewable volume obligations.

We are also finalizing the proposed provision that the automatic five year exemption, and any small refinery extended exemptions (extensions of the small refiners exemption will only be available to small refineries), may be waived upon notification to EPA. Gasoline produced by a small refiner who waives its exemption will be included in the RFS program and will be included in the gasoline used to determine the refiner's renewable fuel obligation. If a refiner waives the exemption, the refiner will be able to separate and transfer RINs like any other obligated party. However, exempt small refiners cannot separate a RIN simply by owning a batch, a RIN can only be separated by these parties once the volume of renewable fuel is blended with gasoline or diesel to produce a motor vehicle fuel (as stated in the regulations at §80.1129). If a small refiner does not waive its small refiner exemption, it can still separate and transfer RINs, but only for the renewable fuel that the refiner itself blends into gasoline (i.e., the refinery operates as an oxygenate blender facility). Lastly, exempt small refiners who blend ethanol can separate RINs from batches without formally opting in to the program.

9.8 Conclusions

After considering the economic impacts of today's proposed rule on small entities, we do not believe that this action will have a significant economic impact on a substantial number of small entities. While the Energy Policy Act provided for a temporary exemption for small refineries from the requirements of today's proposed rule, these parties will have to comply with the requirements following the exemption period. Therefore, we had to take into account the economic effects of the program on small entities when they would need to comply with the standard. As described in section VI of the preamble to this final rule, the annual projections of ethanol production are greater than the annual renewable fuel volumes required by the Energy Policy Act. For example, in 2011, when the Energy Policy Act's small refinery exemption ends, over one billion gallons in excess RINs are projected to be available. Further, excess RINs are anticipated for each year of the program. Due to this projected excess supply in comparison to the standard, the cost of RINs should be very low—near the level of the transaction costs.

Due to the low cost to affected small entities, and the projected RIN availability, as well as the temporary relief provided to small refineries and small refiners, we do not believe that this program will impose a significant economic impact on a substantial number of small entities.

Endnotes

[A] Renewable Fuels Association (RFA), Ethanol Biorefinery Locations (Updated October 16, 2006).

[B] Ethanol Producer Magazine (EPM), Plant List (Downloaded October 18, 2006) monthly magazine publications (June 2006 through October 2006).

[C] Ethanol Producer Magazine (EPM), monthly magazine publications (June 2006, July 2006, August 2006, September 2006 and October 2006).

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[E] BioFuels Journal, News & Information for the Ethanol and BioFuels Industries (breaking news posted June 16, 2006 through October 18, 2006).

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[G] Ethanol Producer Magazine (EPM), U.S. & Canada Fuel Ethanol Plant Map (Spring 2006).

[H] International Fuel Quality Center (IFQC), Special Biofuels Report #75 (April 11, 2006).

[I] "Biodiesel Performance, Costs, and Use", Anthony Radich, EIA page 6.

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[K] From Independent Biodiesel Feasibility Group Presentation.

[L] "Pipeline Considerations for Ethanol", Department of Agricultural Economics, Kansas State University, August 2002. http://www.agmrc.org/NR/rdonlyres/4EE0E81C-C607-4C3F-BBCF-B75B7395C881/0/ksupipelineethl.pdf , and "Shipping Ethanol Through Pipelines", American Petroleum Institute, April 6, 2006, http://api-ep.api.org/printerformat.cfm?ContentID=54FD1A11-95FA-4B7C-ACE1D7C6F121FB1C.

[M] Infrastructure Requirements for an Expanded Fuel Ethanol Industry, Downstream Alternatives Inc., January 15, 2002.

[N] "Ethanol Industry's Interest in River Sites Grows", River Transport News, Vol. 15, No. 10, May 22, 2006.

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[Q] F.O. Licht, "World Ethanol Markets, The Outlook to 2015" (2006).

[R] EIA AEO 2006 Table 12: Petroleum Product Prices

[S] EIA Crude Oil Spot Pricing (http://tonto.eia.doe.gov/dnav/pet/pet_pri_spt_s1_d.htm)

[T] Sources: U.S. EPA Office of Transportation & Air Quality, List of Federal Reformulated Gasoline Areas (Updated February 23, 2004) and U.S. EPA Office of Transportation & Air Quality, 2004 RFG Fuel Survey Results (http://www.epa.gov/otaq/regs/fuels/rfg/properf/rfgperf.htm).

[U] Source: U.S. EPA Office of Transportation and Air Quality, State Winter Oxygenated Fuel Program Requirements for Attainment or Maintenance of CO NAAQS (November 2005).

[V] National Ethanol Vehicle Coalition (http://www.e85fuel.com/e85101/faqs/number_ffvs.php).

[W] EIA 2004 Petroleum Marketing Annually (Table 48: Prime Supplier Sales Volumes of Motor Gasoline by Grade, Formulation, PAD District, and State).

[X] EIA Historical RFG MTBE Usage (file received from EIA representative on March 9, 2006).

[Y] EIA Monthly Energy Review, June 2006 (Table 10.1: Renewable Energy Consumption by Source, Appendix A: Thermal Conversion Factors).

[Z] FHWA Highway Statistics 2004: Estimated Use of Gasohol (April 2006).

[AA] EPA Reformulated Gasoline (RFG) Survey (http://www.epa.gov/otaq/regs/fuels/rfg/properf/rfgperf.htm).

[BB] Alliance of Automobile Manufacturers (AAM) North American Fuel Survey 2004. The report and data can be purchased through the AAM website, http://autoalliance.org/fuel/fuel_surveys.php, or by contacting the Alliance at 1401 Eye Street, N.W., Suite 900, Washington, DC 20005, Tel: (202) 326-5500.

[CC] EIA Monthly Energy Review, June 2006 (Table 10.1: Renewable Energy Consumption by Source, Appendix A: Thermal Conversion Factors).

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[HH] EPA Reformulated Gasoline (RFG) Survey (http://www.epa.gov/otaq/regs/fuels/rfg/properf/rfgperf.htm)

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[OO] EIA 2004 Petroleum Marketing Annually (Table 32: Conventional Motor Gasoline Prices by Grade, Sales Type, PAD District, and State).

[PP] EIA NEMS Petroleum Market Model Documentation, Appendix I, Table I4.

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[RR] *Final Regulatory Impact Analysis for Reformulated Gasoline*, Table VI-A6, December 13, 1993.

[SS] U.S. EPA, *Final Regulatory Impact Analysis for Reformulated Gasoline*, Table VI-A6, EPA420-R-93-017, December 13, 1993. Available from RFG Final Rule, Docket No. A-92-12, February 1994.

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