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Renewable Fuel Standard Program

Draft Regulatory Impact Analysis

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

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This document does not necessarily represent final EPA decisions or positions.
It is intended to present technical analysis of issues using data that are currently available.
The purpose in the release of such reports is to facilitate an exchange of
technical information and to inform the public of technical developments.

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Overview

EPA is proposing 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 Draft Regulatory Impact Analysis (DRIA).

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 proposed 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 proposed 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	Billion gallons
BGY	Billion 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
DGS	Distillers' grains with solubles
DDGS	Dried distillers' 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
IFQC	International Fuel Quality Center
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
MM	Million
MMBTU	Million British Thermal Units
MMbbls/cd	Million barrels per calendar day
MMgal	Million gallons
MGY, 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 (Chapter 9 Only)	Regulatory Flexibility Act
RFA	Renewable Fuels Association
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.	United States
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
WDGS	Wet distillers' grains with solubles
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 each is in.

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*

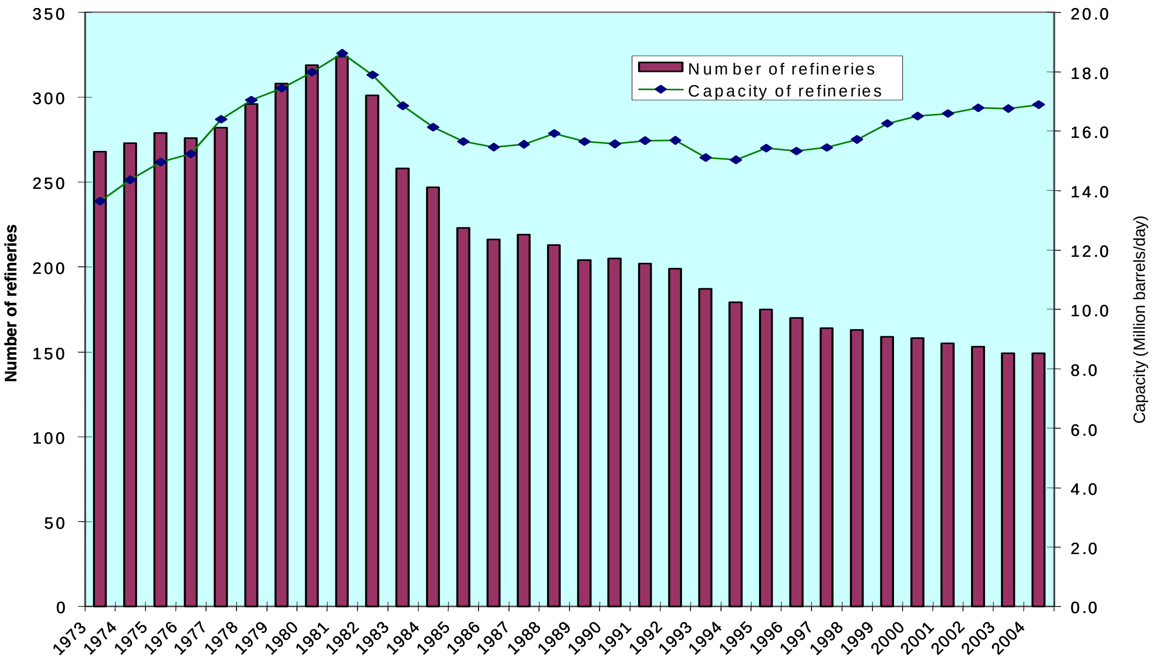
Company	**Capacity (MMbbls/cd)**	**PADD**
Wilmington CA	*0.08*	*5*
Krotz Springs LA	*0.08*	*3*
Exxon Mobil Corp.	**2.0**	
Baytown TX	*0.56*	*3*
Baton Rouge LA	*0.50*	*3*
Beaumont TX	*0.34*	*3*
Joliet IL	*0.24*	*2*
Torrance CA	*0.15*	*5*
Billings MT	*0.06*	*4*
Chalmette, LA	*0.19*	*3*
BP PLC	**1.5**	
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.

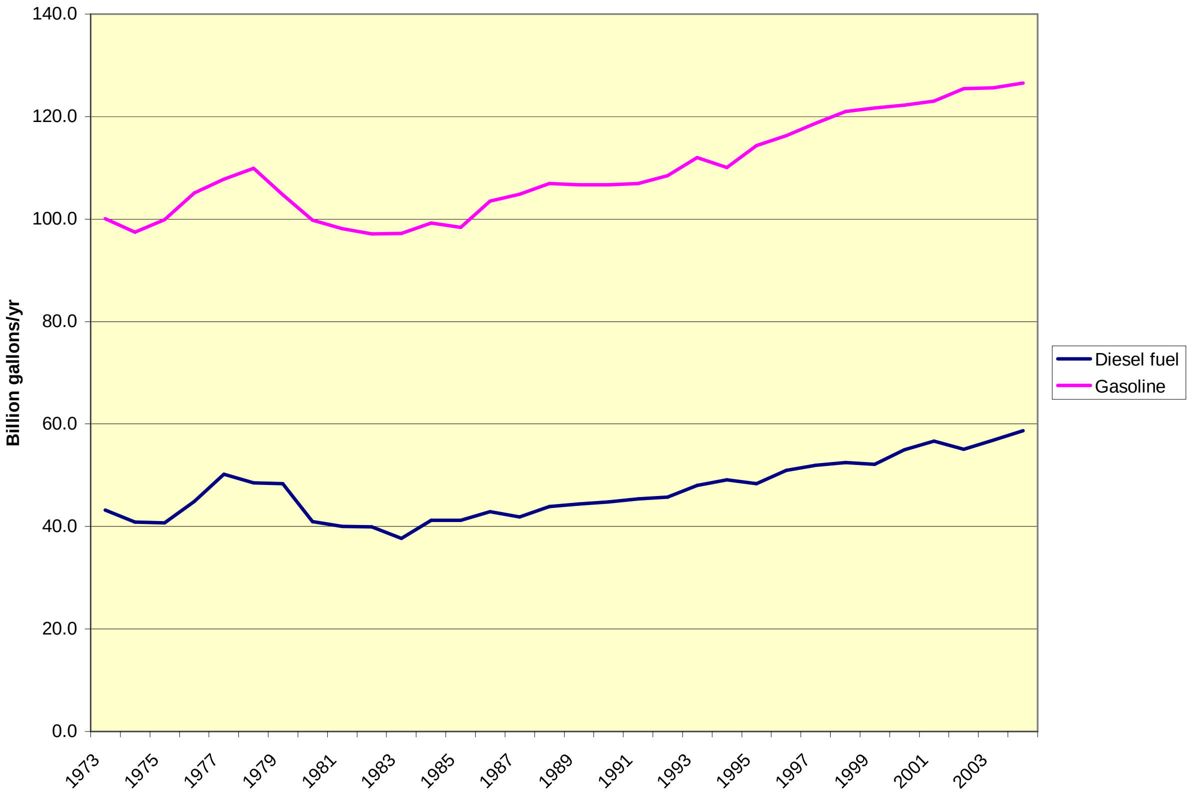
Figure 1.1-1.
Number of Refineries and Total Capacity in the U.S. from 1973-2004



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.



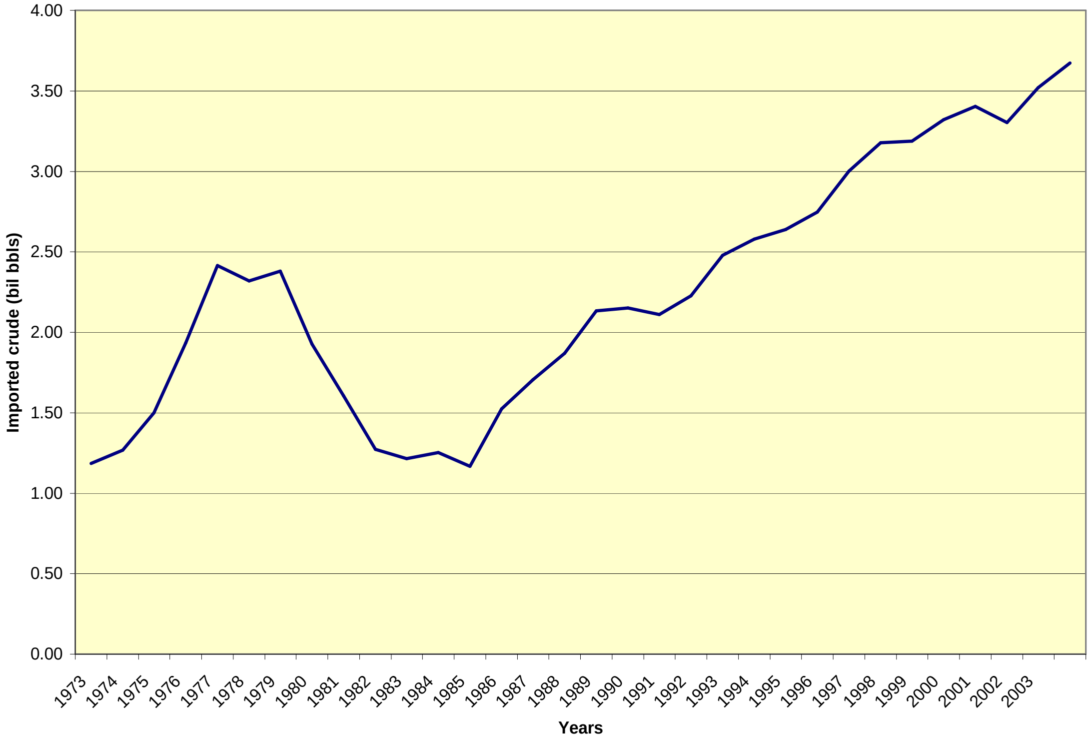
Source: EIA Annual Energy Report, 2005; Table 5.8

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.

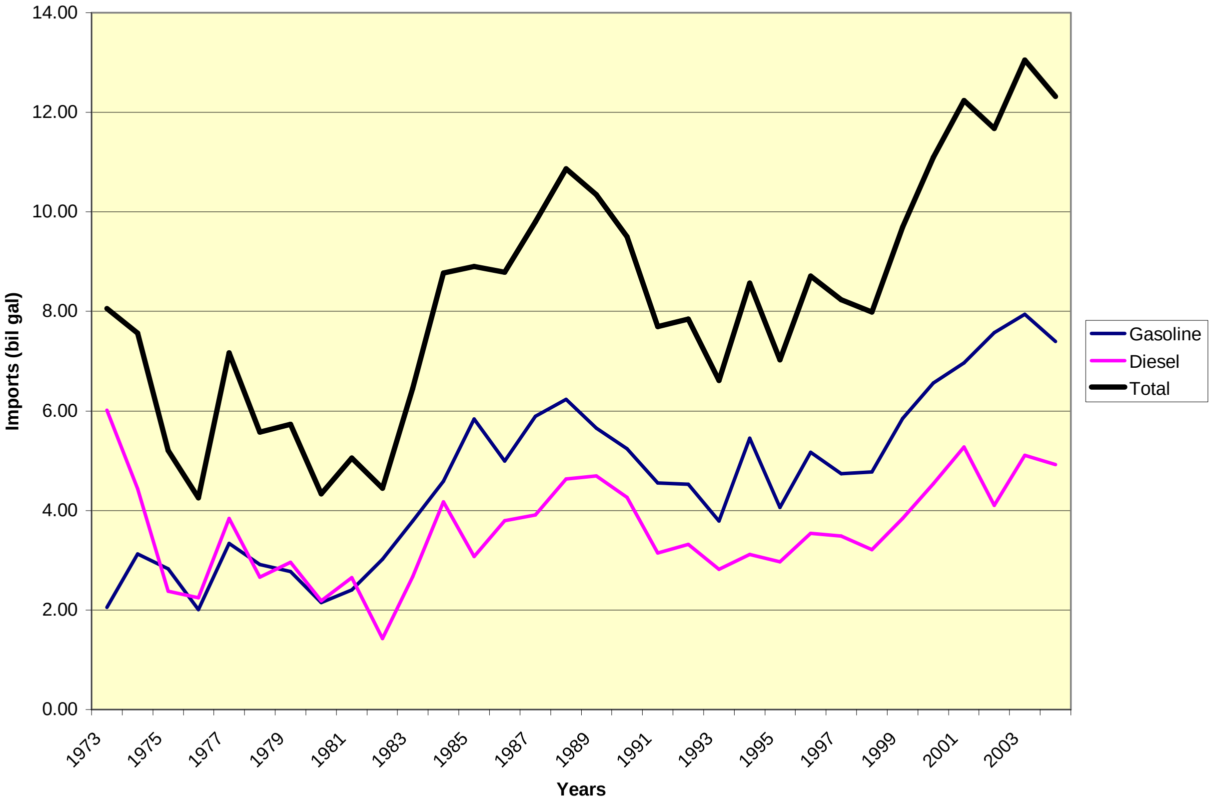
Today, the United States imports approximately 70 percent of all petroleum products used, with two-thirds of these products being used for transportation. From 1973 to 2004, the amount of crude oil imported has increased from 1.2 to 3.7 billion barrels per year, a tripling of volume, representing an 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 1.1-12 and 1.1-2 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)

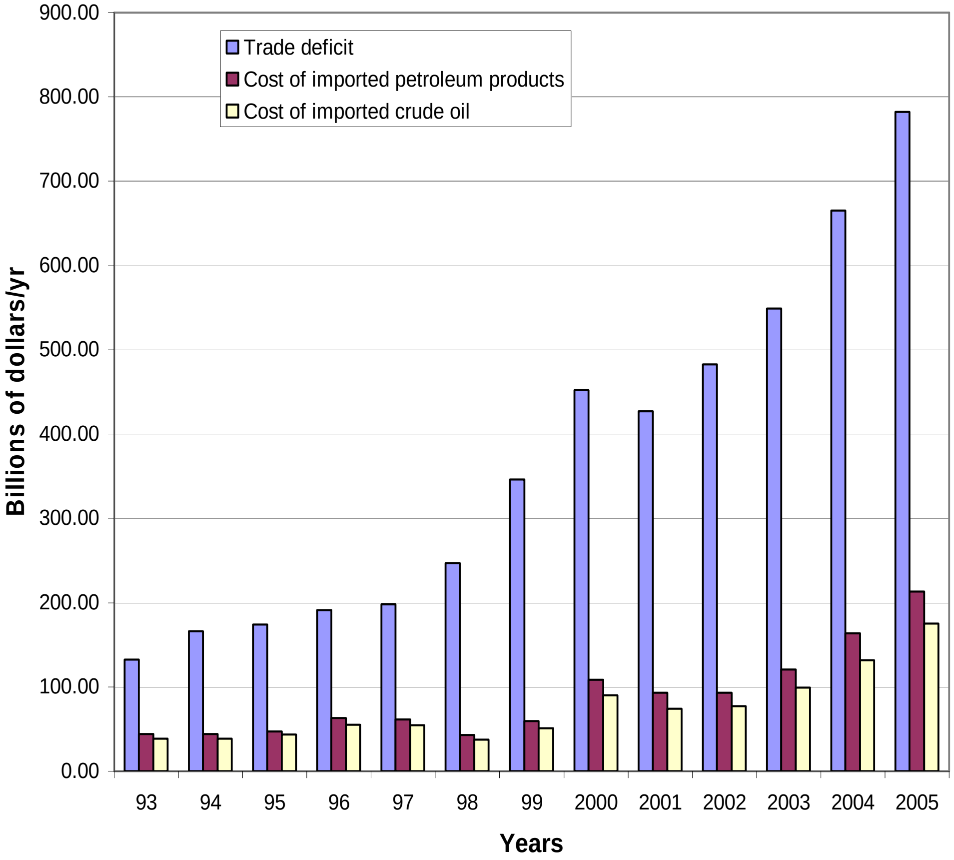
Figure 1.1-4.
Change in Volumes of Imported Gasoline and Diesel fuels (1973-2004)



Source: Annual Energy Outlook, 2005; Energy Information Administration

Twenty seven percent of our trade deficit is from imported petroleum products, a deficit which reached $782 billion in 2005. Approximately 5 percent of the petroleum-related deficit is due to imports of gasoline and diesel fuels. (Figure 1.1-5 shows the trade deficits since 1993 and the portions due to petroleum products and crude imports). 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 and Crude Imports
1993-2005



Source: Energy Information Administration, Annual Energy Report, 2005

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 was 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 gasoline today. Biodiesel represents another 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. Both ethanol and biodiesel are likely to continue to dominate renewable fuel use in the foreseeable future.

1.2.1 Current U.S. Ethanol Production

1.2.1.1 Overview

There are currently 102 ethanol production facilities in the United States with a combined production capacity of 4.9 billion gallons per year. This baseline, or starting point for this regulatory impact analysis is based on U.S. ethanol production facilities operational as of June 2006.[A] [1] [2] [3]

Of the current ethanol production capacity, 93 percent 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 4.7 billion gallons (or almost 97 percent) of the total U.S. ethanol production. Leading the Midwest in ethanol production are Iowa, Illinois, Nebraska, Minnesota, and North Dakota which together represent 80 percent of the total domestic product. In addition to the concentration of facilities located in PADD 2, there is a sprinkling of ethanol plants located outside the corn belt ranging from California to Tennessee to Georgia.

1.2.1.2 How is Ethanol Produced?

All of the ethanol currently produced 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 93 percent by volume) is produced exclusively from corn. Most of the corn originates from the Midwest, and not surprisingly, most of the ethanol is produced in PADD 2 close to where the corn is grown. However, corn-ethanol plants are also found outside the traditional “corn belt”. In Colorado, New Mexico, Colorado, and Wyoming, corn is shipped in from the Midwest to supplement locally grown grains or in some cases, serve as the sole feedstock. As for the remaining ethanol, almost 7 percent is produced from a blend of corn and/or similarly processed grains (milo, wheat, or barley) and less than 1 percent is produced from waste beverages, cheese whey, and sugars/starches combined. A summary of ethanol production by feedstock is presented in Table 1.2-1.

[A] The June 2006 ethanol production baseline (plant locations, ownership, capacities, configurations, feedstocks, energy sources, marketing agreements) was generated from a variety of data sources including Renewable Fuels Association (RFA), Ethanol Producer Magazine, and International Fuel Quality Center (IFQC) publications as well as ethanol producer/marketer websites. The production 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 were used to represent plant capacity, as nameplate capacities are often underestimated.

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

Plant Feedstock	Capacity MMGal/yr	% of Capacity	No. of Plants	% of Plants
Corn[a]	4,516	92.7%	85	83.3%
Corn/Milo	162	3.3%	5	4.9%
Corn/Wheat	90	1.8%	2	2.0%
Corn/Barley	40	0.8%	1	1.0%
Milo/Wheat	40	0.8%	1	1.0%
Waste Beverage[b]	16	0.3%	5	4.9%
Cheese Whey	8	0.2%	2	2.0%
Sugars & Starches	2	0.0%	1	1.0%
Total	**4,872**	**100.0%**	**102**	**100.0%**

[a] Includes seed corn

[b] Includes brewery waste

There are two primary plant configurations for processing grains (mainly corn) into ethanol: dry mill and wet mill.

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 animal 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. Carbon dioxide is also produced during the ethanol fermentation process and may be recovered as a saleable product.

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 possible co-products are sold into food and agricultural markets. Production of these multiple streams is more capital-intensive than the dry mill process, and thus wet mill plants are generally more expensive to build and tend to be larger in size.

Dry milling is the most predominant production process implemented by today's ethanol plants. Of the 94 plants processing corn (and/or other similarly processed grains), 84 utilize dry milling technologies and the remaining 10 plants rely on wet milling processes. Additionally, all under construction or "planned" plants (defined in Section 1.2.2.1) are scheduled to be dry mill. A list of the existing wet mill facilities is provided in Table 1.2-2.

Table 1.2-2. 2006 U.S. Ethanol Production - Wet Mill Plants

Ethanol Plant	City	State	Capacity MMgal/yr
Archer Daniels Midland (ADM)[a]	Cedar Rapids	IA	300
Archer Daniels Midland (ADM)[a]	Clinton	IA	150
Archer Daniels Midland (ADM)	Columbus	NE	90
Archer Daniels Midland (ADM)[a]	Decatur	IL	250
Archer Daniels Midland (ADM)	Marshall	MN	40
Aventine Renewable Energy, Inc.	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

The remaining 8 plants which process waste beverages, cheese whey, or sugars/starches, operate differently than their grain-based counterparts. These facilities do not require milling and instead operate a more simplistic enzymatic fermentation process.

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 feedstocks 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 to achieve this goal, but the technologies are still not fully developed for large-scale commercial production. As of June 2006, there were no U.S ethanol plants processing cellulosic feedstocks. Currently, the only known cellulose-to-ethanol plant in North America is Iogen in Canada, which produces approximately one million gallons of ethanol per year from wood chips. For more a more detailed discussion on cellulosic ethanol production/technologies, refer to Section 7.1.2.

The ethanol production process is relatively resource-intensive and 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 102 ethanol production facilities, 98 burn natural gas, 2 burn coal, 1 burns coal and biomass, and 1 burns syrup from the process to produce steam. A summary of ethanol production by plant energy source is found below in Table 1.2-3.

Table 1.2-3. 2006 U.S. Ethanol Production by Plant Energy Source

Energy Source	Capacity MMGal/yr	% of Capacity	No. of Plants	% of Plants
Natural Gas[a]	4,671	95.9%	98	96.1%
Coal	102	2.1%	2	2.0%
Coal & Biomass	50	1.0%	1	1.0%
Syrup	49	1.0%	1	1.0%
Total	**4,872**	**100.0%**	**102**	**100.0%**

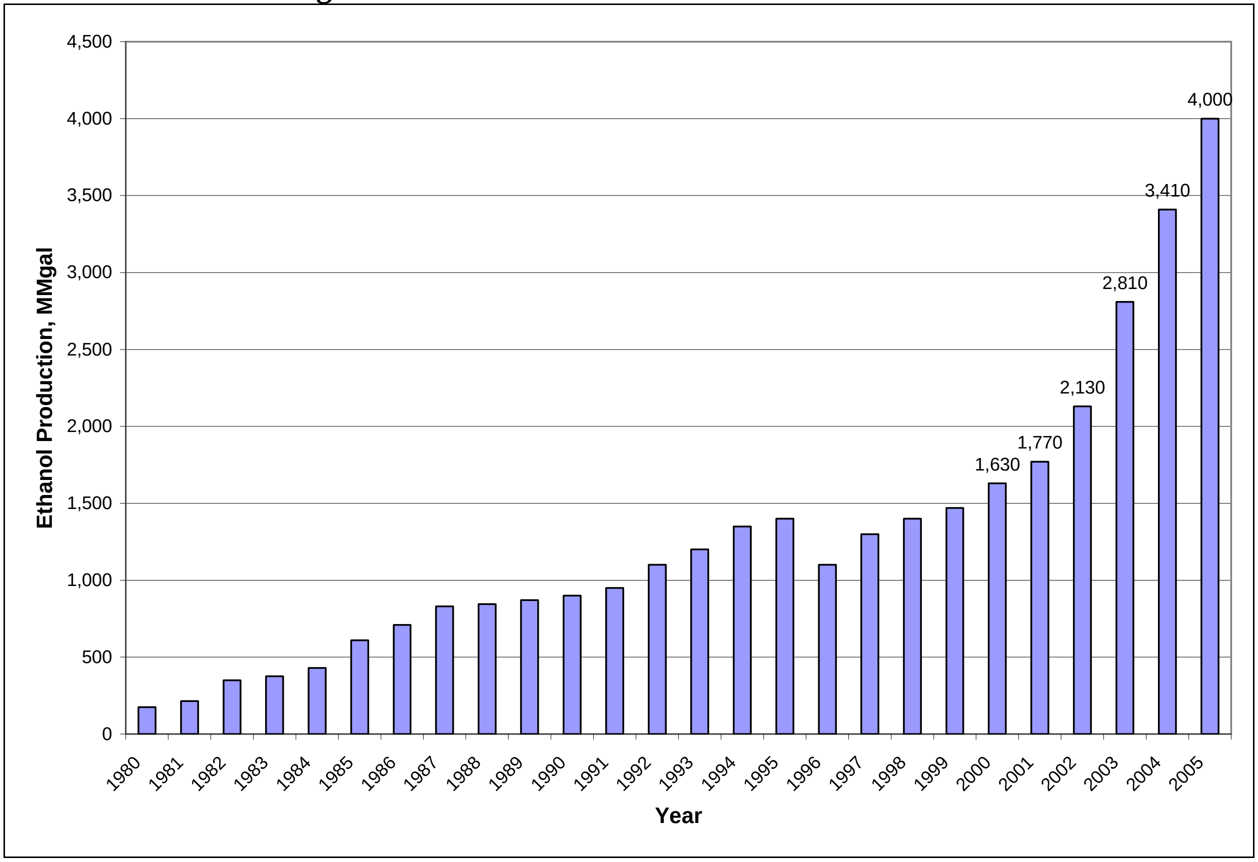
[a] Includes a natural gas facility which is considering transitioning to coal

Currently, 7 of the 102 ethanol plants utilize co-generation or combined heat and power (CHP) technology. CHP is a mechanism for improving overall plant efficiency. CHP facilities produce their own electricity (or coordinate with the local municipality) and use otherwise-wasted exhaust gases to help heat their process, reducing the overall demand for boiler fuel.

1.2.1.3 How Much Ethanol is Produced?

Grain-to-ethanol fermentation technologies are well-known and have been used to produce motor vehicle fuel since the 1860s. However, alcohol-based motor vehicle fuels have had a hard time competing with their fossil fuel counter-parts until recently. Over the past 25 years, domestic fuel ethanol production has steadily increased due to technological advances, environmental regulation (oxygenate requirements in ozone non-attainment areas, carbon monoxide non-attainment areas, etc.), and the rising cost of crude oil. More recently, ethanol production has soared due to state MTBE bans, steep increases in crude oil prices, and tax incentives. 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 as shown in Figure 1.2-1[4]. Current ethanol production capacity as of June 2006 was approximately 4.9 billion gallons per year. This upward trend in ethanol production is expected to continue on into the future as discussed in Section 1.2.2.1.

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



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

1.2.1.4 Where is the Ethanol Produced?

Currently, the majority of ethanol is produced in the Midwest within PADD 2 – not surprisingly, where most of the corn is grown. Of the 102 U.S. ethanol production facilities, 93 are located in Midwest. As a region, PADD 2 accounts for about 97 percent (or 4.7 billion gallons per year) of domestic ethanol production, as shown in Table 1.2-4.

Table 1.2-4. 2006 U.S. Ethanol Production by PADD

PADD	Capacity MMgal/yr	% of Capacity	No. of Plants	% of Plants
PADD 1	0.4	0.0%	1	1.0%
PADD 2	4,710	96.7%	93	91.2%
PADD 3	30	0.6%	1	1.0%
PADD 4	98	2.0%	4	3.9%
PADD 5	34	0.7%	3	2.9%
Total	**4,872**	**100.0%**	**102**	**100.0%**

Leading the Midwest in ethanol production are Iowa, Illinois, Nebraska, Minnesota, and South Dakota with capacities of 1.61, 0.71, 0.57, 0.55, and 0.48 billion gallons per year, respectively. Together, these five states' 69 ethanol plants account for 80 percent of the total domestic product. Although the majority of ethanol production comes from the Midwest, there is a sprinkling of plants situated outside the corn belt ranging from California to Tennessee all the way down to Georgia. As of June 2006, 19 states contributed to the total domestic ethanol production. A summary of these states' ethanol production capacities is found in Table 1.2-5.

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

State	Capacity MMGal/yr	% of Capacity	No. of Plants	% of Plants
Iowa	1,606	33.0%	25	24.5%
Illinois	706	14.5%	6	5.9%
Nebraska	566	11.6%	11	10.8%
Minnesota	546	11.2%	16	15.7%
South Dakota	475	9.7%	11	10.8%
Wisconsin	193	4.0%	5	4.9%
Kansas	179	3.7%	7	6.9%
Indiana	122	2.5%	2	2.0%
Missouri	110	2.3%	3	2.9%
Colorado	93	1.9%	3	2.9%
Tennessee	67	1.4%	1	1.0%
North Dakota	51	1.0%	2	2.0%
Michigan	50	1.0%	1	1.0%
Kentucky	38	0.8%	2	2.0%
California	34	0.7%	3	2.9%
New Mexico	30	0.6%	1	1.0%
Wyoming	5	0.1%	1	1.0%
Ohio	3	0.1%	1	1.0%
Georgia	0.4	0.0%	1	1.0%
Total	**4,872**	**100.0%**	**102**	**100.0%**

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

1.2.1.5 Who are the Ethanol Producers?

The U.S. ethanol industry is currently comprised of a mixture of corporations and farmer-owned cooperatives (co-ops). More than half of the plants (55) are owned by corporations and the remainder (47 plants) are farmer owned co-ops. On average, a U.S. ethanol production facility has a mean plant capacity of about 48 million gallons per year. As shown below in Table 1.2-6, plants owned by corporations (company-owned) are above average in size and farmer-owned co-ops are below average. Similarly, company-owned plants have a much broader range in production levels than farmer-owned co-ops.

Table 1.2-6. 2006 U.S. Ethanol Production by Plant Ownership

Plant Ownership	Total No. of Plants	Production Capacity, MMGal/yr Total	Avg	Min	Max
Company-Owned	55	3,124	57	0.4	300
Farmer-Owned	47	1,748	37	2.6	60
Total	**102**	**4,872**	**48**	**0.4**	**300**

Based on the dominating number of company-owned plants and their above-average production size, company-owned plants account for nearly 65 percent of the total U.S. ethanol production capacity. Additionally, as of June 2006, 45 percent of the total capacity originated from 22 plants owned by just 8 different companies. A list of the top eight ethanol producing companies and their respective capacities is found in Table 1.2-7.

Table 1.2-7. 2006 U.S. Ethanol Production - Top Eight Producers

Company	Capacity MMGal/yr	No. of Plants
Archer Daniels Midland (ADM)	1,070	7
VeraSun Energy	230	2
Hawkeye Renewables, LLC	200	2
MGP Ingredients, Inc.	190	3
Aventine Renewable Energy, Inc.	150	2
Cargill Inc.	120	2
Abengoa Bioenergy Corporation	110	3
New Energy Corp.	102	1
Total	**2,172**	**22**

1.2.1.6 Who are the Ethanol Marketers?

Over 90 percent of today's U.S. ethanol production is sold to the gasoline industry by 8 primary marketing companies. The remaining ethanol is marketed by other small marketers. A summary of the top eight ethanol marketers and their respective volumes is found in Table 1.2-8.

Table 1.2-8. 2006 U.S. Ethanol Production - Top Eight Marketers[5]

Ethanol Marketer	Marketing Volume[a] MMgal/yr	No. of Plants
Archer Daniels Midland (ADM)	1,172	9
Ethanol Products	906	20
Renewable Products Marketing Group (RPMG)[b]	850	14
Aventine Renewable Energy	648	14
Eco-Energy	325	5
United Bio Energy	287	8
Cargill, Inc.	120	2
Abengoa Bioenergy	110	3
Total	**4,417**	**75**

[a]Volume based on marketing agreements and respective ethanol plant capacities
[b]Estimated RPMG marketing volume/plants.

1.2.2 Expected Growth in U.S. Ethanol Production

The Act requires 7.5 billion gallons of renewable fuel to be used in gasoline by 2012. Of that, a large percentage (or 7.2 billion gallons, explained further in DRIA Section 2.1.4.1) is expected to be ethanol. In addition to the Act's renewable fuel requirements, record-high crude oil prices coupled with a growing number of state ethanol mandates and MTBE bans is strongly driving the U.S. ethanol industry. Ethanol production technologies continue to improve making fuel-grade ethanol production economically-favorable and profitable in most cases. Accordingly, EPA predicts that ethanol production capacity will exceed the Act's renewable fuel requirements in 2012 and beyond. The forecasted ethanol production, presented below, supports this prediction.

1.2.2.1 Increases in Ethanol Plant Capacity

Today's U.S. ethanol production capacity (4.9 billion gallons) is already exceeding the 2006 renewable fuel requirement (4.0 billion gallons). In addition, there is another 2.5 billion gallons of ethanol production capacity currently under construction.[B] [6] [7] [8] A summary of the new construction and expansion projects currently underway (as of June 2006) is found in Table 1.2-9

[B] 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, and International Fuel Quality Center (IFQC) publications as well as ethanol producer websites.

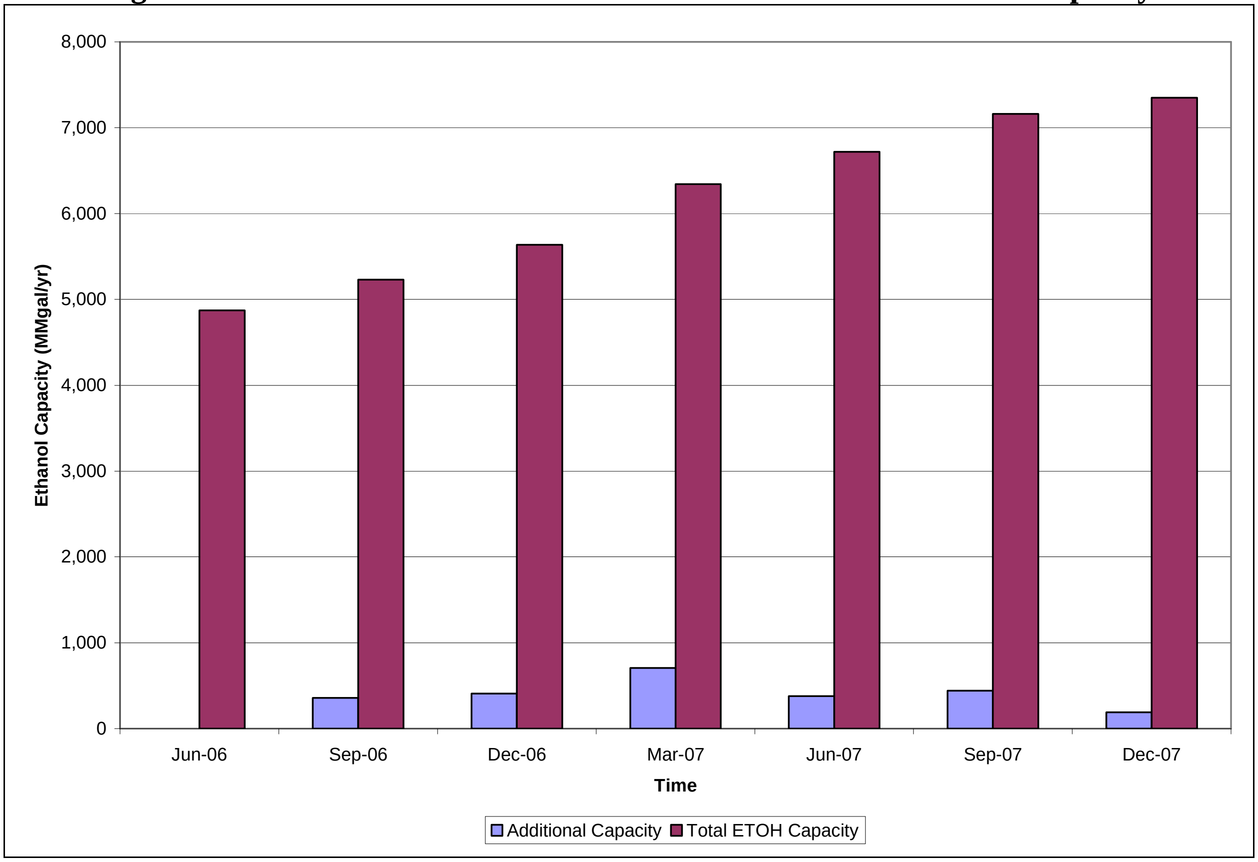
Table 1.2-9. Under Construction U.S. Ethanol Plant Capacity

	2006 ETOH Baseline		New Construction		Plant Expansions		2006 Baseline + UC[a]	
	MMGal/yr	Plants	MMGal/yr	Plants	MMGal/yr	Plants	MMGal/yr	Plants
PADD 1	0.4	1	0	0	0	0	0.4	1
PADD 2	4,710	93	2,048	35	252	8	7,010	128
PADD 3	30	1	30	1	0	0	60	2
PADD 4	98	4	50	1	7	1	155	5
PADD 5	34	3	90	2	0	0	124	5
Total	**4,872**	**102**	**2,218**	**39**	**259**	**9**	**7,349**	**141**

[a] Under Construction

A select group of builders, technology providers, and construction contractors are completing the majority of the construction projects described in Table 1.2-9. 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.

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



Source: April 6, 2006 Biofuels Journal: Ethanol Plants Under Construction in the United States and Canada (supplemented by ethanol producer website information)

As shown in Table 1.2-9 and Figure 1.2-2, once all the construction projects currently underway are complete (estimated by December 2007), the resulting U.S. ethanol production capacity would be over 7.3 billion gallons. Together with estimated biodiesel production (300 million gallons by 2012), this would be more than enough renewable fuel to satisfy the 2012 renewable fuel requirement (7.5 billion gallons). However, ethanol production is not expected to stop here. There are more and more ethanol projects being announced each day. The potential projects are at various stages of planning from conducting feasibility studies to gaining city/county approval to applying for permits to financing/fundraising to obtaining contractor agreements. If all these plants were to come to fruition, the combined domestic ethanol production could exceed 20 billion gallons as shown in Table 1.2-10.

Table 1.2-10. Potential U.S. Ethanol Production Projects

	2006 Baseline + UC[a]		Planned		Proposed		Total ETOH Potential	
	MMGal/yr	Plants	MMGal/yr	Plants	MMGal/yr	Plants	MMGal/yr	Plants
PADD 1	0.4	1	250	3	1,005	21	1,255	25
PADD 2	7,010	128	1,940	15	7,508	90	16,458	233
PADD 3	60	2	108	1	599	9	767	12
PADD 4	155	5	0	0	815	14	970	19
PADD 5	124	5	128	2	676	18	928	25
Total	**7,349**	**141**	**2,426**	**21**	**10,603**	**152**	**20,378**	**314**

[a] Under Construction

However, although there is clearly a great potential for growth in ethanol production, it is unlikely that all the announced projects would actually reach completion in a reasonable amount of time. There is no precise way to know exactly which plants would come to fruition in the future; however, we've chosen to focus our further discussions on only those plants which are under construction or in the final planning stages (denoted as "planned" above in Table 1.2-10). The distinction between "planned" versus "proposed" is that as of June 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 1.2-10, once all the under construction and planned projects are complete (by 2012 or sooner), the resulting U.S. ethanol production capacity would be 9.8 billion gallons, exceeding the 2012 EIA demand estimate (9.6 billion gallons, discussed in DRIA Section 2.1.4.1). This forecasted growth would double today's production capacity and greatly exceed the 2012 renewable fuel requirement (7.5 billion gallons). In addition, domestic ethanol production would be supplemented by imports, which are also expected to increase in the future. A more detailed discussion on future ethanol imports is found in Section 1.5.

1.2.2.2 Changes in Ethanol Production

Of the 60 forecasted new ethanol plants (39 under construction and 21 planned), all would (at least initially) rely on grain-based feedstocks. Of the plants, 56 would rely exclusively on corn as a feedstock. As for the remaining plants: two would rely on both corn and milo, one would process molasses and sweet sorghum, and the last would start off processing corn and then transition into processing bagasse, rice hulls, and wood. A summary of the resulting overall feedstock usage is found in Table 1.2-11.

Table 1.2-11. Forecasted U.S. Ethanol Production by Feedstock

Plant Feedstock	Capacity MMGal/yr	% of Capacity	No. of Plants	% of Plants
Corn[a]	9,226	94.4%	141	87.0%
Corn/Milo	202	2.1%	6	3.7%
Corn then bagasse, rice hulls, wood	108	1.1%	1	0.6%
Corn/Wheat	90	0.9%	2	1.2%
Corn/Barley	40	0.4%	1	0.6%
Milo/Wheat	40	0.4%	1	0.6%
Milo	30	0.3%	1	0.6%
Waste Beverage[b]	16	0.2%	5	3.1%
Molasses, sweet sorghum	15	0.2%	1	0.6%
Cheese Whey	8	0.1%	2	1.2%
Sugars & Starches	2	0.0%	1	0.6%
Total	**9,775**	**100.0%**	**162**	**100.0%**

[a] Includes seed corn

[b] Includes brewery waste

The Act requires 250 million gallons of the renewable fuel consumed in 2013 and beyond to 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 or more of the fossil fuel normally used in the production of ethanol.

As of June 2006, there were zero cellulosic ethanol plants (as discussed above in 1.2.1.2). Of the forecasted plants, only one is expected to meet the definition of "cellulosic biomass ethanol" based on feedstocks.[C] The 108 MMgal/yr Bionol facility slated for East Carroll Parish, LA is proposing to start off processing corn and then transition into processing bagasse, rice hulls, and wood (cellulosic feedstocks).[9] It is unclear as to whether this facility would be processing cellulosic material by 2013, however there are several other facilities that could potentially meet the Act's definition of cellulosic biomass ethanol based on plant energy sources. There are 7 ethanol production plants with a combined ethanol production capacity of 461 MMgal/yr that burn or plan to burn renewable fuels to generate steam for their processes. A brief description of each potentially-cellulosic facility is provided in Table 1.2-12.

[C] At the time of this analysis (June 2006) there were other plants proposing cellulosic ethanol production technologies. However, they are not included in this in-depth discussion of forecasted plants because they were not under construction or in the final stages of planning.

Table 1.2-12. Potential U.S. Cellulosic Ethanol Plants (Based on Energy Source)

Ethanol Plant	City	State	Plant Energy Source	Capacity MMGal/yr	Status
Corn Plus, LLP	Winnebago	MN	Syrup	49	Existing
Central Iowa Renewable Energy	Goldfield	IA	Coal & Biomass	50	Existing
E Caruso Ethanol	Goodland	KS	Coal & Biomass	25	Under Construction
Central Minnesota Ethanol Co-op	Little Falls	MN	Natural Gas then Biomass	22	Under Construction
E3 Biofuels	Mead	NE	Manure/Syngas	20	Under Construction
Harrison Ethanol, LLC	Cadiz	OH	Manure/Syngas	20	Under Construction
Archer Daniels Midland (ADM)	Columbus	NE	Coal, Tires & Biomass	275	Planned
Total cellulosic ethanol potential based on plant energy source				**461**	

Depending on how much fossil fuel is displaced by these renewable feedstocks (on a plant-by-plant basis), a portion or all of the aforementioned ethanol production (up to 461 MMgal/yr) could potentially qualify as "cellulosic biomass ethanol" under the Act. Combined with the 108 MMgal/yr Bionol plant planning to process renewable feedstocks, the total cellulosic potential could be as high as 569 MMgal/yr in 2013. Even if only half of this ethanol were to end up qualifying as cellulosic biomass ethanol, it would still be more than enough to satisfy the Act's cellulosic requirement (250 million gallons).[D]

Including the above-mentioned facilities, a summary of the resulting overall ethanol plant energy usage is found below in Table 1.2-13.

Table 1.2-13. Forecasted U.S. Ethanol Production by Energy Source

Energy Source	Capacity MMGal/yr	% of Capacity	No. of Plants	% of Plants
Biomass	22	0.2%	1	0.6%
Coal[a]	729	7.5%	12	7.4%
Coal & Biomass	75	0.8%	2	1.2%
Coal, Tires & Biomass	275	2.8%	1	0.6%
Manure/Syngas	40	0.4%	2	1.2%
Natural Gas	8,586	87.8%	143	88.3%
Syrup	49	0.5%	1	0.6%
Total	**9,775**	**100.0%**	**162**	**100.0%**

[a]Includes one existing and three under construction plants that plan on transitioning from natural gas to coal.

Of the 60 new forecasted plants, 2 plan to utilize co-generation or combined heat and power (CHP) technology. This would increase the number of energy efficient CHP ethanol plants from 8 to 10.

[D] 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.

1.2.2.3 Changes in Where Ethanol is Produced

In 2012, the majority of ethanol production is still expected to originate from PADD 2. Once all the under construction and planned projects are complete, approximately 92 percent of the U.S. ethanol production capacity would come from PADD 2, as shown below in Table 1.2-14. This is a slight decrease from the Midwest marketshare held in June 2006 (97 percent as described in Section 1.2.1.4).

Table 1.2-14. Forecasted U.S. Ethanol Production by PADD

PADD	Capacity MMgal/yr	% of Capacity	No. of Plants	% of Plants
PADD 1	250	2.6%	4	2.5%
PADD 2	8,950	91.6%	143	88.3%
PADD 3	168	1.7%	3	1.9%
PADD 4	155	1.6%	5	3.1%
PADD 5	252	2.6%	7	4.3%
Total	**9,775**	**100.0%**	**162**	**100.0%**

Despite the growth in PADD 2 ethanol production, the shift in marketshare is attributed to the growing number of ethanol plants outside the cornbelt. In particular, New York, Louisiana, Texas, Arizona, Hawaii, and Oregon are scheduled to join the 19 ethanol producing states described in Table 1.2-5. A summary of the forecasted ethanol production by state is found below in Table 1.2-13.

Table 1.2-15. Forecasted U.S. Ethanol Production by State

State	Capacity MMGal/yr	% of Capacity	No. of Plants	% of Plants
Iowa	2,418	24.7%	30	18.5%
Nebraska	1,790	18.3%	24	14.8%
Illinois	1,200	12.3%	12	7.4%
South Dakota	678	6.9%	13	8.0%
Minnesota	659	6.7%	18	11.1%
Indiana	622	6.4%	8	4.9%
Kansas	299	3.1%	10	6.2%
Wisconsin	283	2.9%	7	4.3%
North Dakota	261	2.7%	5	3.1%
Michigan	212	2.2%	4	2.5%
Missouri	195	2.0%	5	3.1%
Ohio	193	2.0%	4	2.5%
New York	150	1.5%	2	1.2%
Colorado	143	1.5%	4	2.5%
Oregon	113	1.2%	1	0.6%
Louisiana	108	1.1%	1	0.6%
Tennessee	104	1.1%	1	0.6%
Georgia	100	1.0%	2	1.2%
California	69	0.7%	4	2.5%
Arizona	55	0.6%	1	0.6%
Kentucky	38	0.4%	2	1.2%
New Mexico	30	0.3%	1	0.6%
Texas	30	0.3%	1	0.6%
Hawaii	15	0.2%	1	0.6%
Wyoming	12	0.1%	1	0.6%
Total	**9,775**	**100.0%**	**162**	**100.0%**

1.2.3 Current Biodiesel Production

Biodiesel is a diesel fuel substitute produced by combining virgin plant or animal oils with alcohol through a transesterification process, yielding esters of the fat (biodiesel) and a glycerine byproduct. 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. Biodiesel is defined in several sections of the Act, which we have used in formulating our definition for the regulations. 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 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.

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 theses 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.

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 start problems 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[10]. 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. Another factor which is expanding the use of biodiesel are the mandates from states and local municipalities, which require the use of biodiesel in transport fuels.

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 1.2-16).

Table 1.2-16. Estimated Biodiesel Production[a]

Year	Million Gallons per Year
2001	5
2002	15
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 65 biodiesel plants in operation with an annual production capacity of 395 million gallons per year[11]. The majority of the current production capacity was built in 2005, and was first available to produce fuel in the last quarter of 2005. Though 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 1.2-17.

Table 1.2-17. U.S. Production Capacity History

	2001	2002	2003	2004	2005	2006
Plants	9	11	16	22	45	53
Capacity (MM gals/yr)	50	54	85	157	290	354

Note: Capacity Data based on surveys conducted.

Excess production capacity is not easily quantified, though 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, as when the economics are favorable they can shift their operations and make biodiesel esters, instead of products for the ole-chemical market.[E] 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 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. In early 2006, there were 58 plants in the construction phase, which when completed would provide 714 billion gallons per year of additional throughput capacity. Of these facilities, fifty are new while eight are expanding capacity to their existing plants. This planned capacity is likely to be built, since the equity has been raised and the new plants are actively being built at the site of production. Also in early 2006, there were approximately 36 plants with a capacity of 754.7 billion gallons/year in the preconstruction phase (i.e. raising equity, permitting, conceptual design, buying equipment) but had not started construction. For these plants, it is not as likely that they will be completed since industry capacity, equity financing and other issues may alter the economics for new plants. Table 1.2-18 presents the data for the biodiesel plant capacities per the categories discussed.

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

Table 1.2-18. Biodiesel Plant Capacities

	Existing Plants (53 total)	**Construction Phase (58 total)**	**Pre-Construction Phase (36 total)**
Total Plant Capacity, (MM Gallon/year)	354	714	754.7

Considering that it takes 12 to18 months to construct a biodiesel plant (from project feasibility analysis to startup), a large portion of the capacity in the construction phase in early 2006 will be available to produce fuel in early 2007.[12] Data on biodiesel plant construction reveal that most of the new capacity that is currently being constructed is expected to be online and producing fuel in 2006 or by early 2007. Therefore, the existing capacity plus the capacity in the construction phase totals an aggregate amount of about one 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 and preconstruction phase are larger than existing biodiesel plants. The average capacity of existing plants is 6.7 MM gallons per year, while plants in construction phase are averaging 7.7 MM gallons per year, and plants in the preconstruction phase are averaging 22.1 MM gallons per year and are presented in Table 1.2-19. The distribution of biodiesel plants by size and number of companies within each size range are presented in Table 1.2-20.

Table 1.2-19. Average Plant Capacity by Feedstock (MM gallons per year)

Feedstock	Existing*	Construction*	Pre-Construction*
Canola		6.5	50.0
Multi Feedstock	5.7	8.6	18.4
Other Vegetable	3.0	30.0	
Recycled Cooking Oil	0.5	0.3	8.3
Soybean Oil	8.7	9.1	30.3
Tallow	5.0		

Table 1.2-20. Biodiesel Plant Size versus Number of Companies

Plant Size (MM gallons per year)[a]	Existing Plants (58 total)	Construction Phase (36 total)	Pre-Construction Phase (22 total)
<1.00	12	12	1
1.0- 5.0	26	15	3
5.0-10.0	3	8	5
10.0 to 15 .0	6	1	3
15.0 to 20.0	1	1	1
20.0+	5	5	9
Average Plant Size	6.7	7.7	22.1

[a] Total capacity of plants in each category; existing plants is 354 MM gal/yr, construction phase is 324 MM gal/yr, and pre-construction is 485 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 in the construction and pre-construction phase, 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 1.2-21.

Table 1.2-21. Feedstock Selection for Biodiesel Producers

Feedstock	Existing	Construction	Pre-Construction
Camelia		1	
Canola		2	1
Cottonseed	1		
Multi Feedstock	13	8	10
Palm Oil	1		
Recycled Cooking Oil	5	8	3
Soybean oil	30	23	7
Tallow	1		
Unknown	2		1

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 gasoline (described in Section 2.1.3). The resulting 2012 reference case consisted of approximately 28 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.[13] 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 is 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.[14] 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.[F] 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.[15] 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

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[F] 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.

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.[16] 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 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 type 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 DRIA.

In the past, the refining industry raised concerns regarding whether the distribution infrastructure can expand rapidly enough to accommodate the increased demand for ethanol. The most comprehensive study of the infrastructure requirements for an expanded fuel ethanol industry was conducted for the Department of Energy (DOE) in 2002 .[17] 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.[G] 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

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[G] See section 7.3 of this DRIA regarding the projected costs of the necessary infrastructure improvements.

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 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 may 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.

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[H]

[H] 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 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 with out 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)[I] forms wax crystals when the temperature falls to 35 to 45 degrees Fahrenheit.[J] 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 alternately 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.[K]

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 is blended with 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

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distant from the refinery, barge and rail are the preferred means of transport and relatively little MTBE is transported by truck.

[I] 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).

[J] 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.

[K] 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.

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 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 to be blended 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 than 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 is “splash-blended” although an increasing volume of ethanol is being blended into special blends of conventional gasoline (e.g. sub-octane). Finally, a very small amount is blended as E85 or made into ETBE.

1.4.2 Biodiesel Blending

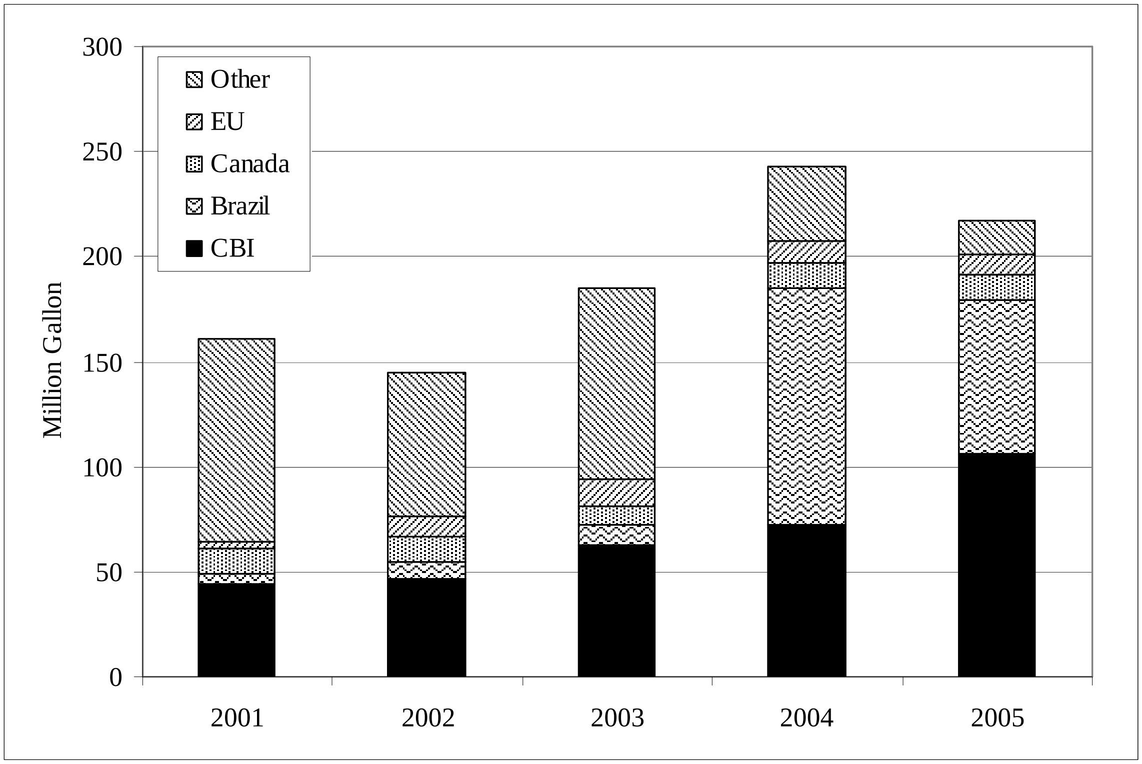
Biodiesel generally leaves the production facility in its neat form and is shipped by truck to locations where it can be blended with conventional diesel fuel. The blending generally occurs at centralized distribution points such as terminals, although it also sometimes occurs within tank trucks themselves.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



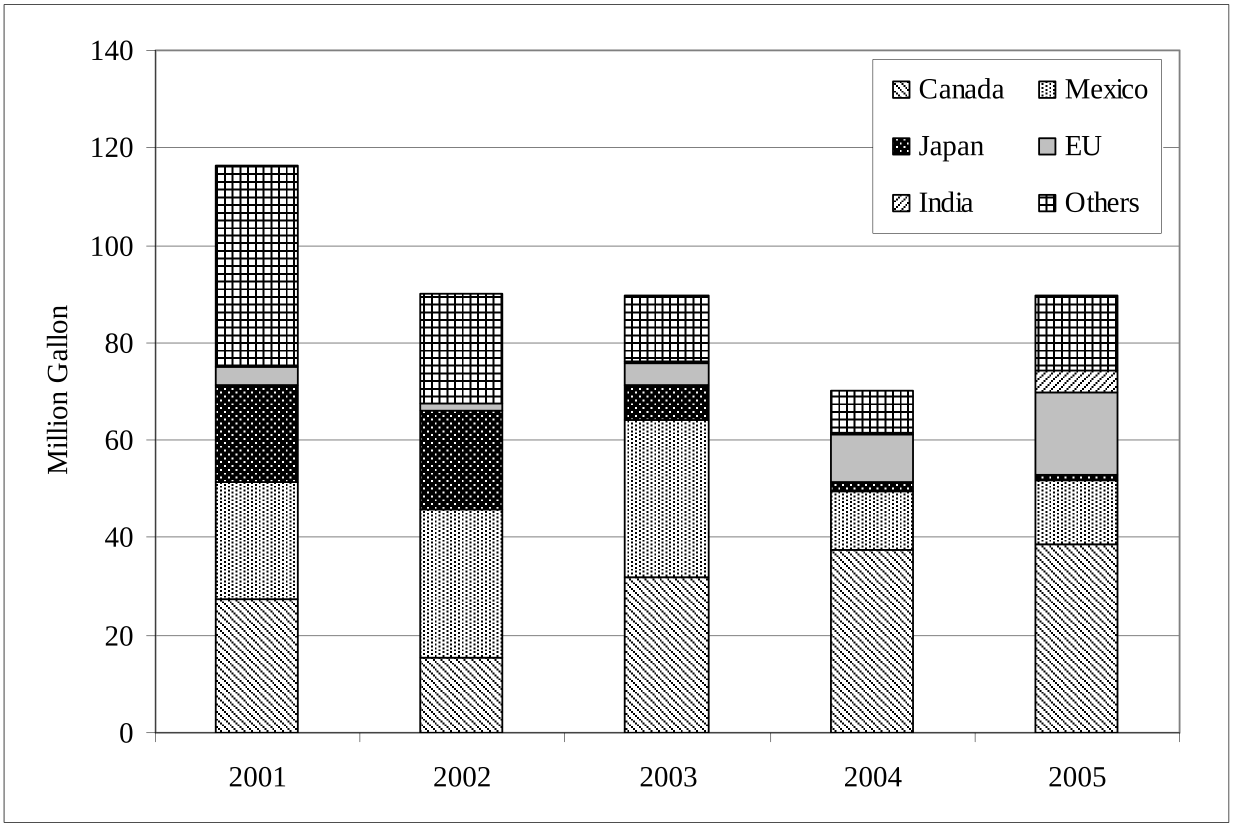
[a] F.O. Licht, “World Ethanol Markets, The Outlook to 2015” (2006). Gross imports (does not account for export volumes) including hydrous, dehydrated, and denatured volumes.

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.[18]

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

As described in the preamble, we developed two scenarios representing renewable fuel volumes produced in 2012, the year when the Renewable Fuel Standard (RFS) program will be fully phased in. The first scenario represented the statutorily required minimum volume of 7.5 billion gallons, while the second scenario reflected the 9.9 billion gallon volume estimated by the Energy Information Administration (EIA). These two control cases were compared to a reference case to determine the impacts of incremental use of renewable fuel.

In order to evaluate the economic and environmental impacts of the control and reference cases, it was first necessary to evaluate the impacts of renewable fuels on the motor vehicle fuel pool. In this context, we investigated a number of relevant issues for both current and future renewable fuel use scenarios, with a particular focus on the use of ethanol in gasoline:

- What factors drive ethanol use?
- Where is ethanol used (geographically and by fuel type)?
- When is ethanol blended into gasoline (seasonal differences)?
- How will other fuel properties change when ethanol is blended into gasoline?

Our analysis of these issues led us to estimate the amount of ethanol used in each state, each fuel type (reformulated gasoline, oxygenated gasoline, and conventional gasoline) for each season. These ethanol use estimates were then used as the basis for our emissions and air quality analyses as well as our estimates of production, distribution, and blending costs.

In Section 2.1, we estimate the volumes of renewable fuels (namely ethanol) which are currently being used in the U.S. as a whole and by state, and we forecast the volumes into the future. We also project the geographical and seasonal distribution of ethanol use. These analyses led us to our reference and control cases. In Section 2.2, we estimate the impact that ethanol blending and the removal of methyl tertiary butyl ether (MTBE) will have on gasoline properties. Section 2.3 summarizes our estimate of the effect of blending biodiesel into conventional diesel fuel.

2.1 Gasoline/Oxygenate Use

Fuel ethanol use has steadily increased over the past decade due to its high gasoline octane value, increasing availability, and more recently due to a series of state MTBE bans and extremely favorable economics. Over the past four years, ethanol consumption has more than doubled from 1.7 billion gallons in 2001 to 4.0 billion gallons in 2005.[19] This growth in domestic ethanol use shows no signs of stopping any time soon, especially given today's record-high crude oil prices.

In August 2005, the president signed into law the Energy Policy Act of 2005 (the Energy Act), creating a national Renewable Fuels Standard (RFS). This RFS program institutes a requirement for renewable fuel consumption beginning with 4.0 billion gallons in 2006 and growing to 7.5 billion gallons in 2012. Despite the forecasted expansion in biodiesel, ethanol is expected to continue to dominate U.S. renewable fuel consumption in the future. As such, the nation is on track for meeting if not exceeding the RFS, and the use of ethanol is expected to more than double again over the next six years.

To understand the impact of the increased ethanol use on gasoline properties and the corresponding impact on overall air quality, we first need to gain a better understanding of where ethanol is used today and how the picture is going to change in the future. We begin Section 2.1 of the draft regulatory impact analysis (DRIA) by discussing current ethanol use and go onto examine four potential 2012 ethanol use/distribution scenarios (control cases). We arrive at four different 2012 control cases based on the uncertainty of future ethanol use (EIA predicts ethanol consumption will exceed the minimum RFS requirements) and the uncertainty of the distribution of ethanol into reformulated gasoline (we predict that refiners and thus RFG areas may behave differently in response to the recent removal of the RFG oxygenate requirement). An more in depth discussion is described below.

2.1.1 Why are oxygenates currently blended into gasoline?

The blending of oxygenates into gasoline dates back to the 1970's. However, their use expanded greatly 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 carbon monoxide were required to use oxygenated fuel, and areas with the worst ambient ozone levels were required to use reformulated gasoline (containing oxygenate). Oxygenates have also been used in gasoline for other reasons, including state mandates and as a volume extender. This section summarizes the current driving forces behind gasoline oxygenate use in the U.S.

2.1.1.1 Federal Reformulated Gasoline Program

Areas found to be in non-attainment with the ozone standard are required to use reformulated gasoline (RFG) year-round. In 2004, the Federal RFG program contained a minimum oxygenate requirement as well as other fuel quality standards.[L] Adding oxygen to gasoline is one way to reformulate gasoline to reduce the production of smog-forming pollutants that contribute to unhealthy ground-level ozone. In addition to the ozone non-attainment areas required to use oxygenate in gasoline, several states/areas also opted into the Federal RFG program (otherwise known as "opt-in"). Additionally, some states/areas (namely California and Arizona) have state-implemented programs which require or promote the use of oxygenated gasoline.

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

A list of the 2004 Federal RFG areas and their corresponding oxygenate(s) is provided in Table 2.1-1. For the purpose of this analysis, only ethanol (ETOH) and methyl tertiary-butyl ether (MTBE) have been considered as oxygenates.[M]

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

Table 2.1-1. 2004 Federal RFG Areas by State[20][21]

RFG Area Location State	 City	No. of Counties	Type of RFG Area	Oxygenate Used[b]
California	Los Angeles	5	Required	ETOH
	Sacramento	6	Required	ETOH
	San Diego	1	Required	ETOH
	San Joaquin Valley	8	Required	ETOH
Connecticut[a]	Hartford	6	Required	ETOH
	Long Island Area	3	Required	ETOH
	Rest of State	6	Opt In	ETOH
Delaware[a]	Philadelphia Area	2	Required	MTBE
	Sussex County	1	Opt In	MTBE
District of Columbia	Washington DC Area	1	Opt In	MTBE
Illinois	Chicago Area	8	Required	ETOH
Indiana	Chicago Area	2	Required	ETOH
Kentucky	Covington	3	Opt In	ETOH
	Louisville	3	Opt In	ETOH
Maryland	Baltimore	6	Required	MTBE
	Kent & Queen Anne's	2	Opt In	MTBE
	Philadelphia Area	1	Required	MTBE
	Washington DC Area	5	Opt In	MTBE
Massachusetts[a]	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[a]	Atlantic City	2	Opt In	MTBE
	Philadelphia Area	6	Required	MTBE
	Warren County	1	Opt In	MTBE
	Long Island Area	11	Required	ETOH, MTBE
New York	Essex Area	2	Opt In	ETOH
	Long Island Area	11	Required	ETOH
Pennsylvania	Philadelphia Area	5	Required	MTBE
Rhode Island[a]	Providence Area	5	Opt In	MTBE*
Texas	Dallas/Fort Worth	4	Opt In	MTBE
	Houston	8	Required	MTBE
Virginia	Norfolk	11	Opt In	MTBE
	Richmond	7	Opt In	MTBE
	Washington DC Area	10	Opt In	MTBE
Wisconsin	Milwaukee	6	Required	ETOH
Total (Required+Opt-In)		**181**		

[a] Entire state operates under the RFG program

[b] Oxygenate determination based on 2004 EPA RFG fuel survey results. An asterisk next to the oxygenate name denotes the predominant oxygenate, but also indicates that there were trace amounts (<3% by vol) of the other oxygenate (either MTBE of ETOH) found. All other RFG oxygenate usage was assumed to be exclusive within a given area with the exception of the NJ Long Island area (57/43 percent volume ratio of MTBE to ETOH).

As shown above in Table 2.1-1, in 2004 a little more than half of the Federal RFG areas (on a county-by-county basis) used MTBE as an oxygenate as opposed to ethanol. However, on a volumetric basis, more ethanol was consumed than MTBE (2.2 billion gallons compared to 1.9 billion gallons as shown below in Table 2.1-3).

2.1.1.2 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.[N] Together, the winter oxy-fuel program coupled with improving vehicle emissions control systems help 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 winter oxy-fuel as part of a maintenance strategy for remaining in compliance with the CO NAAQS. A list of the 2004 oxy-fuel areas is provided in Table 2.1-2. According to regional fuel contacts, all oxy-fuel areas used ethanol as an oxygenate in 2004.

Table 2.1-2. 2004 State Implemented Oxy-Fuel Programs[22]

Oxy-Fuel Area Location		Oxy-Fuel Period	Carbon Monoxide Status		Winter Oxy-Fuel Program	
State	**City**		**Designation**	**Working on 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[d]	X	X	
Washington	Spokane	9/1-2/29	Non-attainment[e]	X	X	

[a] Currently working on redesignation to attainment

[b] Oxy-fuel program is part of CO maintenance plan.

[c] Area was redesignated to attainment effective 7/23/04. Oxy-fuel program will be a contingency measure.

[d] EPA has been granted enforcement discretion during redesignation process.

[e] Area was redesignated to attainment effective 8/29/05. Oxy-fuel program will be a contingency measure.

2.1.1.3 Other Reasons to Blend Ethanol

[N] 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 (10 volume percent ethanol required in each gallon of gasoline). Second, blending ethanol into gasoline could help them meet their mobile source air toxics (MSAT1) performance standards as determined by the Complex Model.[O] Additionally, 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 extremely economical. The 1.1 billion gallons of ethanol used in PADD 2 conventional gasoline in 2004 (see Table 2.1-4 of Section 2.1.2.2) 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 ethanol (E10) or less. However, there are now about five million flexible fuel vehicles (FFVs) on the road today with more being produced and sold each day. FFVs are specifically designed to be able to handle a wide range of gasoline/ethanol blends up to 85 percent ethanol, or E85.

2.1.2 Development of the Base Case

In order to evaluate the impact of increased ethanol use on gasoline, we had to develop a 2012 reference case as a point of comparison for the two 2012 control cases (discussed further in DRIA Section 2.1.4). In order to develop the reference case, we first needed to establish a base case or a historical foundation representing pre-RFS gasoline conditions. A more in-depth discussion of how the base case was established is presented below.

2.1.2.1 Strategy for Establishing the 2004 Base Case

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

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. All ethanol-blended gasoline was assumed to be E10, with the exception of California gasoline (both Federal RFG and California Phase 3 RFG (CaRFG3)).[P] All California

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[O] This RFS proposal is based on MSAT1 conditions. Impacts of the recent MSAT2 NPRM which proposes to remove individual refinery toxic performance standards (baselines) in exchange for a nationwide benzene standard will be reflected in the analysis for that rulemaking.

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

"RFG" was assumed to contain approximately 5.7 percent ethanol (E5.7) based on discussions with California Air Resource Board (CARB) officials. This includes all California "RFG" supplied to the Phoenix metropolitan area in the summertime under Arizona's clean burning gasoline (CBG) program.[Q] Finally, MTBE use in the base case was assumed to occur in 11 volume percent proportions.

Total gasoline consumption was obtained from the 2004 Petroleum Marketing Annual (PMA) report published by the Energy Information Administration (EIA).[23] 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.[R] [24] 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 June 2006 Monthly Energy Review.[25] State ethanol contributions originated from the 2004 Federal Highway Administration (FHWA) gasohol report.[26] 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.[S] And third, not all states using ethanol reported their 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, a series of oxygenate verification tools were applied including knowledge of state ethanol mandates, state MTBE bans, Arizona's CBG program, as well as fuel survey results.[27] [28] 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.

2.1.2.2 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 Tables 2.1-3.

[Q] For the purpose of this 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).

[R] 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).

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

Table 2.1-3.
2004 Gasoline & Oxygenate Consumption by PADD

PADD	Gasoline MMgal	Ethanol MMgal	Ethanol %	MTBE[a] MMgal	MTBE[a] %
PADD 1	49,193	660	1.34%	1,360	2.76%
PADD 2	38,789	1,616	4.17%	1	0.00%
PADD 3	20,615	79	0.38%	498	2.42%
PADD 4	4,542	83	1.83%	0	0.00%
PADD 5[b]	7,918	209	2.63%	19	0.23%
California	14,836	853	5.75%	0	0.00%
Total	**135,893**	**3,500**	**2.58%**	**1,878**	**1.38%**

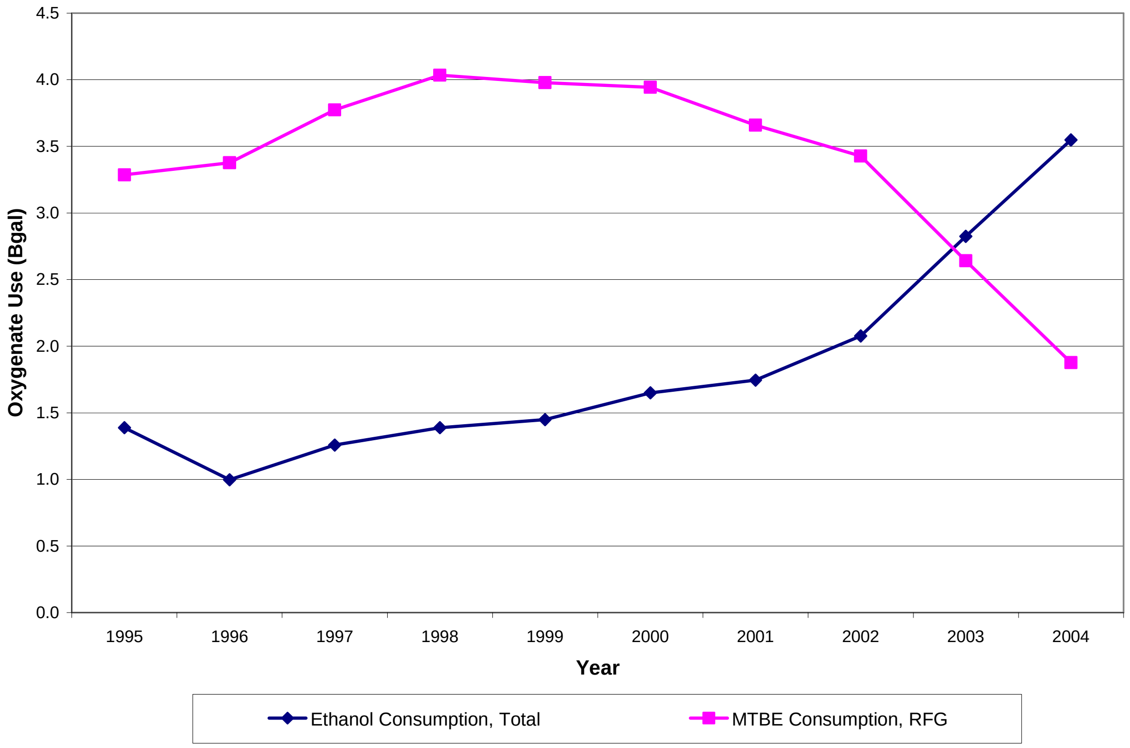
[a] MTBE blended into RFG

[b] PADD 5 excluding California

As shown above, nearly half (or about 45 percent) of the ethanol was consumed in PADD 2 gasoline in 2004, not surprisingly, where the majority of ethanol was produced. The next highest region of use was the State of California which accounted for about 25 percent of domestic ethanol consumption. This makes sense since California alone accounts for over 10 percent of the nation’s total gasoline consumption and all fuel (both Federal RFG and CaRFG3) was presumed to contain ethanol in 2004 (following their recent MTBE ban) at 5.7 volume percent.

In 2004, total ethanol use exceeded MTBE use. Ethanol’s lead oxygenate role is relatively new, however the trend has been a work in progress 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 2.1-1.

Figure 2.1-1. Oxygenate Consumption Over Time



Source: Energy Information Administration[29] [30]

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 have prompted several states to significantly restrict or completely ban MTBE use in gasoline. At the time of this 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 will become effective in 2005 and beyond. A list of the states with MTBE bans (listed in order of phaseout date) is provided in Table 2.1-4.

Table 2.1-4. States with MTBE Bans Enacted as of June 2004

State[a]	MTBE Phaseout Date	Type of MTBE 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. Arizona adopted legislation on 4/28/00 calling for a complete phaseout of MTBE as soon as feasible but no later than 6 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%)

Source: U.S. EPA, State Actions Banning MTBE (Statewide), June 2004

In 2004, all remaining MTBE consumption was assumed to occur in reformulated gasoline (explained in 2.1.2.1). As shown above in Table 2.1-3, 99 percent of MTBE use 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.

2.1.2.3 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.[T] [31] Similarly, according to EIA Monthly Energy Review June 2006, 38 percent of

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[T] Reported seasonal splits for gasoline and ethanol (presented throughout this section) were computed based on RFG production seasons (Summer: May 1 through September 15th; Winter: January 1st through April 30th and September 16th through December 31st).

the ethanol was consumed in the summertime and 62 percent was consumed in the wintertime in 2004[32].

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).[U] The remaining 7.5 months are considered 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, are all believed to use ethanol as their oxygenate (as described in 2.1.1.2). 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 the gasoline they produce in order to add ethanol and still comply with the Reid vapor pressure (RVP) requirements.

2.1.2.4 2004 Gasoline/Oxygenate Consumption by Fuel Type

Of the 3.5 billion gallons of ethanol blended into gasoline in 2004, approximately 2.2 billion gallons were used in reformulated gasoline and the remaining 1.3 billion gallons were used in conventional gasoline (including wintertime oxygenated fuel).[V] A breakdown of the 2004 ethanol consumption by fuel type and PADD is found in Table 2.1-5.

[U] 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).

[V] Ethanol allocation to reformulated gasoline based on U.S. EPA Office of Transportation & Air Quality, 2004 RFG Fuel Survey Results (http://www.epa.gov/otaq/regs/fuels/rfg/properf/rfgperf.htm). Ethanol allocation to conventional gasoline based on Alliance of Automobile Manufacturers (AAM) North American Fuel Survey 2004 (report can be purchased at http://autoalliance.org/fuel/fuel_surveys.php). Ethanol allocation to oxyfuel based on knowledge of 2004 oxyfuel areas (refer to Table 2.1.2) and assumption that all oxyfuel contained ethanol in 2004 (according to regional fuel contacts).

Table 2.1-5. 2004 Ethanol Consumption by Fuel Type

	Ethanol Consumption (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 2.1.2.2, 100 percent of the 1.9 billion gallons of MTBE blended into gasoline in 2004, was assumed to be consumed in reformulated gasoline.

2.1.2.5 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 these results are provided in Table 2.1-6 and Figure 2.1-2. 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 volume percent (E10) proportions, except in the case of California gasoline (E5.7).

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 2.1-1), and since they also have a state MTBE ban, ethanol is found in each gallon of gasoline.

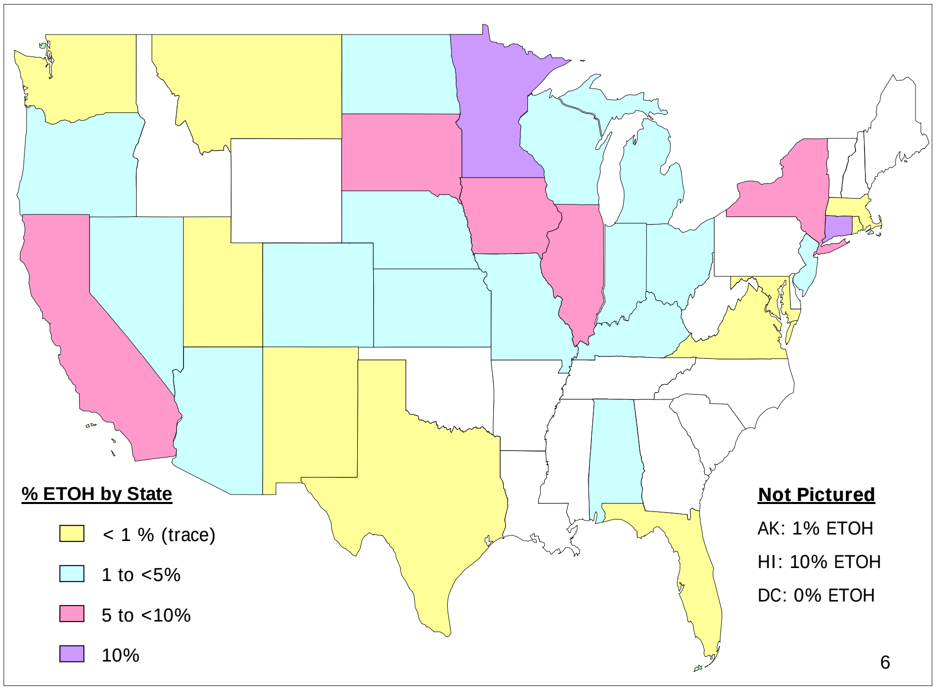
Table 2.1-6.
2004 Gasoline/Ethanol Consumption by State

State	Gasoline MMgal	Ethanol MMgal	Percent Ethanol
California	14,836	853	5.75%
Illinois	5,177	422	8.14%
New York	5,626	301	5.35%
Minnesota	2,684	268	10.00%
Ohio	5,156	192	3.72%
New Jersey	4,235	188	4.43%
Connecticut	1,522	152	10.00%
Indiana	3,059	148	4.84%
Missouri	3,159	122	3.86%
Iowa	1,635	117	7.14%
Wisconsin	2,471	109	4.39%
Arizona	2,187	88	4.04%
Colorado	1,999	80	4.01%
Michigan	4,861	77	1.58%
Kentucky	2,177	50	2.29%
Hawaii[a]	452	45	10.00%
Kansas	1,396	41	2.92%
Texas	11,948	39	0.33%
Nebraska	819	37	4.54%
Alabama	2,392	31	1.31%
Oregon	1,500	31	2.05%
South Dakota	434	24	5.51%
Nevada	857	23	2.69%
Massachusetts	2,934	18	0.63%
Washington	2,621	18	0.68%
North Dakota	350	11	3.00%
New Mexico	966	8	0.83%
Alaska	302	3	1.11%
Utah	1,097	2	0.17%
Montana	503	1	0.22%
Rhode Island[b]	490	0	0.06%
Maryland[b]	2,480	0	0.01%
Florida[b]	8,605	0	0.00%
Virginia[b]	3,920	0	0.00%
Total	**104,853**	**3,500**	**3.34%**

[a] Hawaii was assumed to have a state mandate in the 2004 base case (Source: Renewable Fuels Associaion, Homegrown for the Homeland: Ethanol Industry Outlook 2005)

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

Figure 2.1-2. 2004 Ethanol Distribution, % ETOH by State



2.1.3 Development of the 2012 Reference Case

To conduct the subsequent economic and environmental analyses, we compared a base year without RFS fuel changes (reference case) to a modeled year with renewable fuel changes. Or more accurately, we compared a 2012 reference case to four potential 2012 renewable fuel control cases (discussed further in DRIA Section 2.1.4).

To establish the 2012 reference case, we started with the 2004 base case (presented in Table 2.1-3) and grew out gasoline/oxygenate use according to the EIA AEO 2006 motor gasoline energy growth rate from 2004 to 2012.[33] Accordingly, in the resulting 2012 reference case, ethanol and MTBE use was proportional to 2004 use both by region and fuel type. A summary of the 2012 reference case is found in Table 2.1-7.

Table 2.1-7.
2012 Gasoline & Oxygenate Consumption by PADD
(Reference Case)

PADD	Gasoline MMgal	Ethanol MMgal	Ethanol %	MTBE[a] MMgal	MTBE[a] %
PADD 1	54,788	735	1.34%	1,515	2.76%
PADD 2	43,201	1,800	4.17%	2	0.00%
PADD 3	22,959	88	0.38%	555	2.42%
PADD 4	5,059	93	1.83%	0	0.00%
PADD 5[b]	8,819	232	2.63%	21	0.23%
California	16,523	950	5.75%	0	0.00%
Total	**151,349**	**3,898**	**2.58%**	**2,092**	**1.38%**

[a]MTBE blended into RFG

[b]PADD 5 excluding California

2.1.4 Development of the 2012 Control Cases

In Section 2.1.2 we described the development of the 2004 base case, which was used to develop the 2012 reference case as described in Section 2.1.3. In this section we describe the development of the two 2012 control cases representing increased use of renewable fuel. As described in the preamble, the first control scenario represented the statutorily required minimum volume of 7.5 billion gallons, while the second control scenario reflected the 9.9 billion gallon volume estimated by EIA. Both control scenarios were used in comparison to the reference case to evaluate the economic and environmental impacts of increased use of renewable fuels.

2.1.4.1 Strategy for Forecasting Ethanol Consumption

As mentioned earlier in Section 2.1.2.2, groundwater contamination concerns have caused many states to ban the use of MTBE in gasoline. In response to the Energy Policy Act (the Energy Act) of 2005, essentially all U.S. refiners are expected to eliminate the use of MTBE in gasoline in 2006 or 2007, and certainly prior to 2012. Ethanol consumption, on the other hand is expected to continue to grow at unprecedented rates in the future. Not only is ethanol replacing MTBE, ethanol will fuel the growing number of ethanol-friendly vehicles being produced, as well as satisfy the growing number of state ethanol mandates (Washington and Montana recently joined Minnesota and Hawaii).[W][34] Additionally, the Energy Act requires a minimum amount of renewable fuels to be used beginning in 2006. By 2012, the Act requires 7.5 billion gallons of renewable fuels to be consumed domestically, most of which is expected to be ethanol.

[W] Montana state mandate requires all gasoline to contain 10% ETOH once plant production ramps up to 40 MMgal/yr and Washington state mandate requires 20% of all gasoline to contain 10% ethanol by 12/1/08. At the time of our analysis, these were the only two new state ethanol mandates. However, EPA recognizes that as of 7/13/06, several states have enacted biofuel standards (Iowa, Louisiana, and Missouri) and several others have biofuel standards pending (California, Colorado, Idaho, Illinois, Indiana, Kansas, New Mexico, Pennsylvania, Virginia, and Wisconsin) which mandate a minimum amount of ethanol use.

However, it's predicted that renewable fuel consumption will be much higher than 7.5 billion gallons in 2012. In Annual Energy Outlook (AEO) 2006, EIA forecasts that by 2012, total ethanol use (corn, cellulosic, and imports) would be about 9.6 billion gallons and biodiesel use would be about 300 million gallons.[35] A comparison between the EIA AEO 2006 forecasted renewable fuel consumption and the Energy Act renewable fuels standard is presented below in Table 2.1-8.

Table 2.1-8. Renewable Fuel Consumption Forecast

	EIA AEO 2006 Forecasted Renewable Fuel Consumption (Bgal)			EPAct Renewable Fuels Standard (Bgal)
Year	Ethanol[a]	Biodiesel	Total	
2006	4.1	0.2	4.3	4.0
2007	5.2	0.4	5.6	4.7
2008	6.0	0.4	6.4	5.4
2009	6.9	0.4	7.3	6.1
2010	7.9	0.3	8.2	6.8
2011	8.8	0.3	9.1	7.4
2012	9.6	0.3	9.9	7.5

[a] Sum of corn ethanol, cellulosic ethanol, and imports

As shown above in Table 2.1-8, EIA's renewable fuel projection in 2012 (9.9 billion gallons total) greatly exceeds the 7.5 billion gallon RFS requirement. More specifically, EIA predicts that ethanol production alone would exceed the RFS in 2006 through 2012. The projected AEO 2006 fuel consumption levels were estimated using EIA's LP refinery model. In 2012, EIA's renewable fuel projection was based on a crude oil price of $47/bbl, which is significantly lower than today's crude oil price (tracking above $70/bbl at the time of this analysis).[X][36] Therefore, current market conditions indicate that ethanol and biodiesel production could be even more favorable and/or prevalent in the future based on economics. However, EIA's AEO 2006 analysis also considers the feasibility of building production facilities to accommodate the growing renewable fuel demand. As such, we interpret EIA's 2012 ethanol and biodiesel projections to be reasonable estimates considering both economics and the rate at which new plants could feasibly come on-line.

To summarize, it is abundantly clear that renewable fuel use is growing rapidly, faster than the RFS requires. However quantifying future renewable fuel consumption, namely ethanol growth, is a difficult task. The gasoline refining industry and ethanol industry are currently undergoing a variety of changes/expansions and there's no definite way to know exactly how things are going to "fall out" in the future. Accordingly, EPA has chosen to model two different 2012 renewable fuel consumption scenarios to represent a reasonable range of ethanol use - 7.2 billion gallons (based on the Energy Act RFS requirement less EIA's biodiesel projection) and 9.6 billion gallons (based on EIA's AEO 2006 ethanol projection). The Agency is not concluding that ethanol consumption could not possibly exceed 9.6 billion gallons by 2012, but

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[X] West Texas Intermediate (WTI) crude oil pricing was $70.84/bbl in May, 2006; $70.95/bbl in June, 2006; and $74.41/bbl in July 2006 according to EIA.

rather that this volume is a reasonable "ceiling" for our analysis. The two future consumption estimates are reasonably consistent with the total "under construction" (7.3 billion gallons) and "planned" (9.8 billion gallons) ethanol production capacities discussed earlier in Section 1.2.2.1. For each renewable fuel consumption scenario, EPA has considered cellulosic ethanol and biodiesel consumption to be fixed at 250 million gallons (required by the Energy Act) and 300 million gallons (projected by EIA), respectively.

In addition to modeling two different 2012 ethanol consumption levels, two scenarios were considered based on how refineries could potentially respond to the recent removal of the RFG oxygenate mandate. In the maximum scenario ("max-RFG"), refineries could continue to add oxygenate (ethanol) into all batches of reformulated gasoline. In this case, refineries currently blending MTBE (at 11 volume percent) would be expected to replace it with ethanol (at 10 volume percent). In the minimum scenario ("min-RFG"), some refineries could respond by using less (or even zero) ethanol in RFG based on the minimum amount needed to meet volume, octane, and/or total toxics performance requirements. The rationale behind the max-RFG and min-RFG assumptions for each area is explained in greater detail in Section 2.1.3.1. The max-RFG and min-RFG criteria result in a total of four different 2012 ethanol consumption control cases:

- 7.2 billion gallons of ethanol, maximum amount used in RFG areas;
- 7.2 billion gallons of ethanol, minimum amount used in RFG areas;
- 9.6 billion gallons of ethanol, maximum amount used in RFG areas; and
- 9.6 billion gallons of ethanol, minimum amount used in RFG areas.

Each of these control cases has been analyzed in more detail and the results are presented in Section 2.1.4.6.

2.1.4.2 Forecast for RFG Ethanol Use

In the 2004 base case, there were 19 states with RFG programs covering a total of 181 counties (summarized previously in Table 2.1-1). For this analysis, we are assuming that in the future the number of RFG areas would not change. As such, the RFG fuel contribution to the gasoline pool of each state would remain the same, yet the amount of ethanol added to RFG could change 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 2.1.1.1. However, effective May 5, 2006, EPA removed the RFG oxygenate requirement in response to the Energy Act.[37] 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, we have made an attempt to bracket the responses as described below.

Some refineries may continue to add oxygenate (ethanol) to all their reformulated gasoline in 2012 based on octane, volume, and/or toxic performance requirements. Others, particularly those located in close proximity to the ethanol production facilities (namely PADD 2), may continue to add ethanol as if the oxygenate requirement was still effective or may even increase their ethanol use due to favorable economics. Still for others it may be more economical to pare back or eliminate RFG ethanol use completely.

For the purpose of this analysis, future RFG area behavior (with respect to ethanol use) was considered to be uniform within a PADD. Therefore RFG areas located in PADD 1 would respond the same but perhaps differently from PADD 2 and PADD 3 RFG areas. Additionally, California "RFG" (Federal RFG and CA Phase 3 RFG) would behave according to its own set of RFG assumptions as would Arizona "RFG" (Arizona CBG in Phoenix Metropolitan Area).

For the max-RFG sensitivity, ethanol blending was assumed to be favorable year-round throughout the country. Hence, in Table 2.1-10 (below), the resulting percent market share for ethanol-blended gasoline is 100% in both summer and winter for all RFG areas.

For the min-RFG sensitivity, determining the percent market share for each area was more involved. Since this proposal assumes that MSAT1 baselines are still in place, a minimum level of ethanol blending (market share) could be estimated based on what would be required to maintain required toxics performance accounting for the MTBE phase-out. This was carried out at a PADD level for summer and winter gasoline using aggregated fuel parameters from 2001-02 batch data and MSAT1 baseline toxics performance figures.

In general, this analysis consisted of generating PADD-level estimated toxics baselines for future years and comparing those to results of Complex Model runs using estimated future fuel parameters. The amount of ethanol was reduced from 3.5 weight percent oxygen toward zero until the Complex Model performance of the fuel parameters just met the estimated toxics baselines, and that amount of ethanol was determined to be the minimum quantity to maintain compliance. This estimation was made for calendar year 2012.

To estimate toxics baselines for the future years, new RFG volume was added at a fixed annual growth rate of 1.7% based on historical production volume data, and this new volume was assumed to come in at the minimum required toxics performance level of 21.5% total toxics reduction. This resulted in a lower effective PADD-average MSAT1 baseline going into the future.

Next, 2001-02 seasonal aggregate fuel parameters were modified using a balance between 10 volume percent ethanol (3.5 weight percent oxygen) and 5 volume percent aromatics. This adjustment to the aromatics values was determined from examining fuel quality surveys, and corresponds to an adjustment a refiner could make to replace the octane value in 10 percent oxygenate in RFG. As the ethanol quantity was stepped down, aromatics were added proportionally. This addition was done incrementally to find the point where annual average MSAT1 total toxics compliance would be just met. The results are presented below in Table 2.1-9.

This analysis did not make changes to other gasoline parameters. Discussion of changes to other fuel parameters, and their relationship to the RFG VOC standard, can be found in Section 2.2.4. We expect that for some refiners, their toxics standard would limit their ability to remove oxygenate from their gasoline, while for others the VOC standard would be more restrictive. More rigorous refinery modeling work is underway that will provide further details for the final rulemaking; therefore the analysis presented in this section should be considered an estimate.

Table 2.1-9.
Fuel Parameter Adjustments for "Min-RFG" Estimation

	2001-02 wt% Oxygen[a]	Estimated 2012 wt% Oxygen[b]
Summer		
PADD 1	2.12	0.35
PADD 2	3.25	0.00
PADD 3	2.13	0.00
Winter		
PADD 1	1.93	3.50
PADD 2	3.18	0.00
PADD 3	1.99	0.70
Annual		
PADD 1	2.01	2.13
PADD 2	3.20	0.00
PADD 3	2.06	0.36

[a] PADD 1 & 3 oxygenate was primarily MTBE and TAME during this time period, while PADD 2 used primarily ethanol.
[b] All future oxygenate is assumed to be ethanol.

With respect to PADD 1, Table 2.1-9 shows that next to zero oxygen (as ethanol) would be required in summertime RFG and 3.5 weight percent (10 percent ethanol in every batch) would be required in wintertime RFG. Accordingly, PADD 1 RFG has been assigned ethanol blending market shares of zero percent in the summer and 100 percent in the winter (shown in Table 2.1-10).

With respect to PADD 2, Table 2.1-9 shows that no oxygen would be required in RFG to meet MSAT1 requirements. However, while this analysis suggests that PADD 2 RFG could go without oxygenate in the future, ethanol blending is expected to occur due to proximity to ethanol production and desire to support local economies. Ethanol blending is expected to be lower in the summer compared to the winter due to economic penalties associated with summertime ethanol blending (necessity to remove butanes and pentanes to meet RVP requirements). Accordingly, PADD 2 RFG has been assigned ethanol blending market shares of 50 percent in the summer and 100 percent in the winter (shown in Table 2.1-10).

With respect to PADD 3, Table 2.1-9 shows that no oxygen would be required in summertime RFG and 0.7 weight percent would be required in wintertime RFG. Accordingly, PADD 3 RFG has been assigned ethanol blending market shares of zero percent in the summer and 25 percent in the winter (shown in Table 2.1-10).

A separate approach was used to determine the minimum ethanol blending market shares for California "RFG" (Federal RFG and California Phase 3 RFG) and Arizona "RFG" (Arizona CBG in Phoenix Metropolitan Area). In 2001, MathPro Inc. conducted a study to determine the amount of ethanol blending expected to occur in California Phase 3 Reformulated Gasoline (CaRFG3) under an oxygen waiver.[38] MathPro concluded that ethanol blending in CaRFG3 would be in the range of 25 to 65 percent (E5.7). For the purpose of this analysis, we assumed that the entire State of California would behave uniformly or more specifically like CaRFG3. Thus, we applied the MathPro range to all California gasoline (both Federal RFG and CaRFG3). We assumed that minimum California ethanol blending would be 25 percent (E5.7) in the summertime (as suggested by the lower limit of the study). However, instead of selecting 65 percent in the wintertime (to match the upper limit of the study) we selected a higher value (100 percent) based on increased crude oil prices, increased ethanol availability (since 2001), and favorability based on existing infrastructure. Accordingly, California "RFG" has been assigned ethanol blending market shares of 25 percent (E5.7) in the summer and 100 percent (E5.7) in the winter (shown in Table 2.1-10).

Finally, we assumed that Arizona "RFG" would be governed by winter oxy-fuel requirements (Phoenix CBG is also covered by state oxy-fuel program). As such, we assumed that all wintertime Arizona "RFG" would contain 10 percent ethanol. With respect to summertime fuel, we assumed that Arizona "RFG" would be comprised of 2/3 CA "RFG" and 1/3 PADD 3 RFG. These seasonal assumptions are identical to the 2004 base case methodology described in Section 2.1.2.1. However, in the future, the gasoline received from California is assumed to be a single fuel to minimize the number of gasoline blends shipped via pipeline and the predominant fuel available in California (75% of summer California fuel contains no ethanol according to Table 2.1-10). As a result, no Arizona "RFG" would contain ethanol in the summer (2/3 x 0 percent from CA and 1/3 x 0 percent from PADD 3). Accordingly, Arizona "RFG" has been assigned ethanol blending market shares of 0 percent (E5.7) in the summer and 100 percent (E10) in the winter (shown in Table 2.1-10).

Table 2.1-10. 2012 RFG Area Assumptions

	ETOH-Blended Gasoline (% Market Share)[a]			
	Min-RFG Scenario		Max-RFG Scenario	
RFG Areas	Summer	Winter	Summer	Winter
PADD 1	0%	100%	100%	100%
PADD 2	50%	100%	100%	100%
PADD 3	0%	25%	100%	100%
California[b]	25%	100%	100%	100%
Arizona[c]	0%	100%	100%	100%

[a] Percent marketshare of E10, with the exception of California (E5.7 year-round) and Arizona (E5.7 summer only)

[b] Pertains to both Federal RFG and California Phase 3 RFG

[c] Pertains to Arizona Clean Burning Gasoline (CBG)

2.1.4.3 Forecast for CG Ethanol Use

Once we determined the range of potential ethanol use in RFG (by PADD), we needed a systematic way to allocate the remaining ethanol into CG areas. 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.[39]

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.[40] 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). Unfortunately, at the time of this analysis we had not yet completed the production analysis to better understand where the future ethanol plants would be located. However, while the results of the production analysis do not completely coincide with this assumption (as shown in Table 1.2-14, only 92 percent of the total anticipated plant capacity would actually come from PADD 2 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 2.1-11 shows the gasoline price and ethanol distribution cost for each state as used in this analysis.

Table 2.1-11. Gasoline Price & Ethanol Distribution Costs

State	CD	Gasoline Rack Price (c/gal)	Ethanol Distribution Cost (c/gal)
Alabama	6	123.2	7.2
Alaska	9	157.0	41.5
Arizona	8	138.0	15.4
Arkansas	7	123.3	7.3
California	9	142.1	16.5
Colorado	8	129.5	10.4
Connecticut	1	No CG sold	11.4
DC	5	No CG sold	11.4
Delaware	5	No CG sold	11.4
Florida	5	124.9	8.4
Georgia	5	125.8	11.4
Hawaii	9	151.7	36.5
Idaho	8	134.2	15.4
Illinois	3	125.7	4.4
Indiana	3	125.6	5.4
Iowa	4	127.5	3.4
Kansas	4	124.3	4.4
Kentucky	6	125.9	6.2
Louisiana	7	123.1	7.3
Maine	1	125.5	13.4
Maryland	5	124.8	11.4
Massachusetts	1	No CG sold	11.4
Michigan	3	126.5	6.4
Minnesota	4	127.4	4.4
Mississippi	6	123.0	6.2
Missouri	4	126.0	4.4
Montana	8	130.5	13.4
Nebraska	4	126.0	4.4
Nevada	8	141.6	16.4
New Hampshire	1	125.3	12.4
New Jersey	2	No CG sold	11.4
New Mexico	8	128.4	12.4
New York	2	126.0	11.4
North Carolina	5	124.4	11.4
North Dakota	4	127.7	5.4
Ohio	3	126.2	5.4
Oklahoma	7	123.4	8.3
Oregon	9	133.8	16.5
Pennsylvania	2	126.1	8.4
Rhode Island	1	No CG sold	11.4
South Carolina	5	124.9	11.4
South Dakota	4	127.8	4.4
Tennessee	6	124.5	6.2
Texas	7	122.5	10.3
Utah	8	132.3	13.4
Vermont	1	127.3	12.4
Virginia	5	123.4	11.4
Washington	9	132.1	16.5
West Virginia	5	125.8	11.4
Wisconsin	3	125.2	4.4
Wyoming	8	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.[Y] [41]

In addition to state subsidies, small penalty adjustments were made for distributing ethanol into rural areas in several states. These are given in Table 2.1-12. 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. Based on these considerations, 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 navigable water access on one or more sides. The states that do not appear on this list of adjustments were generally in the Midwest where ethanol is produced and were not believed to have significant differences in rural and urban distribution costs.

Table 2.1-12.
Adjustment for Ethanol Distribution into Rural Areas

States	Rural Area Adjustment (c/gal)
OH	1
AK, AL, AR, FL, GA, KY, LA, MD, ME, MS, NC, NH, NY, OK, OR, PA, SC, TN, TX, VA, VT, WA, WV	2
AZ, CO, ID, NM, NV, UT, WY	3

The resulting ranking system for distributing ethanol into conventional gasoline by state and region is summarized below in Table 2.1-13. The amount of ethanol leftover after filling both RFG (according to RFG assumption Table 2.1-10) and winter oxy-fuel (discussed below in Section 2.1.4.4), determined the cut off point or last state to receive ethanol in conventional gasoline.

[Y] 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 seemed likely to be applicable in 2012.

Table 2.1-13. 2012 Precedence for Adding ETOH to Conventional Gasoline

Rank	State[a]	Region[b]	Rank	State[a]	Region[b]
1	IA	All	37	ID	Rural
2	SD	All	38	LA	Urban
3	IL	All	39	PA	Rural
4	NV	Urban (s)	40	WA	Urban
5	AZ	Urban (s)	41	AK	Urban
6	ND	All	42	OR	Rural
7	NV	Rural	43	WY	Rural
8	MO	All	44	VT	Urban
9	NE	All	45	MS	Rural
10	OH	Urban	46	OK	Rural
11	WI	All	47	NY	Urban
12	IN	All	48	FL	Rural
13	MI	All	49	GA	Urban
14	KS	All	50	WV	Urban
15	OH	Rural	51	AR	Rural
16	KY	Urban	52	AL	Rural
17	AZ	Rural	53	LA	Rural
18	ME	Urban	54	WA	Rural
19	CO	Urban	55	AK	Rural
20	UT	Urban	56	SC	Urban
21	ID	Urban	57	MD	Urban
22	TN	Urban	58	NM	Rural
23	WY	Urban	59	NC	Urban
24	KY	Rural	60	NH	Urban
25	PA	Urban	61	VT	Rural
26	ME	Rural	62	NY	Rural
27	OR	Urban (s)	63	GA	Rural
28	MS	Urban	64	WV	Rural
29	OK	Urban	65	TX	Urban (s)
30	FL	Urban	66	VA	Urban
31	TN	Rural	67	SC	Rural
32	CO	Rural	68	MD	Rural
33	NM	Urban (s)	69	NC	Rural
34	AR	Urban	70	NH	Rural
35	AL	Urban	71	TX	Rural
36	UT	Rural	72	VA	Rural

[a] MN, HI, and MT are not included on the CG order of precedence table because they have state mandates requiring ETOH in all gasoline. WA is included because their state mandate only accounts for 20% of their fuel.

[b] With respect to state ethanol distribution, "all" means the entire state fills with ethanol at the same precedence level, whereas "urban" and "rural" imply that these regions fill separately. An (s) next to urban refers to summer gasoline only (winter is covered by respective state oxy-fuel programs).

2.1.4.4 Forecast for Winter Oxy-fuel Ethanol Use

In the 2004 base case, there were 14 state-implemented winter oxy-fuel programs in 11 states (summarized previously in Table 2.1-2). Of these programs, 9 were required in response to non-attainment with the CO National Ambient Air Quality Standards (NAAQS) and 4 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[Z]. These areas are: Anchorage, AK; Las Vegas, NV; Provo/Orem, UT; and Spokane, WA. In addition, 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 oxyfuel areas in Tuscon and Phoenix, AZ; Los Angeles, CA; Missoula, MT; Reno, NV; Albuquerque, NM; Portland, OR; and El Paso, TX. We assumed that these remaining areas would continue to use 10 percent ethanol for their entire winter oxy-fuel period (duration varies by area, six month maximum) in the 2012 control cases.

2.1.4.5 2012 Forecasted Ethanol Consumption by Season

In 2012, for the purpose of this analysis, we have assumed that 45 percent of the gasoline would be consumed in the summertime and 55 percent would be consumed in the wintertime[AA]. Additionally, we made the assumption that 100 percent of the winter oxy-fuel would be consumed in the wintertime. Applying the RFG assumptions along with the CG order of precedence, the resulting seasonal ethanol use for the four 2012 control cases is shown below in Table 2.1-14.

Table 2.1-14. 2012 Forecasted Ethanol Consumption by Season

	Ethanol Consumption (MMgal)						
	CG		OXY[a]	RFG[b]		Total	
2012 Control Case	Summer	Winter	Winter	Summer	Winter	Summer	Winter
7.2 Bgal / Max-RFG	1,269	1,537	72	1,932	2,389	3,201	3,999
7.2 Bgal / Min-RFG	2,144	2,571	72	244	2,168	2,388	4,812
9.6 Bgal / Max-RFG	2,356	2,830	73	1,941	2,400	4,297	5,303
9.6 Bgal / Min-RFG	3,223	3,881	73	246	2,178	3,468	6,132

[a] Winter oxy-fuel programs

[b] Federal RFG plus CA Phase 3 RFG and Arizona CBG

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

[AA] We acknowledge that the volumetric seasonal split used in this analysis may or may not correspond with 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). However, we believe it is a reasonable assumption for this analysis.

2.1.4.6 2012 Gasoline/Oxygenate Consumption by Fuel Type

7.2 Bgal / Max-RFG Control Case

In 2012, when modeling the minimum or “floor” amount of ethanol (7.2 billion gallons) coupled with the “Max-RFG” assumption, there was only 2.9 billion gallons leftover to fill conventional gasoline. After satisfying state mandates and winter oxy-fuel requirements, this left 1.8 billion gallons to be used in the CG pool. This leftover ethanol filled about two thirds (by volume) of PADD 2 conventional gasoline and made its way to the State of Kansas (Rank #14 on the CG order of precedence table), filling 29 percent of the state’s CG before reaching the 1.8 billion gallon amount (7.2 billion gallons total). A summary of the ethanol consumption by fuel type and PADD is found in Table 2.1-15. Additionally, a summary of ethanol consumption by state is found in Table 2.1-19 and a graphical representation (by season) is found in Figures 2.1-3 and 2.1-4.

Table 2.1-15. 2012 Ethanol Consumption by Fuel Type (MMgal)
7.2 Bgal / Max-RFG Control Case

	CG		OXY[a]	RFG[b]		
PADD	**Summer**	**Winter**	**Winter**	**Summer**	**Winter**	**Total**
PADD 1	0	0	0	956	1,168	2,124
PADD 2	1,144	1,398	0	274	335	3,151
PADD 3	0	0	24	241	295	560
PADD 4	25	30	1	0	0	56
PADD 5[c]	100	109	47	31	66	353
California	0	0	0	430	525	955
Total	**1,269**	**1,537**	**72**	**1,932**	**2,389**	**7,200**

[a] Winter oxy-fuel programs

[b] Federal RFG plus CA Phase 3 RFG and Arizona CBG

[c] PADD 5 excluding California

7.2 Bgal / Min-RFG Control Case

In 2012, when modeling the 7.2 billion gallon case coupled with the “Min-RFG” assumption, there was 4.8 billion gallons leftover to fill conventional gasoline. After satisfying state mandates and winter oxy-fuel requirements, this left 3.7 billion gallons to be used in the CG pool. This leftover ethanol filled an even larger portion of PADD 2 conventional gasoline than in the 7.2 Bgal / Max-RFG control case (91 percent by volume compared to 67 percent). Further, the ethanol made its way to the urban portion of Florida (Rank #30 on the CG order of precedence table), filling 24 percent of the state’s CG before reaching the 3.7 billion gallon amount (7.2 billion gallons total). A summary of the ethanol consumption by fuel type and PADD is found in Table 2.1-16. Additionally, a summary of ethanol consumption by state is found in Table 2.1-19 and a graphical representation (by season) is found in Figures 2.1-5 and 2.1-6.

Table 2.1-16. 2012 Ethanol Consumption by Fuel Type/PADD (MMgal)
7.2 Bgal / Min-RFG Control Case

	CG		OXY[a]	RFG[b]		
PADD	**Summer**	**Winter**	**Winter**	**Summer**	**Winter**	**Total**
PADD 1	231	283	0	0	1,168	1,682
PADD 2	1,544	1,888	0	137	335	3,904
PADD 3	41	50	24	0	74	188
PADD 4	150	182	1	0	0	334
PADD 5[c]	177	169	47	0	66	459
California	0	0	0	107	525	633
Total	**2,144**	**2,571**	**72**	**244**	**2,168**	**7,200**

[a] Winter oxy-fuel programs

[b] Federal RFG plus CA Phase 3 RFG and Arizona CBG

[c] PADD 5 excluding California

9.6 Bgal / Max-RFG Control Case

In 2012, when modeling the maximum or "ceiling" amount of ethanol (9.6 billion gallons) coupled with the "Max-RFG" assumption, there was a significant amount of ethanol leftover (about 5.3 billion gallons) to fill conventional gasoline. After satisfying state mandates and winter oxy-fuel requirements, this left 4.2 billion gallons to be used in the CG pool. This leftover ethanol filled an even larger portion of PADD 2 conventional gasoline than the 7.2 Bgal / Min-RFG control case (97 percent by volume compared to 91 percent). Further, the ethanol made its way to the rural portion of Colorado (Rank #32 on the CG order of precedence table), filling 80 percent of the state's CG reaching the 4.2 billion gallon amount (9.6 billion gallons total). A summary of the ethanol consumption by fuel type and PADD is found in Table 2.1-17. Additionally, a summary of ethanol consumption by state is found in Table 2.1-19 and a graphical representation (by season) is found in Figures 2.1-7 and 2.1-8.

Table 2.1-17. 2012 Ethanol Consumption by Fuel Type/PADD (MMgal)
9.6 Bgal / Max-RFG Control Case

	CG		OXY[a]	RFG[b]		
PADD	**Summer**	**Winter**	**Winter**	**Summer**	**Winter**	**Total**
PADD 1	345	421	0	960	1,173	2,900
PADD 2	1,634	1,997	0	275	336	4,243
PADD 3	41	50	24	243	296	654
PADD 4	158	192	1	0	0	352
PADD 5[c]	178	170	48	31	66	492
California	0	0	0	432	528	960
Total	**2,356**	**2,830**	**73**	**1,941**	**2,400**	**9,600**

[a] Winter oxy-fuel programs

[b] Federal RFG plus CA Phase 3 RFG and Arizona CBG

[c] PADD 5 excluding California

9.6 Bgal / Min-RFG Control Case

In 2012, when modeling the 9.6 billion gallon case coupled with the "Min-RFG" assumption, there was a maximum amount of ethanol leftover (about 7.2 billion gallons) to fill conventional gasoline. After satisfying state mandates and winter oxy-fuel requirements, this left 6.1 billion gallons to be used in the CG pool. The leftover ethanol filled PADD 2 conventional gasoline entirely and made its way to the urban portion of Georgia (Rank #49 on the CG order of precedence table), filling 26 percent of the state's CG before reaching the 6.1 billion gallon amount (9.6 billion gallons total). A summary of the ethanol consumption by fuel type and PADD is found in Table 2.1-18. Additionally, a summary of ethanol consumption by state is found in Table 2.1-19 and a graphical representation (by season) is found in Figures 2.1-9 and 2.1-10.

Table 2.1-18. 2012 Ethanol Consumption by Fuel Type/PADD (MMgal)
9.6 Bgal / Min-RFG Control Case

	CG		OXY[a]	RFG[b]		
PADD	**Summer**	**Winter**	**Winter**	**Summer**	**Winter**	**Total**
PADD 1	788	963	0	0	1,173	2,925
PADD 2	1,689	2,064	0	138	336	4,226
PADD 3	243	288	24	0	74	629
PADD 4	230	280	1	0	0	511
PADD 5[c]	273	286	48	0	66	672
California	0	0	0	108	528	636
Total	**3,223**	**3,881**	**73**	**246**	**2,178**	**9,600**

[a] Winter oxy-fuel programs

[b] Federal RFG plus CA Phase 3 RFG and Arizona CBG

[c] PADD 5 excluding California

2.1.4.7 2012 Gasoline/Oxygenate Consumption by State

A summary of each state's total ethanol consumption for each of the four 2012 control cases is found below in Table 2.1-19. Additionally Figures 2.1-3 through 2.1-10 graphically show the percent ethanol use by state for each of the control cases broken down by season (summer versus winter).

Table 2.1-19. 2012 Ethanol Consumption by State

	7.2 Bgal / Max-RFG		7.2 Bgal / Min-RFG		9.6 Bgal / Max-RFG		9.6 Bgal / Min-RFG	
State	**MMgal**	**%**	**MMgal**	**%**	**MMgal**	**%**	**MMgal**	**%**
Alabama	0	0.0%	0	0.0%	0	0.0%	135	5.0%
Alaska	0	0.0%	0	0.0%	0	0.0%	17	5.0%
Arizona	113	4.6%	191	7.8%	223	9.1%	192	7.8%
Arkansas	0	0.0%	0	0.0%	0	0.0%	79	5.0%
California	955	5.8%	633	3.8%	960	5.8%	636	3.8%
Colorado	0	0.0%	163	7.3%	180	8.0%	225	10.0%
Connecticut	171	10.0%	94	5.5%	171	10.0%	94	5.5%
Delaware	50	10.0%	28	5.5%	50	10.0%	28	5.5%
District of Columbia	13	10.0%	7	5.5%	13	10.0%	7	5.5%
Florida	0	0.0%	233	2.4%	484	5.0%	968	10.0%
Georgia	0	0.0%	0	0.0%	0	0.0%	138	2.6%
Hawaii	51	10.0%	51	10.0%	51	10.0%	51	10.0%
Idaho	0	0.0%	35	5.0%	36	5.0%	71	10.0%
Illinois	580	10.0%	502	8.6%	582	10.0%	504	8.6%
Indiana	343	10.0%	332	9.7%	344	10.0%	333	9.7%
Iowa	183	10.0%	183	10.0%	184	10.0%	184	10.0%
Kansas	46	2.9%	156	10.0%	157	10.0%	157	10.0%
Kentucky	56	2.3%	231	9.5%	245	10.0%	232	9.5%
Louisiana	0	0.0%	0	0.0%	0	0.0%	129	5.0%
Maine	0	0.0%	85	10.0%	85	10.0%	85	10.0%
Maryland	247	8.9%	136	4.9%	248	8.9%	136	4.9%
Massachusetts	329	10.0%	181	5.5%	330	10.0%	182	5.5%
Michigan	544	10.0%	544	10.0%	547	10.0%	547	10.0%
Minnesota	301	10.0%	301	10.0%	302	10.0%	302	10.0%
Mississippi	0	0.0%	91	5.0%	91	5.0%	182	10.0%
Missouri	354	10.0%	334	9.4%	355	10.0%	335	9.4%
Montana	56	10.0%	56	10.0%	57	10.0%	57	10.0%
Nebraska	92	10.0%	92	10.0%	92	10.0%	92	10.0%
Nevada	96	10.0%	96	10.0%	96	10.0%	96	10.0%
New Hampshire	58	7.4%	32	4.1%	58	7.4%	32	4.1%
New Jersey	474	10.0%	261	5.5%	477	10.0%	262	5.5%
New Mexico	9	0.8%	9	0.8%	9	0.8%	16	1.5%
New York	337	5.4%	186	2.9%	339	5.4%	333	5.3%
North Carolina	0	0.0%	0	0.0%	0	0.0%	0	0.0%
North Dakota	39	10.0%	39	10.0%	39	10.0%	39	10.0%
Ohio	289	5.0%	577	10.0%	580	10.0%	580	10.0%
Oklahoma	0	0.0%	121	5.0%	121	5.0%	243	10.0%
Oregon	34	2.1%	63	3.7%	63	3.7%	169	10.0%
Pennsylvania	144	2.7%	275	5.1%	341	6.3%	473	8.8%
Rhode Island	55	10.0%	30	5.5%	55	10.0%	30	5.5%
South Carolina	0	0.0%	0	0.0%	0	0.0%	0	0.0%
South Dakota	49	10.0%	49	10.0%	49	10.0%	49	10.0%
Tennessee	0	0.0%	182	5.0%	366	10.0%	366	10.0%
Texas	551	4.1%	88	0.7%	554	4.1%	89	0.7%
Utah	0	0.0%	61	5.0%	62	5.0%	123	10.0%
Vermont	0	0.0%	0	0.0%	0	0.0%	19	5.0%
Virginia	246	5.6%	135	3.1%	247	5.6%	136	3.1%
Washington	59	2.0%	59	2.0%	59	2.0%	147	5.0%
West Virginia	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Wisconsin	277	10.0%	261	9.4%	278	10.0%	262	9.4%
Wyoming	0	0.0%	17	5.0%	17	5.0%	35	10.0%
Total	**7,200**	**4.7%**	**7,200**	**4.7%**	**9,600**	**6.3%**	**9,600**	**6.3%**

Figure 2.1-3. 2012 7.2 Bgal / Max-RFG Summer Ethanol Distribution (% ETOH by State)

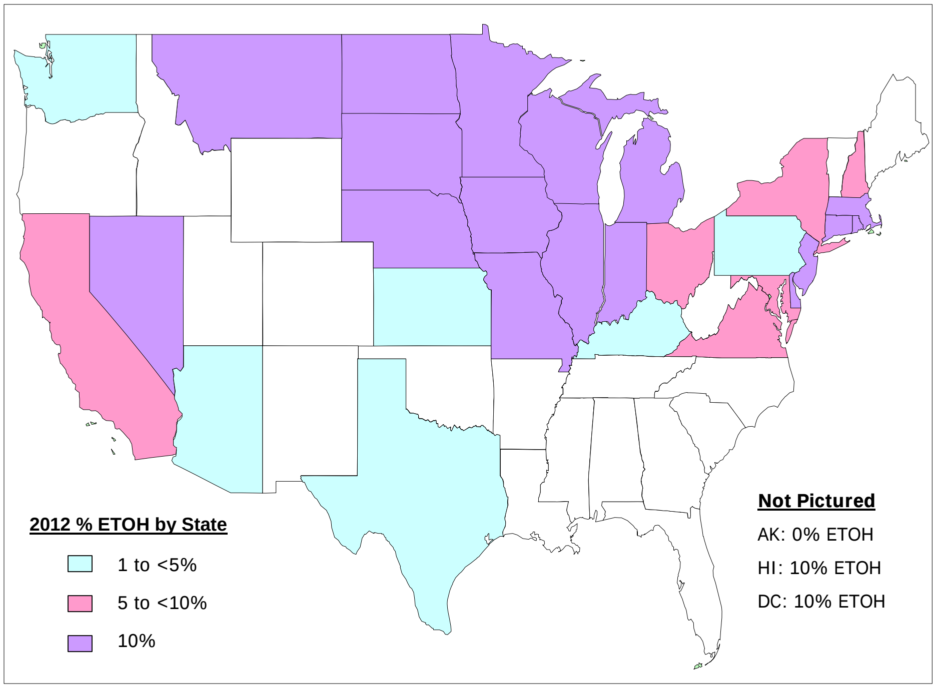


Figure 2.1-4. 2012 7.2 Bgal /Max-RFG Winter Ethanol Distribution (% ETOH by State)

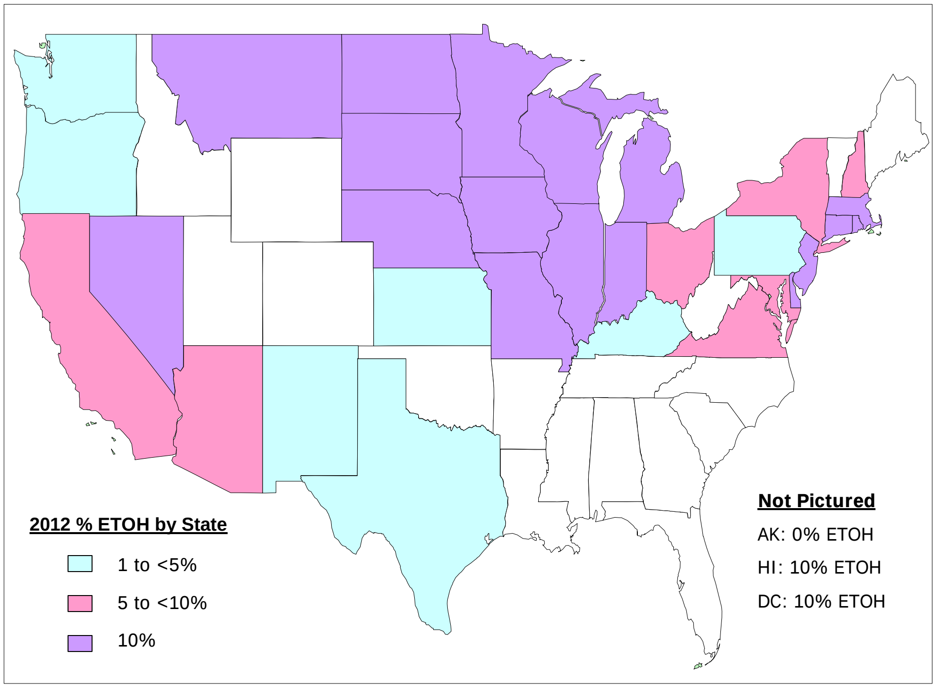


Figure 2.1-5. 2012 7.2 Bgal / Min-RFG Summer Ethanol Distribution (% ETOH by State)

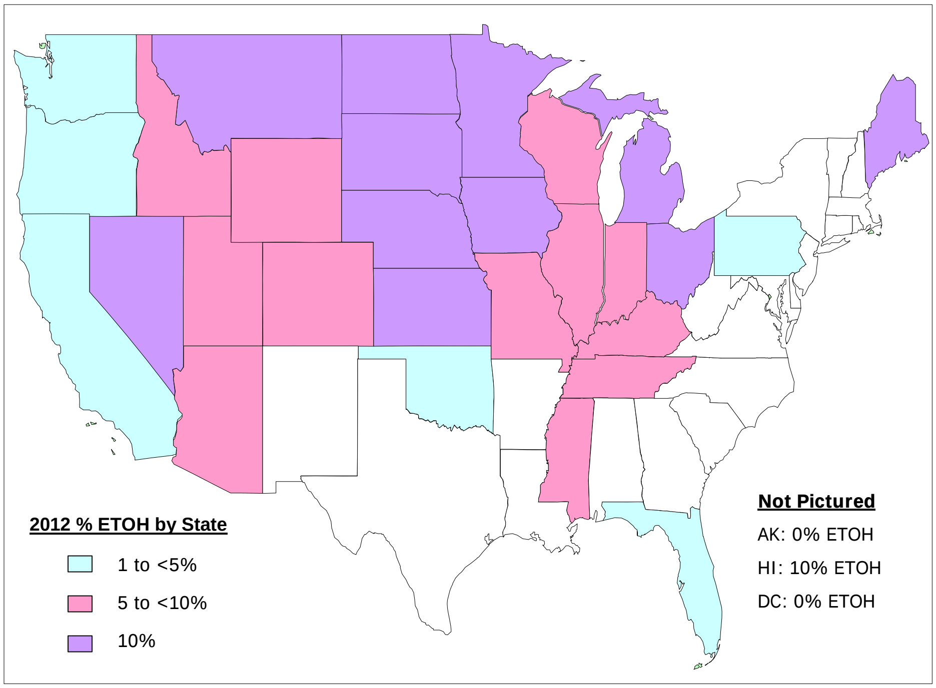


Figure 2.1-6. 2012 7.2 Bgal / Min-RFG Winter Ethanol Distribution (% ETOH by State)

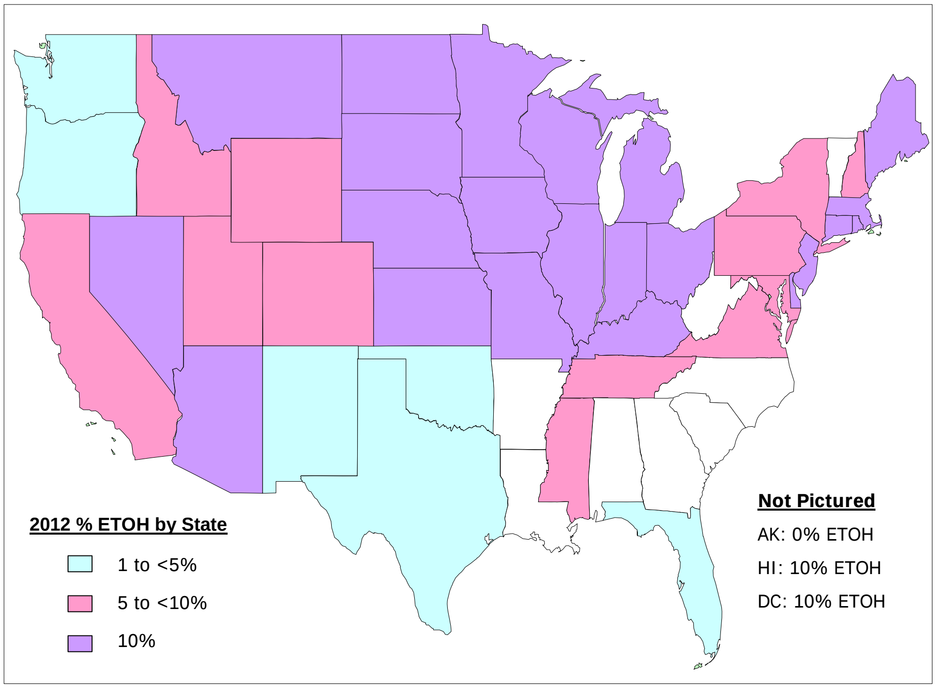


Figure 2.1-7. 2012 9.6 Bgal / Max-RFG Summer Ethanol Distribution (% ETOH by State)

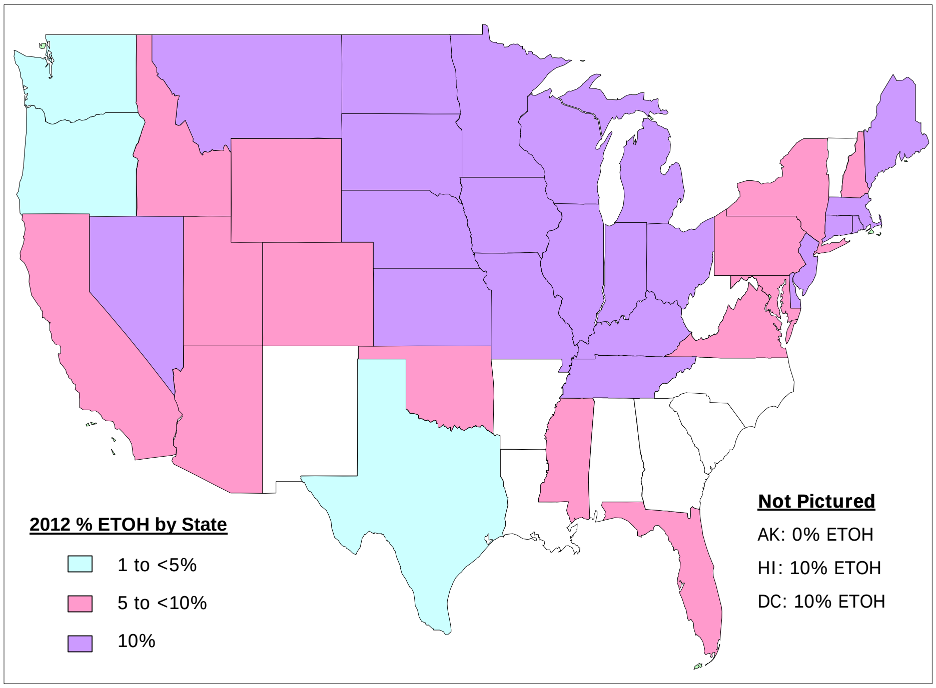


Figure 2.1-8. 2012 9.6 Bgal / Max-RFG Winter Ethanol Distribution (% ETOH by State)

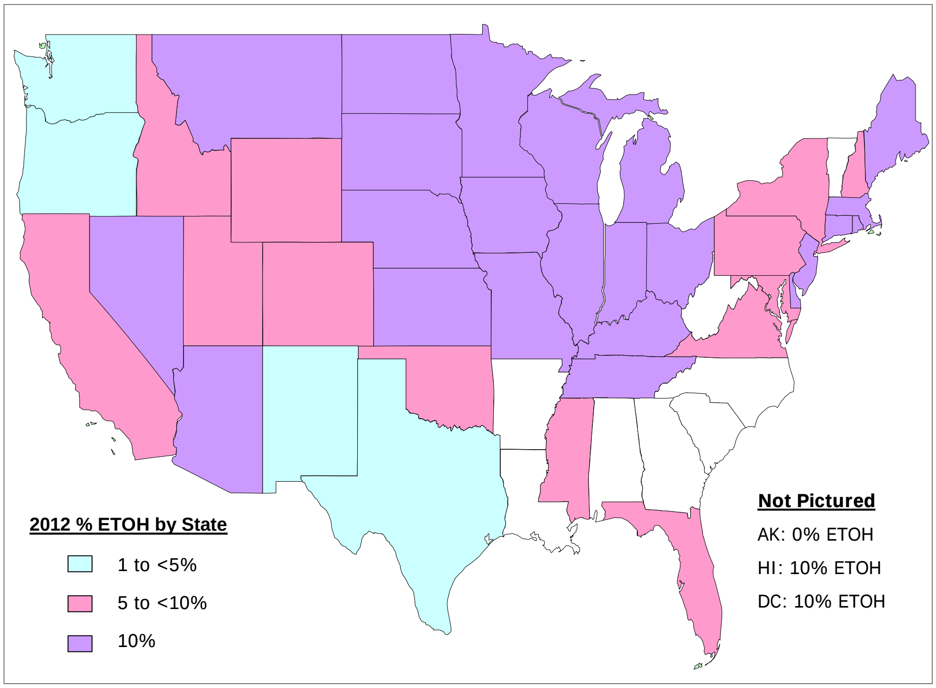


Figure 2.1-9. 2012 9.6 Bgal / Min-RFG Summer Ethanol Distribution (% ETOH by State)

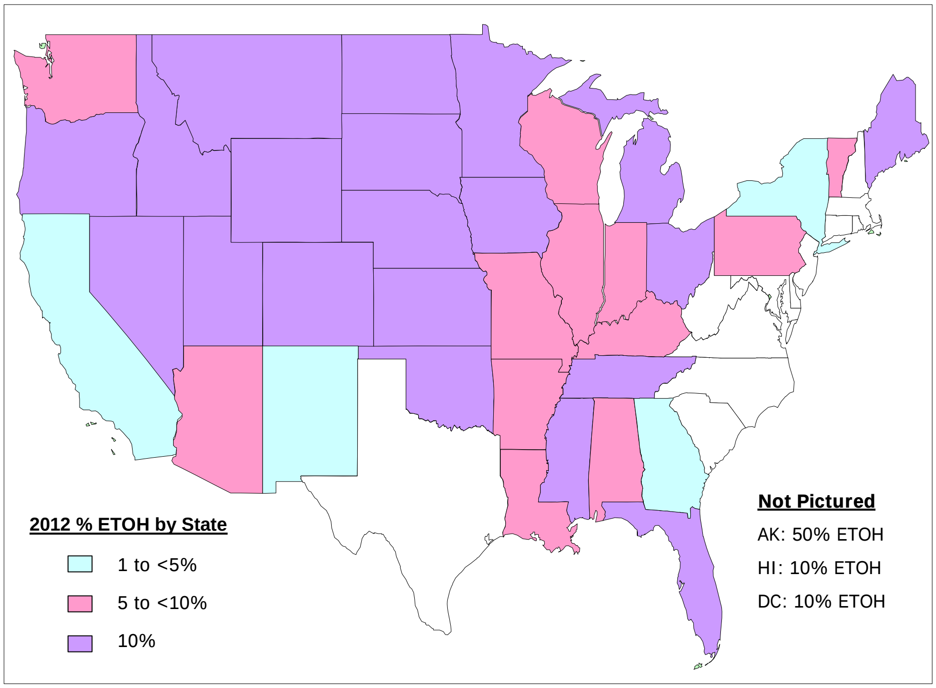
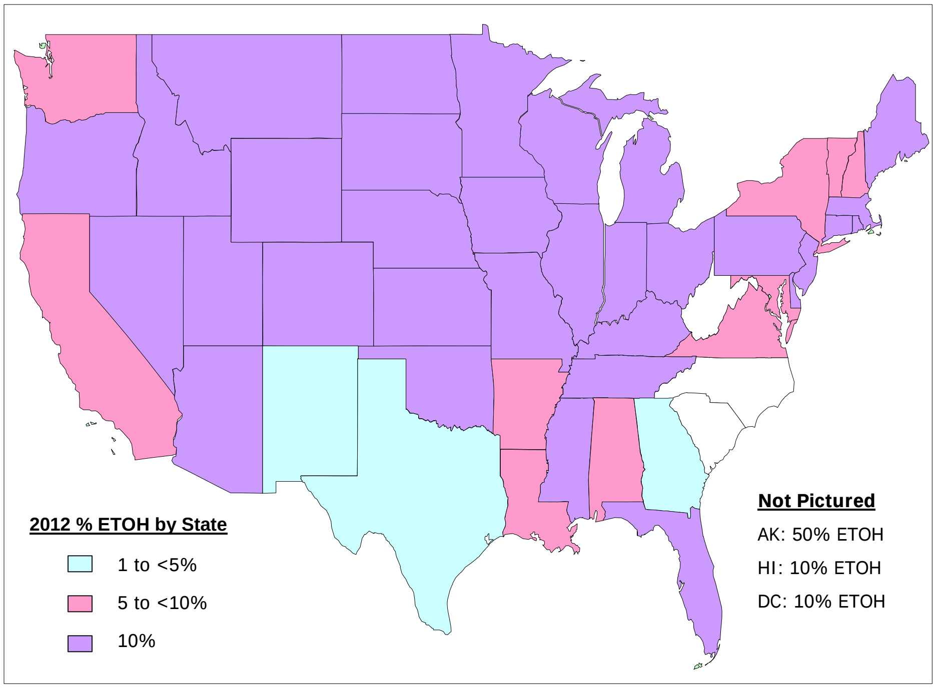


Figure 2.1-10. 2012 9.6 Bgal / Min-RFG Winter Ethanol Distribution (% ETOH by State)



2.2 Effects of Ethanol and MTBE on Gasoline Fuel Properties

2.2.1 Effect of Ethanol on Conventional Gasoline Fuel Properties

Gasoline fuel properties include parameters such as aromatics and olefins levels, and vapor pressure. When ethanol is added to gasoline, it modifies these properties. The changes in these properties are not simply a factor of how much ethanol is added to gasoline, but can also depend on changes made to the hydrocarbon portion of the blend which the refiner may have made in anticipation of ethanol blending. Two methods by which ethanol is added to gasoline include splash-blending and match-blending. In splash-blending, ethanol is typically added to gasoline in a fuel delivery truck containing gasoline that otherwise meets all applicable specifications. The finished blend is a product of the controlled volumes of ethanol and gasoline, but properties of the gasoline portion of the finished blend were not specifically designed for ethanol blending. Splash-blending is a common method by which ethanol is added to conventional gasoline (CG), since EPA regulations allow it. Only a few states require that conventional gasoline with ethanol meet the same RVP standards as gasoline. This effectively prohibits splash-blending, since splash-blending increases RVP by roughly 1.0 psi.

The downside to splash-blending is that the ethanol blend contains more octane than the original gasoline. While some of the value of this octane increase can be recovered by increasing the grade of the ethanol blend from regular to midgrade or midgrade to premium, practically, this can only be done for a fraction of the gasoline. Thus, splash-blending tends to give away octane value. The alternative is to match-blend the ethanol. With match-blending, the refiner produces a hydrocarbon component which is designed to meet applicable gasoline specifications after 10 vol% ethanol has been added. Thus, this hydrocarbon component can have a lower octane value than required for finished gasoline. The downside to match-blending is that the low octane hydrocarbon component must be distributed separately from finished gasoline and it must be blended with ethanol prior to sale.

Historically, most ethanol has been splash-blended into conventional gasoline. However, whenever the market share of ethanol blending reaches a sufficient level, refiners serving that market tend to supply a sub-octane gasoline for match-blending with ethanol. With the dramatic increase in ethanol blending already occurring, plus that which is anticipated over the next several years, we believe that most ethanol will be match-blended into gasoline to allow refiners to reduce their octane requirements. Due to the way in which gasoline is refined, this has the beneficial side effect of increasing the total supply of hydrocarbon gasoline.

Reformulated gasoline (RFG) requires more precise control of fuel properties, such as vapor pressure. This control can only be, and has historically been, achieved through match-blending.

Our purpose in this section is to estimate the impact of blending ethanol on the properties of both CG and RFG. Typically, EPA has estimated such impacts using refinery linear programming models. These models simulate the feedstocks and chemical processes used in refineries and determine the types of processes needed to produce specific quantities of finished products and their properties. As discussed in Chapter 7, EPA is currently conducting such modeling via contract. The results of this modeling will be completed in time for use in the analyses supporting the final RFS rule. In addition, past refinery modeling does not sufficiently reflect the conditions now existing (such as high crude oil prices), nor the specific volumes of ethanol expected to occur in the future. Thus, in the absence of such refinery modeling, we opted to analyze empirical gasoline property data available through annual fuel survey data conducted by the Alliance of Automobile Manufacturers (AAM).[42] The AAM data reflect the properties of gasoline from many refineries and in many geographic locations. By investigating the relationship between ethanol content and other fuel properties used in emission inventory models, we can predict the changes in gasoline quality which will occur with increased use of ethanol and the resultant changes in in-use emissions. For the final rule analysis, we plan to update these estimates using the refinery modeling which will then be complete.

The first step in assessing the effect of ethanol content on gasoline properties was to determine which of the AAM data to consider. The AAM reports include fuel sample data from across North America. Given the focus of our analysis is ethanol blending in the U.S., we decided to only use the data for the 26 U.S. cities represented in the survey, thereby excluding data from Canada and Mexico. We then examined the data in order to identify those cities which had data for both ethanol and non-ethanol blends. We could have simply averaged all of the data for ethanol and non-ethanol blends and compared the two results. However, this comparison is likely to include factors which affect fuel quality other than simply the addition of ethanol (e.g., regional differences in crude oil quality and refinery configuration). Even restricting the comparison to ethanol and non-ethanol blends likely includes differences between specific refineries serving the same city. However, this potentially confounding factor cannot be avoided in this type of analysis.

Specifically, we counted the number of winter and summer samples in each city, as well as the number of samples in each season near 10 vol% ethanol content (E10) and the number of samples at or near 0 vol% ethanol content (E0). (We considered any gasoline that contained less than 5 vol% ethanol as being representative of E0, and gasoline that contained 5 vol% or more ethanol as being representative of E10.) The number of samples according to this breakdown is shown in Table 2.2-1.

Table 2.2-1. Number of Fuel Samples Collected in AAM Fuel Surveys, U.S. Cities, 2001-2005.

City	RFG Area	Total # of Samples	Number of Winter Samples			Number of Summer Samples		
			Winter Total	E10[a]	E0[b]	Summer Total	E10[a]	E0[b]
Albuquerque, NM		112	54	53	1	58	12	46
Atlanta, GA		202	104	0	104	98	0	98
Billings, MT		138	68	0	68	70	0	70
Boston, MA	Yes	183	92	6	86	91	0	91
Chicago, IL	Yes	154	78	78	0	76	76	0
Cleveland, OH		174	87	50	37	87	57	30
Dallas, TX		154	77	0	77	77	0	77
Denver, CO		180	92	92	0	88	47	41
Detroit, MI		191	93	23	70	98	26	72
Fairbanks, AK		80	40	0	40	40	0	40
Houston, TX	Yes	66	0	0	0	66	0	66
Kansas City, MO		154	74	0	74	80	1	79
Las Vegas, NV		162	80	80	0	82	5	77
Los Angeles, CA	Yes	151	76	41	35	75	46	29
Miami, FL		222	110	0	110	112	0	112
Minneapolis/St. Paul, MN		183	87	84	3	96	91	5
New Orleans, LA		168	85	0	85	83	0	83
New York City, NY	Yes	156	73	25	48	83	30	53
Philadelphia, PA	Yes	166	85	2	83	81	0	81
Phoenix, AZ	Yes	221	110	110	0	111	0	111
Pittsburgh, PA		69	0	0	0	69	11	58
San Antonio, TX		129	64	0	64	65	0	65
San Francisco, CA	Yes	166	83	37	46	83	43	40
Seattle, WA		151	77	16	61	74	14	60
St. Louis, MO	Yes	156	78	61	17	78	62	16
Washington, DC	Yes	183	92	0	92	91	0	91

[a] "E10," or 10 vol% ethanol, represents gasoline that contains 5 vol% or more ethanol.
[b] "E0," or 0 vol% ethanol, represents gasoline that contains less than 5 vol% ethanol.

We identified four cities that contained a reasonable number of E0 and E10 samples for each season. Cleveland (PADD 2), Detroit (PADD 2), Denver (PADD 4), and Seattle (PADD 5) met these criteria while representing various geographic and fuel-processing regions. Denver was an exception in that only the summer survey data showed a mix of fuels, since Denver has an oxygenated fuel mandate in the winter (i.e., there were no E0 samples in the winter months). Overall, very few of the data from any of the four cities deviated more than a few tenths of a percent from E0 and E10. The exception to this was Seattle, where 4 of the 16 winter data points were between 5 and 6 vol% ethanol. Table 2.2-2 shows the fuel properties for E0 and E10 for each city, by season.

Table 2.2-2. Effect of Ethanol Content on Gasoline Properties in Individual Cities

City	Season	Fuel Type	# Samples	T50 (°F)	T90 (°F)	E200 (%)	E300 (%)	Aromatics (Vol%)	Olefins (Vol%)	RVP (psi)	Octane (R+M)/2	Benzene (Vol%)
Cleveland, OH	Sum	E0	30	223	332	39.0	81.4	34.2	7.6	8.9	90.0	0.9
		E10	57	190	327	51.4	83.8	26.1	7.1	9.9	90.0	1.1
	Win	E0	37	208	326	46.6	83.5	24.0	22.3	--	89.4	0.9
		E10	50	163	320	57.4	85.8	19.9	16.0	--	90.6	1.0
Denver, CO	Sum	E0	41	212	330	44.5	82.6	29.1	9.5	8.3	86.9	1.4
		E10	47	178	319	54.8	85.7	23.4	9.2	9.3	86.7	1.5
	Win	E0	0	--	--	--	--	--	--	--	--	--
		E10	0	--	--	--	--	--	--	--	--	--
Detroit, MI	Sum	E0	72	220	338	41.0	80.3	32.2	6.5	7.5	89.8	1.2
		E10	26	202	332	48.8	82.7	27.1	7.5	8.7	90.4	1.0
	Win	E0	70	202	335	49.1	81.3	22.6	19.9	--	89.6	1.3
		E10	23	161	327	57.4	84.3	19.8	17.4	--	90.7	0.9
Seattle, WA	Sum	E0	60	218	326	40.4	83.1	32.5	8.0	7.6	89.5	1.5
		E10	14	195	324	51.0	84.6	29.9	5.4	8.7	89.9	1.6
	Win	E0	61	208	316	46.0	85.7	26.7	17.2	--	89.7	1.6
		E10	16	179	310	54.4	87.3	22.2	18.3	--	90.3	1.6

Conceivably, the effect of ethanol blending on gasoline properties could vary regionally. However, given the availability of comparable data in only four cities, none of which is located in the southern or northeastern U.S., we decided to combine the results for the four cities to develop a single set of fuel quality changes for the entire U.S. Table 2.2-3 shows the average fuel properties across the four cities, where the averages have been weighted by the number of samples from each city.

Table 2.2-3. Fuel Properties for E0 and E10 (Four-City Average)

Season	Fuel Type	T50 (°F)	T90 (°F)	E200 (%)	E300 (%)	Aromatics (Vol%)	Olefins (Vol%)	RVP (psi)	Octane (R+M)/2	Benzene (Vol%)
Summer	E0	218	332	41.2	81.8	32.0	7.7	7.9	89.2	1.3
	E10	189	325	52.0	84.3	25.8	7.7	9.4	89.0	1.3
Winter	E0	205	326	47.4	83.3	24.4	19.5	--	89.6	1.3
	E10	165	320	56.9	85.7	20.3	16.8	--	90.6	1.1

We then calculated the differences between the properties of E0 and E10 conventional gasoline. Table 2.2-4 shows how fuel properties change when adding ethanol to create a 10 vol% ethanol blend from gasoline with no ethanol.

Table 2.2-4. Change in Fuel Properties Due to Addition of Ethanol (E0 to E10)

Season	T50 (°F)	T90 (°F)	E200 (%)	E300 (%)	Aromatics (Vol%)	Olefins (Vol%)	RVP (psi)	Octane (R+M)/2	Benzene (Vol%)
Summer	-29	-7	10.8	2.6	-6.2	0.0	1.5	-0.2	0.0
Winter	-40	-6	9.5	2.4	-4.1	-2.7	--	1.0	-0.2

Finally, Table 2.2-5 averages the effects of Table 2.2-4, weighting the average by season (assuming five summer months and seven winter months). Where the final values in Table 2.2-5 indicate the changes in fuel properties as the level of ethanol in gasoline increases from 0 vol% to 10 vol%, we assumed adding smaller amounts of ethanol would simply change properties proportionally. Table 2.2-5 also includes the change in fuel property on a per vol% ethanol basis, which provides a useful factor for later adjustments to fuel properties based on changes in ethanol content. As will be discussed below, we assume that ethanol is always blended into conventional gasoline at 10 vol% (E10). Thus, the ethanol content of an area's gasoline is only less than 10 vol% when the E10 market share is less than 100%. In this case, simple linear interpolation of properties is reasonable.

Table 2.2-5.
Change in Properties of Conventional Gasoline Due to Addition of Ethanol

	T50 (°F)	T90 (°F)	E200 (%)	E300 (%)	Aromatics (Vol%)	Olefins (Vol%)	RVP (psi)	Octane (R+M)/2	Benzene (Vol%)	Oxygen (Wt%)
Change between E0 and E10	-36	-7	10.0	2.4	-5.0	-1.6	1.0[a]	0.5	-0.1	3.5
Change per 1 vol% increase in ethanol	-3.6	-0.7	1.0	0.24	-0.5	-0.16	--	0.05	-0.01	0.35

[a] Summer only. Based on average of city-specific differences shown in Table 2.2-2.

The first item to note about the differences shown in Table 2.2-5 is that the difference in octane ((R+M)/2) is 0.5. Splash-blending ethanol typically increases octane by 2 to 2.5 octane numbers. Thus, it appears that most of the ethanol blending being performed in these cities is match-blending. Our projection of match-blending for the future appears very reasonable in light of this. The presence of match-blending is also confirmed by the 5.0 vol% decrease in aromatic content. As indicated in Table 2.2-3, the aromatic content of non-oxygenated gasoline tends to average just under 30 vol%. Splashblending 10 vol% ethanol should reduce this value by 3 vol%. Reforming tends to be the refinery process which increases octane on the margin and does so by increasing the aromatic content. Thus, the fact that aromatics decreased by well above 3 vol% indicates a reduction in the severity of reforming when the fuel is being blended with ethanol.

The other significant item to note is the difference in RVP. We do not show a seasonally weighted value for RVP, as RVP is usually only relevant for summertime emission projections. In Table 2.2-4, the difference in summer RVP is 1.5 psi. This is well above the 1.0 psi value typically found for ethanol blending. The 1.5 psi difference is due to the sample weighting scheme used to develop the figures in Tables 2.2-4 and 2.2-5. The number of ethanol and non-ethanol samples is not evenly weighted across the four cities and the applicable RVP standards in each city differ. As can be seen in Table 2.2-2, the difference in RVP in each city is 1.0-1.2 psi. Thus, we will assume the typical RVP increase associated with ethanol blending of 1.0 psi applies here. We do not believe that the sample weighting scheme affects any of the other fuel properties in this manner.

In our above approach, aggregating data within urban areas loses any refinery-specific effects. Also, we lose the ability to apply region-specific effects since we only include four cities and do not have any cities with both ethanol and non-ethanol fuels from the Gulf area or east coast. However, the results use available data to provide an acceptable national assessment of ethanol and fuel properties. We checked our results against the AAM data from all U.S. cites, comparing all conventional gasoline non-ethanol blends (with an RVP greater than or equal to 8.2 psi) to all conventional gasoline ethanol blends (with an RVP greater than or equal to 8.7

psi). The results were very similar to those from the four cities, supporting the validity of our approach. These results are shown in Table 2.2-6 below.

Table 2.2-6.
Change in Properties of Conventional Gasoline Due to Addition of Ethanol, Using All U.S. Conventional Gasoline Data from AAM Survey

Season	Fuel Type	T50 (°F)	T90 (°F)	E200 (%)	E300 (%)	Aromatics (Vol%)	Olefins (Vol%)	RVP (psi)	Octane (R+M)/2	Benzene (Vol%)
Summer	E0	216	328	42.3	82.4	29.7	7.4	8.6	88.5	1.1
	E10	179	325	54.0	84.5	24.3	7.8	9.6	88.8	1.2
Winter	E0	203	329	48.5	82.8	22.7	20.2	--	89.4	1.0
	E10	171	322	56.4	85.3	18.8	18.5	--	89.3	1.1
Average change between E0 and E10[a]		-34	-5	9.5	2.3	-4.5	-0.9	1.0[b]	0.1	0.1

[a] Weighted by seasons of five summer months and seven winter months.
[b] Summer only.

2.2.2 Effects of Ethanol on Reformulated Gasoline Fuel Properties

RFG must meet tight specifications for VOC, NOx and toxic emission performance. These emission performance standards result in particularly tight control of RVP, benzene and aromatics. This means that the RVP increase shown above in Table 2.2-5 cannot occur and must be compensated for through the removal of low molecular weight, high RVP hydrocarbon components.

Until recently, all RFG was required to contain 2.0 wt% oxygen on average. Thus, all RFG contained either MTBE or ethanol. Any additional ethanol use in RFG relative to our 2004 base case will thus replace MTBE. Both MTBE and ethanol are high octane components and have relatively low vapor pressures (i.e., they both tend to decrease T50 substantially). RFG has typically contained 11 vol% MTBE or 10 vol% ethanol. Given their similar usage levels and generally similar properties other than RVP, plus the restrictions imposed by the applicable VOC, NOx and toxic emission performance standards, we assume here that the replacement of MTBE by ethanol in RFG will not change any fuel properties other than the type of oxygenate and oxygen content.

2.2.3 Effects of MTBE on Conventional Gasoline Fuel Properties

The purpose of this section is to estimate the impact of removing MTBE from conventional gasoline. Unlike the situation with respect to ethanol blending, we do have refinery modeling available which indicates the impact of MTBE blending. This modeling 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.

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.[43] 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 2.2-7 shows the results of adding MTBE based on this refinery modeling.

Table 2.2-7. 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
Sulfur (ppm)	339	309	-30
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 2.2-7 are expected to occur when MTBE is removed from gasoline (when the MTBE content was 11 vol%). Table 2.2-8 shows these changes (in terms of the addition of MTBE) for both a fuel containing 11 vol% MTBE and on the basis of 1 vol% MTBE.

Table 2.2-8.
Change in Properties of Conventional Gasoline Due to Addition of MTBE

	T50 (°F)	T90 (°F)	E200 (%)	E300 (%)	Aromatics (Vol%)	Olefins (Vol%)	RVP (psi)	Oxygen (Wt%)
Change between 0 vol% and 11 vol% MTBE	-11	-8	5.7	1.9	-6.5	0	0	2.1
Change per 1 vol% increase in MTBE	-1.0	-0.7	0.52	0.17	-0.6	0	0	0.2

2.2.4 Effects of MTBE on Reformulated Gasoline Fuel Properties

Reformulated Gasoline (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 2.1, we expect that the use of MTBE in RFG will cease soon. It will be 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 2.2.2, RFG will continue to have to meet stringent VOC, NOx, and toxic emission performance standards.

Compliance with the NOx standard is essentially assured with compliance with the Tier 2 sulfur standards applicable to all gasoline. Compliance with the MSAT1 toxics standards was discussed in Section 2.1.4.2 above. There, we concluded that if refiners used reformate to compensate for MTBE's octane, then aromatic content would increase, limiting the volume of non-oxygenated RFG which could be produced and still comply with the MSAT1 toxics standards. This was the basis for our projections of the use of ethanol in RFG under the "minimum ethanol use in RFG" scenarios.

The VOC emission performance standard could also limit the production of non-oxygenated RFG if reformate was used to compensate for MTBE's octane. Assuming an RVP level of 6.8 psi and a sulfur content of 30 ppm, per the Complex Model, refiners still have to increase E200 and E300 and reduce aromatic content relative to typical conventional gasoline in order to meet the RFG VOC standard. Refiners have some flexibility in which of these parameters to adjust and to what degree. They could also reduce RVP below 6.8 psi, as this level is well above that needed for the hydrocarbon portion of ethanol RFG, if the latter is to be at 6.8 RVP after ethanol blending.

The refinery modeling currently underway will provide considerable insight into both the potential market share of non-oxygenated RFG and its likely properties. For the purpose of this analysis, we assume that most of the properties of non-oxygenated RFG will be very similar to those of ethanol RFG. We decreased the levels of E200 and E300 of non-oxygenated RFG as much as possible while still complying with the VOC performance standard for southern RFG of 29%. We plan to update this estimate of the quality of non-oxygenated RFG for the final RFS rule analysis based on the refinery modeling to be completed soon. For comparison purposes, Table 2.2-9 also shows the specifications of a comparable ethanol RFG.

Table 2.2-9. RFG Quality With and Without Oxygenate

Fuel Parameter	Non-Oxygenated RFG	MTBE RFG	Ethanol RFG
RVP (psi)	6.8	6.8	6.8
T50	210	212	194
T90	320	321	322
E200 (vol%)	45	44	53
E300 (vol%)	85	85	85
Aromatics (vol%)	25.5	25.5	25.5
Olefins (vol%)	13.1	13.1	13.1
Oxygen (wt%)	0	2.1	3.5
Sulfur (ppm)	30	30	30
Benzene (vol%)	0.65	0.65	0.65

2.2.5 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.[44] 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 2.1 to be sold there under each of the five ethanol use scenarios. 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.

2.2.5.1 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.[45] 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 AAM fuel survey data in these two areas, 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.[46] 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.

2.2.5.2 County-Specific Oxygenate Type and Content

The five ethanol use scenarios developed in Section 2.1 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.

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 2.1. 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.

2.2.5.3 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 five 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 2.1. 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 basis for these adjustments were those developed in Sections 2.2.1 through 2.2.4. above. As described there these adjustments apply primarily to conventional gasoline. These adjustments are summarized in Table 2.2-10 below.

Table 2.2-10.
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, or in equation form:

$$\text{New Fuel Property Level} = \text{NMIM Database Fuel Property Level} + \text{Ethanol Effect} + \text{MTBE Effect}$$

For example, the equation for the ethanol effect is as follows:

$$\text{Ethanol Effect} = \left\{ \left(\text{RFS Ethanol Content}\right)\left(\text{RFS Market Share}\right) - \left(\text{NMIM Ethanol Content}\right)\left(\text{NMIM Market Share}\right) \right\} \times \left(\text{Fuel Property Change per 1 vol\% Ethanol Increase}\right)$$

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, as discussed above, 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 five ethanol use scenarios developed in Section 2.1.

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:

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

Then, the effect of any ethanol projected to be sold in that county in the five ethanol use scenarios developed in Section 2.1 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:

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

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. 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 psi in all states where the E10 market share was significant (i.e., more than 10%) but less than 100%. In the four, future ethanol use scenarios, we tend to project that ethanol use will be either zero or 100% in any particular state, due to the difficulty in projecting different ethanol use levels within a state. Theoretically, commingling would not exist under these situations. However, in reality, ethanol blending will not often stop at a state line between two states, one with a projection of zero E10 market share and the other with 100% market share. The former will likely receive some ethanol, while the latter will be less than 100%. Therefore, we added a commingling effect of 0.1 psi RVP to counties in those states where the projected level of ethanol blending changed from 100% to zero. These states are shown in Table 2.2-11.

Table 2.2-11. States Where RVP was Increased Due to Commingling

7.2 Min	Arizona, Arkansas, Kansas, Kentucky, Maine, Missouri, Montana, Nebraska, Nevada, Ohio, West Virginia
7.2 Max	Arkansas, Colorado, Idaho, Indiana, Kentucky, Missouri, Montana, Nebraska, Nevada, Pennsylvania, Utah, West Virginia, Wyoming
9.6 Min	Arizona, Colorado, Florida, Idaho, Kentucky, Maine, Maryland, Mississippi, Missouri, Nevada, New Hampshire, Ohio, Oklahoma, Oregon, Pennsylvania, Tennessee, West Virginia
9.6 Max	Alabama, Arizona, Arkansas, Kansas, Kentucky, Maine, Maryland, Missouri, Montana, Nevada, Ohio, Tennessee, West Virginia

2.3 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"[47]. Table 2.3-1 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, which is the type of diesel considered in the biodiesel emissions effects in Chapter 3.1.3.

Table 2.3-1. 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 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. 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 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 for use in gasoline and biodiesel.

3.1 Effect of Fuel Quality on Vehicle and Equipment 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 and nonroad equipment 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 will not be available for inclusion in the analyses supporting the final Renewable Fuel Standard (RFS) rule.

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. This draft 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

This section is divided into two parts. The first evaluates the impact of ethanol and MTBE use on motor vehicle emissions. The second evaluates the impact of ethanol and MTBE use on emissions from nonroad equipment.

3.1.1.1 Motor Vehicles

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 2000, 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 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 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 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.

3.1.1.1.1 Exhaust VOC and NOx Emissions

3.1.1.1.1.1 Complex Model 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 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[48]. 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 data which did not include several studies which has since been published. Second, the EPA Complex Model was developed using a fixed effects statistical modeling approach[BB]. In contrast, both the CARB Phase 2 and 3 models were

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[BB] 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 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 they 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 driver's 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.[CC] 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.

Recently, the Coordinating Research Council (CRC) completed an emission testing and modeling effort (the E-67 study) involving low emission vehicles (LEVs), ultra low emission vehicles (ULEVs), and one super ultra low emission vehicles (SULEV). This new data provides the opportunity to confirm the assumption made in EPA's analysis of the California waiver request. The data from this study is evaluated in the next section, below.

3.1.1.1.1.2 CRC E-67 Study

In early 2006, 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

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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.

[CC] 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 and so the effect of sulfur is moot.

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[DD] 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 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 predicted changes in measured exhaust emissions of 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 3.1-1[49], 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 the results of gasoline survey results across the U.S.)

Table 3.1-1. 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 of predicted to measured NOx emissions are 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 T90 (lowest again on the left and highest on the right). The y-axis scale

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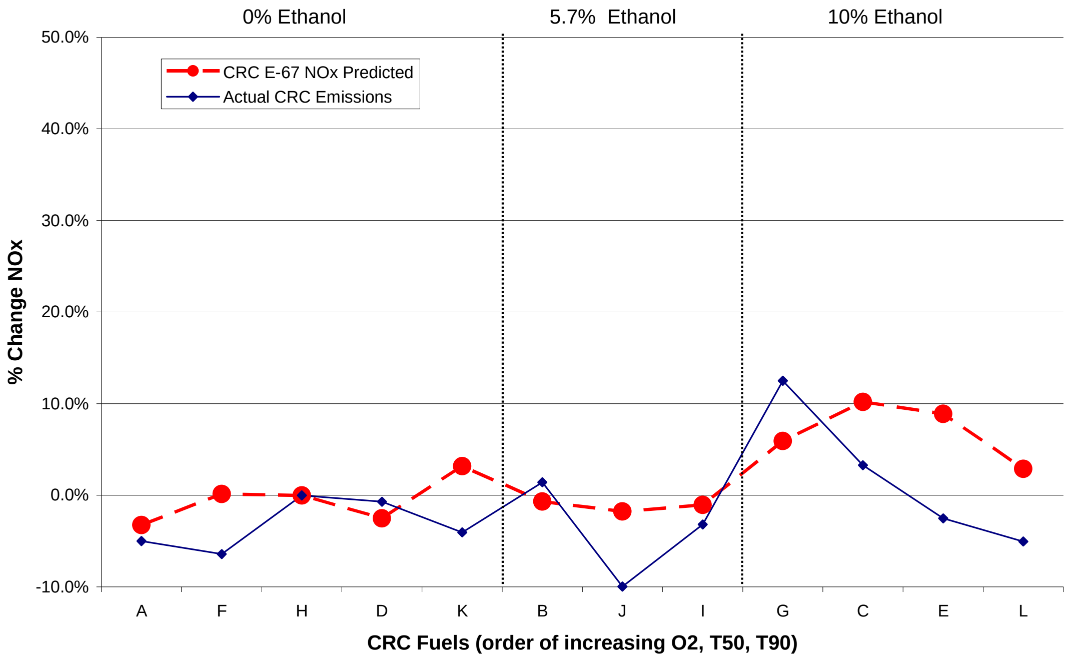
[DD] NMHC is essentially equivalent to VOC for our purposes in this study.

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)

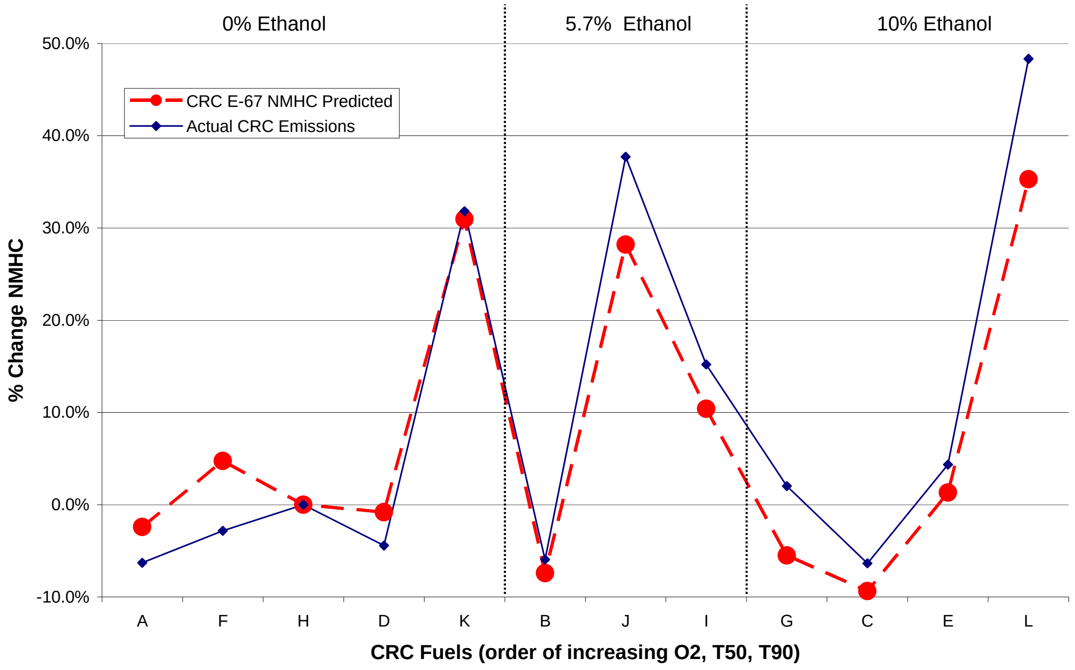


As shown in Figure 3.1-1, the CRC model for NOx emissions predicts the general trend in the emission data, which roughly indicates an increase in NOx emissions with increasing ethanol content. However, the model clearly does not reflect many of the fuel to fuel differences indicated by the actual emissions data. One example of this is the change between fuels G and C – two10% 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. However, directionally 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.[EE] 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 Predictive Models, our procedures would normally exclude the least significant term. A new

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[EE] In general, $p \leq 0.05$ is considered to be statistically significant, $0.05 < p \leq 0.10$ is marginally significant, and $p > 0.10$ is not considered statistically significant.

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.[FF]

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.

3.1.1.1.1.3 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 3.1-2.

Table 3.1-2. 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 3.1-3, on the following page, shows the p-values and coefficients for the fixed effect terms of each model.

[FF] 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 3.1-3. 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 3.1-3, 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.

(a) Model Comparison: EPA E-67 vs. EPA Predictive Models

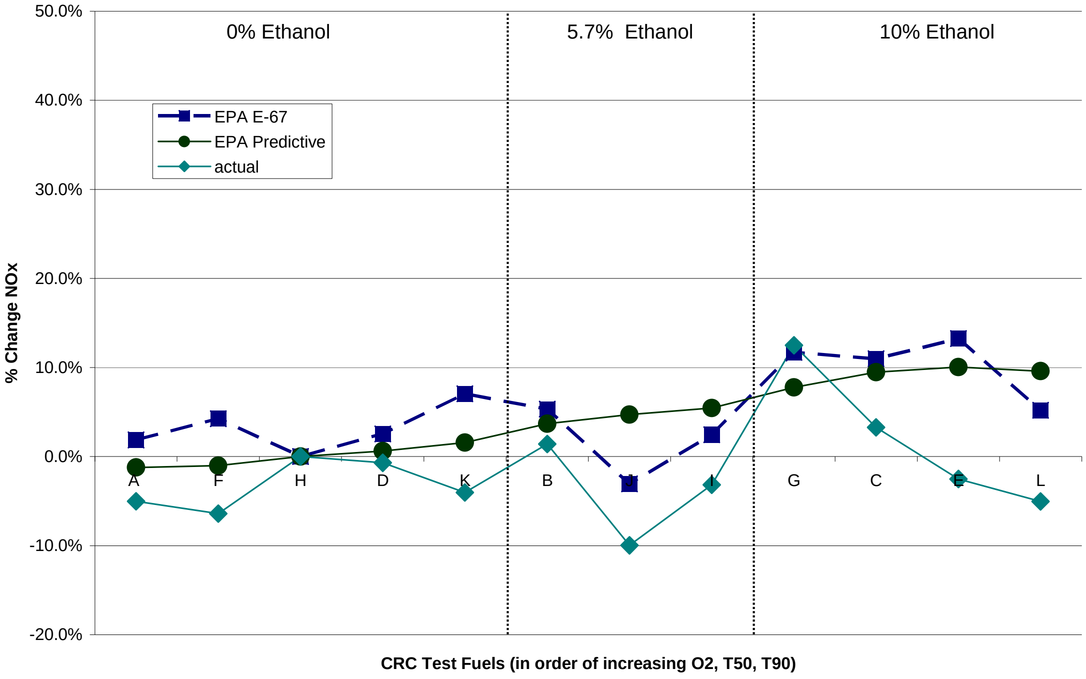
Both the EPA E-67 and EPA Predictive models are mixed models that predict the relative changes in exhaust emissions due to carefully controlled changes in gasoline quality, including the addition of an oxygenate such as ethanol. The models are not intended to be accurate at predicting absolute emission 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)



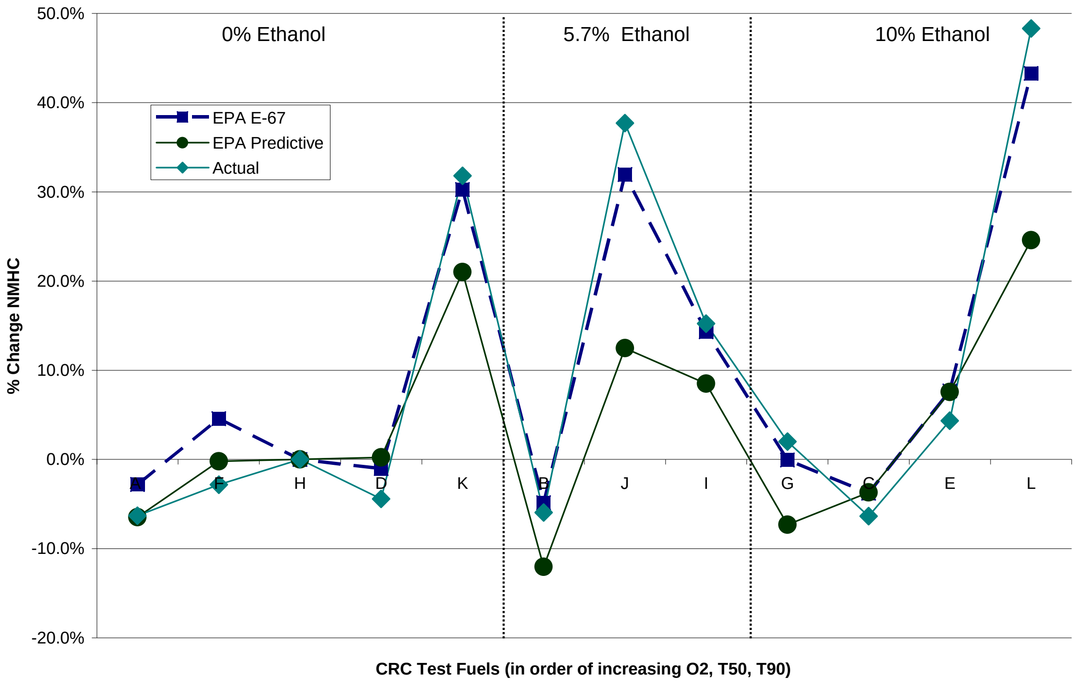
As shown in Figure 3.1-3, neither model predicts the actual test data with complete accuracy. The EPA E-67 shows the same general relationship to the emission data as did the CRC E-67 NOx model. Thus, removing the statistically insignificant terms had little impact on the relative fit of the model to 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 3.1-4 below.

Table 3.1-4. Predicted NOx and NMHC Emissions Changes for EPA E-67and Predictive Models[GG]

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 3.1-4, 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.

The data from the CRC E-67 study are too limited, both in terms of the number of vehicles tested and the fuel parameters evaluated, to be used here to predict the effect of increased ethanol use on exhaust emissions. However, these data clearly indicate that assuming no effect of fuel quality on emissions from these vehicles could very well be incorrect. Therefore, we believe that it is appropriate to estimate the potential impact of the sensitivity of these vehicles to fuel quality via a sensitivity analysis. In this sensitivity analysis, we will extend

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[GG] 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.

the effect of the EPA Predictive Models to Tier 1 and later vehicles. Therefore, in this case, all gasoline vehicles are assumed to be sensitive to fuel quality to the degree predicted by the EPA Predictive Models for NMHC and NOx. At the same time, our primary analysis here will continue to use the EPA Predictive models to predict the fuel-emission effects for Tier 0 vehicles and assume that exhaust NMHC and NOx emissions from Tier 1 and later vehicles are not affected by fuel quality.

As mentioned previously, the difference in sensitivity between the models, as well as the very limited dataset used to develop the E-67 model, further illustrates the need to conduct additional testing using newer vehicle technology.

3.1.1.1.1.4 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 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. 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 3.1-5. We show the effect of fuel quality on CO emissions here for convenience. These effects will be discussed further in the next section.

Table 3.1-5. 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%	-0.7%	-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%	-0.7%	-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%	-0.7%	-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 3.1-6. 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 3.1-6.
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.

3.1.1.1.1.5 Selection of Models for Each Pollutant

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. The CRC E-67 study indicates that these vehicles' emissions are at least as sensitive to changes in ethanol, T50 and T90 as Tier 0 vehicles. However, the study only tested 12 vehicles on 12 fuels. It also did not investigate the effect of other fuel parameters, such as aromatics, olefins and RVP. As discussed above, there are also problems with trying to substitute the CRC E-67 effects for the three fuel parameters tested with the other fuel effects in the EPA Predictive Models.

Overall, we believe that we still lack reasonable estimates of the effect of fuel quality on exhaust VOC and NOx emissions from Tier 1 and later vehicles. Given this, we believe that it is valuable to maintain consistency with our analysis conducted in response to California's request for an RFG oxygen waiver. Thus, we will continue to assume here in our primary analysis that exhaust VOC and NOx emissions from Tier 1 and later vehicles are unaffected by fuel quality. However, in recognition of the strong evidence presented by the CRC E-67 study, we believe that it is important to evaluate the possibility that these vehicles respond to changes in fuel quality. Therefore, in a sensitivity analysis, we will assume that Tier 1 and later vehicles respond to fuel quality in the same way as Tier 0 vehicles.

3.1.1.1.2 CO Emissions

Fewer options are available to project the impact of fuel quality on CO emissions. The Complex and EPA Predictive Models do not 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 only EPA model which predicts the impact of fuel quality on CO emissions is MOBILE6.2. The effect of RVP, ethanol and MTBE on CO emissions were shown in Table 3.1-5 above. MOBILE6.2 does not project any impact of the other relevant fuel parameters (aromatics, olefins, T50, and T90) on CO emissions.

It is interesting to compare the effect of ethanol contained in MOBILE6.2 to that from the EPA E-67 model discussed above. Changing just ethanol content in the EPA E-67 model produces a 1.15% reduction in CO emissions per 1 vol% ethanol. This is larger than that the MOBILE6.2 effect of 0.7% shown in Table 3.1-5. As mentioned above, MOBILE6.2 does not project the effect of changes in most fuel parameters on CO emissions, like aromatics, olefins, T50 and T90. The effect of increasing ethanol content on CO emissions in MOBILE6.2 is based on the testing both splash-blended and match-blended ethanol fuels. Therefore, the fuel-emission effect includes the typical effect of ethanol blending on these other fuel parameters. Adding ethanol and decreasing T50 and T90 per the relationships described in Section 2.2.3 above increases the CO emission reduction per the EPA E-67 model to 1.25% per vol% ethanol. Thus, considering these associated effects of ethanol on T50 and T90, the EPA E-67 model suggests a larger impact than that in MOBILE6.2.

As discussed above, the models representing the CRC E-67 study are not sufficient for use in quantitatively projecting the impact of fuel quality on emissions. Additional data must still be collected over a broader set of vehicles, fuel changes, and conditions. Therefore, we use MOBILE6.2 here to project the impacts of ethanol use on CO emissions.

3.1.1.1.3 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.

3.1.1.1.4 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. 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 itself. Subsequent testing as 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.[50] This study provides a useful starting point for incorporating these emissions into this RFS analysis.

As a starting point, 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.[51] This study tested 10 vehicles, 6 cars and 4 light trucks, ranging in model year from 1989 to 2001. 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.

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 potentially 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, as well as earlier vehicles.

Permeation emissions vary significantly with ambient temperature, with emission 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 next year. 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 7.2 billion gallon ethanol, minimum ethanol use in RFG scenario and the base case scenario) against the change in RVP, ethanol content and MTBE content. The results are summarized in Table 3.1-7.

Table 3.1-7. Fuel-Non-Exhaust Emission Effects in MOBILE6.2: 2012

	RVP (%/psi)	Ethanol (%/Vol %)	MTBE (%/Vol%)	Adjusted r-Square
VOC	15.6%	-0.1%	0.0%	0.98
Benzene	14.8%	-1.3%	-0.7%	0.08

3.1.1.1.5 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).[52] 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.[53] 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 both 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 testing 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 few percent 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.[54] 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 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.[HH] 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 vehicles, like disconnecting the oxygen sensor. We focus on the emissions from the properly operating vehicles here.

Of the 26 combinations of vehicle and temperature tested, valid PM measurements over the FTP were successfully obtained for both fuels in 21 of them. The average percentage 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.

3.1.1.1.6 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.[55] 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

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[HH] 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.

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 3.1-8, on the following page.[56]

Table 3.1-8. 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 3.1-8, 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 3.1-8. 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.

3.1.1.1.7 Emission Effects Associated with Specific Fuel Blends

3.1.1.1.7.1 Conventional Gasoline Analysis

In Section 2.2 of Chapter 2, we estimated the effect of blending ethanol and MTBE on gasoline quality. 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. Table 3.1-9 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 3.1-9. 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	206	186
T90	332	324	325
Aromatics (vol%)	32	25.5	27
Olefins (vol%)	7.7	7.7	6.1
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 3.1-10 presents the differences in emissions of the MTBE and ethanol blends relative to that of non-oxygenated conventional gasoline.

Table 3.1-10. Effect of Oxygenates on Conventional Gasoline Emissions[a]

Pollutant	Source	11 Volume Percent MTBE	10 Volume Percent Ethanol
Exhaust VOC	EPA Predictive Models	-9.2%	-7.4%
NOx		2.6%	7.7%
CO[b]	MOBILE6.2	-6% / -11%	-11% / -19%
Exhaust Benzene	EPA Predictive and Complex Models	-22%	-27%
Formaldehyde		+10%	+3%
Acetaldehyde		-8%	+141%
1,3-Butadiene		-12%	-27%
Non-Exhaust VOC	MOBILE6.2	Zero	+30%
Non-Exhaust Benzene	MOBILE6.2 & Complex Models	-10%	+13%

[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.

3.1.1.1.7.2 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.

Whether MTBE is removed from RFG and replaced by ethanol, or is removed and simply left without an oxygenate, it is assumed for the purposes of this analysis that sulfur concentrations in the fuel will remain at 30 ppm, and that olefin content and benzene would not change. Since RFG has tighter aromatics control than conventional gasoline, we will assume that aromatics will remain constant for toxics control when oxygen is either removed or added. Therefore the only fuel properties that change in this analysis are oxygen, T50, and T90.

Table 3.1-11 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.

Table 3.1-11. RFG Fuel Quality With and Without Oxygenates[a]

Fuel Parameter	Non-Oxygenated RFG	MTBE RFG	Ethanol RFG
RVP (psi)	6.7	6.7	6.7
T50	214	212	194
T90	325	321	322
Aromatics (vol%)	25.5	25.5	25.5
Olefins (vol%)	13.1	13.1	13.1
Oxygen (wt%)	0	2.1	3.5
Sulfur (ppm)	30	30	30
Benzene (vol%)	0.65	0.65	0.65

[a] Assumes summer (July) conditions

Table 3.1-12 presents the emission impacts of these three types of RFG relative to the 9 RVP CG described in Table 3.1-9.

Table 3.1-12.
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	-7.7%	-11.1%	-12.9%
NOx		-1.7%	2.4%	6.3%
CO	MOBILE6.2	-24%	-28%	-32%
Exhaust Benzene	EPA Predictive and Complex Models	-18%	-30%	-35%
Formaldehyde		7%	11%	2%
Acetaldehyde		7%	-8%	143%
1,3-Butadiene		22%	2%	-7%
Non-Exhaust Emissions				
VOC	MOBILE6.2 & CRC E-65	-30%	-30%	-18%
Benzene	MOBILE6.2 & Complex Models	-5%	-15%	-7%

[a] Assumes summer (July) conditions

As can be seen, the oxygenated RFG blends are predicted to produce a greater reduction in exhaust VOC and CO emissions, but a larger increase in NOx emissions. 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 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).

3.1.1.2 Nonroad Equipment

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 3.1-13 shows the effect of moving to a 10 volume percent ethanol blend on these emissions, either from a non-oxygenated fuel or from an 11 volume percent MTBE blend.

Table 3.1-13.
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	-15%	-6%	-1%	~ zero
CO	-21%	-8%	-12%	-4%
NOx	+37%	+13%	+18%	+6%

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.

[II] 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.

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.[58] 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-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.

3.1.2 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. Therefore, it is useful to examine the available data regarding the emission impacts of E85.

3.1.2.1 Exhaust emissions

3.1.2.1.1 Regulated 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. Another source of emission data is EPA's Certification and Fuel Economy Information System (CFEIS) database, which contains certification data for all FFVs sold in the US.[59]

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. The 2005 and 2006 CFEIS data from new FFVs, on the other hand, show a 4% increase is NOx emissions with E85, with a large degree of vehicle to vehicle variability (standard deviation of 35%). Neither the Auto/Oil study nor the certification data found statistically significant changes in CO. Emissions of Non-Methane Organic Gases (NMOG) increased 33% and 56% in the CFEIS and Auto/Oil data, respectively. 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 are expected 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. NMOG emissions with E85 at colder temperatures could be much greater (2 to 3 times higher than with E0). Much of this increase occurs during cold start, before the combustion chamber has reached high enough temperatures to allow ethanol vaporization. As with NMOG emissions at normal engine operating temperatures, a high percentage of the increased NMOG emissions are ethanol and acetaldehyde.

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 3.1-14, 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.[60]

Table 3.1-14.
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 3.1-14. 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).[61] 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 that the aromatic content of E85 will be lower than gasoline is not known with any confidence. Lack of data regarding on 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 is 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[JJ] 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.

3.1.3 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”. This report included a technical analysis of biodiesel effects on regulated and unregulated pollutants from diesel powered vehicles. It gathered existing data from various test programs to investigate these effects. About 80% of engines tested in those programs represented model years 1991 through 1997. The remaining engines spanned model years 1983 to 1990. None of them were equipped with exhaust gas recirculation (EGR) or

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[JJ] Organic Material Hydrocarbon Equivalent exhaust aftertreatment devices. Since the majority of then-available data was collected on production highway engines, it formed the basis of this study. Only test results generated using the heavy-duty transient Federal Test Procedure (FTP) or multiple-mode steady-state cycles were included in the quantitative analysis.

All base fuels met boiling range requirements of the ASTM D975 diesel fuel specification and were either high sulfur (< 5000 ppm S) or low sulfur (< 500 ppm S) No.1 or No.2 grades. Fuels made from pure chemicals rather than refinery streams were excluded from analysis. Base fuels included in this study were divided into "clean" and "average" depending on their cetane number, aromatic content, density and conformance with CA diesel fuel requirements.

Emission impacts of B20 biodiesel fuel blended using an "average" diesel base fuel and soybean-based biodiesel are characterized in Table 3.1-15. The B20 blend is shown to moderately reduce HC, CO and particulate emissions while slightly increasing NOx. This fuel was also found to reduce fuel economy by 1.6%. Aggregate toxics were predicted to be reduced, but results differed considerably from one species to another and should be treated as preliminary due to limited sample size. It is important to note that the conclusions of this study should be considered to only apply to heavy-duty highway engines as insufficient data on the effects of biodiesel on exhaust emissions of light-duty and nonroad engines were available for analysis.

Table 3.1-15.
Effect of Soybean-Based B20 Biodiesel Fuel on Exhaust Emissions from Diesel Engines – 2002 EPA Study.

Pollutant	Change in Emissions
NOx	+ 2 %
PM	-10.1 %
HC	-21.1 %
CO	-11.0 %

For this rulemaking, EPA again reviewed the technical literature related to biodiesel effects on exhaust emissions from diesel engines and diesel powered vehicles. This review covered technical papers and reports published between 2002 and 2006, as well as one 2001 report which was not included in the 2002 EPA study. The same data selection criteria were used, but the review was focused exclusively on soybean-based B20 blends. Due to the much shorter time period involved and the scope of analysis limited to B20 blends, the volume of engine and vehicle test data available for analysis was considerably smaller than in the 2002 EPA study. This was true, in particular, of experimental data generated using newer technology engines and vehicles. We do not perform any detailed statistical analysis of the new experimental data here, due to the complexities involved in combining data obtained using different test cycles. Also, the reasons why the engine and vehicle testing sometimes yield different results are not yet clear.

Engine test data selected for analysis in this follow-up review corresponded mainly to model years 1998 - 2003. Two engines included in the data set were equipped with oxidation catalysts and two with EGR systems. This is a marked improvement over the kind of engines which had been tested at the time of the 2002 study, where the vast majority of the data was obtained on 1997 and earlier engines. Only test data based on the heavy-duty transient FTP test or the AVL 8-mode steady-state cycle was considered.

Vehicle emission test data utilized in this review was split between model years 1983 to 1993 and 2002 to 2004. The vehicles included a passenger van, six pick-up trucks and two non-combat military vehicles. Three different driving cycles were represented in the data set, including the light-duty FTP, US06 and one test schedule representative of a specific vehicle application. It is important to note that a substantial volume of chassis test data related to B20 effects in diesel powered vehicles has recently been generated in the course of several ongoing test programs, but has not yet been published. We expect to be able to incorporate this data into our analysis for the FRM.

The base fuels included in the analysis were refinery products conforming to the ASTM D975 diesel fuel specification and were either low sulfur (< 500 ppm S) or ultra low sulfur (< 15 ppm S) No.2 grades. The B20 blends met boiling range requirements of the ASTM D975 specification.

Data indicating the emission impacts of B20 biodiesel fuel on exhaust emissions from diesel engines which has become available since the 2002 study are shown in Tables 3.1-16. This table shows the effect of B20 on the emissions of various pollutants for individual engines and vehicles, as well as minimum, maximum and average values for each pollutant across the entire group of engines tested.

Table 3.1-16.
Recent Studies of the Effect of B20 on Emissions from Diesel Engines
(% change relative to base fuel)

Author	Vehicles Tested	Test Cycle	NOx	HC	CO	PM
McCormick R.L. et. al. (2001) [62]	1991 DDC Series 60	Hot FTP	2.9	-35.0	-7.7	-23.6
Souligny M. et. al. [63]	1998 Cummins C Series (w/oxycat)	Hot FTP	0	-12.2	-24.6	-30.8
	2000 Cummins C Series (w/oxycat)	Hot FTP	0	-21.0	-28.1	-16.6
Alam M. et. al. [64]	2000 Cummins B Series	AVL 8-mode, base fuel #1	0	-	-	-27.0
		AVL 8-mode, base fuel #2	-3.0	-	-	6.0
McCormick R.L. et. al. (2005) [65]	2002 Cummins ISB (w/EGR)	Hot FTP	3.6	-4.2	-10.5	-24.9
	2003 DDC Series 60 (w/EGR)	Hot FTP	6.0	13.5	1.0	-24.1
		Minimum	-3.0	-35	-28.1	-30.8
		Maximum	6.0	13.5	1.0	6.0
		Average	1.4	-11.8	-14.0	-20.1

The average B20 effects on diesel engine emissions shown in Table 3.1-16 reinforce the general conclusions of the 2002 EPA study. More specifically, they indicate that the B20 blend causes moderate reductions in HC, CO and particulate emissions and a small - if any - increase in NOx emissions.

Data indicating the emission impacts of B20 biodiesel fuel on exhaust emissions from diesel vehicles which has become available since the 2002 study are shown in Tables 3.1-17.

Table 3.1-17.
Recent Studies of the Effect of B20 on Emissions from Diesel Powered Vehicles
(% change relative to base fuel)

Author	Vehicles Tested	Test Cycle	NOx	HC	CO	PM
Durbin, T.D., et al[66]	1993 Ford 350	FTP chassis	0.7	-21.3	-6.1	17.2
	1990 Ford E350 van	FTP chassis	2.8	39.4	-0.4	-8.1
	1990 Chevy 2500	FTP chassis	3.3	-33	-10.6	-2.5
	1989 Chevy 2500	FTP chassis	3.2	40.9	12	22.1
	1987 Chevy C-30	FTP chassis	1.7	15.7	-1.3	15.1
	1985 Chevy C-30	FTP chassis	8.7	-9.7	-1.8	-11.3
	1983 Ford F-250	FTP chassis	3.5	-0.7	-5.2	39.8
Holden Bruce et. al.[67]	2004 Humvee	FTP chassis	-1	113	26	-9
		US06	-1	3	44	-57
	2002 Thomas bus – Lab 2	Cheyenne Mountain Cycle	3	-22	-17	-29
	2002 Thomas bus – Lab 1		0.2	-11.2	-1.3	-8.4
		Minimum	-1	-33	-10.6	-57.0
		Maximum	8.7	113	44	39.8
		Average	2.3	10.4	3.5	-2.8

As expected, the vehicle test data provided in Table 3.1-17 are considerably more variable reflecting the strong effect of the different driving cycles used in their generation. The average B20 effects on vehicle HC, CO and particulate emissions differ markedly from the effects observed during engine testing. However, the response of NOx emissions to B20 was similar to that seen in engine tests. These results should be treated as preliminary due to the limited size of the vehicle population included in this analysis and the variability in the observed emission effects.

The results of two additional test programs are shown in Table 3.1-18. The first is the ongoing National Renewable Energy Laboratory (NREL) study of Denver transit buses. The second study is a North Carolina State University (NCSU) study of twelve dump trucks operated on B20 fuels. These programs are considered separately as they did not meet the data selection criteria established for this review. The results of the NREL study are still considered to be preliminary. We currently only have the averages of the emission data for several buses. The NCSU study used an on-board emissions measurement system to monitor exhaust emissions of the trucks during normal duty cycles. This system measured HC, CO, NO and particulate emissions, but was not capable of measuring NO_2; NO_2 emissions have been shown to be affected by biodiesel use in laboratory testing. Therefore, the NOx results shown here are not reliable. Both sets of data show moderate improvements of HC, CO and particulate emissions associated with B20 use, similar to those seen in the 2002 EPA study.

Table 3.1-18.
Recent Studies of the Effect of B20 on Emissions from Diesel Powered Vehicles: Supplementary data (% change relative to base fuel)

Author	Vehicles Tested	Test Cycle	NO	HC	CO	PM
Proc K., et. al. [68]	5 Denver Regional Transit District Buses	City Suburban Heavy Vehicle Cycle	-4 (ave)	-29 (ave)	-24 (ave)	-18 (ave)
Frey Christopher, et. al. [69]	12 1998-2004 dump trucks	On-road tests using a portable emissions measurement system	-10 (ave)	-22 (ave)	-11 (ave)	-10 (ave)

In summary, the additional data which has become available since the time of the 2002 EPA study generally supports the results of the 2002 EPA study. In addition, the more recent data indicates that the impacts of B20 on emissions from new engines may not be that different from those of older engines (on a percentage basis). However, there is still a need for additional test data, particular for newer technology engines and across the board for nonroad engines.

3.2 Emissions from Fuel Production Facilities

3.2.1 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. We approximate the impact of increased ethanol production, including corn farming, on emissions based on DOE’s GREET model, version 1.6. We also include emissions related to distributing the ethanol and take credit for reduced emissions related to distributing displaced gasoline. These emissions are summarized in Table 3.2-1.

Table 3.2-1.
Well-to-Pump Emissions for Producing and Distributing Ethanol from Corn (grams per gallon ethanol)

Pollutant	Corn Farming and Transportation	Ethanol Production	Co-Product Credits	Ethanol Trans-portation	Gasoline Transportation Credit	Total Emissions
VOC	0.8	6.8	-3.7	0.5	-0.9	3.6
CO	4.3	3.0	-3.0	0.2	-0.1	4.4
NOx	11.3	4.9	-6.4	1.5	-0.4	10.8
PM10	8.1	0.4	-2.5	0.0	0.0	6.1
SOx	1.2	6.8	-0.8	0.2	-0.1	7.2

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 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.

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.

3.2.2 Biodiesel

Like ethanol, we base our emission factors for biodiesel production distribution on the estimates contained in the GREET model. Table 3.2-2 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. These emissions are summarized in Table 3.2-2.

Table 3.2-2.
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	3.1	38.3	0.5	-0.4	41.5
CO	14.5	10.6	0.2	-0.1	25.1
NOx	24.4	19.4	1.1	-0.7	44.3
PM10	1.0	0.5	0.0	0.0	1.5
SOx	3.7	3.8	0.1	-0.1	7.5

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 195°F	**E10**: AAM Summer avg, T50 T90 O2 only for EPA model (T50=195°F)	**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 (°F)	218	218	218	186	195	195	206	214	212	194
T90 (°F)	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

Chapter 4: National Emission Inventory Impacts

This chapter describes the methods used to develop national emissions inventories under the Renewable Fuel Standard (RFS) program. 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

We consider five cases for the future use of ethanol-blend gasoline: a reference case, then four control scenarios for increased ethanol use. The main difference between the cases is our assumption about how much ethanol will be used and where it will go. 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 DRIA uses those distributions to derive estimates of the impact on national emissions inventories.

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. The five ethanol use cases are summarized in Table 4.1-1. The Reference Case represents our estimate of fuel quality by county which existed in 2004. The remaining four cases represent increased levels of ethanol use. Two of these assume that 7.2 billion gallons of ethanol will be consumed nationally, while the other two assume a level of 9.6 billion gallons of ethanol use. For both the 7.2 and 9.6 billion gallon volumes, we consider two alternative cases of minimum and maximum use of ethanol in RFG. This min/max use of ethanol in RFG is reflected in the naming conventions used for the cases in Table 4.1-1.

Table 4.1-1. Overview of Cases for Future Ethanol Use and Distribution

Reference	Fuel quality is estimated for 2012, based on data fuel properties and programs in 2004 (the last year for which appropriate data were available).
7.2 Min	Fuel quality is based on allocation of 7.2 billion gallons of renewable fuel in 2012, with a minimum amount of ethanol allocated to RFG areas.
7.2 Max	Fuel quality is based on allocation of 7.2 billion gallons of renewable fuel in 2012, with a maximum amount of ethanol allocated to RFG areas.
9.6 Min	Fuel quality is based on allocation of 9.6 billion gallons of renewable fuel in 2012, with a minimum amount of ethanol allocated to RFG areas.
9.6 Max	Fuel quality is based on allocation of 9.6 billion gallons of renewable fuel in 2012, with a maximum amount of ethanol allocated to RFG areas.

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)[70] 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.

We chose 2012 because it is the year of full RFS program implementation. We 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.

We ran NMIM separately for onroad and nonroad emissions, as each set of emissions required a different set of adjustments subsequent to the model runs. For onroad emissions, the effect of fuel quality on exhaust VOC and NOx emissions contained in the model (i.e., those in MOBILE6.2) had to be replaced with those from the EPA Predictive Model. The effect of ethanol on permeation emissions also had to be added to the onroad emission estimates. This required a series of post-processing steps which are described below.

For nonroad emissions, NMIM was run using two simplified county-specific fuel matrices. One represented no ethanol use nationally, while the other represented ethanol use nationwide. We then interpolated between the two sets of county-specific emission estimates based on the actual level of ethanol use expected in each county under the relevant ethanol use case.

These steps for calculating emissions inventories are described in the following sections. A summary of the models used and fundamental post-processing steps are listed below.

Onroad Exhaust Emissions: Modeled using NMIM, which runs MOBILE6.2. Post-processed model output to (1) replace VOC and NOx fuel effects for Tier 0 vehicles from MOBILE6.2 with fuel effects from EPA Predictive Model (no fuel effect for Tier 1 and later vehicles); (2) adjust exhaust air toxics emissions based on adjusted exhaust VOC emissions. Conducted sensitivity analysis by applying fuel effects from EPA Predictive Model to all vehicles.

Onroad Non-Exhaust Emissions: Modeled using NMIM, which runs MOBILE6.2. Post-processed model output to account for permeation effects.

Nonroad Exhaust Emissions: Modeled using NMIM, which runs NONROAD2005 (which was modified to account for hose permeation). Post-processed model output to interpolate between the no-ethanol and ethanol cases using the county ethanol level.

Nonroad Non-Exhaust Emissions: Modeled using NMIM, which runs NONROAD2005 (which was modified to account for hose permeation). Post-processed model output to interpolate between the no-ethanol and ethanol cases using RVP.

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 five onroad cases (Base, 7.2 Min, 7.2 Max, 9.6 Min, and 9.6 Max). The NMIM model utilizes the MOBILE6.2[71] 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 3.1.1.1.1.4 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 3.1.1.1.1.4, 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.

The following equation illustrates conceptually how we made this adjustment.

$$\text{Adjusted Exhaust Emissions} = \text{NMIM Exhaust Emissions} \div (1 + \text{NMIM Fuel-Emission Effect}) \times (1 + \text{EPA Predictive Model Fuel-Emission Effect} \times \text{Tier 0 Emission Percentage})$$

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.

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 3.1.1.1.4 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. 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.[72] We increased this figure by 1.9% per year[KK] 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.

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[73] 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). However, the model is not able to select these ethanol related emission factors based on the fuel quality inputs to the model. When run for multiple counties via NMIM, as is being done here, the permeation emission factors either reflect E0 or E10 fuel in all counties. It was infeasible to run NMIM one county at a time. Therefore, in order to be able to access these recent estimates of ethanol-related permeation emissions, we developed a methodology which would include these permeation emissions appropriately while limiting the number of NMIM runs to a reasonable number. Namely, we ran NMIM for two extreme ethanol use cases and used these results to estimate emissions for the five ethanol use cases which are the focus of this proposed rule.

The first case, called "No Oxygen," assumed the market share for ethanol-blend fuel was zero nationwide. The second case, called "All Oxygen," assumed the market share for ethanol-blend fuel was 100% nationwide. For both cases, we set the market share of all other oxygenates to zero. The effects of ethanol use on other fuel properties, such as aromatics and olefins, were calculated using the same methods described in Chapter 2. The only difference here is that the changes were more extreme, as ethanol use (in the form of E10) always increased from zero to 100%. A commingling RVP effect of 0.1 psi was included in the 100% Oxygen case in order to increase the spread of RVP between the two runs and to ensure that we were always interpolating (and never extrapolating) during our subsequent processing of the results.

This approach is capable of simulating all the relevant effects of fuel quality on nonroad emissions due to the way these effects are represented in the NONROAD model. Exhaust emissions are only a function of gasoline oxygen content. Thus, we could use the overall oxygen content of gasoline projected to be sold in a particular county (which is a function of both the MTBE and ethanol content) under each of the five ethanol use scenarios to interpolate between the zero and 3.5 wt% oxygen contents of the two extreme ethanol cases modeled, as described in the following equation:

[KK] 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.

$$\text{Exhaust Emissions} = \text{No Oxygen Emissions} + (\text{All Oxygen Emissions} - \text{No Oxygen Emissions}) \times (\text{County Ethanol Fraction} / 10)$$

For nonroad toxic exhaust emissions, the toxic emissions factors for nonroad equipment are based on very limited data. Therefore, we base the nonroad inventories on ratios derived from onroad results. We calculated the ratios of onroad ethanol control case emissions to the reference case for each county. Then, we applied these ratios to the nonroad reference case to derive the nonroad control case emissions.

Non-exhaust emissions are only a function of RVP and ethanol content. In our two runs, these two fuel parameters varied together (i.e., were perfectly co-linear), as the county-specific RVP level in the No Oxygen case was always increased by 1.1 psi in the 100% ethanol case. Thus, we could use either the county-specific RVP or ethanol content of the gasoline projected to be sold in a particular county under each of the five ethanol use scenarios to interpolate between the zero and 3.5 wt% oxygen contents of the two extreme ethanol cases modeled. RVP was used in order to account for the presence of a commingling RVP effect in some counties and not in others, as described in the following equation:

$$\text{Evaporative and Refueling Emissions} = \text{No Oxygen Emissions} + \text{All Oxygen Emissions} - \text{No Oxygen Emissions} \times \frac{(\text{County RVP} - \text{No Oxygen RVP})}{(\text{All Oxygen RVP} - \text{No Oxygen RVP})}$$

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 Base case.

Table 4.1-4 shows ethanol impacts on VOC inventories for each of the five 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 9.6 Min case, where the increase is less than 2% of the Base 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			
Total	**2012**	**2015**	**2020**
Reference Inventory	5,837,000	5,536,000	5,316,000
7.2 Min (Change)	31,000	33,000	57,000
7.2 Max (Change)	8,000	11,000	18,000
9.6 Min (Change)	57,000	61,000	91,000
9.6 Max (Change)	29,000	34,000	51,000
Onroad	**2012**	**2015**	**2020**
Reference Inventory	3,412,000	3,270,000	3,257,000
7.2 Min (Change)	20,000	21,000	24,000
7.2 Max (Change)	12,000	14,000	18,000
9.6 Min (Change)	39,000	40,000	44,000
9.6 Max (Change)	29,000	32,000	37,000
Nonroad	**2012**	**2015**	**2020**
Reference Inventory	2,425,000	2,266,000	2,059,000
7.2 Min (Change)	10,000	13,000	33,000
7.2 Max (Change)	-4,000	-3,000	0
9.6 Min (Change)	18,000	21,000	47,000
9.6 Max (Change)	-1,000	2,000	14,000

Table 4.1-5 shows ethanol impacts on CO inventories for each of the five 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 largest reduction is seen in the 9.6 Max case; this decrease is still less than 4% 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			
Total	**2012**	**2015**	**2020**
Reference Inventory	64,799,000	64,328,000	64,827,000
7.2 Min (Change)	-843,000	-818,000	-36,000
7.2 Max (Change)	-1,229,000	-1,231,000	-1,119,000
9.6 Min (Change)	-1,971,000	-1,953,000	-992,000
9.6 Max (Change)	-2,319,000	-2,330,000	-1,980,000
Onroad	**2012**	**2015**	**2020**
Reference Inventory	37,671,000	36,237,000	35,921,000
7.2 Min (Change)	-202,000	-173,000	-114,000
7.2 Max (Change)	-234,000	-209,000	-167,000
9.6 Min (Change)	-381,000	-328,000	-212,000
9.6 Max (Change)	-402,000	-354,000	-271,000
Nonroad	**2012**	**2015**	**2020**
Reference Inventory	27,128,000	28,090,000	28,906,000
7.2 Min (Change)	-642,000	-645,000	78,000
7.2 Max (Change)	-995,000	-1,021,000	-952,000
9.6 Min (Change)	-1,590,000	-1,625,000	-780,000
9.6 Max (Change)	-1,918,000	-1,975,000	-1,709,000

Table 4.1-6 shows ethanol impacts on NOx inventories for each of the five 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 9.6 Min 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 upwards of 15% in the 9.6 Min 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			
Total	**2012**	**2015**	**2020**
Reference Inventory	2,576,000	2,180,000	1,856,000
7.2 Min (Change)	19,000	17,000	21,000
7.2 Max (Change)	20,000	18,000	20,000
9.6 Min (Change)	40,000	35,000	41,000
9.6 Max (Change)	39,000	35,000	38,000
Onroad	**2012**	**2015**	**2020**
Reference Inventory	2,345,000	1,935,000	1,594,000
7.2 Min (Change)	5,000	2,000	0
7.2 Max (Change)	4,000	1,000	0
9.6 Min (Change)	10,000	3,000	0
9.6 Max (Change)	9,000	3,000	0
Nonroad	**2012**	**2015**	**2020**
Reference Inventory	231,000	245,000	262,000
7.2 Min (Change)	14,000	15,000	21,000
7.2 Max (Change)	16,000	17,000	20,000
9.6 Min (Change)	30,000	32,000	41,000
9.6 Max (Change)	30,000	32,000	37,000

Table 4.1-7 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.

For all air toxics shown, the most extreme changes occur in the 9.6 Min case. The data suggest that, in 2012, total benzene emissions will decrease by as much as 6% due to decreases in both onroad and nonroad emissions. Total formaldehyde emissions increase by up to 2% due to increases in both onroad and nonroad emissions. Total acetaldehyde emissions increase by as much as 48% due to increases in both onroad and nonroad emissions. Total 1,3-butadiene emissions decrease by about 4% due to decreases in both onroad and nonroad emissions.

Generally, the trends in 2015 and 2020 parallel those of 2012. Benzene maintains a drop of up to about 6% with increased ethanol use. Formaldehyde continues to increase with ethanol use, by as much as 3%. Acetaldehyde also increases with greater ethanol use, by as much as roughly 50%. Finally, 1,3-butadiene maintains a decrease in emissions with ethanol use, by as much as 4%.

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 Inventory	177,000	18,200	40,200	19,800
7.2 Min (Change)	-6,000	-500	300	6,200
7.2 Max (Change)	-3,000	-300	0	5,000
9.6 Min (Change)	-11,000	-800	800	9,600
9.6 Max (Change)	-8,000	-600	500	8,500
Onroad				
Reference Inventory	124,000	11,600	29,900	15,500
7.2 Min (Change)	-5,000	-400	300	4,900
7.2 Max (Change)	-3,000	-200	0	3,700
9.6 Min (Change)	-8,000	-600	600	7,400
9.6 Max (Change)	-6,000	-400	400	6,400
Nonroad				
Reference Inventory	53,000	6,700	10,200	4,300
7.2 Min (Change)	-1,000	-200	200	1,300
7.2 Max (Change)	0	-200	100	1,300
9.6 Min (Change)	-3,000	-400	300	2,200
9.6 Max (Change)	-2,000	-300	200	2,100

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 five 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 in some cases. Onroad emissions decrease in all cases, while nonroad trends across the years are mixed.

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			
Total	**2012**	**2015**	**2020**
Reference Inventory	5,775,000	5,459,000	5,218,000
7.2 Min (Change)	4,000	-1,000	10,000
7.2 Max (Change)	-8,000	-10,000	-10,000
9.6 Min (Change)	14,000	6,000	17,000
9.6 Max (Change)	-5,000	-9,000	-6,000
Onroad	**2012**	**2015**	**2020**
Reference Inventory	3,350,000	3,193,000	3,159,000
7.2 Min (Change)	-6,000	-13,000	-23,000
7.2 Max (Change)	-4,000	-7,000	-11,000
9.6 Min (Change)	-4,000	-15,000	-30,000
9.6 Max (Change)	-4,000	-11,000	-20,000
Nonroad	**2012**	**2015**	**2020**
Reference Inventory	2,425,000	2,266,000	2,059,000
7.2 Min (Change)	10,000	13,000	33,000
7.2 Max (Change)	-4,000	-3,000	0
9.6 Min (Change)	18,000	21,000	47,000
9.6 Max (Change)	-1,000	2,000	14,000

Table 4.1-9 shows ethanol impacts on CO inventories for each of the five cases of renewable fuel use in years 2012, 2015, and 2020. These figures are the same as those presented for the primary analysis, since the EPA Predictive Models do not address CO emissions. In any given year, the data suggest that total CO emissions will decrease as ethanol use increases. The largest reduction is seen in the 9.6 Max case; this decrease is still less than 4% of the Reference inventory for total emissions.

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			
Total	**2012**	**2015**	**2020**
Reference Inventory	64,799,000	64,328,000	64,827,000
7.2 Min (Change)	-843,000	-818,000	-36,000
7.2 Max (Change)	-1,229,000	-1,231,000	-1,119,000
9.6 Min (Change)	-1,971,000	-1,953,000	-992,000
9.6 Max (Change)	-2,319,000	-2,330,000	-1,980,000
Onroad	**2012**	**2015**	**2020**
Reference Inventory	37,671,000	36,237,000	35,921,000
7.2 Min (Change)	-202,000	-173,000	-114,000
7.2 Max (Change)	-234,000	-209,000	-167,000
9.6 Min (Change)	-381,000	-328,000	-212,000
9.6 Max (Change)	-402,000	-354,000	-271,000
Nonroad	**2012**	**2015**	**2020**
Reference Inventory	27,128,000	28,090,000	28,906,000
7.2 Min (Change)	-642,000	-645,000	78,000
7.2 Max (Change)	-995,000	-1,021,000	-952,000
9.6 Min (Change)	-1,590,000	-1,625,000	-780,000
9.6 Max (Change)	-1,918,000	-1,975,000	-1,709,000

Table 4.1-10 shows ethanol impacts on NOx inventories for each of the five 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 9.6 Min case, where the increase in total emissions is as high as 4.7% of the Reference inventory.

As in the primary analysis, nonroad NOx emissions increase much greater than onroad emissions. While onroad inventories increase up to 2.9%, nonroad inventories increase upwards of 15% in the 9.6 Min 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			
Total	**2012**	**2015**	**2020**
Reference Inventory	2,610,000	2,211,000	1,883,000
7.2 Min (Change)	49,000	44,000	46,000
7.2 Max (Change)	45,000	40,000	40,000
9.6 Min (Change)	95,000	87,000	88,000
9.6 Max (Change)	89,000	81,000	79,000
Onroad	**2012**	**2015**	**2020**
Reference Inventory	2,379,000	1,966,000	1,621,000
7.2 Min (Change)	35,000	29,000	25,000
7.2 Max (Change)	29,000	24,000	20,000
9.6 Min (Change)	65,000	55,000	47,000
9.6 Max (Change)	59,000	49,000	42,000
Nonroad	**2012**	**2015**	**2020**
Reference Inventory	231,000	245,000	262,000
7.2 Min (Change)	14,000	15,000	21,000
7.2 Max (Change)	16,000	17,000	20,000
9.6 Min (Change)	30,000	32,000	41,000
9.6 Max (Change)	30,000	32,000	37,000

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 Cases (Tons/Year)

Sensitivity Case	Benzene	1,3-Butadiene	Formaldehyde	Acetaldehyde
Total				
Reference Inventory	175,000	17,900	39,300	19,200
7.2 Min (Change)	-9,000	-600	0	5,800
7.2 Max (Change)	-5,000	-400	-200	4,700
9.6 Min (Change)	-14,000	-1,100	300	9,000
9.6 Max (Change)	-10,000	-800	0	8,000
Onroad				
Reference Inventory	121,000	11,300	29,100	14,900
7.2 Min (Change)	-6,000	-500	-100	4,500
7.2 Max (Change)	-3,000	-300	-200	3,400
9.6 Min (Change)	-10,000	-800	100	6,800
9.6 Max (Change)	-7,000	-600	-100	5,900
Nonroad				
Reference Inventory	53,000	6,700	10,200	4,300
7.2 Min (Change)	-1,000	-200	200	1,300
7.2 Max (Change)	0	-200	100	1,300
9.6 Min (Change)	-3,000	-400	300	2,200
9.6 Max (Change)	-2,000	-300	200	2,100

As in the primary analysis, the most extreme changes in the sensitivity analysis tend to occur in the 9.6 Min case. The data suggest that, in 2012, total benzene emissions will decrease by as much as 8% due to decreases in both onroad and nonroad emissions.[LL] Total formaldehyde emissions may either increase or decrease, but the either way the change is less than 1%. Nonroad formaldehyde emissions tend to increase, while onroad emissions tend to decrease, except for the 9.6 Min case. Total acetaldehyde emissions increase by as much as 47% due to increases in both onroad and nonroad emissions. Total 1,3-butadiene emissions decrease by about 6% due to decreases in both onroad and nonroad emissions.

4.1.3.3 Local and Regional VOC and NOx Emissions in July 2012

We also estimate the percentage change in July 2012 for VOC and NOx 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. 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

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[LL] Just prior to publication of the NPRM, we discovered an error in the MOBILE6 algorithms for estimating the impact of oxygenate use on non-benzene emissions. This error led to an over-estimation of the reduction in non-exhaust benzene emissions due to increased ethanol use. We will fix this error for the FRM analysis. We believe that the size of the error is small (i.e., the 8% reduction in benzene emissions may drop to 7% with the correction).

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 and NOx emission inventories for these three types of areas when compared to the 2012 reference case. While ethanol use is going up in the vast majority of the nation, ethanol use in RFG areas under the “Minimum Use in RFG” cases is actually decreasing compared to the 2012 reference case. This is important to note in order to understand the changes in emissions indicated.

Table 4.1-12.
Change in Emissions from Gasoline Vehicles and Equipment in Counties Where Ethanol Use Changed Significantly, July 2012, Primary Analysis

Ethanol Use	7.2 Billion Gallons		9.6 Billion Gallons	
Ethanol Use in RFG	Minimum	Maximum	Minimum	Maximum
RFG Areas				
Ethanol Use	Down	Up	Down	Up
VOC	1.6%	0.4%	1.6%	0.4%
NOx	-5.2%	2.4%	-5.2%	2.4%
Low RVP Areas				
Ethanol Use	Up	Up	Up	Up
VOC	3.1%	3.2%	4.1%	3.5%
NOx	4.1%	6.0%	4.8%	4.4%
Other Areas				
Ethanol Use	Up	Up	Up	Up
VOC	4.1%	4.1%	5.4%	4.4%
NOx	4.6%	6.0%	5.8%	4.8%

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 and NOx 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 Emissions from Gasoline Vehicles and Equipment in Counties Where Ethanol Use Changed Significantly, July 2012, Sensitivity Analysis

	7.2 Bgal Min	7.2 Bgal Max	9.6 Bgal Min	9.6 Bgal Max
RFG Areas				
Ethanol Use	Down	Up	Down	Up
VOC	2.6%	0.2%	2.6%	0.2%
NOx	-9.0%	4.7%	-9.0%	4.7%
Low RVP Areas				
Ethanol Use	Up	Up	Up	Up
VOC	2.1%	2.1%	3.1%	2.5%
NOx	8.2%	10.6%	9.8%	8.9%
Other Areas				
Ethanol Use	Up	Up	Up	Up
VOC	3.4%	3.4%	4.6%	3.7%
NOx	8.4%	10.1%	10.3%	8.8%

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

Increased biodiesel use is expected to have a small effect on diesel emissions. As discussed in Chapter 1, biodiesel use totaled 25 million gallons in 2004 and is projected to increase to 300 million gallons in 2012. As the vast majority of the limited emission data on biodiesel use was obtained from onroad engines and vehicles, we assume here that all biodiesel fuel is used in onroad vehicles. This is unlikely to be the case, as farmers in particular, seem likely to use some in their agricultural equipment. However, given the lack of data with which to support a projected emissions impact on nonroad diesel emissions, it is more consistent with the emissions data to assume biodiesel fuel will be used in onroad vehicles.

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.[MM] The volumes of biodiesel produced represent 0.06% and 0.6% of onroad diesel fuel consumption in 2004 and 2012, respectively. In Chapter 3, we presented the emission impacts for a 20 percent biodiesel blend (B20). In terms of B20, these biodiesel volumes represent 0.3% and 3.2% of onroad diesel fuel consumption in 2004 and 2012, respectively.

[MM] 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.

We based the impact of biodiesel use on the CAIR emission inventories for onroad diesels. CAIR inventories are not available for 2012, only for 2015 and 2020. Therefore, we adjusted the 2015 inventories using year-by-year inventories developed for the EPA FRM establishing new PM and NOx emission standards for 2007 and later model year heavy-duty diesels.[NN] This analysis did not address CO emissions, so we assumed that CO emissions were changing in the same way as VOC emissions. Table 4.2-1 shows the expected emission reductions associated with the increase in biodiesel use.

Table 4.2-1.
Annual Emissions Nationwide from Onroad Diesels in 2012

	2015 CAIR Inventory (tons per year)	Ratio of 2012 to 2015 Emissions	2012 Reference Case Inventory (tons per year)	Change in Inventory Due to Biodiesel (tons per year)
VOC	128,000	1.049	135,000	-800
NOx	1,033,000	1.385	1,430,000	800
CO	336,000	1.049	353,000	-1,100
Fine PM	25,000	1.182	27,000	-100

As can be seen, due to the low volume of biodiesel fuel use, the emission effects are very small, essentially 1000 tons per year or less for any of the four pollutants.

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. Based on growth in overall gasoline demand between 2004 and 2012,[OO] this would represent 3.9 billion gallons of ethanol in 2012. Here, we estimate the increase in emissions which will occur with an increase in ethanol production and distribution from 3.9 billion gallons to either 7.2 or 9.6 billion gallons per year.

We describe the emissions associated with producing and distributing ethanol on a per gallon basis in Chapter 3.2.1, where the emissions factors were obtained from DOE's GREET model, version 1.6. 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.

[NN] From Figures II-B-8 thru 10 in the 2007 Onroad Diesel FRM Final RIA, EPA420-R-00-026, December 2000, available in Public Docket No. A-99-06.

[OO] 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)

	Reference Inventory	Increase in Emissions	
		7.2 Billion gallons of ethanol	9.6 Billion gallons of ethanol
VOC	16,000	13,000	22,000
NOx	19,000	16,000	28,000
CO	47,000	39,000	68,000
PM10	26,000	23,000	39,000
SOx	31,000	26,000	45,000

As can be seen, the potential increases in emissions from ethanol production and transportation are of the same order of magnitude as those from ethanol use, with the exception of CO emissions. 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.

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,[PP] this would represent the equivalent of 28 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 28 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.

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	1,300	12,700
NOx	1,400	13,600
CO	800	7,200
PM10	50	1,000
SOx	200	1,800

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

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[PP] 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.

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.

Chapter 4: Appendix

Table 4A-1. VOC Emission Inventories under Various Ethanol Use Cases

	Tons/Year			Change from Reference			%Change from Reference		
PRIMARY CASE									
Total	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	5,837,000	5,536,000	5,316,000	--	--	--	--	--	--
7.2 Min	5,868,000	5,569,000	5,373,000	31,000	33,000	57,000	0.5%	0.6%	1.1%
7.2 Max	5,845,000	5,547,000	5,334,000	8,000	11,000	18,000	0.1%	0.2%	0.3%
9.6 Min	5,894,000	5,597,000	5,407,000	57,000	61,000	91,000	1.0%	1.1%	1.7%
9.6 Max	5,866,000	5,570,000	5,367,000	29,000	34,000	51,000	0.5%	0.6%	1.0%
Onroad	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	3,412,000	3,270,000	3,257,000	--	--	--	--	--	--
7.2 Min	3,432,000	3,291,000	3,281,000	20,000	21,000	24,000	0.6%	0.6%	0.7%
7.2 Max	3,424,000	3,284,000	3,275,000	12,000	14,000	18,000	0.4%	0.4%	0.6%
9.6 Min	3,451,000	3,310,000	3,301,000	39,000	40,000	44,000	1.1%	1.2%	1.4%
9.6 Max	3,441,000	3,302,000	3,294,000	29,000	32,000	37,000	0.8%	1.0%	1.1%
Nonroad	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	2,425,000	2,266,000	2,059,000	--	--	--	--	--	--
7.2 Min	2,435,000	2,279,000	2,092,000	10,000	13,000	33,000	0.4%	0.6%	1.6%
7.2 Max	2,421,000	2,263,000	2,059,000	-4,000	-3,000	0	-0.2%	-0.1%	0.0%
9.6 Min	2,443,000	2,287,000	2,106,000	18,000	21,000	47,000	0.7%	0.9%	2.3%
9.6 Max	2,424,000	2,268,000	2,073,000	-1,000	2,000	14,000	0.0%	0.1%	0.7%
SENSITIVITY CASE									
Total	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	5,775,000	5,459,000	5,218,000	--	--	--	--	--	--
7.2 Min	5,779,000	5,458,000	5,228,000	4,000	-1,000	10,000	0.1%	0.0%	0.2%
7.2 Max	5,767,000	5,449,000	5,208,000	-8,000	-10,000	-10,000	-0.1%	-0.2%	-0.2%
9.6 Min	5,789,000	5,465,000	5,235,000	14,000	6,000	17,000	0.2%	0.1%	0.3%
9.6 Max	5,770,000	5,450,000	5,212,000	-5,000	-9,000	-6,000	-0.1%	-0.2%	-0.1%
Onroad	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	3,350,000	3,193,000	3,159,000	--	--	--	--	--	--
7.2 Min	3,344,000	3,180,000	3,136,000	-6,000	-13,000	-23,000	-0.2%	-0.4%	-0.7%
7.2 Max	3,346,000	3,186,000	3,148,000	-4,000	-7,000	-11,000	-0.1%	-0.2%	-0.3%
9.6 Min	3,346,000	3,178,000	3,129,000	-4,000	-15,000	-30,000	-0.1%	-0.5%	-0.9%
9.6 Max	3,346,000	3,182,000	3,139,000	-4,000	-11,000	-20,000	-0.1%	-0.3%	-0.6%
Nonroad	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	2,425,000	2,266,000	2,059,000	--	--	--	--	--	--
7.2 Min	2,435,000	2,279,000	2,092,000	10,000	13,000	33,000	0.4%	0.6%	1.6%
7.2 Max	2,421,000	2,263,000	2,059,000	-4,000	-3,000	0	-0.2%	-0.1%	0.0%
9.6 Min	2,443,000	2,287,000	2,106,000	18,000	21,000	47,000	0.7%	0.9%	2.3%
9.6 Max	2,424,000	2,268,000	2,073,000	-1,000	2,000	14,000	0.0%	0.1%	0.7%

Table 4A-2. CO Emission Inventories under Various Ethanol Use Cases

	Tons/Year			Change from Reference			%Change from Reference		
PRIMARY CASE									
Total	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	64,799,000	64,328,000	64,827,000	--	--	--	--	--	--
7.2 Min	63,956,000	63,510,000	64,791,000	-843,000	-818,000	-36,000	-1.3%	-1.3%	-0.1%
7.2 Max	63,570,000	63,097,000	63,708,000	-1,229,000	-1,231,000	-1,119,000	-1.9%	-1.9%	-1.7%
9.6 Min	62,828,000	62,375,000	63,835,000	-1,971,000	-1,953,000	-992,000	-3.0%	-3.0%	-1.5%
9.6 Max	62,480,000	61,998,000	62,847,000	-2,319,000	-2,330,000	-1,980,000	-3.6%	-3.6%	-3.1%
Onroad	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	37,671,000	36,237,000	35,921,000	--	--	--	--	--	--
7.2 Min	37,469,000	36,064,000	35,807,000	-202,000	-173,000	-114,000	-0.5%	-0.5%	-0.3%
7.2 Max	37,437,000	36,028,000	35,754,000	-234,000	-209,000	-167,000	-0.6%	-0.6%	-0.5%
9.6 Min	37,290,000	35,909,000	35,709,000	-381,000	-328,000	-212,000	-1.0%	-0.9%	-0.6%
9.6 Max	37,269,000	35,883,000	35,650,000	-402,000	-354,000	-271,000	-1.1%	-1.0%	-0.8%
Nonroad	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	27,128,000	28,090,000	28,906,000	--	--	--	--	--	--
7.2 Min	26,486,000	27,445,000	28,984,000	-642,000	-645,000	78,000	-2.4%	-2.3%	0.3%
7.2 Max	26,133,000	27,069,000	27,954,000	-995,000	-1,021,000	-952,000	-3.7%	-3.6%	-3.3%
9.6 Min	25,538,000	26,465,000	28,126,000	-1,590,000	-1,625,000	-780,000	-5.9%	-5.8%	-2.7%
9.6 Max	25,210,000	26,115,000	27,197,000	-1,918,000	-1,975,000	-1,709,000	-7.1%	-7.0%	-5.9%
SENSITIVITY CASE									
Total	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	64,799,000	64,328,000	64,827,000	--	--	--	--	--	--
7.2 Min	63,956,000	63,510,000	64,791,000	-843,000	-818,000	-36,000	-1.3%	-1.3%	-0.1%
7.2 Max	63,570,000	63,097,000	63,708,000	-1,229,000	-1,231,000	-1,119,000	-1.9%	-1.9%	-1.7%
9.6 Min	62,828,000	62,375,000	63,835,000	-1,971,000	-1,953,000	-992,000	-3.0%	-3.0%	-1.5%
9.6 Max	62,480,000	61,998,000	62,847,000	-2,319,000	-2,330,000	-1,980,000	-3.6%	-3.6%	-3.1%
Onroad	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	37,671,000	36,237,000	35,921,000	--	--	--	--	--	--
7.2 Min	37,469,000	36,064,000	35,807,000	-202,000	-173,000	-114,000	-0.5%	-0.5%	-0.3%
7.2 Max	37,437,000	36,028,000	35,754,000	-234,000	-209,000	-167,000	-0.6%	-0.6%	-0.5%
9.6 Min	37,290,000	35,909,000	35,709,000	-381,000	-328,000	-212,000	-1.0%	-0.9%	-0.6%
9.6 Max	37,269,000	35,883,000	35,650,000	-402,000	-354,000	-271,000	-1.1%	-1.0%	-0.8%
Nonroad	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	27,128,000	28,090,000	28,906,000	--	--	--	--	--	--
7.2 Min	26,486,000	27,445,000	28,984,000	-642,000	-645,000	78,000	-2.4%	-2.3%	0.3%
7.2 Max	26,133,000	27,069,000	27,954,000	-995,000	-1,021,000	-952,000	-3.7%	-3.6%	-3.3%
9.6 Min	25,538,000	26,465,000	28,126,000	-1,590,000	-1,625,000	-780,000	-5.9%	-5.8%	-2.7%
9.6 Max	25,210,000	26,115,000	27,197,000	-1,918,000	-1,975,000	-1,709,000	-7.1%	-7.0%	-5.9%

Table 4A-3. NOx Emission Inventories under Various Ethanol Use Cases

	Tons/Year			Change from Reference			%Change from Reference		
PRIMARY CASE									
Total	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	2,576,000	2,180,000	1,856,000	--	--	--	--	--	--
7.2 Min	2,595,000	2,197,000	1,877,000	19,000	17,000	21,000	0.7%	0.8%	1.1%
7.2 Max	2,596,000	2,198,000	1,876,000	20,000	18,000	20,000	0.8%	0.8%	1.1%
9.6 Min	2,616,000	2,215,000	1,897,000	40,000	35,000	41,000	1.6%	1.6%	2.2%
9.6 Max	2,615,000	2,215,000	1,894,000	39,000	35,000	38,000	1.5%	1.6%	2.0%
Onroad	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	2,345,000	1,935,000	1,594,000	--	--	--	--	--	--
7.2 Min	2,350,000	1,937,000	1,594,000	5,000	2,000	0	0.2%	0.1%	0.0%
7.2 Max	2,349,000	1,936,000	1,594,000	4,000	1,000	0	0.2%	0.1%	0.0%
9.6 Min	2,355,000	1,938,000	1,594,000	10,000	3,000	0	0.4%	0.2%	0.0%
9.6 Max	2,354,000	1,938,000	1,594,000	9,000	3,000	0	0.4%	0.2%	0.0%
Nonroad	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	231,000	245,000	262,000	--	--	--	--	--	--
7.2 Min	245,000	260,000	283,000	14,000	15,000	21,000	6.1%	6.1%	8.0%
7.2 Max	247,000	262,000	282,000	16,000	17,000	20,000	6.9%	6.9%	7.6%
9.6 Min	261,000	277,000	303,000	30,000	32,000	41,000	13.0%	13.1%	15.6%
9.6 Max	261,000	277,000	299,000	30,000	32,000	37,000	13.0%	13.1%	14.1%
SENSITIVITY CASE									
Total	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	2,610,000	2,211,000	1,883,000	--	--	--	--	--	--
7.2 Min	2,659,000	2,255,000	1,929,000	49,000	44,000	46,000	1.9%	2.0%	2.4%
7.2 Max	2,655,000	2,251,000	1,923,000	45,000	40,000	40,000	1.7%	1.8%	2.1%
9.6 Min	2,705,000	2,298,000	1,971,000	95,000	87,000	88,000	3.6%	3.9%	4.7%
9.6 Max	2,699,000	2,292,000	1,962,000	89,000	81,000	79,000	3.4%	3.7%	4.2%
Onroad	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	2,379,000	1,966,000	1,621,000	--	--	--	--	--	--
7.2 Min	2,414,000	1,995,000	1,646,000	35,000	29,000	25,000	1.5%	1.5%	1.5%
7.2 Max	2,408,000	1,990,000	1,641,000	29,000	24,000	20,000	1.2%	1.2%	1.2%
9.6 Min	2,444,000	2,021,000	1,668,000	65,000	55,000	47,000	2.7%	2.8%	2.9%
9.6 Max	2,438,000	2,015,000	1,663,000	59,000	49,000	42,000	2.5%	2.5%	2.6%
Nonroad	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	231,000	245,000	262,000	--	--	--	--	--	--
7.2 Min	245,000	260,000	283,000	14,000	15,000	21,000	6.1%	6.1%	8.0%
7.2 Max	247,000	262,000	282,000	16,000	17,000	20,000	6.9%	6.9%	7.6%
9.6 Min	261,000	277,000	303,000	30,000	32,000	41,000	13.0%	13.1%	15.6%
9.6 Max	261,000	277,000	299,000	30,000	32,000	37,000	13.0%	13.1%	14.1%

Table 4A-4. Benzene Emission Inventories under Various Ethanol Use Cases

	Tons/Year			**Change from Reference**			**%Change from Reference**		
PRIMARY CASE									
Total	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	177,000	175,000	180,000	--	--	--	--	--	--
7.2 Min	171,000	169,000	173,000	-6,000	-6,000	-7,000	-3.4%	-3.4%	-3.9%
7.2 Max	174,000	172,000	176,000	-3,000	-3,000	-4,000	-1.7%	-1.7%	-2.2%
9.6 Min	166,000	165,000	169,000	-11,000	-10,000	-11,000	-6.2%	-5.7%	-6.1%
9.6 Max	169,000	167,000	172,000	-8,000	-8,000	-8,000	-4.5%	-4.6%	-4.4%
Onroad	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	124,000	124,000	132,000	--	--	--	--	--	--
7.2 Min	119,000	119,000	126,000	-5,000	-5,000	-6,000	-4.0%	-4.0%	-4.5%
7.2 Max	121,000	122,000	129,000	-3,000	-2,000	-3,000	-2.4%	-1.6%	-2.3%
9.6 Min	116,000	116,000	123,000	-8,000	-8,000	-9,000	-6.5%	-6.5%	-6.8%
9.6 Max	118,000	119,000	126,000	-6,000	-5,000	-6,000	-4.8%	-4.0%	-4.5%
Nonroad	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	53,000	51,000	48,000	--	--	--	--	--	--
7.2 Min	52,000	49,000	47,000	-1,000	-2,000	-1,000	-1.9%	-3.9%	-2.1%
7.2 Max	53,000	50,000	48,000	0	-1,000	0	0.0%	-2.0%	0.0%
9.6 Min	50,000	48,000	46,000	-3,000	-3,000	-2,000	-5.7%	-5.9%	-4.2%
9.6 Max	51,000	49,000	46,000	-2,000	-2,000	-2,000	-3.8%	-3.9%	-4.2%
SENSITIVITY CASE									
Total	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	175,000	172,000	175,000	--	--	--	--	--	--
7.2 Min	166,000	164,000	167,000	-9,000	-8,000	-8,000	-5.1%	-4.7%	-4.6%
7.2 Max	170,000	168,000	171,000	-5,000	-4,000	-4,000	-2.9%	-2.3%	-2.3%
9.6 Min	161,000	159,000	161,000	-14,000	-13,000	-14,000	-8.0%	-7.6%	-8.0%
9.6 Max	165,000	162,000	165,000	-10,000	-10,000	-10,000	-5.7%	-5.8%	-5.7%
Onroad	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	121,000	121,000	127,000	--	--	--	--	--	--
7.2 Min	115,000	114,000	120,000	-6,000	-7,000	-7,000	-5.0%	-5.8%	-5.5%
7.2 Max	118,000	117,000	123,000	-3,000	-4,000	-4,000	-2.5%	-3.3%	-3.1%
9.6 Min	111,000	110,000	116,000	-10,000	-11,000	-11,000	-8.3%	-9.1%	-8.7%
9.6 Max	114,000	113,000	119,000	-7,000	-8,000	-8,000	-5.8%	-6.6%	-6.3%
Nonroad	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	53,000	51,000	48,000	--	--	--	--	--	--
7.2 Min	52,000	49,000	47,000	-1,000	-2,000	-1,000	-1.9%	-3.9%	-2.1%
7.2 Max	53,000	50,000	48,000	0	-1,000	0	0.0%	-2.0%	0.0%
9.6 Min	50,000	48,000	46,000	-3,000	-3,000	-2,000	-5.7%	-5.9%	-4.2%
9.6 Max	51,000	49,000	46,000	-2,000	-2,000	-2,000	-3.8%	-3.9%	-4.2%

Table 4A-5. Acetaldehyde Emission Inventories under Various Ethanol Use Cases

	Tons/Year			**Change from Reference**			**%Change from Reference**		
PRIMARY CASE									
Total	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	19,800	19,900	20,900	--	--	--	--	--	--
7.2 Min	26,000	26,300	27,900	6,200	6,400	7,000	31.3%	32.2%	33.5%
7.2 Max	24,800	25,100	26,400	5,000	5,200	5,500	25.3%	26.1%	26.3%
9.6 Min	29,400	29,700	31,500	9,600	9,800	10,600	48.5%	49.2%	50.7%
9.6 Max	28,300	28,500	30,100	8,500	8,600	9,200	42.9%	43.2%	44.0%
Onroad	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	15,500	15,800	17,000	--	--	--	--	--	--
7.2 Min	20,400	21,000	22,900	4,900	5,200	5,900	31.6%	32.9%	34.7%
7.2 Max	19,200	19,700	21,400	3,700	3,900	4,400	23.9%	24.7%	25.9%
9.6 Min	22,900	23,600	25,700	7,400	7,800	8,700	47.7%	49.4%	51.2%
9.6 Max	21,900	22,400	24,400	6,400	6,600	7,400	41.3%	41.8%	43.5%
Nonroad	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	4,300	4,100	3,900	--	--	--	--	--	--
7.2 Min	5,600	5,300	5,000	1,300	1,200	1,100	30.2%	29.3%	28.2%
7.2 Max	5,600	5,400	5,000	1,300	1,300	1,100	30.2%	31.7%	28.2%
9.6 Min	6,500	6,100	5,800	2,200	2,000	1,900	51.2%	48.8%	48.7%
9.6 Max	6,400	6,100	5,700	2,100	2,000	1,800	48.8%	48.8%	46.2%
SENSITIVITY CASE									
Total	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	19,200	19,200	20,000	--	--	--	--	--	--
7.2 Min	25,000	25,100	26,300	5,800	5,900	6,300	30.2%	30.7%	31.5%
7.2 Max	23,900	23,900	25,000	4,700	4,700	5,000	24.5%	24.5%	25.0%
9.6 Min	28,200	28,300	29,600	9,000	9,100	9,600	46.9%	47.4%	48.0%
9.6 Max	27,200	27,100	28,300	8,000	7,900	8,300	41.7%	41.1%	41.5%
Onroad	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	14,900	15,100	16,200	--	--	--	--	--	--
7.2 Min	19,400	19,800	21,400	4,500	4,700	5,200	30.2%	31.1%	32.1%
7.2 Max	18,300	18,600	19,900	3,400	3,500	3,700	22.8%	23.2%	22.8%
9.6 Min	21,700	22,100	23,800	6,800	7,000	7,600	45.6%	46.4%	46.9%
9.6 Max	20,800	21,100	22,600	5,900	6,000	6,400	39.6%	39.7%	39.5%
Nonroad	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	4,300	4,100	3,900	--	--	--	--	--	--
7.2 Min	5,600	5,300	5,000	1,300	1,200	1,100	30.2%	29.3%	28.2%
7.2 Max	5,600	5,400	5,000	1,300	1,300	1,100	30.2%	31.7%	28.2%
9.6 Min	6,500	6,100	5,800	2,200	2,000	1,900	51.2%	48.8%	48.7%
9.6 Max	6,400	6,100	5,700	2,100	2,000	1,800	48.8%	48.8%	46.2%

Table 4A-6. Formaldehyde Emission Inventories under Various Ethanol Use Cases

	Tons/Year			**Change from Reference**			**%Change from Reference**		
PRIMARY CASE									
Total	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	40,200	39,900	41,300	--	--	--	--	--	--
7.2 Min	40,500	40,400	41,900	300	500	600	0.7%	1.3%	1.5%
7.2 Max	40,200	40,000	41,400	0	100	100	0.0%	0.3%	0.2%
9.6 Min	41,000	41,000	42,600	800	1,100	1,300	2.0%	2.8%	3.1%
9.6 Max	40,700	40,600	42,100	500	700	800	1.2%	1.8%	1.9%
Onroad	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	29,900	30,200	32,300	--	--	--	--	--	--
7.2 Min	30,200	30,600	32,800	300	400	500	1.0%	1.3%	1.5%
7.2 Max	29,900	30,300	32,400	0	100	100	0.0%	0.3%	0.3%
9.6 Min	30,500	31,000	33,300	600	800	1,000	2.0%	2.6%	3.1%
9.6 Max	30,300	30,700	32,900	400	500	600	1.3%	1.7%	1.9%
Nonroad	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	10,200	9,700	9,000	--	--	--	--	--	--
7.2 Min	10,400	9,800	9,100	200	100	100	2.0%	1.0%	1.1%
7.2 Max	10,300	9,800	9,000	100	100	0	1.0%	1.0%	0.0%
9.6 Min	10,500	10,000	9,300	300	300	300	2.9%	3.1%	3.3%
9.6 Max	10,400	9,900	9,200	200	200	200	2.0%	2.1%	2.2%
SENSITIVITY CASE									
Total	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	39,300	38,800	39,900	--	--	--	--	--	--
7.2 Min	39,300	38,900	39,900	0	100	0	0.0%	0.3%	0.0%
7.2 Max	39,100	38,700	39,700	-200	-100	-200	-0.5%	-0.3%	-0.5%
9.6 Min	39,600	39,100	40,200	300	300	300	0.8%	0.8%	0.8%
9.6 Max	39,300	38,900	40,000	0	100	100	0.0%	0.3%	0.3%
Onroad	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	29,000	29,100	30,900	--	--	--	--	--	--
7.2 Min	28,900	29,000	30,800	-100	-100	-100	-0.3%	-0.3%	-0.3%
7.2 Max	28,800	28,900	30,700	-200	-200	-200	-0.7%	-0.7%	-0.6%
9.6 Min	29,100	29,200	30,900	100	100	0	0.3%	0.3%	0.0%
9.6 Max	28,900	29,000	30,800	-100	-100	-100	-0.3%	-0.3%	-0.3%
Nonroad	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	10,200	9,700	9,000	--	--	--	--	--	--
7.2 Min	10,400	9,800	9,100	200	100	100	2.0%	1.0%	1.1%
7.2 Max	10,300	9,800	9,000	100	100	0	1.0%	1.0%	0.0%
9.6 Min	10,500	10,000	9,300	300	300	300	2.9%	3.1%	3.3%
9.6 Max	10,400	9,900	9,200	200	200	200	2.0%	2.1%	2.2%

Table 4A-7. 1,3-Butadiene Emission Inventories under Various Ethanol Use Cases

	Tons/Year			**Change from Reference**			**%Change from Reference**		
PRIMARY CASE									
Total	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	18,200	18,000	18,500	--	--	--	--	--	--
7.2 Min	17,700	17,500	18,000	-500	-500	-500	-2.7%	-2.8%	-2.7%
7.2 Max	17,900	17,700	18,200	-300	-300	-300	-1.6%	-1.7%	-1.6%
9.6 Min	17,400	17,200	17,700	-800	-800	-800	-4.4%	-4.4%	-4.3%
9.6 Max	17,600	17,400	17,900	-600	-600	-600	-3.3%	-3.3%	-3.2%
Onroad	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	11,600	11,700	12,500	--	--	--	--	--	--
7.2 Min	11,200	11,300	12,100	-400	-400	-400	-3.4%	-3.4%	-3.2%
7.2 Max	11,400	11,500	12,300	-200	-200	-200	-1.7%	-1.7%	-1.6%
9.6 Min	11,000	11,100	12,000	-600	-600	-500	-5.2%	-5.1%	-4.0%
9.6 Max	11,200	11,300	12,100	-400	-400	-400	-3.4%	-3.4%	-3.2%
Nonroad	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	6,700	6,300	6,000	--	--	--	--	--	--
7.2 Min	6,500	6,200	5,900	-200	-100	-100	-3.0%	-1.6%	-1.7%
7.2 Max	6,500	6,200	5,900	-200	-100	-100	-3.0%	-1.6%	-1.7%
9.6 Min	6,300	6,100	5,800	-400	-200	-200	-6.0%	-3.2%	-3.3%
9.6 Max	6,400	6,100	5,800	-300	-200	-200	-4.5%	-3.2%	-3.3%
SENSITIVITY CASE									
Total	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	17,900	17,600	18,000	--	--	--	--	--	--
7.2 Min	17,300	17,000	17,300	-600	-600	-700	-3.4%	-3.4%	-3.9%
7.2 Max	17,500	17,200	17,600	-400	-400	-400	-2.2%	-2.3%	-2.2%
9.6 Min	16,800	16,600	16,900	-1,100	-1,000	-1,100	-6.1%	-5.7%	-6.1%
9.6 Max	17,100	16,800	17,200	-800	-800	-800	-4.5%	-4.5%	-4.4%
Onroad	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	11,300	11,300	12,000	--	--	--	--	--	--
7.2 Min	10,800	10,800	11,500	-500	-500	-500	-4.4%	-4.4%	-4.2%
7.2 Max	11,000	11,000	11,700	-300	-300	-300	-2.7%	-2.7%	-2.5%
9.6 Min	10,500	10,500	11,100	-800	-800	-900	-7.1%	-7.1%	-7.5%
9.6 Max	10,700	10,700	11,400	-600	-600	-600	-5.3%	-5.3%	-5.0%
Nonroad	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**	**2012**	**2015**	**2020**
Reference	6,700	6,300	6,000	--	--	--	--	--	--
7.2 Min	6,500	6,200	5,900	-200	-100	-100	-3.0%	-1.6%	-1.7%
7.2 Max	6,500	6,200	5,900	-200	-100	-100	-3.0%	-1.6%	-1.7%
9.6 Min	6,300	6,100	5,800	-400	-200	-200	-6.0%	-3.2%	-3.3%
9.6 Max	6,400	6,100	5,800	-300	-200	-200	-4.5%	-3.2%	-3.3%

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 for the 7.2 billion gallon ethanol use case. 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).[74]

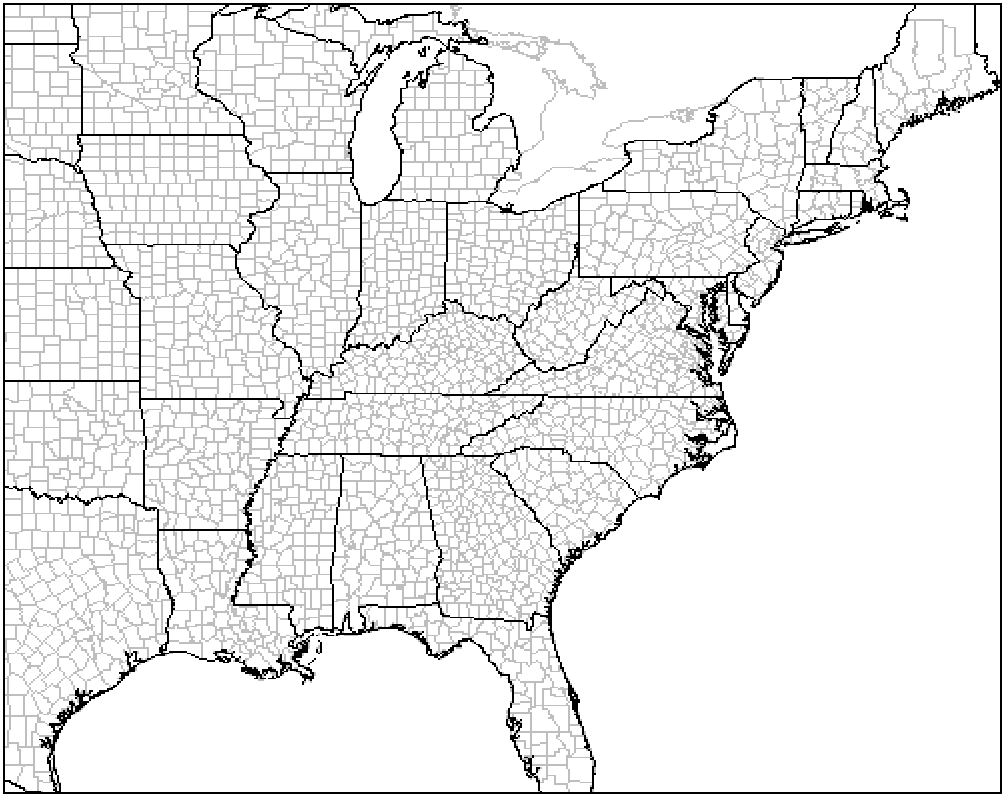
The foundation for the ozone response surface metamodeling analyses was the CAMx modeling done in support of the final Clean Air Interstate Rule (CAIR). The CAIR modeling is fully described in the CAIR Air Quality Modeling Technical Support Document, but a brief description is provided below.[75] The 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 proposed standards.[76] 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.[77] 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 proposed 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 the ozone design value metric. Validation was performed and is summarized in the AQMTSD. 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.

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 emission impacts to only those states. The Ozone RSM also only projects ozone impacts for the years 2015, 2020, and 2030. Since we develop most of our impacts of the RFS for the year 2012, we chose to run the Ozone RSM for the closest year to 2012, or 2015. Finally, the Ozone RSM is designed to accept emission changes in terms of total onroad and total nonroad sources, respectively. 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, the inclusion of diesel emissions and the focus on 2015 instead of 2012. The results of these calculations are shown in Table 5.1-1.

Table 5.1-1.
Emission Inputs to Ozone Modeling: Change in Mobile Sources Emissions in 37 Eastern States where Ethanol Use Changes Significantly, July 2015 (percent change)

Case	RFG Nonattainment		Low RVP Nonattainment		Attainment	
	VOC	NOx	VOC	NOx	VOC	NOx
Primary Analysis						
Onroad						
7.2 Min	-1.8	-0.2	6.0	0.2	7.1	0.2
7.2 Max	3.4	0.1	6.7	0.3	7.6	0.2
Nonroad						
7.2 Min	4.7	-3.5	0.5	3.6	2.3	2.4
7.2 Max	-2.0	1.4	0.5	6.3	2.3	2.7
Sensitivity Analysis						
Onroad						
7.2 Min	0.6	-3.2	3.6	3.7	5.1	3.0
7.2 Max	2.8	1.7	3.7	4.3	5.3	3.3
Nonroad						
7.2 Min	4.7	-3.5	0.5	3.6	2.3	2.4
7.2 Max	-2.0	1.4	0.5	6.3	2.3	2.7

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 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.

The second 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.

We chose to use the first Ozone RSM run as our base for further adjustment. The main reason for doing so involved the possibility that some nonattainment areas as defined in the Ozone RSM might have 9 RVP fuel. The percentage changes in VOC and NOx emissions for Low RVP areas were more similar to those for 9 RVP areas than those for RFG areas. Thus, the first run more closely represented the emission impacts expected in these 9 RVP, nonattainment areas than the second run.

The first adjustment made to the first Ozone RSM run was to 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.

The second adjustment made to the first Ozone RSM run was to substitute the projected ozone impacts for RFG areas with those from the second run. Clearly, the second run does a better job of representing the emission changes expected in RFG areas. Since the areas upwind of RFG areas tend to have 9 RVP fuel, as opposed to Low RVP fuel, the second run should also reasonably represent ozone transport from non-RFG areas. 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 Chapter 5 Appendix presents the impacts of increased ethanol use on a number of alternative measures of ambient ozone concentration.

Table 5.1-2.
Impact of Increased Ethanol Use on 8-hour Design Value Ozone Levels in 2015 (ppb): 7.2 Billion Gallons of Ethanol Use Scenario

	Minimum Use in RFG	Maximum Use in RFG
Primary Analysis		
Minimum Change	-0.030	-0.025
Maximum Change	0.395	0.526
Average Change Across 37 States	0.062	0.047
Population-Weighted Change Across 37 States	0.057	0.055
Average Change Where Ethanol Use Changed Significantly States	0.137	0.171
Population-Weighted Change Where Ethanol Use Changed Significantly States	0.134	0.129
Sensitivity Analysis		
Minimum Change	-0.180	0.000
Maximum Change	0.637	0.625
Average Change Across 37 States	0.134	0.088
Population-Weighted Change Across 37 States	0.114	0.106
Average Change Where Ethanol Use Changed Significantly States	0.294	0.318
Population-Weighted Change Where Ethanol Use Changed Significantly States	0.268	0.250

As can be seen, ozone levels generally increase to a small degree 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 0.055-0.057 ppb. Since the 8-hour ambient ozone standard is 0.08 ppm (85 ppb), this increase represents about 0.07 percent of the standard, a very small percentage[QQ]. 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 0.129-0.134 ppb. This increase represents about 0.16 percent of the standard, still a very small percentage.

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 roughly twice as high, or 0.106-0.114 ppb. This increase represents about 0.13 percent of the standard, still a very small percentage. When we focus just on those areas where the market share of ethanol blends changed by 50 percent or

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[QQ] Appendix I of 40 CFR Part 50.

more, the population-weighted increase in ambient ozone levels rises to 0.250-0.268 ppb. This increase represents about 0.32 percent of the standard.

As we show in Table 5.1-2, the expanded use of ethanol in fuel is projected to result in a small population-weighted net increase in future ozone. For much of the ozone RSM domain, the net increase is generally so small as to be rendered insignificant when presenting design values. Nonetheless, there are areas where the ozone increase is more significant. For the primary analysis, we present the counties with the largest increases in the ozone design value in Table 5.1-3 and Table 5.1-4. Each table presents the county level ozone design value results of the minimum use in RFG areas scenario and the maximum use in RFG areas scenario, respectively. 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 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. 2015 Ozone Response Surface Metamodeling Results[a]: Primary RFS 7.2 Billion Gallons of Ethanol Scenario, Minimum Use in RFG, Counties with Largest Increases in the Ozone 8hr Design Value[b] (ppb) Due to Increased Use of Ethanol

State Name	County Name	2015 Baseline (Post-CAIR)[c]	2015 With Ethanol Use (minimum use in RFG)	Effect of Expanded Ethanol Use (ppb)	2015 Population
Illinois	Cook Co	81.1	81.5	0.4	5,362,932
Wisconsin	Walworth Co	70.1	70.5	0.4	109,939
Indiana	Lake Co	80.7	81.1	0.4	490,796
Maine	Hancock Co	76.8	77.1	0.3	55,606
Indiana	Shelby Co	76.2	76.5	0.3	47,904
Missouri	Cedar Co	68.6	68.9	0.3	14,634
Wisconsin	Rock Co	69.1	69.4	0.3	170,498
Illinois	Du Page Co	66.1	66.4	0.3	1,076,917
Wisconsin	Sheboygan Co	83.6	83.9	0.3	121,785
Ohio	Geauga Co	82.5	82.8	0.3	108,600
Ohio	Clinton Co	75.7	76.0	0.3	50,635
Ohio	Stark Co	71.7	72.0	0.3	384,672
Maine	Penobscot Co	69.5	69.8	0.3	152,896
Maine	York Co	77.6	77.9	0.3	210,006
Indiana	Marion Co	74.6	74.9	0.3	889,645
Ohio	Mahoning Co	74.7	75.0	0.3	248,545
Indiana	Porter Co	78.6	78.9	0.3	176,761
Michigan	Ingham Co	69.0	69.3	0.3	290,178
New York	Westchester Co	83.1	83.4	0.3	950,661
Ohio	Summit Co	77.4	77.7	0.3	557,892

[a] Note that the results of the ozone response surface metamodeling (Ozone RSM) exercise is meant for screening-level purposes only and do not represent results that would be obtained from full-scale photochemical ozone modeling. There are a number of important caveats concerning these estimates: 1) The emission effects of adding ethanol to gasoline are based on extremely limited data for recent vehicles and equipment; 2) The Ozone RSM does not account for changes in CO emissions. Ethanol use should reduce CO emissions significantly, directionally reducing ambient ozone levels in areas where ozone formation is VOC-limited; and, 3) 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 in areas where ozone formation is VOC-limited.

[b] A design value is the mathematically determined pollutant concentration at a particular 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).

[c] 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. 2015 Ozone Response Surface Metamodeling Results[a]: Primary RFS 7.2 Billion Gallons of Ethanol Scenario, Maximum Use in RFG, Counties with Largest Increases in the Ozone 8hr Design Value[b] (ppb) Due to Increased Use of Ethanol

State Name	County Name	2015 Baseline (Post-CAIR)[c]	2015 With Ethanol Use (maximum use in RFG)	Effect of Expanded Ethanol Use (ppb)	2015 Population
Wisconsin	Walworth Co	70.1	70.6	0.5	109,939
Wisconsin	Sheboygan Co	83.6	84.0	0.4	121,785
Wisconsin	Rock Co	69.1	69.5	0.4	170,498
Michigan	Mason Co	74.7	75.0	0.3	32,204
Michigan	Benzie Co	74.0	74.3	0.3	18,857
Michigan	Ingham Co	69.0	69.3	0.3	290,178
Indiana	Shelby Co	76.2	76.5	0.3	47,904
Indiana	Allen Co	72.0	72.3	0.3	362,480
Wisconsin	Winnebago Co	66.3	66.6	0.3	175,935
Michigan	Huron Co	71.9	72.2	0.3	37,530
Wisconsin	Door Co	77.9	78.2	0.3	32,597
Indiana	Elkhart Co	65.8	66.1	0.3	202,845
Indiana	Delaware Co	70.4	70.7	0.3	119,183
Indiana	Marion Co	74.6	74.9	0.3	889,645
Indiana	Posey Co	70.5	70.8	0.3	28,544
Maryland	Frederick Co	74.2	74.5	0.3	254,989
Massachusetts	Middlesex Co	75.8	76.1	0.3	1,498,849
Wisconsin	Fond Du Lac Co	65.9	66.2	0.3	104,289
Wisconsin	Kewaunee Co	75.7	76.0	0.3	20,715
Virginia	Henrico Co	75.5	75.7	0.2	308,516

[a] Note that the results of the ozone response surface metamodeling (Ozone RSM) exercise is meant for screening-level purposes only and do not represent results that would be obtained from full-scale photochemical ozone modeling. There are a number of important caveats concerning these estimates: 1) The emission effects of adding ethanol to gasoline are based on extremely limited data for recent vehicles and equipment; 2) The Ozone RSM does not account for changes in CO emissions. Ethanol use should reduce CO emissions significantly, directionally reducing ambient ozone levels in areas where ozone formation is VOC-limited; and, 3) 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 in areas where ozone formation is VOC-limited.

[b] A design value is the mathematically determined pollutant concentration at a particular 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).

[c] 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).

The Wisconsin Department of Natural Resources recently performed a similar study of the impact of increased ethanol use on ozone.[78] 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.

Of the two ethanol use scenarios which we examined for ozone impacts, the 7.2 Max scenario is closer to that examined by the State of Wisconsin. In the 7.2 Max scenario, RFG in the Midwest continues to contain 10 vol% ethanol in the future, as assumed by Wisconsin. It is interesting that the three counties with the highest predicted ozone increase in the 37 state area covered by the Ozone RSM (and five out of the top eleven counties) are located in Wisconsin (see Table 5.1-4). However, the ozone impacts are well below 1-2 ppb, ranging from 0.4-0.5 ppb. One difference between the estimates made here and those made by the State of Wisconsin is that it appears that Wisconsin performed there modeling for calendar year 2003, while those described above are for 2015. Emission standards applicable to new vehicles and equipment are continually reducing emissions from these sources over time. Per the emission models used here and by the State of Wisconsin (NONROAD and MOBILE6), the effect of fuel quality is generally assumed to be proportional to 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 are likely to be much lower than those predicted by Wisconsin for 2003.

There are a number of important caveats concerning these estimates. 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. For example, the Wisconsin study cited above states that ozone formation in rural Wisconsin is NOx-limited. This includes those Wisconsin counties listed in Tables 5.1-3 and 5.1-4 above. The inability of the Ozone RSM to account for changes in CO emissions, therefore, may have little impact on the direction and magnitude on the predicted level of ambient ozone concentrations in these Wisconsin, and other NOx-limited, counties.

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 proposed 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.

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.

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 used in the calculation of ozone-related health impacts. The changes in these statistics are also very small, and would likely lead to negligible monetized impacts. We therefore do not estimate and monetize ozone health impacts here due to the magnitude of this change and the uncertainty present in the air quality modeling. 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[79,80]. 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 and 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 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 SO2, NOx, and VOC oxidize or otherwise react to form a wide variety of secondary PM. For example, SO2 oxidizes to SO3 and sulfuric acid and NOx oxidizes to NO3 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.[81] 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[82] 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, NO2, 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.[83] 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 NO2 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]=1.0x10^6 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.[84] 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 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[85].

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.

Overall, we expect 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[86]. In contrast, gasoline-fueled vehicles and equipment comprised over 60% of all national gaseous aromatic VOC emissions[RR]. The percentage increase in national NOx emissions due to increased ethanol use should be smaller than the percentage decrease in national emissions of gaseous aromatics. 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.

There are numerous uncertainties associated with these predictions. These uncertainties arise from uncertainty in the emissions inventory of a given area, from uncertainty in the kinetic VOC reaction rate calculations, as well as from the uncertainty in the aerosol yield found experimentally in smog chamber studies and their use in providing mechanisms in models. While these predictions shed light on the VOC functional groups that play the most important role in SOA formation, these estimates are too uncertain to base quantitative estimates of the impact of gaseous VOC emissions on ambient levels of SOA. 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. Therefore, this updated information will not be available in time for the RFS final rulemaking, but should be available in time for the comprehensive study of the Act's fuel requirements which is due in 2008.[SS]

Given these uncertainties and gaps in the available data, we are unable to estimate the cumulative impact that an increase in the future use of ethanol in fuel will have on $PM_{2.5}$ formation. EPA currently utilizes the CMAQ model to predict ambient levels of PM as a function of gaseous and PM emissions. This model includes mechanisms to predict the formation of nitrate PM from NOx emissions. However, it does not currently include any mechanisms addressing the formation of secondary organic PM. EPA is currently developing a model of secondary organic PM from gaseous toluene emissions for incorporation into the CMAQ model in 2007, as mentioned in section 5.2.2. The impact of other aromatic compounds will be added as further research clarifies their role in secondary organic PM formation. Therefore, we expect to be able to quantitatively estimate the impact of decreased toluene emissions and increased NOx emissions due to increased ethanol use as part of the comprehensive analysis of U.S. fuel requirements required by Congress in 2008. As we stated above, however, reductions in the aromatic content of fuel, and the related reduction in

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[RR] Based on internal analyses of emissions inventories.

[SS] Subject to funding.

secondarily formed $PM_{2.5}$, are expected to offset increases in secondarily formed $PM_{2.5}$ as a result of increased emissions of NOx.

Chapter 5: Appendix

Table 5A-1. 2015 Ozone Response Surface Metamodeling Summary Statistics for the RFS Rule[a, b]; Primary Scenario, 7.2 Billion Gallons of Ethanol

8hour Design Value (ppb)		
Statistic	**Minimum Use in RFG**	**Maximum Use in RFG**
Minimum Change	-0.030	-0.025
Maximum Change	0.395	0.526
Average Change	0.062	0.047
Standard Deviation	0.087	0.089
Population-Weighted Change	0.057	0.055
24hr Average (ppb)		
Statistic	**Minimum Use in RFG**	**Maximum Use in RFG**
Minimum Change	-0.105	-0.128
Maximum Change	0.308	0.084
Average Change	0.010	0.005
Standard Deviation	0.018	0.014
Population-Weighted Change	0.025	0.007
1hr Maximum (ppb)		
Statistic	**Minimum Use in RFG**	**Maximum Use in RFG**
Minimum Change	-0.056	-0.070
Maximum Change	0.393	0.153
Average Change	0.019	0.011
Standard Deviation	0.033	0.027
Population-Weighted Change	0.037	0.021
Average 9-to-5 (ppb)		
Statistic	**Minimum Use in RFG**	**Maximum Use in RFG**
Minimum Change	-0.108	-0.145
Maximum Change	0.575	0.211
Average Change	0.023	0.014
Standard Deviation	0.041	0.035
Population-Weighted Change	0.050	0.026
Average 10-to-3 (ppb)		
Statistic	**Minimum Use in RFG**	**Maximum Use in RFG**
Minimum Change	-0.081	-0.076
Maximum Change	0.353	0.167
Average Change	0.015	0.008
Standard Deviation	0.027	0.021
Population-Weighted Change	0.032	0.014

[a] Note that the statistics presented here represent ethanol use changes across the entire 37-state ozone RSM domain.

[b] A design value is the mathematically determined pollutant concentration at a particular 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). The other ozone metrics (24hr average, 1hr maximum, average 9-to-5, and average 10-to-3) are calculated at the ozone RSM grid cell level (based on the CAMx model grid). Air quality metrics are daily values calculated from daily observations (or modeled estimates), or through mathematical manipulations of hourly observations (or modeled estimates). The ozone metrics presented here are those typically used in ozone-related health impact functions.

Table 5A-2. 2015 Ozone Response Surface Metamodeling Summary Statistics for the RFS Rule[a,b]; Sensitivity Scenario, 7.2 Billion Gallons of Ethanol

8hour Design Value (ppb)

Statistic	Minimum Use in RFG	Maximum Use in RFG
Minimum Change	-0.180	0.000
Maximum Change	0.637	0.625
Average Change	0.134	0.088
Standard Deviation	0.164	0.152
Population-Weighted Change	0.114	0.106

24hr Average (ppb)

Statistic	Minimum Use in RFG	Maximum Use in RFG
Minimum Change	-0.113	-0.139
Maximum Change	0.345	0.132
Average Change	0.022	0.011
Standard Deviation	0.038	0.028
Population-Weighted Change	0.042	0.015

1hr Maximum (ppb)

Statistic	Minimum Use in RFG	Maximum Use in RFG
Minimum Change	-0.121	-0.118
Maximum Change	0.635	0.364
Average Change	0.039	0.020
Standard Deviation	0.066	0.050
Population-Weighted Change	0.073	0.041

Average 9-to-5 (ppb)

Statistic	Minimum Use in RFG	Maximum Use in RFG
Minimum Change	-0.155	-0.150
Maximum Change	0.577	0.229
Average Change	0.031	0.015
Standard Deviation	0.052	0.038
Population-Weighted Change	0.062	0.027

Average 10-to-3 (ppb)

Statistic	Minimum Use in RFG	Maximum Use in RFG
Minimum Change	-0.154	-0.149
Maximum Change	0.584	0.225
Average Change	0.031	0.015
Standard Deviation	0.053	0.039
Population-Weighted Change	0.063	0.028

[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.

[b] A design value is the mathematically determined pollutant concentration at a particular 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). The other ozone metrics (24hr average, 1hr maximum, average 9-to-5, and average 10-to-3) are calculated at the ozone RSM grid cell level (based on the CAMx model grid). Air quality metrics are daily values calculated from daily observations (or modeled estimates), or through mathematical manipulations of hourly observations (or modeled estimates). The ozone metrics presented here are those typically used in ozone-related health impact functions.

Chapter 6: Lifecycle Impacts on Fossil Energy and Greenhouse Gases

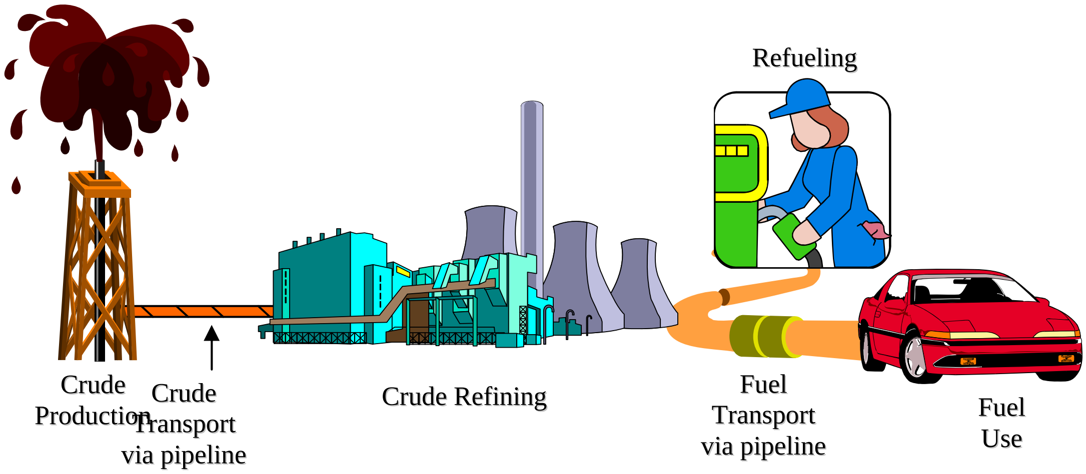
6.1 Lifecycle Modeling

Lifecycle modeling is an established methodology for accounting for all energy and emissions from a production process. It is meant to incorporate the material aspects, input and output, of each step in a product system. This methodology allows you to identify key processes and emission sources in the process, and to equitably compare the impacts of varying products and processes on the consumption of natural resources, pollutant generation and environmental burden. It is important to note that lifecycle modeling provides only general comparisons, based on industry-wide estimates and assumptions. 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 the true 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. There are advantages to both approaches, 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 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 most widely known is 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. This is the model used in the analysis for the Renewable Fuel Standard (RFS) program.

There have been other well-respected lifecycle models and analyses of transportation fuels, but none are as comprehensive and user-friendly as GREET. Most of these analyses use similar lifecycle methodology. The differences in results are often due to differences in the assumptions and projections made throughout the model. 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 energy to produce the ethanol than is contained in the resulting fuel, making it an unattractive transportation fuel. However, this work was based on out-dated farming and ethanol production data, included data not normally considered in lifecycle analysis for fuels, and did not follow the standard methodology for lifecycle analysis. This study emphasizes 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. For this reason, 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 Overview of GREET

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. GREET is the most widely known and 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.

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, as assumed by GREET. Therefore, EPA has modified some of the input variables and assumptions made in the GREET model. We will continue to evaluate these factors in preparation for the final rulemaking. As shown in Section 6.2.3 the fuel pathways from GREET evaluated for this proposal include:

- Petroleum-based gasoline (conventional and RFG blendstock)
- Petroleum-based low sulfur diesel
- Corn ethanol
- Cellulosic ethanol (herbaceous and woody biomass feedstock)
- Soybean-based biodiesel

In the timeframe available for developing this proposal, we chose to concentrate our efforts on those GREET input values that had significant influence on the lifecycle emissions or energy estimates and that were likely to be based on outdated information. We reviewed the input values only for corn-based ethanol, since this fuel is likely to continue to dominate the renewable fuel pool through at least 2012. For cellulosic ethanol and biodiesel the GREET default values were used in this proposal. However, we have also initiated a contract with ANL to investigate a wider variety of GREET input values, including those associated with the following fuel/feedstock pathways:

- Ethanol from corn
- Ethanol from cellulosic materials (hybrid populars, switchgrass, and corn stover)
- Biodiesel from soybean oil
- Methanol from renewable sources
- Natural gas from renewable sources
- Renewable diesel formulations

The contract focuses on the potential fuel production developments and efficiency improvements that could occur within the time-frame of the RFS program. The GREET input value changes resulting from this work are not expected to be available in time for this proposal, but they will be incorporated into revised lifecycle assessments for the 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 proposal. 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 for the final rule to determine if any gasoline or diesel fuel GREET input values should be changed.

A summary of the GREET corn ethanol input values we investigated for this proposal is given below.

6.1.2.1 Wet Mill versus Dry Mill Ethanol Plants

As described in Chapter 1, there are two processes for producing ethanol from corn: wet milling and dry milling. The GREET 1.7 model assumes that 70% of existing ethanol plants are dry mill, and 30% are wet mill. For this analysis, we only consider new or incremental ethanol production and it was assumed that essentially all 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. This trend is discussed in more detail in Chapter 1.

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 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 plants built in the last few years have used natural gas. However, based on specific situations and economics, some new plants are using coal. In addition, 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, has the potential to make ethanol plants more efficient, and to make coal a more attractive energy source for new ethanol plants.

GREET 1.7 assumes that 20% of existing dry mills use coal and 80% use natural gas. For wet mills, the model assumes 40% of existing plants use coal while 60% use natural gas. GREET default factors are meant to represent the average percentage of fuel use for the entire industry, and may not reflect the recent growth in the industry as outlined in Chapter 1. Our analysis for this rule is based on new or incremental production. Therefore, for the current analysis, it was assumed that 10% of all future dry mill plants will use coal for process energy. This is based on detailed analysis of the ethanol industry, near-term plant construction and expansion plans, and projected costs for coal and natural gas. This analysis was discussed in detail in Chapter 1. Future work in preparation for the final rule will evaluate the potential trends for combined heat and power and coal as process fuel.

6.1.2.3 Ethanol Plant Process Efficiency

The ethanol plant process energy use values assumed in GREET 1.7 are 36,000 Btu/gallon of ethanol produced by the dry milling process and 49,950 Btu/gallon of ethanol produced by the wet milling process. The values were selected based upon a review of current scientific and technical literature, including U.S. government estimates from National Renewable Energy Laboratory[87] (NREL), Argonne National Laboratory[88] (ANL), U.S. Department of Agriculture (USDA) ethanol plant survey data[89], and other USDA studies[90].

A 1999 ANL report predicted 2005 ethanol process efficiencies of 36,900 Btu/gallon (dry mill) and 34,000 Btu/gallon (wet mill)[91]. Additionally, the average of then-current ethanol plant process efficiencies from the late-nineties[92] yields ethanol process efficiencies of 41,705 Btu/gallon (dry mill) and 47,918 Btu/gallon (wet mill), values which, when projected to the present, coincide with currently achieved ethanol plant process efficiencies selected for use in this analysis.

These process efficiency estimates also coincide with those used in GREET Version 1.7[93] as well as 1997 projected process efficiency cited in GREET Version 1.5 for year 2005[94]. Therefore, we believe that the default values in GREET are reasonable.

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[95] Version 1.7 and GREET Version 1.5.

Corn transport data is limited, however; Graboski[TT] 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[96] 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. Also, a sensitivity analysis indicates that changing these values will not have a significant impact on the results (halving or doubling the transportation distances changes results by ~1 percent). Therefore, we retained the GREET default values for our analysis.

6.1.2.5 Ethanol Transportation Distances and Modes

The default values in GREET for ethanol transportation and modes are shown in Table 6.1-1. These values correspond to numbers in a USDA study on the energy balance of corn ethanol.[97]

Table 6.1-1. 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 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.[98] The report includes 2002 data from a survey of 21 dry mill

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[TT] 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).

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, 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, different studies will produce different results depending on the underlying assumptions, for example, current or future ethanol production scenario, location of ethanol production and use, etc. 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 6.1-1 were used in this analysis.

6.1.2.6 Corn Yield and Related Inputs

GREET includes a collection of energy use and material inputs to corn farming per bushel (bu) of corn produced. Corn farming input data parameters and default values provided in GREET version 1.7 are shown in Table 6.1-2.

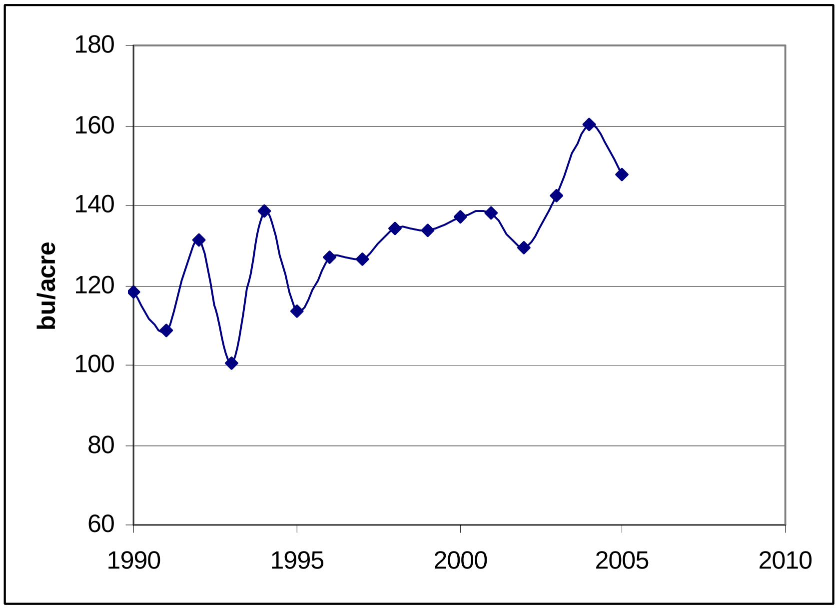
Table 6.1-2. GREET Corn Farming Input Data

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)	460 g/bu
Phosphate Fertilizer (as P_2O_5)	165 g/bu
Potash Fertilizer (as K_2O)	205 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 6.1-2 are based 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 raising over time, see Figure 6.1-2, the annual variation is very volatile[99].

Figure 6.1-2. U.S. Average Corn Yield



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.[100] However, as corn yield is not a direct input into GREET, and corn yield is linked to farm energy and material inputs, we used historic corn yield data for the GREET default parameter analysis. The following USDA information sources were compared to the GREET default values.

- 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 reports listing quantities of fertilizers and chemicals used per acre of corn.
- The NASS also produces annual data on crop production including yields per acre and total production of corn by state.

USDA NASS data on fertilizer and chemical use and corn yields and production values are provided annually. However, the ARMS is only conducted every five years. The three most recent years of the ARMS are 1991, 1996, and 2001. Table 6.1-3 lists corn yield and input data for the three years of the ARMS study.[101,102]

Table 6.1-3. Farm Energy Use and Input Data per Acre

Input	Units	9-State Weighted Average Values		
		1991	1996	2001
Seed	Kernels/acre	25,571	25,577	28,882
Fertilizer:				
- Nitrogen	pounds/acre	126.07	131.06	133.78
- Potash	pounds/acre	53.26	60.28	79.03
- Phosphate	pounds/acre	59.12	48.62	57.72
- Lime	pounds/acre	246.39[a]	15.71	15.67
Energy:				
- Diesel	Gallons/acre	6.75	8.65	5.77
- Gasoline	Gallons/acre	3.46	3.06	1.63
- LPG	Gallons/acre	3.52	6.59	4.80
- Electricity	kWh/acre	31.92	78.97[b]	36.38
- Natural Gas	Cubic ft/acre	255.72	206.59	192.05
Chemicals	[c]	22.90	26.37	2.74

[a] Historic lime use data is highly uncertain. We currently do not include lime use data in the lifecycle modeling. We are examining this issue through work with ANL and may include lime use as part of the analysis for the final rule.

[b] High energy use in the 1996 survey is due to increased corn drying requirements. See the discussion after Table 6.1-5.

[c] Chemicals data for 1991 and 1996 are in terms of dol./acre, data for 2001 is in terms of pounds/acre

Although USDA corn data is available for every state that produces corn, the data documented in Table 6.1-3 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 are projected to represent 82 percent of ethanol production in 2012. The data in Table 6.1-3 are weighted based on corn production data for each of the nine States from the NASS (three year average corn production data is used for weighting).

Values in Table 6.1-3 on energy use and material inputs are divided by corn yield in bu/acre to get corn input parameters on a per bushel basis to compare to GREET default values. The energy use values listed in Table 6.1-3 were converted to Btu based on the lower heating values of the fuels as listed in the GREET model.

Due to the annual variability in corn yield, as shown in Figure 6.1-2, we used a three year average for corn yield instead of the average yield for the survey year.[103] Table 6.1-4 shows the weighted average corn yields used.

Table 6.1-4. Corn Yields (Bu/acre)

9-State Weighted Average Values		
1991	**1996**	**2001**
(1990-1992 Yield)	(1995-1997 Yield)	(2000-2002 Yield)
123.47	124.62	139.94

We adjusted corn yield data to account for seed corn energy use. We assumed that growing seed corn requires 1.5 times the energy and material inputs to grow than corn[104]. Therefore, seed corn input is converted to bushels (80,000 kernels/bu) and multiplied by 1.5. This value is then subtracted from the yield data to get an adjusted yield per acre. This effectively reduces corn yields by about 0.5 bu/acre for each of the three years. Some recent studies have suggested that the energy use required for seed corn production is actually 4.7 times that of corn.[105,106] However this is not thought to have a significant impact on results as it represents a decrease of only about 1 percent in corn yields, and the 1.5 values was used in this analysis.

Table 6.1-5 shows corn farming energy use and material inputs on a per bushel basis.

Table 6.1-5. Farm Energy Use and Input Data per Bushel

Input	Unit	9-State Weighted Average Values		
		1991	**1996**	**2001**
Total Energy Use	Btu/bu	15,674	20,124	11,846
Diesel Fuel Use	%	45.0%	44.5%	44.9%
Gasoline Use	%	20.8%	14.2%	11.5%
Natural Gas Use	%	13.0%	8.1%	11.4%
LPG Use	%	15.5%	22.4%	24.7%
Purchased Elec.	%	5.6%	10.8%	7.5%
Nitrogen	g/bu	465	479	435
Phosphate	g/bu	218	178	188
Potash	g/bu	196	220	257
Chemicals	[a]	0.19	0.21	8.93

[a] Chemicals data for 1991 and 1996 are in terms of dol./bu, data for 2001 is in terms of g/bu

It can be seen from Table 6.1-5 that there is substantial variation in the three years of survey data, especially on energy use. 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.[107]

Comparing the average of the three years of data in Table 6.1-5 with GREET default values for farm energy input show that GREET energy use is about 40 percent more than the survey average. However, while the GREET energy use default value is higher than the average of the historic data there is significant variation in the historic data evaluated ranging from 11,846 to 20,124 Btu/bu of corn produced vs. the GREET default of 22,500 Btu/bu. There is also some uncertainty in the historic values evaluated. The USDA survey data includes a farm input category of custom work (in $/acre). This custom work includes dollars spent on contracted energy use for corn drying, or associated with planting, fertilizing, or harvesting. Depending on the amount of custom work done, this will lead to an increase in corn farming energy input. The potential increase in seed corn energy discussed previously will also increase corn farming energy input. Considering this added energy use, we conclude that the GREET default value falls within the range of historic data available and represents a conservative case for farm energy input. Therefore, due to the uncertainty and variability in the historic data and lack of projections for future energy use, the current GREET default value for energy use was used in the RFS analysis. We will examine this issue as part of the analysis for the final rule.

Comparing the average of the three years of data in Table 6.1-5 with GREET default values for farm material input show that GREET nitrogen fertilizer use is similar, phosphate and potash fertilizer use are about 15 and 10 percent lower in GREET respectively, and total chemical use is about 2 percent lower in GREET. GREET default nitrogen and potash fertilizer use fall within the range of historic values while phosphate use is slightly below the range of historic values. Of all the material inputs, nitrogen fertilizer is the most critical both in terms of upstream energy use to produce the fertilizer and the on-farm N_2O emissions associated with nitrogen fertilizer use. As GREET default nitrogen and potash fertilizer use fall within the range of historic data, and due to uncertainty and variability in the data, we concluded that the current GREET default values are a good representation of farm material inputs and were used for the RFS analysis. We also concluded that the GREET default input for chemical use was an accurate representation based on the historic data available and the default was used in the RFS analysis.

The GREET default value for phosphate input is slightly lower than the range of historic data available, 165 g/bu in GREET vs. 178 – 218 g/bu for the historic values. However, due to variability in the historic data and lack of projections for future usage, there is no clear better value to use for phosphate input, and the current GREET default value was used in the RFS analysis. Lime data is currently not an input to the GREET model for corn farming. This is something we are evaluating through the contract with ANL and may be available for the final rule.

Another corn farming input included in the GREET model is a default factor for CO_2 emissions associated with land use change. The factor is based on the assumption that increased corn demand for ethanol production will require currently idle crop / pastureland to be converted into corn production. This land use conversion is assumed to result in net CO_2 emissions. The GREET default factor for emissions associated with land use change of 195 g CO_2/bu corn was used in this analysis. This value represents approximately 2 percent of corn farming GHG emissions.

6.1.2.7 Ethanol Production Yield

Several data sources have reported that 1 bushel of corn yields approximately 2.7 gallons of ethanol[108]. However, the development of new enzymes, as well as other technology developments, continue to increase the potential ethanol yield, for example, research done by NREL[109], it is projected that yields for dry milling could soon reach 2.85 gal/bu. The cost modeling in Chapter 7 assumed a dry mill ethanol plant yield of 2.77 with 2% denaturant. The GREET model input is based on pure ethanol, so to be consistent with the cost modeling of Chapter 7, we used an ethanol yield of 2.71 gal/bu in our analysis.

6.1.2.8 Byproduct Allocation

As mentioned previously, there are a number of byproducts 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. For example, the DDGS produced by the ethanol plant is a replacement for corn and soybean animal feed. The ethanol receives a credit for the lifecycle emissions of corn and soybean animal feed, since a quantity of that feed type is no longer needed and is displaced by DDGS.

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, in preparation for the Final Rule, EPA will evaluate the other by-product allocation methods to determine the impact this assumption has on the overall results of the analysis.

6.2 Methodology

The results of the lifecycle modeling were used to determine the impacts of increased renewable fuel use on overall U.S. transportation sector, and nationwide fossil energy and GHG emissions. As described below, lifecycle reductions from renewable fuel use were compared to sector wide inventories to show the overall impact of increased renewable fuel use. The GREET model provides estimates on a national average, per fuel unit basis, such as the amount of fossil fuel use per million Btus of ethanol produced, and the same for petroleum fuels. The model could be used to generate estimates of absolute fossil fuel and emissions savings of replacing a given amount of gasoline with ethanol. However, the model does not provide estimates of energy consumed and emissions generated in total, such as the total amount of fossil fuel use in the U.S. transportation sector in a given year. Therefore, we could not use GREET directly to estimate the transportation sector or nationwide inventories needed for the analysis.

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 (%)

$S_{GHC,corn\ ethanol}$ = Lifecycle GHG emission reduction over the reference case associated with use of corn ethanol (million metric tons of GHG)

$S_{GHG,cell\ ethanol}$ = Lifecycle GHG emission reduction over the reference case associated with use of cellulosic ethanol (million metric tons of GHG)

$S_{GHG,biodiesel}$ = Lifecycle GHG emission reduction over the reference case associated with use of biodiesel (million metric tons of GHG)

$TSector_{GHG}$ = 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 a result of 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) 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. As mentioned in Section 6.1, 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).

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 scenarios, we assumed that the biodiesel production volume would be 0.3 billion gallons based on an EIA projection, and that the cellulosic ethanol production volume would be 0.25 billion gallons based on the Energy Act's requirement that 250 million gallons of cellulosic ethanol be produced starting in the next year, 2013. The remaining renewable fuel volumes in each scenario would be ethanol made from corn. The total volumes for all three scenarios are shown in Table 6.2-1. For the purposes of calculating the R values, we assumed the ethanol volumes are 5% denatured, and the volumes were converted to total Btu using the appropriate volumetric energy content values (76,000 Btu/gal for ethanol, and 118,000 Btu/gal for biodiesel).

Table 6.2-1. Volume Scenarios in 2012 (billion gallons)

	Reference Case	Required volume: 7.5 bill gal	Projected Volume: 9.9 bill gal
Corn-ethanol	3.9	6.95	9.35
Cellulosic ethanol	0.0	0.25	0.25
Biodiesel	0.028	0.3	0.3
Total volume	3.928	7.5	9.9

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 6.2-2. The results shown in Table 6.2-2 are direct reductions in fuel use and do not represent lifecycle savings.

Table 6.2-2. Direct Conventional Fuel Replaced in 2012 (quadrillion Btu)

	Required volume: 7.5 bill gal	Projected Volume: 9.9 bill gal
Gasoline Replaced by Corn-ethanol	0.220	0.394
Gasoline Replaced by Cellulosic ethanol	0.018	0.018
Diesel Fuel Replaced by Biodiesel	0.032	0.032
Total energy	0.270	0.444

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 6.2-3.

Table 6.2-3.
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 6.2-3 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[110], 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 6.2-4 shows the total lifecycle petroleum and GHG emissions associated with direct use of a Btu value of gasoline or diesel fuel. These values represented factor LC in the equation described above.

Table 6.2-4.
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 6.2-5

Table 6.2-5. 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

Although the net energy balance and energy efficiency metrics are used most often by researchers in summarizing their lifecycle analyses, they can be misleading. For instance, a negative net energy balance, or an energy efficiency of more than 1.0, is generally interpreted to mean that lifecycle fossil fuel consumption negates the benefits of the "renewable" fuel. However, because these metrics do not involve a direct comparison to the conventional gasoline or diesel that the renewable fuel is replacing, even in these cases there may be an overall reduction in fossil fuel use.

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:

$$\text{Energy efficiency} = 81{,}000 \text{ Btu/gal} \div 76{,}000 \text{ Btu/gal} = 1.07$$

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 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 energy content of ethanol (76,000 Btu) is not considered fossil energy and therefore not included in the comparison with gasoline calculation above.

Because of this potential for the net energy balance and energy efficiency metrics to provide misleading information, 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:

$$DI_{CO2} = 1 \quad - \quad \frac{\text{lifecycle } CO_2 \text{ emitted for ethanol in g/Btu}}{\text{lifecycle } CO_2 \text{ emitted for gasoline in g/Btu}}$$

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[111]. 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 6.3-1, 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 6.2-6.

Table 6.2-6. Output from GREET Used to Develop Displacement Indexes

	Units	Gasoline[a]	Corn ethanol	Cellulosic ethanol[b]	L S Diesel	Biodiesel
Well-to-Pump						
Fossil energy	Btu/mmBtu	224,136	732,712	49,440	207,011	629,122
Petroleum energy	Btu/mmBtu	107,292	85,202	80,389	98,649	169,688
CH_4	g/mmBtu	107	114	4	105	86
N_2O	g/mmBtu	0.29	53	30	0.28	8
CO_2	g/mmBtu	17,893	52,894	-9,531	16,629	40,719
CO_2-eq	g/mmBtu	20,435	71,204	-686	19,134	45,011
End point combustion						
Fossil energy	Btu/mmBtu	1,000,000			1,000,000	
Petroleum energy	Btu/mmBtu	1,000,000			1,000,000	
CO_2 combustion[c]	g/mmBtu	76,419	74,755	74,755	77,570	79,388
CO_2-eq combustion[d]	g/mmBtu	79,015	77,351	77,351	77,669	79,487

[a] Volume-weighted average of conventional gasoline (65%), RFG blendstock (25%), and CaRFG blendstock (10%).

[b] Straight average of results for herbaceous and woody biomass.

[c] Taken from an OTAQ Fact Sheet

[d] Based on assuming an increase over CO_2 emissions, percent increase 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 6.2-7.

Table 6.2-7. Displacement Indexes Derived from GREET

	Corn ethanol	Cellulosic ethanol	Biodiesel
$DI_{Petroleum}$	92.3%	92.7%	84.6%
$DI_{Fossil\ Fuel}$	40.1%	96.0%	47.9%
DI_{GHG}	25.8%	98.1%	53.4%
DI_{CO2}	43.9%	110.1%	56.8%

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 25.8 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 84.6 percent.

Note that our DI estimates for cellulosic ethanol assume that the ethanol in question was in fact produced from a cellulosic feedstock, such as wood, corn stalks, or switchgrass. However, the definition of cellulosic biomass ethanol given in the Energy Act also includes ethanol made from non-cellulosic feedstocks 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 determined that this latter version of cellulosic ethanol is more likely to be produced to meet the Act's requirement of a minimum of 250 million gallons beginning in 2013. Therefore, for cost estimation purposes we have assumed that cellulosic ethanol would actually be made from corn, but at a plant where 90 percent of the process energy has come from a renewable source. Further discussion of this issue can be found in Section 1.2.2. However, for this analysis it was assumed that cellulosic ethanol was in fact produced from cellulosic feedstock[UU].

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., $\text{TSector}_{\text{GHG}}$ 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 6.2-8.

Table 6.2-8.
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 6.2-9.

[UU] There are indications that facilities producing ethanol from cellulosic feedstocks will be online by as early as 2007. For example, Xethanol Corporation announced recently that it plans to build a full-scale cellulosic ethanol plant in Augusta, Georgia, by mid-2007.

Table 6.2-9.
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 CO2 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 6.2-10.

Table 6.2-10.
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[112] values for both CO_2 and total GHG emissions. This same increase is applied to 2012 CO_2 values. Table 6.2-11 shows the fraction increase values for GHGs over CO_2 emissions calculated from the U.S. EPA National Inventory report.

Table 6.2-11. 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 6.2-12.

Table 6.2-12.
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 calculate 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 calculate 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 results are presented in Tables 6.3-1 and 6.3-2.

Table 6.3-1.
Fossil Fuel Impacts of Increased Use of Renewable Fuels in 2012, In Comparison to the Reference Case

	Required volume: 7.5 bill gal	Projected Volume: 9.9 bill gal
Reduction (quadrillion Btu)	0.2	0.3
Percent reduction in Transportation Sector Energy Use	0.5 %	0.8 %
Percent reduction in Nationwide Energy Use	0.2%	0.3%

Table 6.3-2.
Petroleum Impacts of Increased Use of Renewable Fuels in 2012, In Comparison to the Reference Case

	Required volume: 7.5 bill gal	Projected Volume: 9.9 bill gal
Reduction (billion gal)	2.3	3.9
Percent reduction in Transportation Sector Energy Use	1.0 %	1.6 %
Percent reduction in Nationwide Energy Use	0.7%	1.1%

6.3.2 Greenhouse Gases and Carbon Dioxide

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 the 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 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 by GREET were developed by the UN Intergovernmental Panel on Climate Change (IPCC) as listed in their Third Assessment Report[113], and are shown in Table 6.3-3.

Table 6.3-3.
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 emission for each pollutant. The sum of impacts for CH_4, N_2O, and CO_2, yields the total effective GHG impact.

We used the S equation in Section 6.2 to calculate 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 results are presented in Table 6.3-4.

Table 6.3-4.
CO_2 Emission Impacts of Increased Use of Renewable Fuels in 2012, In Comparison to the Reference Case

	Required volume: 7.5 bill gal	**Projected Volume: 9.9 bill gal**
Reduction (million metric tons CO_2)	12.6	19.8
Percent reduction in Transportation Sector Emissions	0.6 %	0.9 %
Percent reduction in Nationwide Emissions	0.2%	0.3%

Carbon dioxide is a subset of GHGs, along with CH_4 and N_2O as discussed above. It can be seen from Table 6.2-7 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 as shown in Table 6.2-6. Therefore, reductions associated with the increased use of renewable fuels on lifecycle emissions of GHGs are lower than the values for CO_2. The results for GHGs are presented in Table 6.3-5.

Table 6.3-5.
GHG Emission Impacts of Increased Use of Renewable Fuels in 2012, In Comparison to the Reference Case

	Required volume: 7.5 bill gal	**Projected Volume: 9.9 bill gal**
Reduction (million metric tons CO_2-eq.)	9.0	13.5
Percent reduction in Transportation Sector Emissions	0.4 %	0.6 %
Percent reduction in Nationwide Emissions	0.1%	0.2%

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 will change their mix of imports in response to a decrease in fuel demand.

We do not expect the projected reductions in petroleum consumption (0.3 to 0.57 Quads) to impact world oil prices by a measurable amount. We base this assumption on the overall size of worldwide petroleum demand and analysis of the AEO 2006 cases. Domestic and international crude oil production, facing the world oil price, would also be expected to remain unchanged relative to the reference case. If petroleum demand changes were much larger and international refinery operations were impacted, the market economics might be expected to be different. However, this is outside the scope of this assessment which focuses solely on the RFS impacts.

The displacement of domestic crude oil production, imports of crude oil, and imports of finished products will depend on the marginal costs of each source. In general, it is financially preferable for domestic refineries to eliminate the most expensive marginal cost sources. The highest cost sources tend to be finished product imports followed by crude oil imports.[114] Refineries prefer to refine crude oil as opposed to importing finished products because of the higher margins involved with the former and the greater utilization 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. Thus, we expect the domestic crude production to be only marginally affected.

The Energy Information Administration (EIA) has modeled the effects of the RFS in the current AEO 2006.[115] In addition, the EIA has conducted three separate analyses of Congressional bills which include 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. Thus, we did not directly use these earlier analyses, rather opting to use only the results in the AEO 2006 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 demand would affect the mix of imported finished products, imported crude oil, and domestic production. Similar to the assumptions above, the 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 demand for petroleum products (approximately 300,000 barrels per day), net imports will account for approximately 95% of the reductions.[116] Both reduced domestic crude production and natural gas plant liquids account for most of the remainder. Since imported finished products are the highest marginal cost sources, they account for all the initial reductions in petroleum imports. If demand is reduced even further (over 860,000 barrels per day), approximately 50% of the reductions come from imported products, 44% from imported crude oil, and the remainder from reduced domestic, natural gas plant liquid (NGL) production, and exports.

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 low price case (as opposed to low macroeconomic growth case) and the reference case would yield a 50-50 split between product and crude imports. We believe that the actual refinery response could range between these two points, so that finished product imports would compose between 50 to 100% of the net import reductions, with crude oil imports making up the remainder. For the purposes of this RIA, we show values for the case where net import reductions come entirely from imports of finished products, as discussed 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 exclusively from finished petroleum products rather than from crude oil, for the economic reasons given above and consistent with the results of the AEO 2006 low 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 145,000 and 241,000 barrels per day, respectively, for the 7.5 and 9.9 cases (note that both these cases account for the 7.2 and 9.5 billion gallons of ethanol plus the additional 0.3 billion gallons of biodiesel, as discussed earlier in the RIA section 6.2.1). 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 1 to 2%, as shown in Table 6.4-2.

Table 6.4-1.
Reductions in Imports of Finished Products
(barrels per day)

Cases	2012
7.5	145,454
9.9	240,892

Table 6.4-2.
Percent Reductions in Petroleum Imports
Compared to AEO2006 Import Projections

Cases	2012
7.5	1.1%
9.9	1.7%

One of the effects of increased use of renewable fuel is that it diversifies the energy sources used in making transportation fuel. To the extent that diverse sources of fuel energy reduce the dependence on any one source, the risks, both financial as well as strategic, of potential disruption in supply or spike in cost of a particular energy source is reduced.

In order to understand the energy security implications of the RFS, EPA will work with Oak Ridge National Laboratory (ORNL). As a first step, ORNL will update and apply the method used in the 1997 report *Oil Imports: An Assessment of Benefits and Costs,* by Leiby, Jones, Curlee and Lee.[117] This paper was cited and its results utilized in previous DOT/NHTSA rulemakings, including the 2006 Final Regulatory Impact Analysis of CAFE Reform for Light Trucks.[118] This method is consistent with that used in the *Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards Report* conducted by the National Research Council/National Academy of Sciences in 2002. Both reports estimate the marginal benefits to society, in dollars per barrel, of reducing either imports or consumption. This "oil premium" approach emphasizes identifying those energy-security related costs that are not reflected in the market price of oil, and which maybe change in response to an incremental change in the level of oil imports *or* consumption.

Since the 1997 publication of this report changes in oil market conditions, both current and projected, suggest that the magnitude of the "oil premium" may have changed. Significant factors that should be reconsidered include: oil prices, current and anticipated levels of OPEC production, U.S. import levels, potential OPEC behavior and responses, and disruption likelihoods. ORNL will apply the most recently available careful quantitative assessment of disruption likelihoods, from the Stanford Energy Modeling Forum's 2005 workshop series, as well as other assessments.[119] ORNL will also revisit the issue of the macroeconomic consequences of oil market disruptions and sustained higher oil prices. Using the "oil premium" calculation methodology which combines short-run and long-run costs and benefits, and accounting for uncertainty in the key driving factors, ORNL will provide an updated range of estimates of the marginal energy security implications of displacing oil consumption with renewable fuels. The results of this work effort are not available for this proposal but will be part of the assessment of impacts of the RFS in the final rule.

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 decreased expenditures on petroleum imports assuming this would not result in any other changes consumer behavior that would be reflected in fuel use. All reductions in petroleum imports are expected 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.[120] Since no published forecasts are available for this price, an estimate was made by using the AEO 2006 gasoline and distillate price forecasts and subtracting the average federal and state taxes based on historical data.[VV]

As an example calculation, the RFS is expected to yield a reduction of 2.23 billion gallons of gasoline in the year 2012 (7.5 case). 95% of these reductions, or 2.12 billion gallons, are expected to come from imports of finished gasoline. Thus, the domestic refining sector would avoid purchases of 2.12 billion gallons of gasoline at $1.58 per gallon (2004$), the forecasted price using the method described. The avoided payments abroad total $3.2 billion. Using a similar approach for imported diesel, we estimate that an additional $0.3 billion is saved, for a total of $3.5 billion saved for 2012, as shown in Table 6.4-3.

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).[WW] In Table 6.4-3, we compare the avoided expenditures in petroleum imports versus the total value of U.S. net exports of goods and services for the whole economy for 2012. Relative to the 2012 projection, the avoided petroleum expenditures due to the RFS would represent 0.9 to 1.5% of economy-wide net exports.

Table 6.4-3.
Avoided Petroleum Import Expenditures for 2012 ($2004 billion)

AEO2006 Total Net Exports	RFS Cases	Avoided Expenditures in Petroleum Imports	Percent versus Total Net Exports
- $383	7.5	$3.5	0.9%
	9.9	$5.8	1.5%

[VV] The average taxes per gallon of gasoline and diesel have stayed relatively constant. For 2000-2006, gasoline taxes were $0.44/gallon ($2004) while for 2002-2006, diesel taxes were $0.49/gallon. The average was taken from available EIA data (http://tonto.eia.doe.gov/oog/info/gdu/gasdiesel.asp).

[WW] For reference, the U.S. Bureau of Economic Analysis (BEA, http://www.bea.gov/) 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 $591.3 billion current account deficit in goods and services for 2005 (2004$).

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

7.1 Ethanol

This section provides a description of the analysis we conducted for estimating the cost of corn cellulosic ethanol. Our analysis indicates that corn ethanol will cost $1.20 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 roadblocks remain to the production of large volumes of cellulosic derived ethanol. It appears that good progress has been achieved in the laboratory, but this information must be validated in pilot or demonstration type plants.

7.1.1 Corn Ethanol

Of the new ethanol production capacity expected to be built, according to Section 1.2.2 of this DRIA, 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 a goal of 7.2 billion gallons per year (Bgal/y) in 2012 from the mid-2006 capacity of 4.9 Bgal/yr, 2.3 Bgal/yr of additional capacity will have to be constructed.[XX] If we consider that it is likely that at least 9.6 Bgal/yr of capacity will come on-line by 2012, the annual capacity increase is 4.7 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 average size will be 72 million gallons per year (MMgal/yr) for new plants, or 68 MMgal/yr if expansions are included.

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.

[XX] For details on current and expected ethanol capacity, refer to Section 1.2 of this DRIA.

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 1,200 construction workers and 45 engineers would be required on a monthly basis. For the case of 9.6 Bgal/yr of ethanol capacity being online by the end of 2012, these numbers increase to 2,100 and 90, respectively. These numbers only include those involved with the final construction and startup of the plants, and do not account for additional work required to design and fabricate vessels, control systems, and other equipment that will be delivered to the construction site.

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.[121]

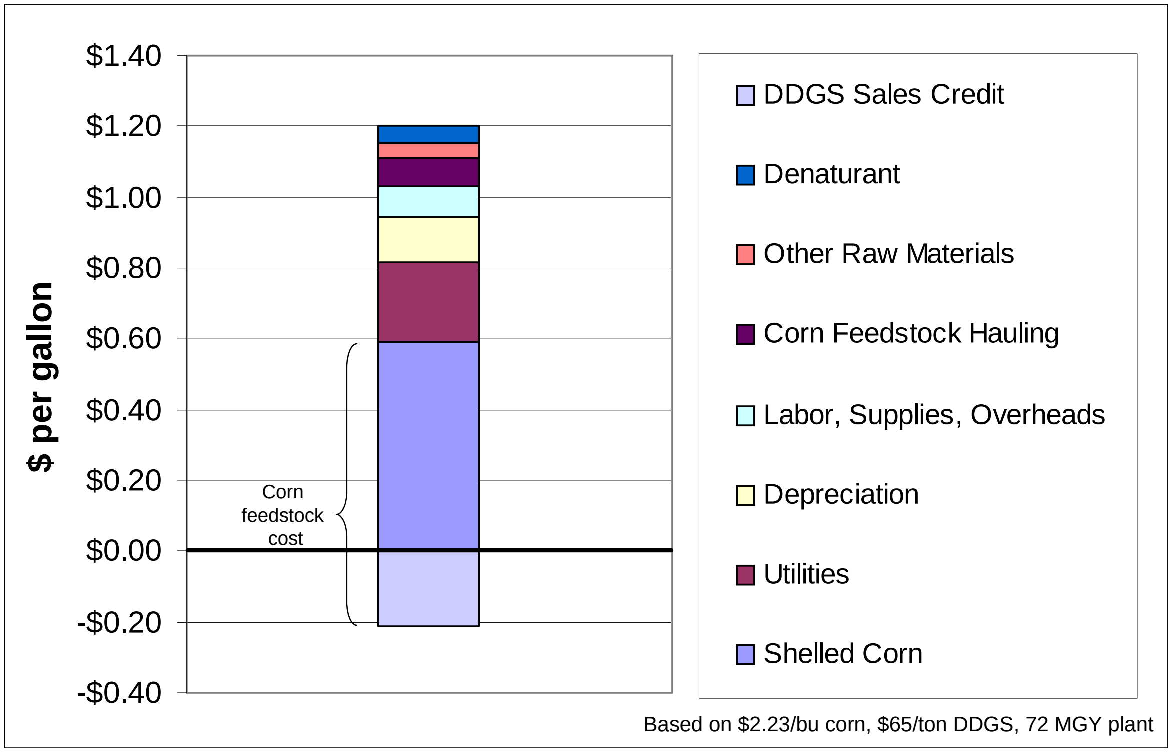
7.1.1.2 Corn Ethanol Production Costs

Corn ethanol costs for our work were estimated using a model developed by USDA, documented in a peer-reviewed journal paper on cost modeling of the dry-grind corn ethanol process.[122] It produces results that compare well with cost information found in surveys of existing plants.[123]

The USDA model is for a forty million gallon per year dry mill (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 2.77 gallons per bushel with 2.0% 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 estimate an average corn ethanol production cost of $1.20 per gallon in 2012 (2004 dollars) in the case of 7.2 Bgal/yr and $1.26 per gallon in the case of 9.6 Bgal/yr. 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 credits represents about 50% of the final per-gallon cost, while utilities, capital and labor comprise about 20%, 10%, and 5%, respectively. For this work, we used corn price projections from USDA of $2.23 per bushel in 2012 for the 7.2 Bgal/yr case, and an adjusted value of $2.31 per bushel for the 9.6 Bgal/yr case. Prices used for DDGS were $65 per ton in the 7.2 Bgal/yr case and $55 per ton in the 9.6 case. Figure 7.1-1 shows the cost breakdown for production of a gallon of ethanol.

Figure 7.1-1. Cost Breakdown of Corn Ethanol Production (2004$).



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.[124] With this factor, the savings in per-gallon production cost is very small between a 40 and 70 MMgal/yr plant, on the order of $0.02. In this analysis we used an average new plant size of 72 MMgal/yr, estimated 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 use of coal will represent about 10% of ethanol production over the next few years, so the effect on average costs is relatively small. We are also aware of a small but increasing amount of ethanol production fueled by waste-derived or cellulosic materials (such as wood, tires, municipal waste or manure biogas), but we had difficulty obtaining information on large-scale feasibility and capital costs for these operations. We expect to include more detailed information on use of these energy sources for the final rulemaking. For the coal system versus natural gas, additional requirements were estimated at $30 million in capital for a 50 MMgal/yr 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 company that designs and builds ethanol plants. Using this information, the cost savings is about $0.11 per gallon of ethanol for a coal-fired plant.

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.[125] It is expected that 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 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 firing 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[126], and scaled according the ratios of 2004-2012 price forecasts published in the Annual Energy Outlook 2006.[127] The prices used in the modeling are shown in Table 7.1-1.

Table 7.1-1. Energy Prices Used for Ethanol Cost Modeling for 2012 (2004$)

Natural Gas[a] **$/MMBtu**	**Coal[a]** **$/MMBtu**	**Electricity[a]** **$/kWh**	**Gasoline[b]** **$/gal**
6.16	1.94	0.044	1.25

[a] Historical data based on averages for Iowa, Illinois, Minnesota, and Nebraska
[b] PADD 2 bulk gasoline prices, excluding taxes

To arrive at the corn price for the two volume cases in 2012, the nominal 2012 USDA price was adjusted to 2004 dollars according to the GDP deflators given in the 2006 FAPRI outlook report.[128,129] This number represents corn price for the 7.2 Bgal/yr case, as the RFS volume was known at the time of USDA's most recent modeling work. This figure was then adjusted for the 9.6 Bgal/yr case by adding 7.7 cents per bushel, determined by interpolating between two nearby cases in the EIA NEMS ethanol cost model.[130] That model generated cost curves for corn and DDGS based on data from a 2005 report by FAPRI examining the effects of different RFS ethanol volume scenarios on agricultural markets.[131] Since USDA does not project DDGS prices in its outlook report, those figures were taken from the FAPRI report, and then adjusted using the same methodology as the corn prices. While we believe the use of USDA and FAPRI estimates for corn and DDGS prices is reasonable, additional modeling work is being done for the final rulemaking using the Forestry and Agricultural Sector Optimization Model described further in Chapter 8 of this DRIA.

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, significant progress in making ethanol from cellulosic feedstocks has been made during the past few years. 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 increased incentive to produce cellulosic ethanol because the Energy Act mandates that, starting in 2013, renewable fuels in gasoline must contain a minimum of 250 million gallons of cellulosic derived ethanol.

To make ethanol from cellulosic feedstocks, pretreatment is necessary to hydrolyze cellulosic and hemicellulosic polymers and break down the lignin sheath. In so doing, the structure of the cellulosic feedstock is opened to allow efficient and effective enzyme hydrolysis of the cellulose/hemicellulose to glucose and xylose. The central problem is that the β-linked saccharide polymers in the cellulose/hemicellulose structure prevent the microbial fermentation reaction. By comparison, the fermentation of the starch produced from corn kernels, which have α-linked saccharide polymers, takes place much more readily. An acid hydrolysis process was developed to pretreat cellulosic feedstocks (through hydrolysis which breaks up the β-links), but it continues to be prohibitively expensive for producing ethanol.

Technologies that are currently being developed may solve some of the problems associated with producing cellulosic ethanol. Specifically, one problem 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.[YY] 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 [ZZ]

[YY] "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.

[ZZ] *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

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 quite 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 required to 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[132] a privately held company, based in Ottawa, Ontario, Canada). As far as we know, the technology that Iogen employs is not yet fully developed or optimized. Consequently, there is no proven process design or operating data which could be used to estimate how much it will cost to produce cellulosic ethanol.

Generally, the industry seems to be moving toward a process that uses dilute acid enzymatic prehydrolysis with simultaneous saccharification (enzymatic) and co-fermentation. 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.

Research, Germantown, MD 20874-1290, August 2005; DOEGenomesToLife.org/roadmap; downloadable as whole or in sections.

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.[133] 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.[134] 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.[AAA] 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,

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[AAA] 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.

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[135] 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, there remain several feedstock issues to be settled, not least being which of the many available types 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 there is reason to expect it to come down a little, as a result of the research that is currently under way. 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.

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[136] 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. We solicit comment, however, on whether and to what extent we should build in projections for lower costs due to availability of grants, developments in enzymatic hydrolysis and improvements in process plant engineering and design.

7.1.4 Ethanol's Blending Cost

Ethanol has a high octane value of 115 (R+M)/2 which contributes to its value as a gasoline blendstock. As the volume of ethanol blended into gasoline increases from 2004 to 2012, refiners will account for the octane provided by ethanol when they plan their gasoline production. This additional octane would allow them to back off of their octane production from their other gasoline producing units resulting in a cost savings to the refinery. For this cost analysis, the cost savings is expressed as a cost credit to ethanol added to the production cost for producing ethanol.

We obtained gasoline blending costs on a PADD basis for octane from a consultant who conducted a cost analysis for a renewable fuels program using an LP refinery cost model.[137] LP refinery models value the cost of octane based on the octane producing capacity for the refinery's existing units, by added capital and operating costs for new octane producing capacity, and based on purchased gasoline blendstocks. We used this projected octane values for ethanol and the other gasoline blendstocks discussed below. The value of octane is expressed as a per-gallon cost per octane value is summarized in Table 7.1-2.

Table 7.1-2.
Octane Value of Ethanol and Other Gasoline Blendstocks (cents/octane-gallon)

PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	CA
0.71	0.38	0.67	0.86	0.86	1.43

Octane is more costly in California because the Phase 3 RFG standards restriction aromatics content which also reduces the use of a gasoline blendstock named reformate - a relatively cheap source of octane. Also, California's Phase 3 RFG distillation restrictions tend to limit the volume of eight carbon alkylate, another lower cost and moderately high octane blendstock.

Another blending factor for ethanol is its energy content. Ethanol contains less heat content per gallon than gasoline. Since refiners blend up their gasoline based on volume, they do not consider the energy content of its gasoline, only its price. Instead, the consumer pay's for a gasoline's energy density based on the distance that the consumer can achieve on a gallon of gasoline. Since we try to capture all the costs of using ethanol, we consider this effect. Ethanol contains 76,000 British Thermal Units (BTU) per gallon which is significantly lower than gasoline, which contains an average of 115,000 BTUs per gallon. This lower energy density is accounted for below in the discussion of the gasoline costs.

7.2 Biodiesel and Renewable Diesel Production Costs

7.2.1 Overview of Analysis

We based our cost to produce biodiesel fuel on a range estimated from the use of USDA's and NREL's biodiesel computer models. Both of these models represent the continuous transesterification process for converting vegetable soy oil to esters, along with the ester finishing processes and glycerol recovery. The models estimate biodiesel production costs using prices for soy oil, methanol, chemicals and the byproduct glycerol. The models estimate the capital, fixed and operating costs associated with the production of soy based biodiesel fuel, considering utility, labor, land and any other process and operating requirements.

Each model is based on a medium sized biodiesel plant that was designed to process raw degummed virgin soy oil as the feedstock, yielding 10 MM gallons per year of biodiesel fuel. USDA estimated the equipment needs and operating requirements for their biodiesel plant 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. The NREL model is also based on process simulation software, though the results are adjusted to reflect NREL's modeling methods. The output for both models were provided in spreadsheet format, though, USDA updated the prices for a plant in year 2005, while the NREL's model is based on prices in year 2002.

The production costs are based on an average biodiesel plant located in the Midwest using soy oil 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 production costs are a based on a plant that makes 10 MM gallons per year of biodiesel fuel. Production costs for yellow grease derived biodiesel, were estimated with the models, using adjustments for feedstock costs.

The model is further modified to use input prices for the feedstocks, byproducts and energy prices to thus reflect the effects of the fuels provisions in the Energy Act. Based on the USDA model, for soy oil-derived biodiesel we estimate a production cost of $2.06 per gallon in 2004 and $1.89 per gal in 2012 (in 2004 dollars) For yellow grease derived biodiesel, USDA's model estimates an average production cost of $1.19 per gallon in 2004 and $1.10 in 2012 (in 2004 dollars). In order to capture a range of production costs, we compared these cost projections to those derived from the NREL biodiesel model. With the NREL model, we estimate biodiesel production cost of $2.11 per gallon for soy oil feedstocks and $1.28 per gallon for yellow grease in 2012, which are slightly higher than the USDA results. We present details on the use of both models later in this section.

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 (c/gal), reducing the net production cost to a range of 89 to 111 c/gal for soy oil fuel and 60 to 78 c/gal for yellow grease biodiesel in 2012. This compares favorably to the projected wholesale diesel fuel prices of 138 c/gal in 2012, signifying that the economics for biodiesel are positive under the effects of the blender credit program, though, the tax credit program expires in 2008 if 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 the Energy Act. 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[138]. This is in close proximity to EIA's soy oil derived biodiesel volume projection of 135 MM, 265 MM 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 grease has sold for about half the price of soy oil[139]. The resulting feedstock costs to make a gallon of biodiesel under projected volumes for RFS are in Table 7.2-1.

Table 7.2-1. Projected Prices of Feedstock[a] (2004 Dollars per Gallon)

Marketing Year	Soy Oil	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 c/gal.

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 BTU's 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 7.2-2 and 7.2-3

Table 7.2-2. 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 7.2-3. 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 c/gal 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 7.2-4.

Table 7.2-4. Reagent Requirements

Reagent	**Annual Requirement, (lbs per gallon of biodiesel)**
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[140]. 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 7.2-5.

Table 7.2-5. 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% glycerine stream, which is usually sold to glycerine refiners for purification. In the past, crude glycerine has sold for around $0.15 / pound. Because of the increase in biodiesel production around the world, however, the crude glycerine 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 7.2-6

Table 7.2-6.
Projected Production Costs for Biodiesel by Feedstock per Gallon
(2004 Dollars)

Marketing Year	Soy Oil	Yellow Grease
2004	2.06	1.19
2012	1.89	1.10

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. 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. To make the results directly comparable to USDA's model, we used energy costs in the Midwest.

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 production costs for biodiesel fuel produced from yellow grease are estimated at $1.38 and $1.28 per gallon for years 2004 and 2012, respectively. 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 c/gal for feedstock costs alone, versus the USDA model. Similar to the USDA modeling analysis, the prices for yellow grease is assumed to be half the cost of soy oil feedstock. The feedstock costs are summarized in Table7.2-7.

Table 7.2-7. Projected Prices of Feedstock (2004 Dollars per Gallon)

Marketing Year	Soy Oil	Yellow Grease
2004	1.81	0.91
2012	1.65	0.83

[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.

7.2.3.2 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 c/gal. All of the economic factors used for amortizing the capital costs are summarized in Table 7.2-8.

Table 7.2-8.
Economic Factors Used in Deriving the Capital Cost Amortization Factor

Depreciation Life	Economic and Project Life	Federal and State Tax Rate	Return on Investment (ROI)	Resulting Capital Amortization Factor
10 Years	15 Years	0%	7%	0.11

7.2.3.3 Operating Costs

The total operating costs are 31 and 30 c/gal 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 c/gal 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 c/gal 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 7.2-9

Table 7.2-9. 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 7.2-10.

Table 7.2-10. Reagent Requirements

Reagent	**Annual Requirement, (lbs per gallon of biodiesel)**
Water	3.4646
HCL[a]	0.0098
Methanol	0.6037
NAOCH3[a]	0.0338
Sodium Hydroxide	0.1901

[a] HCl is Hydrochloric acid, NAOCH3 is sodium methoxide.

The total biodiesel production costs derived from the NREL model are summarized in Table 7.2-11.

Table 7.2-11. Projected Production Costs for Biodiesel by Feedstock per Gallon (2004 dollars)

Marketing Year	Soy Oil	Yellow Grease
2004	2.28	1.38
2012	2.11	1.28

[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 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.[141] That study provided 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 case where just enough ethanol is used to meet the requirements of the RFS in 2012 (7.2 billion gallons per year) and for a market-driven case where the volume of ethanol used is 9.6 billion gallons per year. The 2012 reference case against which we are estimating the cost of distributing the additional volume of ethanol projected for 2012 is 3.9 billion gallons.[BBB]

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 an estimate of the capital costs to support the use of 7.2 Bgal/yr of ethanol in 2012. The 10 Bgal/yr case from the DOE study was used to represent the market-based case examined in today's rule of 9.6 Bgal/yr of ethanol. For both the 7.2 Bgal/yr and 9.6 Bgal/yr cases, we adjusted the results from the DOE study to reflect a 3.9 Bgal/yr 2012 ethanol use baseline. The following 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.

[BBB] See Chapter 1 of this DRIA regarding the 2012 ethanol use reference case.

Table 7.3-1. Ethanol Distribution Infrastructure Capital Costs Relative to a 3.9 Billion Gallon per Year Reference Case

	7.2 billion gallons per year	9.6 billion gallons per year
New Terminal Blending Systems for Ethanol		
Number of terminals	287	515
Capital cost	$96,924,000	$164,663,000
New Ethanol Storage Tanks at Terminals		
Number of tanks	200	370
Capacity	1,826,000 barrels	3,415,000 barrels
Capital cost	$26,208,000	$48,803,000
Terminal Storage Tanks Converted to Ethanol		
Number of tanks	50	83
Capacity	362,000 barrels	592,000 barrels
Capital cost	$1,060,000	$1,739,000
Terminals Using Ethanol for the First Time[a]		
Number of terminals	250	453
Capital cost	$5,005,000	$9,065,000
New Rail Delivery Facilities at Terminals		
Number of terminals	36	59
Capital cost	$12,936,000	$20,867,000
Retail Facilities Using Ethanol for First Time[a]		
Number of retail facilities	40,150	74,820
Capital cost	$23,689,000	44,146,000
New Tractor Trailer Transport Trucks		
Number of Trucks	245	435
Capital Costs	$38,167,000	$50,075,000
New Barges		
Number of new barges	19	32
Capital cost	$29,988,000	$51,974,000
New Rail Cars		
Number of new rail cares	1,735	2,690
Capital cost	$104,161,000	$161,120,000
Total Capital Costs	$317,207,000	$542,319,000
Capital Costs Attributed to Terminal and Retail (i.e. fixed) Facilities	$154,891,000	$297,150,000
Capital Costs Attributed to Mobile Facilities (tank trucks, rail cars, & barges)	$162,316,000	$263,169,000

[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.

Amortized over 15 years, the total capital costs (of $317,207,000 under the 7.2 Bgal/yr case and 542,319,000 Bgal/yr case) equate to an annual cost of approximately $34,830,000 under the 7.2 Bgal/yr case and $59,544,000 under the 9.6 Bgal/yr case. This translates to approximately one cent per gallon of new ethanol volume of which 0.5 c/gal is attributed to fixed facilities and 0.5 c/gal is attributed to mobile facilities.

We performed a sensitivity analysis to evaluate the impact on costs if a relatively greater reliance on rail transport versus marine transport occurs than was assumed in the DOE study.[CCC] 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 increase in ethanol shipments that were projected in the DOE study to be carried by barge 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. The actual increase in rail infrastructure costs may be somewhat lower given improvements in the efficiency of ethanol transport by rail. Under this scenario, a total of 2,260 new rail tank cars would be needed under the 7.2 Bgal/yr case and 3,490 under the 9.6 Bgal/yr case. The overall effect of this increased reliance on rail transport would increase the capital costs by approximately $26,133,000 under the 7.2 Bgal/yr case and $39,004,000 under the 9.6 Bgal/yr case. This equates to an additional 0.1 c/gal of new ethanol production.

7.3.1.2 Ethanol Freight Costs

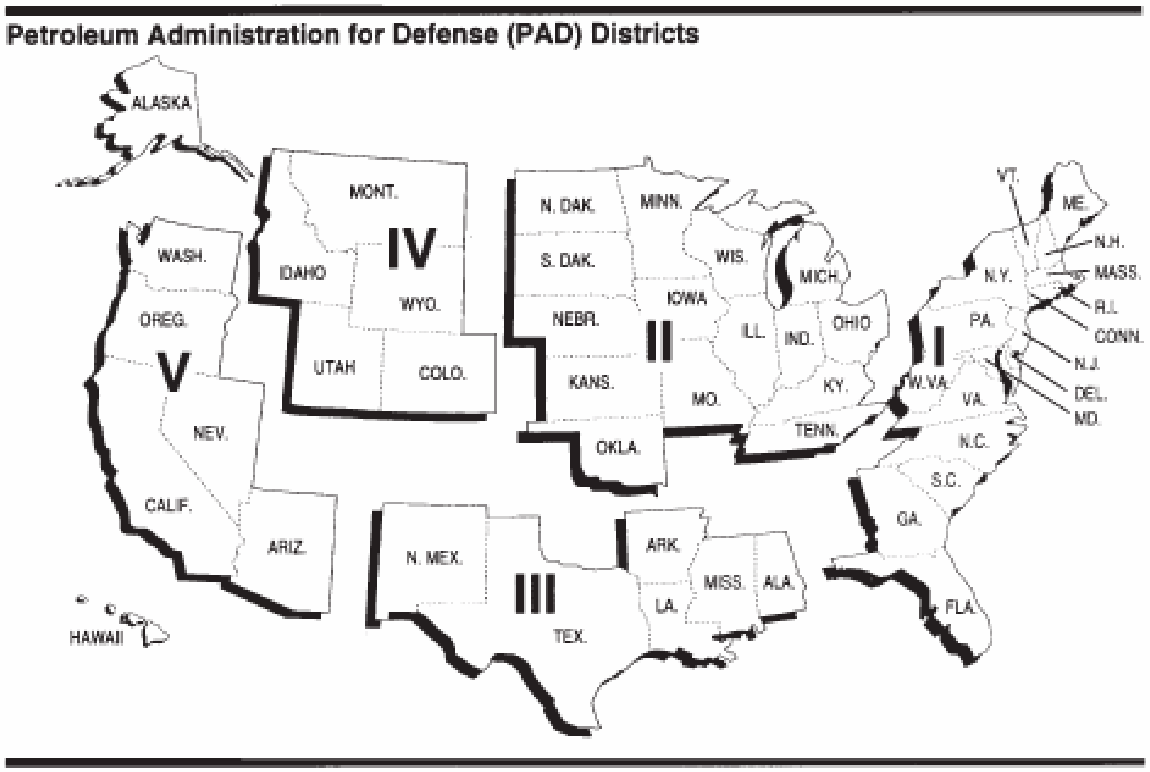
The 2002 DOE study contains estimated ethanol freight costs for each of the 5 PADDs. These estimated costs are summarized in the following Table 7.3-2.[142] A map of the PADDs is contained in Figure 7.3-1.

Table 7.3-2. Estimated Ethanol Freight Costs from the 2002 DOE Study

PADD	Annual ethanol use of 5.1 billion gallons per year (cents per gallon)	Annual ethanol use of 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

[CCC] See chapter 1.5 in this DRIA regarding the modes of transportation used to distribute ethanol.

Figure 7.3-1.

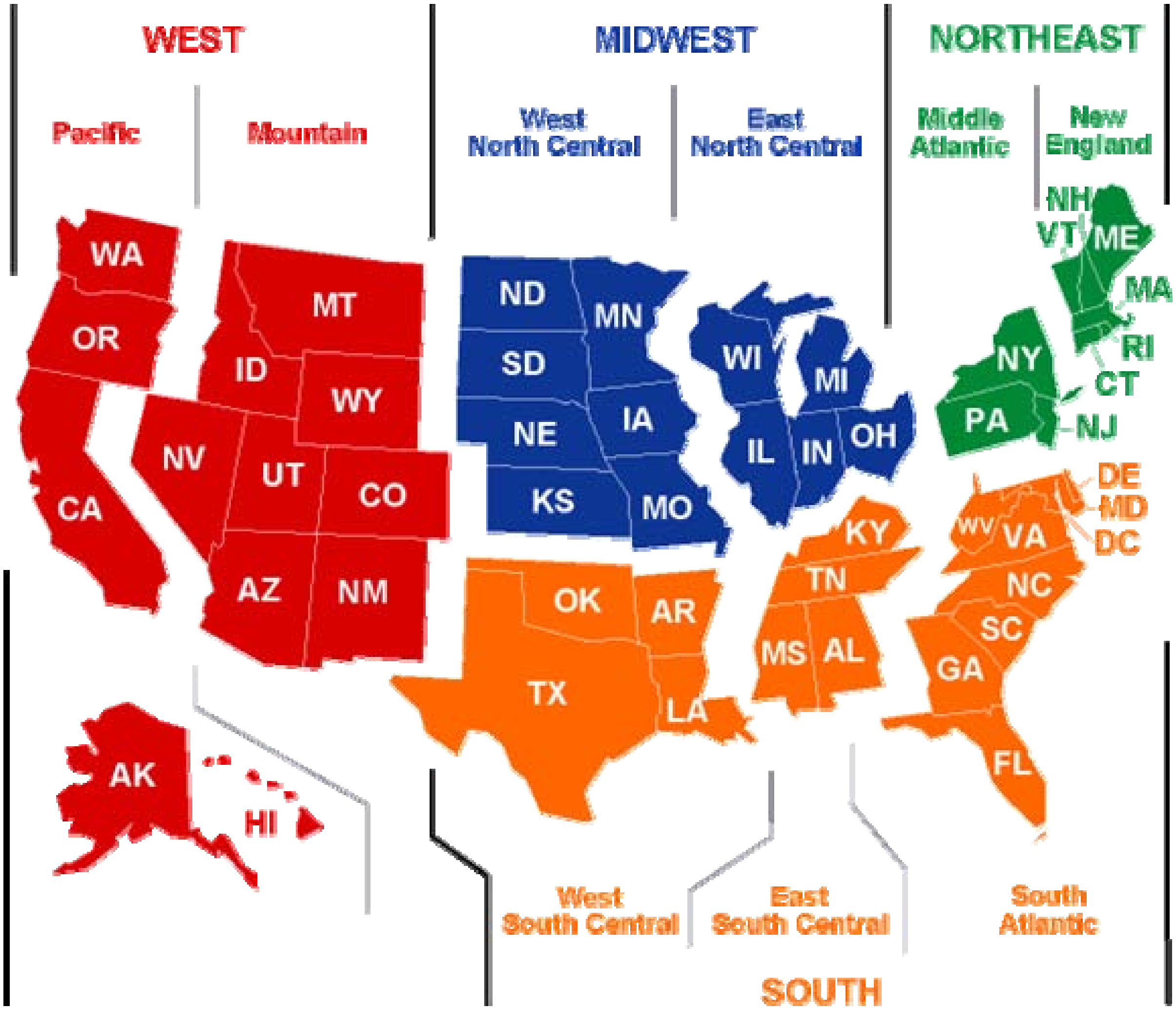


The Energy Information Administration (EIA) translated the cost estimates from the 2002 DOE study to a census division basis.[143] A summary of the resulting (EIA) ethanol distribution cost estimates are contained in the following Table 7.3-3. A map of the census divisions is contained in Figure 7.3-2.

Table 7.3-3. EIA Estimated Ethanol Freight Costs (based on 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. In conducting this translation, we accounted for increases in the cost in transportation fuels used to ship ethanol by truck, rail, and barge. For the purposes of this analysis, all ethanol was assumed to be produced in the Midwest in the East and West North Central Census Divisions (corresponding closely to PADD 2). Ethanol consumed within these census divisions 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 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. For some states, different freight costs for ethanol supplied to large hub terminal 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 be initially unloaded at hub terminals for further distribution to satellite terminals. The estimated additional freight cost of shipping ethanol from hub terminals to satellite terminals is contained in the following Table 7.3-3. 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. 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 the area.

Table 7.3-3.
Additional Freight Costs to Deliver Ethanol from Hub to Satellite Terminals

States	Additional Freight Costs to Deliver Ethanol from a Hub to a Satellite Terminal (cents per gallon)
OH	1
AK, AL, AR, FL, GA, KY, LA, MD, ME, MS, NC, NH, NY, OK, OR, PA, SC, TN, TX, VA, VT, WA, WV	2
AZ, CO, ID, NM, NV, UT, WY	3

Expressed on a national average basis, we estimate that the freight costs to transport ethanol to terminals would be 9.2 c/gal of ethanol. This translates to an annual freight cost for the additional volume of ethanol used in 2012 of $303,600,000 under the 7.2 Bgal/yr case, and $524,400,000 under the 9.6 Bgal/yr case. Adding in the annualized capital costs associated with modifying the distribution system to handle the increased volumes of ethanol results in a total annual ethanol distribution cost in 2012 of $338,430,000 under the 7.2 Bgal/yr case and $583,944,000 under the 9.6 Bgal/yr case.

Our estimates of the State-by-State ethanol freight costs are contained in the following Table 7.3-4.

Table 7.3-4. State-by-State Ethanol Freight Costs

State	PADD	Ethanol Freight Cost: Hub Terminal / Satellite Terminal (cents per gallons)
Florida, Pennsylvania	1	8.4 / 10.4
Maine	1	13.4 / 15.4
New Hampshire, Vermont	1	12.4 / 14.4
Massachusetts	1	11.4 / 13.4
Rhode Island	1	11.4 / 13.4
Delaware, Georgia, Maryland, New Jersey, New York, North Carolina, South Carolina, Virginia, West Virginia	1	11.4 / 13.4
District of Columbia	1	11.4
Iowa	2	3.4
Illinois, Kansas, Minnesota, Missouri, Nebraska, Wisconsin, South Dakota,	2	4.4
Indiana, North Dakota	2	5.4
Ohio	2	5.4 / 6.4
Kentucky	2	6.2 / 8.2
Tennessee	2	6.2 / 8.2
Michigan	2	6.4
Oklahoma	2	8.3 / 10.3
Mississippi	3	6.2 / 8.2
Alabama	3	7.2 / 9.2
Arkansas	3	7.3 / 9.3
Louisiana	3	7.3 / 9.3
Texas	3	10.3 / 12.3
New Mexico	3	12.4 / 15.4
Colorado	4	10.4 / 13.4
Wyoming	4	12.4 / 15.4
Utah, Montana	4	13.4 / 16.4
Idaho	4	15.4 / 18.4
Arizona	5	15.4 / 18.4
Nevada	5	16.4 / 19.4
California, Oregon, Washington	5	16.5 / 18.5
Hawaii	5	36.5 / 39.5
Alaska	5	41.5 / 43.5
National Average	-	9.2

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 28 million gallons.[DDD]

For the purposes of this analysis, we are assuming that to ensure consistent operations under cold conditions all terminals will install heated biodiesel storage tanks and biodiesel will be transported to terminals in insulated tank trucks and rail cars in the cold seasons.[EEE] The capital costs associated with the distribution of biodiesel will be somewhat higher than those associated with the distribution of ethanol. The cost to install the heated storage tanks and blending equipment at terminals is estimated at $250,000 per terminal. We estimate that 180 terminals would need to add the capacity to blend biodiesel in order to meet the requirements of the RFS for a total one time cost to terminals of $44,948,000. The cost to provide insulated tank trucks and rail cars is estimated to add 10 percent to the cost of these vessels. We estimate that 17 new tank trucks and 25 new rail cars will be needed to distribute the additional volume of biodiesel required at a cost of $3,163,000 and $1,650,000 respectively. Thus, the total capital cost to prepare the distribution infrastructure system to handle the increase in the volume of biodiesel under the RFS is estimated at $49,813,000. Amortized over 15 years, this equates to an annual cost of $5,470,000 which translates to approximately 2 c/gal of new biodiesel volume.

Due to the developing nature of the biodiesel industry, specific information on biodiesel freight costs is lacking. The need to protect biodiesel from gelling during the winter may marginally increase freight costs over those for ethanol. Counterbalancing this is the likelihood that biodiesel shipping distances may be somewhat shorter due to the more geographically dispersed nature of biodiesel production facilities. In any event, the potential difference between biodiesel and ethanol freight costs is likely to be small and the cost of distributing biodiesel does not appreciably affect the results of our analysis. Therefore, we believe that estimated freight costs for ethanol of 9.2 c/gal adequately reflects the freight costs for biodiesel. The annual freight cost to distribute the additional volume of biodiesel projected to be used in 2012 is estimated at $25,020,000. Adding the annualized capital costs associated with modifying the distribution system to handle the increased volume of biodiesel ($5,470,000) results in a total annual distribution cost in 2012 for the additional biodiesel volume of $30,490,000.

7.4 Gasoline and Diesel Blendstock Costs

In sections above, we estimated the cost of producing and distributing ethanol and biodiesel. This section summarizes the overall cost of several different changes to the gasoline pool, including the increase in ethanol use, the phase out of MTBE and the reuse of the former MTBE feedstock, isobutylene, to produce alkylate. We also estimate the cost for using more biodiesel in the diesel fuel pool.

[DDD] See Chapter 1 of this DRIA regarding the 2012 reference case.
[EEE] See Section 1.5 of this DRIA regarding the special handling requirements for biodiesel under cold conditions.

7.4.1 General Overview

To estimate the cost of increased use of renewable fuels, the phase out of MTBE and the production of alkylate, EPA retained the services of a contractor to run its LP refinery model. The contractor work to estimate the cost of these changes are underway, however, the work could not be completed in time for this proposed rule. Thus, to provide a cost estimate for this proposal, a simpler spreadsheet analysis was conducted. Although the spreadsheet analysis cannot capture the more complex cost effects for the blending of ethanol that can be captured with the LP refinery model, such as the economics of blending ethanol into premium versus regular grade gasoline or estimate summer versus wintertime ethanol use, it can capture the major cost factors that contribute to these changes.

The cost analysis is conducted by comparing a reference year without the Energy Act fuel changes to a modeled year with the fuel changes. We used 2004 as the base year. We grew the 2004 gasoline demand to 2012 to develop our reference case assuming that MTBE is still used, and ethanol is used proportional to their use in 2004. The sum of fuel changes, including the phase-out of MTBE, the increased use of alkylate and increased use of biofuels, is all assumed to be in place in 2012 and compared to the 2012 reference case. The analysis is conducted based on EIA's forecast that average price of crude oil will drop down to $47 per barrel. Predicting crude oil prices is difficult since so many factors can affect the price of crude oil. To capture the near term effect of higher priced crude oil and the possibility that crude oil prices could remain high into the more distant future, we conducted a sensitivity analysis assuming that crude oil is priced at $70 per barrel.

7.4.2 RVP Cost for Blending Ethanol into Summertime RFG

The following subsection details our assessment of the means and cost for lowering gasoline Reid Vapor Pressure (RVP)[FFF] of summertime RFG to accommodate the removal of MTBE and the addition of ethanol. When MTBE is removed, it results in a reformulated gasoline blendstock for oxygenate blending (RBOB) which is slightly lower in RVP than the MTBE-reformulated gasoline blend. The subsequent blending of ethanol into gasoline, however, causes about a 1 PSI increase in RVP. To end up with an ethanol-blended RFG which averages the same RVP as the MTBE-blended RFG, which is necessary to comply with the RFG hydrocarbon standards, some of the lighter hydrocarbons must be removed from the gasoline blendstock increasing its production cost.

7.4.2.1 Magnitude of RVP Change

Estimating the change in RVP was based on the actual in-use RVP level of RFG. The in-use RVP level for RFG was estimated by averaging the RVP levels of gasoline samples reported in the Association of Automobile Manufactures (AAM) gasoline survey for the RFG cities reported there. The RVP level of the RBOB minus MTBE would have to be about 6.7 RVP to derive a finished MTBE-blended RFG of 6.85 – which assumes that MTBE has an RVP of 8.0

[FFF] RVP is the pressure that gasoline generates when measured at a standardized condition using an American Society of Testing Materials (ASTM) testing methodology. RVP is somewhat related to the true vapor pressure generated by gasoline but tends to be somewhat higher.

and is blended at 11 volume percent. Since ethanol-blended RFG would also be expected to have a final RVP of 6.85, we estimate that the RVP of an RBOB for blending with ethanol would need to be 5.60, assuming that ethanol would be blended into RFG at 10 volume percent and would have a 20 PSI blending RVP. Thus, the RBOB RVP would have to be reduced by 1.1 psi in a transition from MTBE to ethanol. These RVPs are summarized in Table 7.4-1.

Table 7.4-1.
RVP Levels for MTBE and Ethanol-blended Reformulated Gasoline

	MTBE RFG	***RBOB for blending with MTBE***	***RBOB for blending with Ethanol***	***Ethanol RFG***
RVP Level	6.85	6.71	5.60	6.85

7.4.2.2 Means for Reducing RVP

Gasoline contains light, medium and heavy hydrocarbons. Medium and heavy hydrocarbons, which make up the majority of the gasoline pool, have six or more carbon molecules (C6+) while light hydrocarbon compounds have a carbon count less than six. The light hydrocarbon components in gasoline are butanes (C4s) and pentanes (C5s)[GGG]. The gasoline produced by more complex refineries is made up of ten or more different streams produced by refinery processes or streams imported into the refinery. Some of these streams contain significant levels of butanes and pentanes while others do not. A refiner's gasoline pool is the volume of various hydrocarbon streams or components that are added to a refiner's gasoline volume before shipment.

In gasoline, each hydrocarbon compound has its own pure vapor pressure. The compounds usually contribute a different or modified vapor pressure when blended into the gasoline pool due to its physical interaction with the other constituents in the pool. For ease of making blending RVP calculations, the modified vapor pressure of a single compound is called the blending RVP and we will be using blending RVP values in this analysis. The C7+ hydrocarbons in gasoline have relatively low blending RVP values ranging from 9 PSI to near zero. Butane and pentane hydrocarbons have much higher blending RVP's; isobutane's and normal butane's blending RVPs are 71 and 65, respectively, and isopentane's and normal pentane's blending RVPs are 20 and 17, respectively. For gasoline, blending a high RVP stream such as butanes into the gasoline pool will only be minimally reduced by blending in or diluting with lower RVP blend stocks streams due to the physical nature of vapor pressure. Thus, controlling the butane content of the gasoline pool will have the largest impact on pool RVP with minimal impacts on volume.

[GGG] These molecules can have single and/or double bonds between their carbon atoms as well as be straight chain or branched chain. For this cost analysis referral to butanes and pentanes means inclusion of both single and double carbon bond type molecules and straight or branched chain molecules.

Since butanes and pentanes have high blending RVP's, refiners control the amount blended into their gasoline pool up to the RVP allowed by the applicable environmental or other in-use gasoline standards. In the summer low RVP season, refiners are probably not adding butane, but separating some of the butanes and blending back a portion to meet RVP requirements. To accomplish a current RVP goal of say 9.0, refiners utilize existing distillation columns such as light straight run naphtha splitters, reformate splitters, stabilizers and other existing process distillation columns to remove butanes and pentanes[HHH]. These existing distillation columns are limited in making significant reductions in pool RVP. This is because the gasoline supply streams from these units contain only a portion of the amount of butanes and pentanes which ends up into gasoline. After these existing methods and equipment for removing light hydrocarbons from the gasoline pool are fully utilized, further lowering RVP could require a refiner to add additional distillation column capacity to remove butanes and in some cases pentanes.

Further control of RVP can be realized by reducing butanes or pentanes in their fluidized catalytic cracker unit's (FCCUs) gasoline blendstock, which is also called FCC naphtha. To accomplish this task, refiners would likely have to add a distillation column called a debutanizer and perhaps another column called a depentanizer, to separate these light hydrocarbons from the rest of the FCC gasoline blendstock. Debutanizers distill or separate butanes and lighter hydrocarbons off the top of the distillation column while pentanes and heavier C6+ hydrocarbons remain in the bottom and are subsequently blended into gasoline. In depentanizers, pentanes and lighter hydrocarbons (the debutanized stream) are removed from the hydrocarbon feed and drawn off the top of the column while the heavier C6+ hydrocarbon remain in the bottom of the distillation column and are blended into gasoline. If a refiner has a FCC depentanizer the "debutanized" FCC gasoline flows from the debutanizer to the depentanizer as hydrocarbon feed where pentanes are then removed.

In the U.S., 103 of the total 115 refineries that produce gasoline have FCCUs. The FCCU converts gas oil and residual fuel to gasoline, which is the heavy and light hydrocarbons as defined above, and even lighter hydrocarbons, by reacting or cracking the gas oil over fluidized, heated catalyst. The gasoline volume produced by the FCCU makes up to 35-50 volume percent of refiner's gasoline pool and is thus the largest contributor to the gasoline pool.[144] FCCU gasoline contains butanes, pentanes, and C6+ hydrocarbons with the amount of these hydrocarbons being set by each refiner's FCC conversion rate and the FCCU's gasoline distillation capability, as most of the butanes and lighter hydrocarbons are removed off of the top of the debutanizer column.[III] Typical ranges are 0 to 10 percent for butanes and 5 to 17 volume percent for pentanes in the FCC naphtha pool.[145] The higher percentage of butane is likely for a 9.0 RVP gasoline, while lower percentages are consistent with lower RVP gasoline. Each

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[HHH] Distillation columns are the process equipment used to separate light from heavier hydrocarbons through the process of vaporization and condensing. The addition and removal of heat to the column is what drives the separation process. Heat is added to the column through a heat exchanger called a reboiler while heat is removed from the top of the column with an exchanger called a condenser. The lighter hydrocarbons are vaporized and travel up the column where they are removed as a product while the heavier hydrocarbons move down the column are drawn off the bottom. In a distillation column, there are many distillation trays which provide the mechanism for mixing and separation of the hydrocarbons.

[III] FCC conversion can be defined as the amount of FCC charge that is cracked into gasoline and lighter hydrocarbons.

refiner's FCC conversion is set by many process parameters, including the type of FCC unit, the FCC feedstock type, feed throughput, catalyst type, unit constraints, unit bottlenecks, catalyst condition and operational mode. Higher amounts of butanes and pentanes are generated as the FCCU conversion rate is increased with a typical conversion rate being 74 percent.[146]

It is important to determine the gasoline RVP level at which refiners will begin to remove pentanes after the butanes have all been removed. Because butanes are more volatile than pentanes, initial reductions in RVP are achieved by removal of butanes and at some point achieving further reductions in RVP requires removal of pentanes from the pool. This is important because, as described below, we estimate that reducing the gasoline pool RVP by one RVP number requires a reduction of the equivalent of 2 volume percent of the gasoline pool in butane, whereas, attaining the same RVP reduction requires a reduction of the equivalent of 10 percent of the gasoline pool in pentanes.

We used several different means for estimating the point where further RVP decreases requires pentanes to be removed. We spoke to several distillation vendors who have helped refiners make process changes to lower gasoline pool RVP to meet low RVP standards that were instituted in the 1990's and year 2000. One vendor stated that most refiners currently producing a reformulated federal or low RVP (7.0, 7.2 or lower) gasoline today made modifications to their FCC debutanizers to meet the RVP specification. The modifications were achieved either through revamping the existing debutanizer by installing new high capacity trays and heat exchangers, or through the addition of a new debutanizer column. According to this vendor, approximately 40% of refiners revamped their FCC debutanizer while 60% installed a new debutanizer column. The vendor stated that a FCC gasoline RVP of about 6.7 to 7.0 is achieved by most refiners when butanes are removed to less than 0.5 volume percent of the FCC gasoline pool. He further stated that these low levels of butanes could typically be attained through FCC debutanizer modifications. Obtaining a FCC gasoline RVP of 7.0 or below would probably allow most refiners to produce their gasoline to a pool RVP of 7.0 or lower.

The distillation vendor also stated that half of the refiners that made debutanizer modifications also installed new FCC depentanizers. Prior to lower RVP requirements, refiners typically did not have depentanizers for depentanizing their FCC gasoline blendstock. The vendor was not sure as to why the depentanizers were added but thought that refiners only required a FCC debutanizer modification to meet lower RVP specification. The vendor also stated that current refiners producing a 7.8 to 9.0 RVP pool cap may have original unmodified debutanizers and typically do not have FCC depentanizers. The original unmodified debutanizers were designed to remove butanes down to a 1.5 to 2.0 volume percent level in FCC gasoline.

To understand this issue further, we contacted several refiners who make low RVP gasoline or RFG to understand about how they reduced the RVP of their gasoline pool. The refiners reported that they had to spend capital for FCC debutanizer modifications and that these modifications allowed production of a 7.0 RVP gasoline by removing butanes to less than a 1.0% level in the gasoline pool. One refiner operating their FCCU at a low conversion rate actually made a 6.4 RVP FCC gasoline. Only one out of five refiners reported that during the summertime production season they had to remove some pentanes to meet the 7.0 RVP specification for their pool. During the summer low RVP gasoline season, this refiner intermittently had to remove about 20 percent of the refinery's pentanes from the gasoline pool.

The other refiners reported no need to remove pentanes to meet a 7.0 RVP spec. The refiners reported that the new depentanizers the distillation vendor referred to may have been installed for several reasons; to allow segregation of the heavier gasoline C6+ components for sulfur sweetening, to remove pentanes to lower the pool RVP or to segregate the pentanes so that the pentanes may be backblended back into the pool per RVP allowance.[JJJ] Some refiners produce several grades of gasoline with varying RVP specifications, thus segregating pentanes and back blending would allow a refiner to more accurately control each pool's RVP. Backblending of pentanes would be particularly important for refiners producing RBOB (renewable blendstock for oxygenate blending) for blending with ethanol since that RBOB must be very low in RVP to accommodate the RVP boost of ethanol. None of the refiners commented on the operations of their FCC debutanizers/depentanizers, but one refiner reported that pentanes would have to be removed from gasoline to get the pool below a 7.5 RVP specification.

We also evaluated information from several different refinery models in an attempt to understand the breakpoint between butane and pentane reduction to reduce RVP. For this analysis, we used a typical gasoline blend, which represents the gasoline quality for a notional refinery for PADDs 1, 2 and 3. We used this gasoline blend because it seemed like a reasonable mix of gasoline blendstocks. This gasoline blend is summarized in Table 7.4-2.

Table 7.4-2.
Baseline 9 RVP Gasoline Composition

Gasoline Blendstocks	% Volume
Isobutanes	1.3
Normal Butane	4.1
C5s & Isom	5.8
Naphtha C5-160	3.5
Naphtha 160-250	3.7
Alkylate	12.1
Hydrocrackate	4.0
Full Range FCC Naphtha	38.1
Light Reform	5.3
Heavy Reform	21.6
MTBE	0.5
Total	100.0
RVP psi	8.5

We then applied the blending RVPs from different refinery models, which included Mathpro's, Oak Ridge National Laboratory's (ORNL) and a refining industry consultant who wished to remain anonymous, to the typical gasoline blend to estimate this butane/pentane

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[JJJ] Send the C6+ hydrocarbons through a Merox or similar process were mercaptan sulfur molecules are converted to meet odor and corrosion requirements.

breakpoint in RVP. Before proceeding with the analysis, we needed to estimate the amount of butane entrained in the gasoline pool.

Butanes remain entrained in the gasoline pool because distillation of hydrocarbons does not allow a perfect cut between the various hydrocarbons which comprise gasoline and some butanes would be expected to remain in refined streams after distillation to remove them. It is important to know how the various refinery modelers set up the input tables of their refinery models to account for this. Mathpro said that their gasoline blendstocks do not incorporate entrained butane and that they put a lower limit on the amount of butane which can be removed from the gasoline pool. We assumed a lower limit of 1.5 percent butanes in the gasoline blend when using their gasoline blendstocks to evaluate this issue. Ensys, which has provided many of the technical inputs to the Oak Ridge National Laboratory (ORNL) refinery model, stated that the gasoline blendstocks in the ORNL refinery model were based on actual refinery streams, but did not know how much butane was in those streams. Since the blendstock qualities were based on actual refinery blendstocks, we presumed that the blendstocks did contain entrained butane. The refinery industry consultant felt that their gasoline blendstocks contained entrained butane and that they model removing all the butane in their low RVP refining studies and we did the same. The blendstock blending RVP levels are summarized in Table 7.4-3.

Table 7.4-3.
Estimated Gasoline Component Vapor Pressures (psi RVP)

Component	MathPro	ORNL	Consultant X
Isobutanes	71	71	71
Normal Butane	65	65	65
C5s & Isomerate	13.3	13.3	13.8
Straight Run Naphtha	—	—	8.8
(C5-160 F)	13	12	---
(160-250 F)	2.5	3	---
Alkylate	3.5	6.5	4.9
Hydrocrackate	12.5	14	7.2
Full Range FCC Naphtha	3.7	6.9	7.1
Light Reformate	7.5	6.9	6.4
Heavy Reformate	3.8	3.9	3.3
MTBE	8	8	8

Our analysis here showed that applying the Mathpro blendstocks to the typical gasoline blend and limiting butane reduction to 1.5 percent yielded a lower RVP limit of lowering butane to 6.2 RVP. Applying the ORNL blendstocks to the typical gasoline blend and removing all the butane yielded a lower RVP limit for lowering butane to 7.1 RVP. Applying the other refinery industry consultant’s blendstock qualities to the typical gasoline blend and removing all the butane yielded a lower RVP limit for lowering butane to 6.5 RVP. Averaging these three values yields 6.6 RVP as the lower limit for removing butane before pentanes would need to be removed.

We believe that there is a good explanation for why the butane-pentane breakpoint for RVP reduction varies so much based on the people we spoke to and also on our refinery modeling analysis. Each refiner has many differing types of gasoline production processes with varying throughputs and gasoline yield capabilities. Also, each refiner processes a differing crude oil slate, with a varying hydrocarbon composition which further contributes to each refiner producing its own unique gasoline blend stocks. Thus, differing crude slates and process units cause a refiner to yield different amounts of the light and heavy hydrocarbon components for blending into its gasoline pool.

To take into account the various RVP values for the butane-pentane breakpoint based on the low and high figures obtained from the aforementioned discussions with the vendors, refiners, and consultants, and the refinery modeling study, we considered a range of values for this analysis. Based on the above discussions and analyses, we believe that, after butanes have been removed, pentanes would begin to be removed when a gasoline blend's RVP is lowered below a range of values between 7.5 and 6.2 RVP. However, the analysis suggests that for most refiners, the breakpoint is likely at an RVP level of 6.8, the average of summertime RFG.

Thus to accommodate the ethanol, the MTBE is removed from RFG, and the RVP of the base gasoline is adjusted so that when the ethanol is added, the resulting ethanol-blended RFG will have an RVP of 6.8. This occurs by removing pentanes from the gasoline pool because nearly all the butanes are presumed to have been removed in forming the MTBE-blended RFG. Because a small amount of butanes remain entrained with the pentanes, the vapor pressure of the pentanes is presumed to be higher than the pure blendstocks. For our estimates of the impact of lowering pentane content on RVP, we presume that there is about 1 percent butane content in the pentanes which would result in an average blending RVP for pentanes of about 20 RVP.

7.4.2.3 Cost of Reducing Gasoline RVP

The total cost of RVP control was identified as the combination of three separate cost elements. First, capital and operating costs would be incurred through the installation of new depentanizer columns. We assume that separating pentane from the rest of the gasoline pool requires these investments. Then, the removed pentane is assumed to incur an opportunity cost based on the next available price for these hydrocarbons on the open market compared to the price of gasoline. Finally, the removal of these lighter hydrocarbons causes the gasoline pool to increase in energy content. Thus, we determined the energy density change and estimated the cost impact for the energy change based on the wholesale price for gasoline. The calculation of each of these cost elements and the resulting total costs are summarized below.

Costs were developed for adding a new depentanizer distillation column for the removal of pentanes from FCC gasoline in a typical-sized refinery. Capital and operating costs for a new depentanizer were based on the capital and operating cost of a naphtha splitter from Mathpro for cost work conducted for us for the Mobile Source Air Toxics Proposed Rule (MSAT2).[147] The costs for a naphtha splitter are expected to be similar to that of a depentanizer because it distills pentanes out of the top of the column while not boiling the heavier compounds which pass through the bottom of the distillation column. The cost information for this distillation column is summarized in Table 7.4-4.

Table 7.4-4.
Process Operations Information for New Dependentanizer

	Depentanizer
Capacity (bbl/day)	15000
Capital Cost, ISBL (MM$)	6.6
Electricity (kWh/bbl)[a]	2.8
Fuel Gas (foeb/bbl)[b]	0.01
Other Variable Operating Cost ($/bbl)[c]	0.01

[a] kWh/bbl is kilowatt-hours of electricity per barrel of feed
[b] Foeb/bbl is fuel oil equivalent barrel of fuel gas per barrel of feed
[c] $/bbl is dollars per barrel of feed

Capital Costs

Capital costs are the one-time costs incurred by purchasing and installing new hardware in refineries. Capital costs for a particular processing unit are supplied by vendors or estimated from other sources at a particular volume capacity, and these costs are adjusted to match the volume of the particular case being analyzed using the "sixth tenths rule" as described by Gary and Handewerk.[148]

The capital costs are adjusted to account for the off-site costs and differences in labor costs relative to the Gulf Coast using Gary and Handewerk estimates.[149] Off-sites costs were assumed to be 1.25 times the onsite costs. Location factors for the refineries in each PADD were assumed to be the same by PADD. Table 7.4-5 contains the location cost factors for each PADD and for California.

Table 7.4-5.
Location Factors by PADD Used for Estimating Capital Costs[a]

Factor	**PADD 1**	**PADD 2**	**PADD 3**	**PADD 5**	**CA**
Location	1.5	1.3	1.0	1.2	1.2

[a] PADD 4 is not included because PADD 4 does not use any RFG

The capital costs were estimated for the volume of FCC gasoline produced (see Table 7.4-8 below). For costing out the depentanizer, it was assumed that the column would remove all the pentanes in the FCC naphtha, and any excess pentane removed would be reblended back into gasoline. The capital costs were amortized on the yearly gasoline volume. The economic factors used for amortizing the capital costs and the resultant capital cost factor are summarized in Table 7.4-6.

Table 7.4-6.
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

Fixed Costs

Operating costs which are based on the cost of capital are called fixed operating costs. Fixed costs are incurred to maintain the unit in good working order, insure the unit against accidental damage, and for a number of other factors. These are fixed because the cost is normally incurred even when the unit is temporarily shutdown. These costs are incurred each and every year after the unit is installed.

Maintenance cost is estimated to be three percent of capital cost after adjusting for location and offsites. This factor is typical and is based on the maintenance factor used in previous refinery modeling studies. Other fixed operating costs include: 0.2 percent for land, one percent for supplies which must be inventoried such as spare distillation trays, and two percent for insurance. These factors sum to 6.2 percent, which is applied to the total capital costs (after adjusting for offsite costs) to generate the fixed operating costs. Labor costs are very small and are presumed included with the rest of the fixed operating costs.

Variable Operating Costs

Variable operating costs are the costs incurred to run the unit on a day-to-day basis and are based completely on unit throughput. Thus, when the unit is not operating, variable operating costs are not being incurred.

The electricity and natural gas costs are based on a simple arithmetic average of 2004 utility prices paid by industries for the states with refineries within the states.[150] [151] The 2004 average prices for each PADD are adjusted to represent estimated prices in year 2012 using the ratio of projected 2012 prices to 2004 prices in the Annual Energy Outlook 2006.[152] These projected energy prices are summarized in Table 7.4-7.

Table 7.4-7. Summary of 2012 Utility Costs

	PADD 1	PADD 2	PADD 3	PADD 5	CA
Electricity (¢/kWh)	7.18	4.34	5.63	8.34	9.17
Natural Gas ($/MMbtu)	7.77	6.71	5.51	8.35	6.96

For the removal of pentanes, costs developed for additional FCCU depentanizer capacity per treated gallon of FCC gasoline were then amortized over the entire gasoline pool. The volume of FCC naphtha in each PADD as well as the gasoline volume in each PADD was taken from the refinery-by-refinery cost model used for estimating benzene control costs for the MSAT2 proposed rulemaking.[153] For each PADD, the PADD's FCC gasoline volume was divided by the PADD's total refinery gasoline volume to determine the percent contribution of FCC gasoline to the total gasoline pool. The FCC naphtha and total gasoline volume for each PADD is summarized in Table 7.4-8.

Table 7.4-8.
Volume of FCC Naphtha Compared to Total Refinery Gasoline Production by PADD
(barrels per day for an average-sized refinery)

Factor	PADD 1	PADD 2	PADD 3	PADD 5 ex CA	CA
FCC Naphtha (bbl/day)	34,700	24,300	33,800	7,000	27,300
Total Refinery Gasoline (bbl/day)	80,700	69,400	82,700	22,300	90,200

7.4.2.5 Cost Summary for RFG RVP Impacts

RVP control costs were developed by PADD for converting MTBE-blended RFG to ethanol-blended RFG through the addition of new depentanizers. For the min RFG scenarios, there are some situations where ethanol is removed from RFG. For these situations, refiners would be expected to stop using their existing depentanizers resulting in the saving of the pentanizer operating costs only. In Table 7.4-9 we provide the per-gallon capital and operating costs by PADD for adding a new pentanizer, and the operating costs only for the situation that existing pentanizers are shut down.

Table 7.4-9.
Summary of the RVP Impacts for Blending More Ethanol or Reducing the Volume of Ethanol into RFG (¢/gal)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5 (ex CA)	CA
Pentane Distillation Cost With Capital Costs	1.37	1.04	1.02	1.07	1.22	1.01
Pentane Distillation Cost Without Capital Costs	1.15	0.87	0.88	0.83	1.01	0.88

7.4.2.4 Other Costs of Summertime RFG Volatility Control

When butanes, and sometimes pentanes, are removed from the gasoline pool, they are sold off in markets which bring a lower return than gasoline. The lost opportunity of blending and selling these petroleum components in gasoline is called the opportunity cost. The opportunity cost is merely the price difference between higher valued gasoline and the price for these petroleum compounds on the open market. For this analysis, we assume that the removed pentanes would be reblended into gasoline, most likely into the summertime CG pool, although they could be stored up for blending into the wintertime CG or RFG pool. Either way, the pentanes would likely not be lost from the gasoline pool. Instead, we assume that when the pentanes are reblended into another portion of the gasoline pool, the appropriate volume of butanes would be removed from that gasoline pool to balance the RVP of the gasoline pool. We obtained 2004 prices for butane from Platts, and compared them to the gasoline price in 2004.[154] Comparing the butane price with the gasoline price shows that the opportunity cost of removing butanes is about 36 c/gal and we used this cost when assessing the cost for removing the butanes. The 2004 prices for butane and gasoline are summarized in Table 7.4-10 and we apply this cost below.

Table 7.4-10.
Prices for Butane and Gasoline in 2012 Used for Estimating the Opportunity Cost of Removing Butanes from Gasoline (cents/gallon)

Butane price	Gasoline
94	130

The energy density of the removed butane is lower than gasoline which lowers the impact of its removal. This lower energy density is accounted for below in the balancing of the gasoline pool's energy content. The energy contents of butane and gasoline is summarized in Table 7.4-11.

Table 7.4-11.
Energy Content of Butane and Gasoline for Estimating the Fuel Economy Impacts of Reducing the RVP of Gasoline (MMBtu/gal)

Butane	Gasoline
94,000	112,000

7.4.3 Cost savings for phasing out Methyl Tertiary Butyl Ether (MTBE)

The Energy Act rescinded the oxygen standard for RFG and when the provision took effect, U.S. refiners stopped blending MTBE into gasoline. When MTBE use ended, the operating costs for operating those plants also ceased. The total costs saved for not operating the MTBE plants is calculated by multiplying the volume of MTBE no longer blended into gasoline with the operating costs for the plants producing that MTBE.

The volume of MTBE blended into U.S. gasoline in 2004 is provided by EIA and for our reference case is grown using the gasoline growth rate to 2012 as summarized in Section 2.1.3 above. The cost savings of phasing-out of MTBE is based on the reference case volumes to have a single case to which we compare the control cases. These volumes are summarized again here Table 7.4-12 by PADD.

Table 7.4-12.
MTBE Consumption in PADDs 1 – 5 and CA in 2004 (million gallons)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5 (ex CA)	CA	USA
2004 MTBE Consumption	1,360	2	498	0	19	0	1,878
Projected MTBE Consumption in 2012	1,510	2	555	0	21	0	2,092

The operating cost for producing MTBE depends on the type of MTBE plant producing it. There are 4 different types of plants producing MTBE, as well as imports. As MTBE was phased-out under the state MTBE bans in California, Connecticut and New York, most or all of the imported MTBE found a market elsewhere overseas, so this volume of MTBE and the plants producing it was no longer relevant to the U.S. market. There are four different types of domestic MTBE plants and what they have in common is that they react isobutylene with purchased methanol to produce the MTBE.[155] The primary difference between them is how they obtain or produce the isobutylene, which is summarized by plant type:

1) MTBE plants contained in refineries are called "captive" MTBE plants. These plants use isobutylene produced from the refinery's fluidized catalytic cracker (FCC) unit.

2) Propylene Oxide based plants produce tert-butyl alcohol (TBA) as a byproduct. This TBA is converted to isobutylene by a deoxidation reaction.

3) Ethylene crackers produce isobutylene in the process of cracking heavier weight hydrocarbons. Thus, the cost for producing MTBE by these plants is similar to captive units.

4) Merchant MTBE plants produce their isobutylene from the normal butanes or mixed butanes from natural gas condensate. The normal butanes are first isomerized to isobutane and then dehydrogenated to isobutylene. If starting from mixed butanes the normal butane is separated from the branched chain butanes through distillation and are isomerized and combined together with the branched chain butanes and fed to a dehydrogenation reactor for converting to isobutylene.

EPA conducted a detailed analysis of the volume of MTBE produced by each of these MTBE plants several years ago. Table 7.4-13 shows the estimated production by MTBE plant type in the year 2000 (from Pace Consultants[156]).

Table 7.4-13.
Sources of MTBE Used in U.S. Gasoline in the Year 2000

Type of MTBE Plant	**MTBE Production Volume (barrels/day (bbl/day))**	
	Physical Volume	**Percent of non-imported MTBE**
Captive refinery plants	79,000	37
Propylene Oxide (TBA) based merchant plants	45,000	21
Ethylene based merchant plants	21,000	10
Natural gas liquids (NGL) based plants	67,000	32
Imports (NGL based)	51,000	-
Total	263,000	-

Since the year 2000 U.S. demand for MTBE has diminished to about one half of that of the year 2000. The principal reason is that the states of California, New York and Connecticut, which consume significant amounts of RFG, have banned the use of MTBE. However, additional reductions occurred due to the phase-out of elective MTBE use in conventional gasoline. We did not assess how the past MTBE plants might have changed due to the change in MTBE use since the year 2000. It is likely that a portion of the captive MTBE plants have already been shutdown in those refineries that serve RFG markets which are located in states which have banned the use of MTBE. Of the year 2000 petrochemical and merchant MTBE plant capacity, it is likely that a portion of that MTBE plant capacity is being used to export MTBE. Lacking updated information, we assumed the mix of MTBE plants providing MTBE to the U.S. market in 2004, the base year of our analysis, to be the same as that in 2000.

We estimated the costs saved by shutting down this MTBE plant capacity at the volumes of MTBE blended into the projected 2012 reference case gasoline. For estimating the costs, the volumetric feedstock demands and the operating costs factors for each of these MTBE plants were based on an Ethermax MTBE plant found in literature.[157] We could not locate any information on the costs for deoxidizing TBA, so we used the costs for isomerization. The volumetric operating costs for the reactions used to produce isobutylene and for producing MTBE are summarized in Table 7.4-14.

Table 7.4-14.
Volumetric Feedstock Demands and Operating Cost Factors for Producing MTBE

	Isomerization	**Dehydrogenation**	**MTBE Plant**
MTBE plant costs apply for:	Merchant and PO (used for deoxidation of TBA)	Merchant	Merchant, PO, Ethylene Cracker and Captive
n-Butane and TBA (BPSD)	1549	-	-
Isobutane (BPSD)	-	1549	-
Isobutylene (BPSD)	-	-	1549
Methanol (BPSD)	-	-	530
MTBE (BPSD)	-	-	1560
Capital Costs (million $)	15.1	75.7	9.3
Plant Size (kbbl/day)	3800	8260	1560
Steam (lbs/hr)	18,900	63,000	18,900
Electricity (Kwh)	117	10,000	117
Cooling water (gals/min)	545	15,800	151
Catalyst	0.19	3.1	-

The feedstock prices are based on year 2004 average prices from Platts. [reference] A price was not found for TBA, so it was set equal to isobutylene. They are adjusted to 2012 using the same ratio used to estimate gasoline prices in 2012 as discussed below in subsection 7.4.6.

The operating cost factors are multiplied by the utility prices for each factor. We derived the energy prices by averaging the year 2004 prices for Texas and Louisiana, the two primary refining districts where most of the MTBE is manufactured. These prices are adjusted to 2012 by multiplying each price by the ratio of electricity and natural gas prices in 2012 to that from 2004 from AEO 2006, and are the same as the utility prices summarized in Table 7.4-7 above for PADD 3. The estimated feedstock prices and energy prices for 2012 and are summarized in Table 7.4-15.

Table 7.4-15.
Summary of Year 2012 Projected Feedstock and Utility Prices[a]

Mixed and Normal Butanes (c/gal)	93
Isobutylene (c/gal)	105
TBA (c/gal)	105
Methanol (c/gal)	77
Electricity (c/kWh)	5.63
Natural Gas ($/MMbtu)	5.51

[a] c/kWh is cents per kilowatt-hour, $/MMbtu is dollars per million British thermal units.

Applying the 2012 feedstock and utility prices in Table 7.4-15 to the feedstock demands and input cost factors in Table 7.4-14, results in the production costs for each MTBE production type presented in Table 7.4-16. We applied the weighting factors from Table 7.4-13 above to derive the weighted average MTBE production costs shown in Tables 7.4-16.

Table 7.4-16.
Cost Savings for phasing out MTBE Consumption in 2012
(cents/gallon)

MTBE Plant Type	Captive and Ethylene Cracker	Propylene Oxide	Merchant	Weighted Average
MTBE Production Cost	140	148	155	146

We also credited MTBE for its octane value. MTBE has a high octane value of 110 (R+M)/2 which partially offsets its production cost. The cost of octane is presented above and is applied to the difference in octane value between MTBE and the average of the various gasoline grades (89 (R+M)/2). MTBE's blending cost, which is the combined production and octane cost, is summarized in Table 7.4-17.

Table 7.4-17.
MTBE Blending Cost for PADDs 1 – 5 and CA in 2012
(cents/gallon)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5 (ex CA)	CA
2012 MTBE Production Cost	146	146	146	N/A	146	N/A
Octane Value	-15.8	-8.4	-14.7	N/A	-18.9	N/A
Net MTBE Blending Cost	131	138	132	N/A	127	N/A

7.4.4 Production of Alkylate from MTBE Feedstocks

7.4.4.1 Overview of Converting MTBE Feedstocks

Discontinuing the blending of MTBE into U.S. gasoline is expected to result in the reuse of most of one of the primary MTBE feedstocks, isobutylene, to be used to produce alkylate. Alkylate is formed by reacting isobutylene together with isobutane.[158] Prior to the oxygen requirement for RFG, this isobutylene that is sourced from refinery FCCUs was, in most cases, used to make alkylate. Another option would be for reacting isobutylene with itself to form isooctene which would likely be hydrogenated to then form isooctane. There are several differences between using isobutylene to form alkylate versus isooctane.

One difference is that isooctane has a higher octane number (100 (R+M)/2), than alkylate (93 (R+M)/2). A second difference is that an alkylate plant can produce twice the volume of fuel compared to an isooctane plant. If an MTBE plant converts to alkylate production, it produces 80% more gasoline in terms of energy content than it did when producing MTBE. The gain in energy comes from the fact that isobutane is combined with this isobutylene in the production of alkylate, versus the addition of methanol in the production of MTBE. Isobutane contains more energy than methanol, so the product does as well. If an MTBE plant converts to isooctane production, it produces 15% less gasoline in terms of energy content than it did when producing MTBE. The loss in energy comes from the fact that isobutylene is reacted with itself to form isooctane (i.e., no other feedstock is combined with the isobutylene in the reaction). Thus, the energy content of methanol is lost relative to MTBE production.

Alkylate and iso-octane both have low RVP (2-6 psi). Isooctane's RVP is particularly low and alkylate RVP can be very low, though it tends to vary depending on operating condition and feedstock quality. These RVPs are lower than MTBE's RVP of roughly 8 psi. Due to this low RVP, the substitution of alkylate or isooctane for MTBE makes it slightly easier to add ethanol to RFG and still meet the Phase 2 RFG VOC performance standards. Ethanol tends to add approximately 1 RVP when added to gasoline, so the production of a blendstock with an RVP in the range of 5.5 is needed to facilitate ethanol use in RFG. Both alkylate and isooctane would help facilitate this.

Based on previous conversations with a contractor, the MTBE plants operating in the U.S. have different possible fates for converting over to producing alkylate or isooctane depending on the plant type.[159] This is discussed by each plant type.

Captive Refinery MTBE Plants

Captive refinery plants would most likely redirect the isobutylene currently used to produce MTBE to their alkylation unit if this unit has sufficient capacity or can be cost effectively revamped to a higher capacity. Isobutylene was usually used to produce alkylate prior to MTBE production and this would be the preferred route now, due to the higher volume of gasoline produced with alkylate versus isooctane. However, if a refiner's current alkylation unit does not have excess capacity and could not be inexpensively increased, the isobutylene that was going to the MTBE unit could be converted to isooctane. Thus, as a lower volume limit it is possible these units produce isooctane, and as an upper limit all these units will produce alkylate. In no case will the MTBE production from these plants be completely lost as the isobutylene is available at no cost and has no other high value market.

Propylene Oxide Based MTBE Plants

There are several options for the isobutylene produced by the propylene oxide based MTBE plants. The TBA which is converted over to isobutylene, could be sold into the chemicals market since it has other value as a chemical feedstock. Alternatively, the TBA could still be converted to isobutylene, which is what these plants are doing now to produce MTBE, and the isobutylene could be converted over to either alkylate or isooctane production. These plants are also very large and have the economies of scale to support conversion to isooctane or alkylate.

Ethylene Based MTBE Plants

The ethylene based plants tend to be smaller than the other petrochemical MTBE plants and tend to be co-located with refineries. For these reasons, the ethylene-based MTBE plants would likely shutdown and send their isobutylene to their co-located refineries for conversion to alkylate. Thus, while the MTBE plant itself is shut down, the isobutylene volume used to produce MTBE today would not be lost. The main reason for the difference in fate for these plants and the propylene oxide based plants is their size. As a lower limit, the isobutylene used in these ethylene based plants could be used to produce isooctane in refineries, as was the case for the captive refinery plants.

Natural Gas Liquid Based Plants

Merchant, natural gas liquids (NGL) based MTBE plants would face the greatest challenge to stay in business. These plants produce the isobutylene they need to produce MTBE from mixed, field butanes. Isobutane is produced by isomerization of normal butane or is separated from mixed butanes. This isobutane is then dehydrogenated to form isobutylene. Producing isobutylene in this way is more costly than using isobutylene already present within a refinery or raffinate stream in an ethylene plant. It is also more costly than producing isobutylene from tertiary butyl alcohol. The original mixed field butanes perhaps could be stored until winter and then blended into gasoline. Thus, sufficient revenue must be obtained from alkylate or isooctane production to cover the capital cost of the plant conversion plus the cost of producing the isobutylene from mixed field butanes. If these plants were to convert, they would be more likely to convert to alkylate than isooctane production. However, a review of the historic alkylate price premiums suggests that these plants probably could not support conversion to even alkylate production, which is contrary to today’s alkylate prices which would likely support such a conversion. Consequently, with the phase-out of MTBE, due to the uncertainty in future alkylate premiums, in the worst case that all of these plants would shut down or export the MTBE abroad, or in the best case they could convert to alkylate production.

7.4.4.2 Economics of Conversion of MTBE Feedstocks to Alkylate Plants

We assessed the economics for the conversion for MTBE feedstocks to produce alkylate and isooctane. The costs for producing alkylate are based on an Exxon sulfuric acid alkylation plant, and the costs for producing isooctane are based on a UOP catalytic condensation process.[160] The feedstock volumes and operating cost factors are summarized in Tables 7.4-18 and 19.

Table 7.4-18.
Feedstock Volumes and Operating Cost Factors for Producing Alkylate

	Isomerization	**Dehydrogenation**	**Alkylate Plant**
Alkylate plant costs	Merchant and PO	Merchant	Merchant, PO, Ethylene Cracker and Captive
n-Butane & TBA (BPSD)	5110	-	-
Isobutane (BPSD)	-	5110	-
Isobutylene (BPSD	-	-	5110
Mixed Butanes (BPSD)	-	-	4678
Alkylate (BPSD)	-	-	7500
Capital Costs (million $)	15.1	75.7	16.0
Plant Size (kbbl/day)	3800	8260	7500
Steam (lbs/hr)	18,900	63,000	63,000
Electricity (Kwh)	117	10,000	3345
Cooling water (gals/min)	545	15,800	10,900
Catalyst ($MM/yr)	0.19	3.1	-
Other Costs ($/bbl)	-	-	1.1

Table 7.4-19.
Feedstock Volumes and Operating Cost Factors for Producing Isooctane

	Isomerization	**Dehydrogenation**	**Iso-octane Plant**
Isooctane plant costs	Merchant and PO	Merchant	Merchant, PO, Ethylene Cracker and Captive
n-Butane & TBA (BPSD)	5110	-	-
Isobutane (BPSD)	-	5110	-
Isobutylene (BPSD)	-	-	5110
Iso-octane (BPSD)	-	-	3745
Capital Costs (million $)	15.1	75.7	13.1
Plant Size (kbbl/day)	3800	8260	3745
Hydrogen (scf/bbl)	-	-	770
Steam (lbs/hr)	18,900	63,000	39,000
Electricity (Kwh)	117	10,000	390
Cooling water (gals/min)	545	15,800	390
Catalyst ($MM/yr)	0.19	3.1	1.1

Applying the 2012 feedstock and utility prices in Table 7.4-15 to the feedstock demands and input cost factors in Tables 7.4-18 and 7.4-19 and based on the treatment of capital costs per Tables 7.4-5 and 7.4-6, results in the total operating costs for converting MTBE plants over to alkylate and isooctane presented in Table 7.4-20.[KKK]

Table 7.4-20.
Production Cost for Converting MTBE Feedstocks to Alkylate and Iso-octane in 2012 (cents per gallon)

MTBE Plant Type	Captive and Ethylene Cracker	Propylene Oxide	Merchant
Alkylate	142	146	152
Iso-octane	169	190	-

There is a significant cost difference between producing alkylate and isooctane. The octane blending benefit for each pathway helps to offset the production cost differences. Isooctane would receive about a 5 to 17 c/gal credit for its high octane value depending on the PADD, while alkylate would receive about a 2 to 4 c/gal credit. Despite this credit, the economics for isooctane appear to be poorer. This leads use to conclude that the reuse of the MTBE feedstocks would primarily be, if not exclusively, through the production of alkylate. Also, the cost for conversion of the merchant plant feedstocks to alkylate seems to be too high to support the conversion of these plants to alkylate. Even though the cost for production of alkylate by merchant plants is only slightly higher than the 146 c/gal cost for producing MTBE, MTBE benefits from a 8 to 19 c/gal octane blending cost credit compared to only the 2 to 7 c/gal blending benefit for alkylate. Thus, we conclude that the merchant MTBE plants would either shutdown or sell their MTBE elsewhere. We do not know the economics for whether the propylene oxide plants would continue to react their TBA to isobutylene and then produce alkylate, or if they would simply sell the TBA through the chemicals market. Due to this uncertainty, we assumed that half of the TBA would be sold as TBA, and the other half would be converted over to produce alkylate. The projected conversion of MTBE plants that we assumed for our cost analysis is summarized in Table 7.4-21.

[KKK] The cost for supplying steam is estimated by assigning each pound of steam 810 British Thermal Units (BTUs) of heating the water to generate the steam. The cost estimated by applying the natural gas cost to the BTU's required is increased by a factor of 2.0 to account for efficiency losses for steam distribution, for treating the boiler water to prevent fouling and to account for maintenance and other miscellaneous costs (Chemical Engineering Handbook, Perry and Chilton).

Table 7.4-21.
Projected Fate of MTBE Feedstocks

Plant Type	
Captive Plants	Produce Alkylate
Propylene Oxide	½ sell TBA ½ produce Alkylate
Ethylene Cracker	Produce Alkylate
Merchant Plants	Shutdown or sell MTBE Elsewhere

Assuming that the domestic MTBE plants will not all convert over to produce alkylate changes the weighting factors provided in Table 7.4-13 above. The revised weighting factors are shown in Table 7.4-22.

Table 7.4-22.
Revised Estimated MTBE Feedstocks to Alkylate by MTBE Plant Type

MTBE Plant Type	**Total MTBE Production Capacity (barrels/day)**	**Volume Projected to be Converting to Alkylate (barrels/day)**	**Revised Weighting Factors**
Captive Plants	79,000	79,000	0.65
Propylene Oxide	45,000	22,500	0.18
Ethylene Cracker	21,000	21,000	0.17
Merchant Plants	67,000	0	0

Applying these revised weighting factors to the production cost of alkylate results in an average alkylate production cost of 143 c/gal. The production cost is adjusted by PADD to account for the blending octane of alkylate. The blending cost for alkylate is shown in Table 7.4-23.

Table 7.4-23.
Alkylate Blending Cost in 2012
(cents/gallon)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5 (ex CA)	CA
2012 Alkylate Production Cost	143	143	143	N/A	143	N/A
Octane Value	-3.6	-1.9	-3.3	N/A	-4.3	N/A
Alkylate Blending Cost	139	141	139	N/A	138	N/A

7.4.5 Refinery Gasoline Volumes and Costs

In the sections above, we estimated the volume changes associated with the phase out of MTBE, the subsequent conversion of much of the isobutylene to alkylate, the increase in ethanol use and ethanol's impact on summertime RFG. In this section we estimate the volume of refinery-produced gasoline that would change as a result of the aforementioned changes in gasoline blendstocks.

To account for the changes in gasoline and diesel fuel volumes it was necessary to establish a baseline from which to compare the various Energy Act control cases. As summarized in Section 2.1-3, 2004 basecase volumes were established for each PADD identifying the volumes of ethanol, MTBE and refinery produced gasoline or gasoline blendstock. Subsequently, in Section 2.1-7 we describe how we grew the 2004 volumes to 2012 to derive reference case volumes from which to compare the various control cases. However, because of the volumetric increase in low energy density ethanol as well as changes in other gasoline blendstocks with varying energy density, it was necessary to match energy content of the control cases to that of the reference case. We estimated the energy content of the gasoline pool for each PADD of the reference case by assigning each gasoline blendstock an energy content shown in Table 7.4-24.

Table 7.4-24.
Energy Content of Gasoline and Gasoline Blendstocks
(BTU/gallon)

Blendstock	Energy Content
Ethanol	76,000
MTBE	93,500
Alkylate	115,000
Butane	94,000
Gasoline	115,000

Applying the gasoline blendstock energy contents to the volumes represented in the 2012 reference case results in the total energy content for the gasoline in each PADD, for California and the total U.S. shown in Table 7.4-25.

Table 7.4-25.
Summary of 2012 Reference Case Volumes and Energy Content

	Volume (million gallons)						
	PADD 1	**PADD 2**	**PADD 3**	**PADD 4**	**PADD 5 ex CA**	**CA**	**USA**
Ethanol	735	1,800	88	93	232	950	3,898
MTBE	1,514	1,646	555	0	20	0	2,091
Gasoline	52,538	41,399	22,317	4,966	8,566	15,573	145,359
Total Vol.	54,787	43,201	22,959	5,059	8,820	16,523	151,349
	Total Energy Content (10^{15} BTUs)						
Total Energy Content	6.24	4.90	2.62	0.58	1.00	1.86	17.21

We used the total energy content of the reference case regional gasoline pools as the basis for estimating the volume of refinery-produced gasoline for each control case. The control cases are: Maximum RFG, 7.2 billion gallons ethanol; Minimum RFG, 7.2 billion gallons ethanol; Maximum RFG, 9.6 billion gallons ethanol; and Minimum RFG, 9.6 billion gallons ethanol. For each control case the appropriate volume of ethanol from Table 2.1-14 is applied to each PADD. The increase in ethanol volumes causes increases in gasoline vapor pressure which must be accounted for by reductions in butane. In subsection 7.4.2, we discussed this effect for ethanol blended into summertime RFG. However, the increased blending of ethanol into wintertime gasoline may cause the reduction in wintertime butane content as well. The American Standard for Testing Materials (ASTM) has established vapor pressure limits on wintertime gasoline to ensure that the gasoline will not negatively impact motor vehicle driveability. The RVP limits in midwinter are primarily 13.5 PSI in the South and 15 PSI in the North. There is also a vapor/liquid standard which is designed to prevent vapor lock, and it is likely the more stringent standard in the winter. According to a large refiner with refineries all across the U.S., and Jacobs Engineering which is a refining industry consulting firm, refiners today are blending butane into wintertime gasoline up to the ASTM standards and the ASTM standards prevents them from blending more butanes available to them. Because refiners are controlled by these ASTM standards today it suggests that the ethanol newly blended into wintertime gasoline will result in a commensurate decrease in butane content to balance the RVP of those pools, thus we have conducted our analysis based on this.

Yet we also learned that some states have put in place a 1 psi blending waiver for ethanol blended into wintertime gasoline. It is possible that in response to the increased use of ethanol that more states will put in place such waivers. It is also possible that some refiners are butane short and thus could blend more butanes into their wintertime gasoline under the ASTM standards which could allow them to absorb the vapor pressure increase in their wintertime gasoline. Because of these uncertainties that could allow refiners to blend in ethanol into wintertime gasoline without having to remove butanes, we also conducted our analysis to capture this possibility. Despite this potential flexibility, we still assume that the blending of ethanol into summertime RFG will result in the ultimate removal of butane after the removal and reblending of pentanes. This is because if waivers are the primary source for allowing more ethanol blending into wintertime gasoline, these waivers would not provide any relief for the reblended pentanes.

To understand the change in ethanol volume blended into wintertime gasoline for estimating the change in butane blended into wintertime gasoline, we needed to know the volume of ethanol blended into wintertime gasoline in the reference case. In the volume analysis summarized in Sections 2.1-3 and 2.1-7 above, which established the base and reference cases for ethanol consumption, the summer/winter split was not established for the volume of ethanol in gasoline, so we estimated that split here. We assumed that rather than store up ethanol for use during one season or the other, that ethanol is produced and used year-round. Thus, the volumetric summer versus wintertime use of ethanol is determined by the relative volumes of gasoline used during the two seasons. This split is assumed to be 55 percent used during the winter, and 45 percent used during the summer. For estimating the volume of butane which must be removed from the gasoline because of the addition of ethanol, we assumed that ethanol will be blending into gasoline at 10 volume percent, except for California where it would continue to be blended at 5.7 volume percent. For the gasoline blended with the ethanol and when we assume that butanes will be removed, 2 volume percent of butanes would have to be removed to accommodate the ethanol. Table 7.4-26 summarizes the summertime RFG and wintertime RFG and CG volumes of ethanol and estimated change in both summertime and wintertime butane volume blended into gasoline. For the min-RFG cases, ethanol is coming out of the summertime RFG pools in many PADDs which can result in positive butane values which indicates that butanes are being blended back into gasoline, while negative values indicates that butanes are being withdrawn from the gasoline pool.

Table 7.4-26. Estimated Changes in Summertime RFG and Wintertime Gasoline Ethanol Volumes and Their Impact on Butane Blending into Gasoline (million gallons in 2012)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5 ex CA	CA	USA
Reference Case							
Summertime RFG Ethanol	333	274	13	0	105	430	1,155
Wintertime RFG & CG Ethanol	402	1,024	50	54	127	520	2,178
7.2 Bil Gals, Max RFG							
Summertime RFG Ethanol	955	273	241	0	31	430	1,932
Wintertime RFG & CG Ethanol	1,168	1,733	295	30	175	525	3,926
Change in Butane – butanes removed in winter	-250	-128	-85	4	5	-2	-456
Change in Butane – butanes remain in winter	-112	0	-41	0	13	0	-140
7.2 Bil Gals, Min RFG							
Summertime RFG Ethanol	0	137	0	0	0	107	244
Wintertime RFG & CG Ethanol	1,451	2,223	124	182	235	525	4,739
Change in Butane – butanes removed in winter	-128	-191	-11	-23	0	57	-297
Change in Butane – butanes remain in winter	60	25	2	0	19	58	164
9.6 Bil Gals, Max RFG							
Summertime RFG Ethanol	955	273	241	0	31	430	1,932
Wintertime RFG & CG Ethanol	1,594	2,333	346	192	236	528	5,230
Change in Butane – butanes removed in winter	-327	-236	-95	-25	-6	-1	-690
Change in Butane – butanes remain in winter	-112	0	-41	0	13	0	-140
9.6 Bil Gals, Min RFG							
Summertime RFG Ethanol	0	137	0	0	0	107	244
Wintertime RFG & CG Ethanol	2,137	2,400	362	280	352	528	6,059
Change in Butane – butanes removed in winter	-253	-223	-54	-41	-22	57	-535
Change in Butane – butanes remain in winter	60	25	2	0	19	58	164

The volume of MTBE shown in each PADD in the reference case in Table 7.4-25 is eliminated and is replaced with 0.84 gallons alkylate for each gallon of MTBE reduced. We assumed that the replacement volume of alkylate would be used in the same PADD proportional to the removed MTBE volume.

The volume of refinery-produced gasoline needed to balance each PADD's total gasoline pool is determined by a BTU balance. For each PADD and for each control case, the volume change (relative to the reference case) of each gasoline blendstock (ethanol, alkylate and butane) is multiplied times the BTU content of the blendstock and subtracted from the total BTU content of the reference case gasoline pool shown in Table 7.4-26 above. The estimated volume of refinery-produced gasoline needed to make up the balance of the gasoline pool for each control case is calculated by dividing the BTU content of gasoline, also shown in Table 7.4-24, into the remaining BTU value calculated by subtracting the BTU content of the other blendstocks from the reference case gasoline pool BTU content. The BTU-balanced gasoline pool volumes for each PADD and control case are shown in Table 7.4-27. Also, the change in ethanol and gasoline volume between each control case and the reference case is calculated and shown. We also estimate the volumes for each case if butanes currently blended into gasoline are not removed due to the blending of ethanol into wintertime gasoline. These volumes are shown in Table 7.4-28.

Table 7.4-27.
Estimated 2012 Volumes by PADD – Butanes Removed in Winter
(million gallons in 2012)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5 ex CA	CA	USA
7.2 Bil Gals, Max RFG							
Ethanol	2,123	3,151	560	56	353	955	7,200
Change in Ethanol	1,389	1,351	472	-36	121	0	3,302
Change in MTBE	-1,514	-1,646	-555	0	-20	0	-2,091
New Alkylate	1,277	1	468	0	17	0	1,764
Change in Butane	-250	-128	-85	4	5	-2	-456
Gasoline	51,779	40,611	22,058	4,987	8,482	15,571	143,486
Change in Gasoline	-759	-789	-259	20	-84	0	-1,873
Change in Gasoline (%)	-1.4	-1.9	-1.2	0.4	-1.0	0	-1.3
7.2 Bil Gals, Min RFG							
Ethanol	1,682	3,904	188	334	459	633	7,200
Change in Ethanol	947	2,104	100	241	227	-317	3,302
Change in MTBE	-1,514	-1,646	-555	0	-20	0	-2,091
New Alkylate	1,277	1,388	468	0	17	0	1,764
Change in Butane	-128	-191	-11	-23	0	57	-297
Gasoline	51,972	41,165	22,243	4,826	8,416	15,736	143,357
Change in Gasoline	-566	-1,234	-74	-141	-150	163	-2,002
Change in Gasoline (%)	-1.1	-3.0	-0.3	-2.8	-1.8	1.0	-1.4
9.6 Bil Gals, Max RFG							
Ethanol	2,900	4,243	654	352	492	960	9,600
Change in Ethanol	2,165	2,443	566	259	260	0	5,702
Change in MTBE	-1,514	-1,646	-555	0	-20	0	-2,091
New Alkylate	1,277	1,388	468	0	17	0	1,764
Change in Butane	-327	-236	-95	-25	-6	-1	-690
Gasoline	51,329	39,978	22,003	4,815	8,399	15,567	142,092
Change in Gasoline	-1,209	-1,422	-313	-151	-167	0	-3,267
Change in Gasoline (%)	-2.3	-3.4	-1.4	-3.0	-2.0	0	-2.2
9.6 Bil Gals, Min RFG							
Ethanol	2,925	4,226	629	511	672	636	9,600
Change in Ethanol	2,190	2,426	542	418	440	-314	5,702
Change in MTBE	-1,514	-1,646	-555	0	-20	0	-2,091
New Alkylate	1,277	1,388	468	0	17	0	1,764
Change in Butane	-253	-223	-54	-41	-22	57	-535
Gasoline	51,252	39,978	21,986	4,723	8,292	15,734	141,965
Change in Gasoline	-1,286	-1,421	-331	-243	-274	161	-3,394
Change in Gasoline (%)	-2.4	-3.4	-1.5	-4.9	-3.2	1.0	-2.3

Table 7.4-28.
Estimated 2012 Volumes by PADD – Butanes not Removed in Winter
(million gallons in 2012)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5 ex CA	CA	USA
7.2 Bil Gals, Max RFG							
Ethanol	2,123	3,151	560	56	353	955	7,200
Change in Ethanol	1,389	1,351	472	-36	121	0	3,302
Change in MTBE	-1,514	-1,646	-555	0	-20	0	-2,091
New Alkylate	1,277	1	468	0	17	0	1,764
Change in Butane	-112	0	-41	0	13	0	-140
Gasoline	51,666	40,506	22,021	4,990	8,475	15,569	143,228
Change in Gasoline	-871	-893	-295	24	-91	0	-2,131
Change in Gasoline (%)	-1.7	-2.2	-1.3	0.5	-1.1	0	-1.5
7.2 Bil Gals, Min RFG							
Ethanol	1,682	3,904	188	334	459	633	7,200
Change in Ethanol	947	2,104	100	241	227	-317	3,302
Change in MTBE	-1,514	-1,646	-555	0	-20	0	-2,091
New Alkylate	1,277	1,388	468	0	17	0	1,764
Change in Butane	60	25	2	0	19	58	164
Gasoline	51,818	39,988	22,232	4,806	8,400	15,734	142,980
Change in Gasoline	-720	-1,444	-85	-159	-166	162	-2,379
Change in Gasoline (%)	-1.4	-3.4	-0.4	-3.2	-1.9	1.0	-1.6
9.6 Bil Gals, Max RFG							
Ethanol	2,900	4,243	654	352	492	960	9,600
Change in Ethanol	2,165	2,443	566	259	260	0	5,702
Change in MTBE	-1,514	-1,646	-555	0	-20	0	-2,091
New Alkylate	1,277	1,388	468	0	17	0	1,764
Change in Butane	-112	0	-41	0	13	0	-140
Gasoline	51,154	39,785	21,960	4,795	8,382	15,566	141,642
Change in Gasoline	-1,384	-1,614	-357	-171	-183	0	-3,717
Change in Gasoline (%)	-2.6	-3.9	-1.6	-3.4	-2.1	0	-2.6
9.6 Bil Gals, Min RFG							
Ethanol	2,925	4,226	629	511	672	636	9,600
Change in Ethanol	2,190	2,426	542	418	440	-314	5,702
Change in MTBE	-1,514	-1,646	-555	0	-20	0	-2,091
New Alkylate	1,277	1,388	468	0	17	0	1,764
Change in Butane	60	25	2	0	19	58	164
Gasoline	50,996	39,775	21,940	4,690	8,259	15,733	141,394
Change in Gasoline	-1,542	-1,624	-376	-277	-306	160	-3,965
Change in Gasoline (%)	-2.9	-3.9	-1.7	-5.6	-3.6	1.0	-2.7

7.4.6 Overall Gasoline Costs

In the sections above, we estimated the costs for producing and distributing additional volumes of ethanol, ending the use of MTBE and reusing the MTBE feedstock isobutylene for producing alkylate, removing butanes, and for decreases in refinery produced gasoline. This section pulls these individual parts together to estimate the overall costs for these fuel changes. In addition to the costs for increasing and decreasing the volumes of these various gasoline blendstocks, we account for their energy density and octane value.

The costs of these fuels changes are expressed three different ways. First, we express the fuels costs based on the production costs for each gasoline blendstock, including ethanol, without the ethanol consumption subsidies. Second, we express the cost with the ethanol consumption subsidies included since this portion of the renewable fuels costs will be not be represented to the consumer in its fuels costs, but instead is reflected in the federal and state tax payments. Third we present the cost to refiners by assigning historical prices adjusted to 2012 for ethanol and the other gasoline blendstocks.

The costs for each PADD of each control case are estimated by multiplying the change in volume for each gasoline blendstock, relative to the reference case, times its production, distribution and octane blending costs for the cost analyses, or times the projected prices for the cost to refiners analysis. The production and octane blending costs for ethanol are summarized above in Section 7.1. The distribution costs for ethanol are summarized in Section 7.3. The ethanol distribution costs vary by PADD, and also based on whether the ethanol is being added or withdrawn from the PADD. When ethanol is added to gasoline, the distribution costs include both capital and operating costs, while when ethanol is withdrawn from gasoline, only the operating portion of the distribution costs are subtracted. The ethanol blending costs for adding ethanol to summertime RFG are from Table 7.4-9. The production and octane blending costs for MTBE and alkylate are summarized in Tables 7.4-17 and 7.4-23 above. The distribution cost for MTBE and alkylate are assumed to be 4 c/gal, the same as that for gasoline. The cost for changes to butane content are based on the opportunity costs for butane which, based on Platts, is 36 c/gal less than gasoline as shown in Table 7.4-10. The cost of changes to refinery produced gasoline is assumed to be represented by the bulk price of gasoline in each PADD from EIA's 2006 Petroleum Marketing Annual, plus 4 c/gal distribution costs.[161] [162] The 2004 gasoline cost is projected to 2012 costs based on the ratio of the wholesale gasoline price in 2012 to the wholesale gasoline price in 2004 from AEO 2006. This ratio is 1.08. The cost to distribute gasoline to terminals is assumed to remain the same in 2012 at 4 c/gal. These various estimated costs, including production, blending and distribution costs, are summarized in Table 7.4-29.

Table 7.4-29. Gasoline Blendstock Costs Used in Cost Analyses

		PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	CA
Ethanol Cost 7.2 Bil Gals	Max RFG	132	126	130	134	139	139
	Min RFG	132	126	130	134	139	139
Ethanol Cost 9.6 Bil Gals	Max RFG	138	132	136	140	145	145
	Min RFG	138	132	136	140	145	145
MTBE Cost		135	142	136	N/A	131	N/A
Alkylate Cost		143	145	143	N/A	142	N/A
Butane Cost		98	95	94	103	114	118
Gasoline Cost		133	131	130	138	149	153

7.4.6.1 Costs without Ethanol Consumption Subsidies

Tables 7.4-30 through 33 summarize the costs for each aspect of the fuels changes (i.e., adding ethanol, removing butane, removing MTBE…), the total costs, and the per-gallon costs for each PADD and the U.S. for each of the four control scenarios.[LLL] These costs include all fuel changes expected to occur between 2004 and 2012, including the elimination of the RFG oxygen standard, the elimination of MTBE from gasoline in the U.S., and the dramatic expansion in the use of ethanol. The costs represent the production, distribution and blending costs, but not the ethanol consumption subsidies. The costs are presented assuming that butanes are removed, or not removed, from the gasoline pool when ethanol is blended into wintertime gasoline. It was not possible to isolate these gasoline blendstock changes from one another due to their interrelationship. Consequently these costs cannot and should not be associated solely with the Renewable Fuels Standard. Rather, they reflect a combination of the various impacts on fuel quality discussed. To get at some idea of the costs of adding additional ethanol volume to the gasoline pool, a comparison can be made between the 9.6 and 7.2 billion gallon cases as the impacts of the MTBE removal and alkylate addition is made between the reference case and 7.2 billion gallon case and are not changing between the 7.2 and 9.6 billion gallon cases. Because of the very large volume of ethanol being blended into gasoline, the per-gallon costs are indicated for all the gasoline in each PADD, not just the gasoline volume blended with ethanol.

As can be seen in these tables, the aggregated costs of these various fuel changes is estimated to cause a net cost without subsidy which ranges from 0.3 to 1 cent per gallon. However, as shown in the following subsection, when the impact of the tax subsidy is included, the cost of these fuel changes to the fuels industry and to consumers decreases dramatically depending on the control case.

By looking at incremental costs from the 7.2 billion gallon ethanol cases to 9.6 billion

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[LLL] EPA typically assesses the social costs and benefits of its rulemakings. However, this analysis is more limited in scope by evaluating the average cost of producing more ethanol or less gasoline without accounting for some of the market distortions that impact the production costs. For example, some of the costs and cost savings of using more ethanol could not be quantified. Some of these are discussed below in subsection 7.4.5.4 and also above in reference to the farm subsidies impacting the price of corn. Similarly, there are government incentives for the production of crude oil which could not be quantified which would affect the estimates of cost savings for the gasoline displaced by the increased use of ethanol.

gallon ethanol cases, the cost of adding in an additional 2.4 billion gallons of ethanol in isolation becomes apparent.

Table 7.4-30.
Estimated Cost without Ethanol Subsidies for the 7.2 billion Gallon Ethanol Maximum RFG Case
(million dollars per year and cents per gallon; $47/bbl crude oil)

	PADD 1	**PADD 2**	**PADD 3**	**PADD 4**	**PADD 5**	**CA**	**USA**
Adding Ethanol	1,567	1,568	529	-40	140	5	3,769
RFG RVP Cost	62	0	15	0	-5	0	72
Eliminating MTBE	-2,039	-2	-753	0	-27	0	-2,821
Adding Alkylate	1,825	2	669	0	25	0	2,521
	Butanes Removed in Winter						
Changing Butane Volume	-245	-122	-80	4	5	-2	-439
Change in Gasoline Production	-1,013	-1,034	-336	28	-126	-3	-2,484
Total Cost Without Subsidies	157	412	46	-7	11	0	619
Per-Gallon Cost Without Subsidies	0.29	0.94	0.20	-0.15	0.13	0	0.41
	Butanes not Removed in Winter						
Changing Butane Volume	-110	0	-39	0	15	0	-133
Change in Gasoline Production	-1,163	-1,171	-383	33	-137	-5	-2,826
Total Cost Without Subsidies	141	396	40	-7	11	0	582
Per-Gallon Cost Without Subsidies	0.26	0.91	0.17	-0.14	0.12	0	0.38

Table 7.4-31.
Estimated Cost without Ethanol Subsidies for the 7.2 billion Gallon Ethanol Minimum RFG Case
(million dollars per year and cents per gallon; $47/bbl crude oil)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	CA	USA
Adding Ethanol	1,067	2,442	112	268	262	-316	3,837
RFG RVP Cost	-26	-7	-1	0	-7	-33	-74
Eliminating MTBE	-2,039	-2	-753	0	-27	0	-2,821
Adding Alkylate	1,825	2	669	0	25	0	2,521
	Butanes Removed in Winter						
Changing Butane Volume	-126	-182	-10	-24	0	67	-276
Change in Gasoline Production	-755	-1,618	-96	-194	-224	250	-2,638
Total Cost Without Subsidies	-54	633	-78	50	28	-31	548
Per-Gallon Cost Without Subsidies	-0.10	1.44	-0.34	0.98	0.31	-0.19	0.36
	Butanes not Removed in Winter						
Changing Butane Volume	59	24	2	0	22	68	174
Change in Gasoline Production	-961	-1,850	-110	-220	-248	249	-3,141
Total Cost Without Subsidies	-75	608	-79	48	26	-31	496
Per-Gallon Cost Without Subsidies	-0.14	1.38	-0.35	0.93	0.29	-0.19	0.33

Table 7.4-32.
Estimated Cost without Ethanol Subsidies for the 9.6 billion Gallon Ethanol Maximum RFG Case
(million dollars per year and cents per gallon; $47/bbl crude oil)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	CA	USA
Adding Ethanol	2,573	2,981	668	304	316	10	6,852
RFG RVP Cost	62	0	15	0	-5	0	72
Eliminating MTBE	-2,039	-2	-753	0	-27	0	-2,821
Adding Alkylate	1,825	2	669	0	25	0	2,521
	Butanes Removed in Winter						
Changing Butane Volume	-320	-225	-89	-26	-7	-2	-668
Change in Gasoline Production	-1,613	-1,864	-406	-209	-250	-8	-4,350
Total Cost Without Subsidies	487	892	105	69	52	1	1,606
Per-Gallon Cost Without Subsidies	0.88	2.03	0.46	1.35	0.58	0	1.05
	Butanes not Removed in Winter						
Changing Butane Volume	-110	0	-39	0	15	0	-133
Change in Gasoline Production	-1,848	-2,117	-463	-237	-274	-10	-4,948
Total Cost Without Subsidies	462	864	99	67	50	0	1,543
Per-Gallon Cost Without Subsidies	0.84	1.96	0.43	1.30	0.56	0	1.01

Table 7.4-33.
Estimated Cost without Ethanol Subsidies for the 9.6 billion Gallon Ethanol Minimum RFG Case
(million dollars per year and cents per gallon; $47/bbl crude oil)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	CA	USA
Adding Ethanol	2,603	2,961	640	490	535	-332	6,897
RFG RVP Cost	-26	-7	-1	0	-7	-33	-74
Eliminating MTBE	-2,039	-2	-753	0	-27	0	-2,821
Adding Alkylate	1,825	2	669	0	25	0	2,521
	Butanes Removed in Winter						
Changing Butane Volume	-247	-213	-51	-42	-25	67	-510
Change in Gasoline Production	-1,717	-1,863	-458	-336	-409	247	-4,507
Total Cost Without Subsidies	398	877	77	112	92	-50	1,506
Per-Gallon Cost Without Subsidies	0.72	1.99	0.33	2.16	1.02	-0.31	0.99
	Butanes not Removed in Winter						
Changing Butane Volume	59	24	2	0	22	68	174
Change in Gasoline Production	-2,058	-2,129	-488	-382	-459	246	-5,270
Total Cost Without Subsidies	363	848	70	108	88	-50	1,427
Per-Gallon Cost Without Subsidies	0.66	1.93	0.30	2.07	0.99	-0.31	0.93

Crude oil prices are much higher today which decreases the relative cost of producing and blending in more ethanol into gasoline. EIA predicts that crude oil prices will decrease in the future and average $47 per barrel in 2012. However, continued tight supplies caused by strong worldwide demand along with continued unrest in the Middle East could cause crude oil prices to remain high. For this reason, we conducted a sensitivity analysis assuming that crude oil is priced at around $70 per barrel. For this sensitivity analysis we simply ratioed the gasoline production costs, MTBE and alkylate feedstock costs upwards by a 1.38 multiplication factor to adjust these prices. The factor was estimated based on the ratio of wholesale gasoline price increase going from 2004 to 2012, which is 1.08 as discussed above, compared to the ratio of crude oil price increase of the projected crude oil price in 2012, which is $47/bbl, over the average crude oil price in 2004 which was $41 per barrel. Comparing these two ratios established a relative price increase for gasoline of 0.54 c/gal for every 1 cent per gallon increase in crude oil. The crude oil price ratio of $70 per barrel versus the 2004 value of $41 per barrel was multiplied by 0.54 to establish the 1.38 gasoline and gasoline blendstock production cost adjustment factor. We adjusted the gasoline, MTBE feedstocks (except for methanol which is produced from natural gas and so is assumed to remain at the 2012 prices) and alkylate feedstocks using this factor. We set butane prices at 36 c/gal lower than the newer gasoline costs, thus maintaining the same relative butane opportunity cost. We did not adjust the distribution costs, any of the utility costs, octane costs or ethanol prices based on the assumption that these would change much less and for simplicity sakes, we kept these input costs the same as our main analysis.

Table 7.4-34.
Estimated Cost without Ethanol Subsidies for the 7.2 billion Gallon Ethanol Maximum RFG Case with Crude Oil Priced at $70 per Barrel
(million dollars per year and cents per gallon)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	CA	USA
Adding Ethanol	1,567	1,568	529	-40	140	5	3,769
RFG RVP Cost	62	0	15	0	-5	0	72
Eliminating MTBE	-2,467	-3	-909	0	-33	0	-3,412
Adding Alkylate	2,289	3	839	0	31	0	3,162
	Butanes Removed in Winter						
Changing Butane Volume	-336	-167	-110	6	7	-3	-603
Change in Gasoline Production	-336	-167	-110	6	7	-3	-603
Total Cost without Subsidies	-173	85	-63	2	-20	-2	-171
Per-Gallon Cost without Subsidies	-0.32	0.19	-0.27	0.04	-0.23	-0.01	-0.11
	Butanes not Removed in Winter						
Changing Butane Volume	-151	0	-53	0	21	0	-183
Change in Gasoline Production	-1,480	-1,490	-487	42	-174	-7	-3,595
Total Cost without Subsidies	-180	78	-65	2	-20	-2	-187
Per-Gallon Cost without Subsidies	-0.33	0.18	-0.28	0.04	-0.23	0	-0.12

Table 7.4-35.
Estimated Cost without Ethanol Subsidies for the 7.2 billion Gallon Ethanol Minimum RFG Case with Crude Oil Priced at $70 per Barrel
(million dollars per year and cents per gallon)

	PADD 1	**PADD 2**	**PADD 3**	**PADD 4**	**PADD 5**	**CA**	**USA**
Adding Ethanol	1,069	2,442	112	268	262	-316	3,837
RFG RVP Cost	-26	-7	-1	0	-7	-33	-74
Eliminating MTBE	-2,467	-3	-909	0	-33	0	-3,412
Adding Alkylate	2,289	3	839	0	31	0	3,162
	Butanes Removed in Winter						
Changing Butane Volume	-172	-251	-14	-33	-1	91	-380
Change in Gasoline Production	-961	-2,059	-122	-247	-286	318	-3,556
Total Cost without Subsidies	-270	125	-94	-12	-33	61	-223
Per-Gallon Cost without Subsidies	-0.49	0.28	-0.41	-0.22	-0.37	0.37	-0.15
	Butanes not Removed in Winter						
Changing Butane Volume	80	32	3	0	29	93	238
Change in Gasoline Production	-1,223	-2,353	-140	-281	-316	317	-3,996
Total Cost without Subsidies	-279	113	-95	-12	-33	-61	-245
Per-Gallon Cost without Subsidies	-0.51	0.26	-0.42	-0.24	-0.37	-0.37	-0.16

Table 7.4-36.
Estimated Cost without Ethanol Subsidies for the 9.6 billion Gallon Ethanol Maximum RFG Case with Crude Oil Priced at $70 per Barrel
(million dollars per year and cents per gallon)

	PADD 1	**PADD 2**	**PADD 3**	**PADD 4**	**PADD 5**	**CA**	**USA**
Adding Ethanol	2,573	2,981	668	304	316	10	6,851
RFG RVP Cost	62	0	15	0	-5	0	72
Eliminating MTBE	-2,467	-3	-909	0	-33	0	-3,412
Adding Alkylate	2,289	3	839	0	31	0	3,162
	Butanes Removed in Winter						
Changing Butane Volume	-438	-309	-122	-35	-10	-2	-917
Change in Gasoline Production	-2,053	-2,371	-517	-265	-318	-10	-5,535
Total Cost without Subsidies	-35	300	-25	3	-19	-2	222
Per-Gallon Cost without Subsidies	-0.06	0.68	-0.11	0.06	-0.21	0	0.15
	Butanes not Removed in Winter						
Changing Butane Volume	-150	0	-53	0	21	0	-183
Change in Gasoline Production	-2,351	-2,693	-589	-301	-349	-12	-6,295
Total Cost without Subsidies	-45	288	-28	2	-19	-2	196
Per-Gallon Cost without Subsidies	-0.08	0.65	-0.12	0.04	-0.21	0	0.13

Table 7.4-37.
Estimated Cost without Ethanol Subsidies for the 9.6 billion Gallon Ethanol Minimum RFG Case with Crude Oil Priced at $70 per Barrel
(million dollars per year and cents per gallon)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	CA	USA
Adding Ethanol	2,602	2,961	640	490	535	-332	6,897
RFG RVP Cost	-26	-7	-1	0	-7	-33	-74
Eliminating MTBE	-2,467	-3	-909	0	-33	0	-3,412
Adding Alkylate	2,289	3	839	0	31	0	3,162
	Butanes Removed in Winter						
Changing Butane Volume	-339	-293	-70	-57	-33	91	-701
Change in Gasoline Production	-2,185	-2,370	-545	-428	-521	315	-5,734
Total Cost without Subsidies	-125	291	-46	5	-28	41	138
Per-Gallon Cost without Subsidies	-0.23	0.66	-0.20	0.10	-0.32	0.25	0.09
	Butanes not Removed in Winter						
Changing Butane Volume	80	32	3	0	29	93	238
Change in Gasoline Production	-2,618	-2,708	-621	-486	-584	313	-6,705
Total Cost without Subsidies	-140	278	-49	4	-29	41	105
Per-Gallon Cost without Subsidies	-0.25	0.63	-0.21	0.07	-0.32	0.25	0.07

7.4.6.2 Gasoline Costs Including Subsidy

Tables 7.4-38 through 41 express the total and per-gallon gasoline costs for the four control scenarios with the federal and state ethanol subsidies included. These subsidies reduce the cost to fuel producers and to consumers seen “at the pump” for fuel purchases, while the rest of the costs are paid through taxes.[MMM] The federal tax subsidy is 51 c/gal for each gallon of new ethanol blended into gasoline. The state tax subsidies are summarized above in Section 2.1.4.3 and 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. We also show how the subsidized costs change if crude oil is priced at $70 per barrel which is summarized in Tables 7.4-42 through 7.4-45.

Table 7.4-38.
Estimated Cost Including Subsidies for the 7.2 billion Gallon Ethanol Maximum RFG Case (million dollars per year and cents per gallon; $47/bbl crude oil)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	CA	USA
Federal Subsidy	-708	-689	-241	19	-62	-3	-1,684
State Subsidies	0	-180	0	0	0	0	-180
	Butanes Removed in Winter						
Total Cost Including Subsidies	-551	-458	-195	11	-50	-3	-1,246
Per-Gallon Cost Including Subsidies	-1.00	-1.05	-0.85	0.22	-0.56	-0.02	-0.82
	Butanes not Removed in Winter						
Total Cost Including Subsidies	-567	-473	-201	12	-51	-3	-1,282
Per-Gallon Cost Including Subsidies	-1.03	-1.08	-0.87	0.23	-0.57	-0.02	-0.84

[MMM] The subsidy ensures that the ethanol's price set by the marketplace would surely be less than its production cost, but it may not be as low as the subsidized production cost either. This analysis of subsidized costs sets a lower bound on ethanol's price, and it is likely that ethanol's actual price would be somewhere inbetween the two analyses. Additionally, other factors affect the price of ethanol and gasoline which are complicated and beyond the scope of this analysis to project.

Table 7.4-39.
Estimated Cost Including Subsidies for the 7.2 billion Gallon Ethanol Minimum RFG Case
(million dollars per year and cents per gallon; $47/bbl crude oil)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	CA	USA
Federal Subsidy	-483	-1,073	-51	-123	-116	162	-1,684
State Subsidies	-7	-166	0	0	0	0	-173
	Butanes Removed in Winter						
Total Cost Including Subsidies	-543	-606	-129	-73	-87	130	-1,308
Per-Gallon Cost Including Subsidies	-0.99	-1.38	-0.56	-1.42	-0.99	0.79	-0.86
	Butanes not Removed in Winter						
Total Cost Including Subsidies	-564	-632	-130	-75	-89	130	-1,361
Per-Gallon Cost Including Subsidies	-1.03	-1.44	-0.57	-1.47	-1.01	0.79	-0.89

Table 7.4-40.
Estimated Cost Including Subsidies for the 9.6 billion Gallon Ethanol Maximum RFG Case
(million dollars per year and cents per gallon; $47/bbl crude oil)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	CA	USA
Federal Subsidy	-1,104	-1,246	-289	-132	-133	-4	-2,908
State Subsidies	-6	-183	0	0	0	0	-189
	Butanes Removed in Winter						
Total Cost Including Subsidies	-623	-537	-183	-63	-81	-4	-1,492
Per-Gallon Cost Including Subsidies	-1.13	-1.22	-0.80	-1.22	-0.91	-0.03	-0.98
	Butanes not Removed in Winter						
Total Cost Including Subsidies	-648	-565	-190	-65	-83	-5	-1,555
Per-Gallon Cost Including Subsidies	-1.17	-1.28	-0.82	-1.27	-0.93	0	-1.02

Table 7.4-41.
Estimated Cost Including Subsidies for the 9.6 billion Gallon Ethanol Minimum RFG Case
(million dollars per year and cents per gallon; $47/bbl crude oil)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	CA	USA
Federal Subsidy	-1,117	-1,237	-276	-213	-224	160	-2,908
State Subsidies	-6	-169	0	0	0	0	-176
	Butanes Removed in Winter						
Total Cost Including Subsidies	-725	-529	-200	-101	-133	110	-1,578
Per-Gallon Cost Including Subsidies	-1.31	-.20	-0.87	-1.95	-1.48	0.67	-1.03
	Butanes not Removed in Winter						
Total Cost Including Subsidies	-760	-558	-206	-106	-136	110	-1,657
Per-Gallon Cost Including Subsidies	-1.38	-1.27	-0.90	-2.03	-1.52	0.67	-1.08

Table 7.4-42.
Estimated Cost Including Subsidies for the 7.2 billion Gallon Ethanol Maximum RFG Case with Crude Oil Priced at $70 per Barrel
(million dollars per year and cents per gallon)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	CA	USA
Federal Subsidy	-708	-689	-241	19	-62	-3	-1,684
State Subsidies	0	-180	0	0	0	0	-180
	Butanes Removed in Winter						
Total Cost Including Subsidies	-881	-785	-304	20	-82	-4	-2,035
Per-Gallon Cost Including Subsidies	-1.60	-1.80	-1.32	-0.40	-0.93	-0.03	-1.34
	Butanes not Removed in Winter						
Total Cost Including Subsidies	-888	-791	-306	21	-82	-4	-2,051
Per-Gallon Cost Including Subsidies	-1.62	-1.81	-1.33	0.41	-0.93	-0.03	-1.35

Table 7.4-43.
Estimated Cost Including Subsidies for the 7.2 billion Gallon Ethanol Minimum RFG Case with Crude Oil Priced at $70 per Barrel
(million dollars per year and cents per gallon)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	CA	USA
Federal Subsidy	-483	-1,073	-51	-123	-116	162	-1,684
State Subsidies	-6	-166	0	0	0	0	-173
	Butanes Removed in Winter						
Total Cost Including Subsidies	-759	-1,115	-145	-135	-149	223	-2,080
Per-Gallon Cost Including Subsidies	-1.39	-2.54	-0.64	-2.62	-1.67	1.36	-1.37
	Butanes not Removed in Winter						
Total Cost Including Subsidies	-768	-1,126	-146	-135	-149	222	-2,102
Per-Gallon Cost Including Subsidies	-1.40	-2.56	-0.64	-2.63	-1.67	1.36	-1.38

Table 7.4-44.
Estimated Cost Including Subsidies for the 9.6 billion Gallon Ethanol Maximum RFG Case with Crude Oil Priced at $70 per Barrel
(million dollars per year and cents per gallon)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	CA	USA
Federal Subsidy	-1,104	-1,246	-289	-132	-133	-4	-2,908
State Subsidies	-6	-183	0	0	0	0	-189
	Butanes Removed in Winter						
Total Cost Including Subsidies	-1,145	-1,128	-314	-129	-151	-7	-2,875
Per-Gallon Cost Including Subsidies	-2.08	-2.57	-1.36	-2.51	-1.70	-0.04	-1.88
	Butanes not Removed in Winter						
Total Cost Including Subsidies	-1,155	-1,141	-317	-130	-152	-7	-2,901
Per-Gallon Cost Including Subsidies	-2.09	-2.59	-1.38	-2.52	-1.70	-0.04	-1.90

Table 7.4-45.
Estimated Cost Including Subsidies for the 9.6 billion Gallon Ethanol Minimum RFG Case with Crude Oil Priced at $70 per Barrel
(million dollars per year and cents per gallon)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	CA	USA
Federal Subsidy	-1,117	-1,237	-276	-213	-224	160	-2,908
State Subsidies	-6	-169	0	0	0	0	-176
	Butanes Removed in Winter						
Total Cost Including Subsidies	-1,145	-1,128	-314	-129	-151	-7	-2,875
Per-Gallon Cost Including Subsidies	-2.08	-2.57	-1.36	-2.51	-1.70	-0.04	-1.88
	Butanes not Removed in Winter						
Total Cost Including Subsidies	-1,263	-1,129	-325	-210	-253	201	-2,978
Per-Gallon Cost Including Subsidies	-2.29	-2.56	-1.41	-4.03	-2.82	1.23	-1.95

7.4.6.3 Costs to Refiners

Whether refiners choose to blend ethanol depends on the economic incentive to do so. This in turn depends on the price they must pay for the ethanol not the production costs of the ethanol. If they can produce a finished gasoline at a lower cost by purchasing and blending in ethanol, than by refining crude oil, they will have an incentive to do so. Historically, the subsidized price of ethanol has not been based on its octane value, which is very high, but perhaps it is based on its impact on RVP. Prior to the year 2000, the subsidized price of ethanol averaged about the same as the price of gasoline. After 2000, the subsidized price of ethanol averaged about 12 c/gal lower than the price of gasoline.[163] One possible reason for the relative drop in ethanol prices starting in the year 2000 is that the Phase II RFG Program took effect. The Phase RFG program required a much more stringent hydrocarbon standard. Perhaps the relative price of ethanol to gasoline dropped to enable the ethanol manufacturers to participate in the RFG markets, including the summer RFG market. Our analysis shows that the price of ethanol would have to be lower by more than a dime to offset the cost of blending ethanol into summertime RFG which correlates well with the historical price difference between gasoline and ethanol. The cost analysis conducted above was reanalyzed based on a projected ethanol plant gate price for ethanol set at 12 c/gal lower than PADD 2’s bulk gasoline price (which is 4 c/gal less than the PADD 2 gasoline price listed in Table 7.4-29 above). The price of ethanol in each

PADD is based on the PADD ethanol plant gate price for ethanol plants located in the Midwest plus the distribution costs. The prices of MTBE and alkylate were set based on the actual prices listed by Platts for 2004, adjusted to 2012 using a ratio of 1.08 used to estimate the price of gasoline in 2012 from its average price in 2004. These projected prices are summarized in Table 7.4-46.

Table 7.4-46.
Ethanol, MTBE and Alkylate Prices Used in the Cost to Refiners Analysis

		PADD 1	**PADD 2**	**PADD 3**	**PADD 4**	**PADD 5**	**CA**
Ethanol 7.2 & 9.6 Bil Gals	Max RFG	127	121	125	129	-	-
	Min RFG	127	121	125	129	134	134
MTBE		149	149	149	-	149	-
Alkylate		147	147	147	-	147	-

Another way that this analysis was conducted to model the cost to refiners was to balance the volume of the gasoline pool of each control case using the final volume, not its BTU content. This is appropriate because refiners typically ignore the BTU content of gasoline blendstocks when blending up its gasoline. Instead the consumer usually absorbs the costs associated with lower energy density gasoline. To set up the analysis to model the volume of gasoline produced, the final gasoline pool volume of each PADD of each control case was matched to the same gasoline pool volume of the same PADD of the reference case. Thus, the addition of each gallon of ethanol caused a gallon decrease in gasoline (with similar assumptions made for the other gasoline blendstocks). We believe that this better captures the refiners' perspective for the blending of ethanol as well as the other fuel changes. The estimated costs to refiners for each of the four control cases assuming the 12 cent price differential for ethanol is maintained are summarized in Tables 7.4-47 through 50. This analysis suggests that refiners will willingly make these changes including blending in more ethanol, even beyond the RFS minimum, providing that crude oil prices remain above $47 per barrel, and that the relative pricing assumed here also continues to hold true. If anything, ethanol's price to refiners may be lower than the 12 cents below the price of gasoline assumed here because the projected future crude oil price is higher than of the higher crude oil price and the magnitude of the subsidy, further improving the incentive to refiners for using ethanol.

Table 7.4-47.
Estimated Cost to Refiners for the 7.2 billion Gallon Ethanol Maximum RFG Case
(million dollars per year and cents per gallon)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	CA	USA
Adding Ethanol	1,767	1,640	591	-47	162	7	4,121
RFG RVP Cost	62	0	15	0	-5	0	72
Eliminating MTBE	-2,256	-2	-827	0	-31	0	-3,116
Adding Alkylate	1,877	2	688	0	26	0	2,592
	Butanes Removed in Winter						
Changing Butane Volume	-244	-122	-80	4	5	-2	-439
Change in Gasoline Production	-1,202	-1,604	-389	44	-183	-5	-3,339
Total Cost	2	-85	-1	2	-26	0	-109
Per-Gallon Cost	0	-0.20	-0.01	0.04	-0.29	0	-0.07
	Butanes not Removed in Winter						
Changing Butane Volume	-110	0	-39	0	15	0	-133
Change in Gasoline Production	-1,387	-1,771	-446	50	-196	-8	-3,758
Total Cost	-47	-131	-17	3	-29	-1	-221
Per-Gallon Cost	-0.09	-0.30	-0.07	0.07	-0.33	-0.01	-0.15

Table 7.4-48.
Estimated Cost to Refiners for the 7.2 billion Gallon Ethanol Minimum RFG Case
(million dollars per year and cents per gallon)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	CA	USA
Adding Ethanol	1,205	2,555	125	312	303	-423	4,078
RFG RVP Cost	-26	-7	-1	0	-7	-33	-74
Eliminating MTBE	-2,257	-2	-827	0	-31	0	-3,116
Adding Alkylate	1,877	2	688	0	26	0	2,592
	Butanes Removed in Winter						
Changing Butane Volume	-126	-182	-10	-24	0	67	-276
Change in Gasoline Production	-775	-2,508	-3	-301	-333	399	-3,521
Total Cost	-102	-143	-28	-13	-43	11	-317
Per-Gallon Cost	-0.19	-0.33	-0.12	-0.26	-0.48	0.07	-0.21
	Butanes not Removed in Winter						
Changing Butane Volume	59	24	2	0	22	68	174
Change in Gasoline Production	-1,027	-2,791	-20	-333	-362	398	-4,136
Total Cost	-169	-220	-32	-21	-50	11	-481
Per-Gallon Cost	-0.31	-0.51	-0.14	-0.42	-0.56	0.06	-0.32

Table 7.4-49.
Estimated Cost to Refiners for the 9.6 billion Gallon Ethanol Maximum RFG Case (million dollars per year and cents per gallon)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	CA	USA
Adding Ethanol	2,755	2,966	709	335	348	13	7,125
RFG RVP Cost	62	0	15	0	-5	0	72
Eliminating MTBE	-2,257	-2	-827	0	-31	0	-3,116
Adding Alkylate	1,877	2	688	0	26	0	2,592
	Butanes Removed in Winter						
Changing Butane Volume	-320	-225	-89	-26	-7	-2	-668
Change in Gasoline Production	-2,136	-2,893	-498	-324	-374	-13	-6,238
Total Cost	-19	-152	-2	-14	-44	-1	-232
Per-Gallon Cost	-0.03	-0.35	-0.01	-0.28	-0.50	-0.01	-0.15
	Butanes not Removed in Winter						
Changing Butane Volume	-110	0	-39	0	15	0	-133
Change in Gasoline Production	-2,422	-3,202	-567	-358	-404	-15	-6,969
Total Cost	-95	-236	-21	-23	-51	-2	-428
Per-Gallon Cost	-0.17	-0.55	-0.09	-0.45	-0.57	-0.01	-0.28

Table 7.4-50.
Estimated Cost to Refiners for the 9.6 billion Gallon Ethanol Minimum RFG Case (million dollars per year and cents per gallon)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	CA	USA
	Butanes Removed in Winter						
Adding Ethanol	2,786	2,947	678	541	589	-419	7,122
RFG RVP Cost	-26	-7	-1	0	-7	-33	-74
Eliminating MTBE	-2,257	-2	-827	0	-31	0	-3,116
Adding Alkylate	1,877	2	688	0	26	0	2,592
	Butanes Removed in Winter						
Changing Butane Volume	-247	-213	-51	-42	-25	67	-510
Change in Gasoline Production	-2,269	-2,888	-519	-522	-621	395	-6,424
Total Cost	-135	-162	-32	-22	-68	10	-409
Per-Gallon Cost	-0.25	-0.38	-0.14	-0.44	-0.78	0.06	-0.27
	Butanes not Removed in Winter						
Changing Butane Volume	59	24	2	0	22	68	174
Change in Gasoline Production	-2,686	-3,213	-592	-578	-681	393	-7,358
Total Cost	-246	-250	-52	-37	-83	10	-659
Per-Gallon Cost	-0.45	-0.58	-0.23	-0.73	-0.94	0.06	-0.44

7.4.7 Overall Diesel Fuel Costs

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 under two scenarios, with refinery diesel prices as forecasted by EIA's AEO 2006 with crude at $47 and with refinery diesel prices based on $70 per barrel crude oil.

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 2004 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 our estimates based on the USDA and NREL modeling costs derived 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 11.2 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 138 c/gal for the AEO 2006 analysis. For the scenario with crude at $70 per barrel, we used a wholesale refinery diesel price of 175 c/gal. Distribution cost for refinery produced diesel fuel were assumed to be 4 c/gal, as the AEO wholesale price projection does not include the costs associated with distribution, taxes and marketing.

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 2004 year biodiesel production volume of 25 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 254 MM gallons of refinery produced diesel fuel. Table 7.4-51 contains the energy densities used in this analysis.

Table 7.4-51. Energy Content of Fuels per Gallon

Fuel	**LHV BTU's / Gallon**[a]
Biodiesel	117,093
Refinery Produced Diesel	128,700

[a] LHV is lower heating value.

For the AEO scenario, 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 $90 MM per year, which equates to a fuel cost reduction of about 0.15 c/gal[NNN]. Without the subsidy, the transport diesel fuel costs are increased by $118 MM per year, or an increase of 0.20

[NNN] 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.

c/gal for transport diesel fuel. These costs are summarized in Table 7.4-52. With crude at $70 per barrel, including the biodiesel blenders subsidy, results in a cost reduction of $184 MM per year, or a reduction of 0.31 c/gal for the total transport diesel pool. Without the subsidy, transport diesel costs are increased by $25 MM per year, or 0.04 c/gal. See Tables 7.4-53 and 7.4-54 for summaries of these costs.

Table 7.4-52.
Estimated Cost of Increased use of Biodiesel for AEO 2006 prices (2004 dollars)

	Costs without Subsidy	Costs with Subsidy
Total Cost ($million/yr)	118	-90
Per-Gallon Cost (cents/gallon)	0.20	-0.15

Table 7.4-53.
Estimated Cost of Increased use of Biodiesel with Crude at $70 barrel (2004 dollars)

	Costs without Subsidy	Costs with Subsidy
Total Cost ($million/yr)	25	-184
Per-Gallon Cost (cents/gallon)	0.04	-0.31

7.4.8 Summary of Gasoline and Diesel Fuel Costs

Tables 7.4-54 and 7.4-55 summarize the aggregate annual costs to gasoline and diesel fuel in 2012 for the individual fuel changes as well as for the sum of all the fuel changes. The costs are presented with and without the federal and state renewable fuel use subsidies. The costs are presented for the case that crude oil is priced at $47 per barrel.

Table 7.4-54.
Total Estimated Costs in 2012 not Including the Ethanol Consumption Subsidy
($47/bbl crude oil price and 2004 dollars)

		7.2 Max RFG	**7.2 Min RFG**	**9.6 Max RFG**	**9.6 Min RFG**
Gasoline Costs	Adding Ethanol	3,769	3,837	6,852	6,897
	RFG RVP Control	72	-74	72	-74
	MTBE Removal	-2,821	-2,821	2,821	-2,821
	Alkylate	2,520	2,520	2,520	2,520
	Removed Butanes	-133 to -439	-275 to 174	-667 to -133	-510 to 174
	Reduced Gasoline Volume	-2,484 to -2,826	-2,638 to -3,141	-4,350 to -4,948	-4,507 to -5,270
	Total Costs	619 to 582	548 to 496	1,606 to 1,542	1,507 to 1,426
	Per-Gallon Cost	0.41 to 0.38	0.38 to 0.33	1.05 to 1.01	0.99 to 0.93
Diesel Fuel Costs	Total Costs	118	118	118	118
	Per-Gallon Cost	0.20	0.20	0.20	0.20
Total Costs (Gasoline and Diesel Fuel)	Total Costs	737 to 700	666 to 514	1,724 to 1,660	1,625 to 1,544

Table 7.4-55.
Total Estimated Costs in 2012 Including the Ethanol Consumption Subsidy
($47/bbl crude oil price and 2004 dollars)

		7.2 Max RFG	**7.2 Min RFG**	**9.6 Max RFG**	**9.6 Min RFG**
Gasoline Costs	Total Costs without Subsidies	619 to 582	548 to 496	1,606 to 1,542	1,507 to 1,426
	State Subsidies	-180	-173	-189	-176
	Federal Subsidy	-1,684	-1,684	-2,908	-2,908
	Total Cost with Subsidies	-1,245 to -1,282	-1,308 to -1,361	-1,491 to -1,555	-1,578 to -1,657
	Per Gallon Cost with Subsidy	-0.82 to -0.84	-0.86 to -0.89	-0.98 to -1.02	-1.03 to -1.08
Diesel Fuel Costs	Total Cost without Subsidy	118	118	118	118
	Subsidy	-208	-208	-208	-208
	Total Cost with Subsidy	-90	-90	-90	-90
	Per-Gallon Cost with Subsidy	-0.15	-0.15	-0.15	-0.15
Total Costs (Gasoline and Diesel Fuel)	Total Costs with Subsidy	-1,335 to -1,372	-1,398 to -1,451	-1,581 to -1,645	-1,668 to -1,747

Throughout this analysis we conducted sensitivity analyses which attempt to capture known uncertainties that could affect the costs for these fuel changes. The sensitivity analyses conducted include variability in ethanol production or demand, variability in ethanol blended into RFG, variability in whether wintertime gasoline RVP would remain fixed or be allowed to increase by about 1 psi in response to additional ethanol blended into wintertime gasoline, and analyzing a range of possible future crude oil prices. We believe these sensitivities evaluated the most important uncertainties associated with this analysis. However, there are other uncertainties such as the price of corn, the price of natural gas and the conversion percentage of MTBE to other gasoline blendstocks which we did not evaluate.

7.4.9 Other Potential Economic Impacts not Quantified

The above discussion attempts to quantify the impact of expanded use of renewable fuels on the cost of gasoline and diesel fuel. It does so by looking at the cost by itself, as well as in the context of the state and federal tax subsidies for the renewable fuels which may lower the price consumers pay at the pump, but which is still borne by consumers through tax payments. In reality, 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 and we have not attempted to quantify them here. For example, there is a concern that increased renewable fuel use may have adverse impacts on surface and ground water quality and soil erosion. 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. At the same time, expanded renewable fuel use displaces fossil fuel production, distribution, and use, which itself has its own impacts on surface and ground water quality. Thus, any economic impacts would have to be assessed in a holistic manner looking at the impacts across the entire fuel supply.

Similarly, the renewable fuel production costs assumed in our analysis may 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, countercyclical 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 extremely 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 an upper bound estimate of the potential national-level cost impacts; we would expect most areas to have lower health impact costs and certainly lower abatement costs. As a surrogate for total NOx control costs and potential health impacts, we looked at the potential health costs associated with the secondary nitrate PM resulting from the projected increases in NOx emissions. 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). However, inventory modeling suggests that an increase in the use of ethanol will result in increased future emissions of NOx. These increased NOx emissions will add secondary nitrate PM2.5 in the atmosphere and we can estimate the cost impacts considering just this single effect.

In recent rulemakings we have 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. This estimate is derived from dollar-per-ton values based on recent benefits modeling derived from the 2007 Heavy-Duty Highway final rule analysis[164] which is based on REMSAD modeling conducted in 2000; and a dollar-per-ton estimate for nonroad sources is derived from the Clean Air Nonroad Diesel rule[165] and is based on REMSAD modeling conducted in 2004. These dollar-per-ton values represent monetized health impacts in 2015. Using the projected 2015 emission changes presented in Table 4.1-6, we estimate that the potential $PM_{2.5}$-related monetized impact associated with NOx emissions from increased use of ethanol to be up to $150 million in 2015, assuming 7.2 billion gallons of ethanol use in 2012. 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. This value is not intended to reflect potential expenditures related to the control of NOx emissions. Rather, it is presented here as the upper, conservative bound of the potential costs associated with an increase in NOx emissions. 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. Given the potential decrease in ambient $PM_{2.5}$ due to the decrease in aromatic fuel content offset by the increase in NOx, 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.[OOO]

This estimate is also 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. Furthermore, use of these dollar-per-ton values to estimate benefits associated with different emission control programs may lead to higher or

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[OOO] Overall, we expect that the decrease in secondary organic PM is likely to exceed the increase in secondary nitrate PM. In 2006, NOx emissions from gasoline-fueled vehicles and equipment comprise about 37% of national NOx 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 NOx 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.

lower monetized estimates than if values were calculated based on direct air quality modeling. Great care should also be taken when applying these estimates to emission reductions that occur in any specific location, as the dollar-per-ton values are based on national emission reduction programs and therefore represent average the dollars-per-ton over the entire U.S. The dollars-per-ton for emission reductions in specific locations may be very different than the national average.

Potential Fuel Economy Benefits

The assumption used in this analysis is that ethanol use does not change energy efficiency during the combustion process, such that fuel economy is directly proportional to the energy density of the fuel. Since the volumetric energy content of ethanol is approximately 33% less than conventional gasoline, one would expect a fuel economy decrease that is proportional to the percent of ethanol blended into the gasoline. Several studies have suggested, however, that this decrease in fuel economy associated with 10 percent ethanol blends is less than the relative decrease in volumetric energy content of the fuel. In other words, there is less of a fuel consumption increase than the lower energy density of E10 would suggest.

Several studies point to a net efficiency increase of 1 percent for E10, although these findings are often accompanied by a caveat that makes drawing a firm conclusion difficult. For example, the 2006 CRC E-67 study (discussed in further detail in RIA chapter 4) found that 10 percent Ethanol tended to decrease volumetric heat content by 2.2 percent on average. Since one would expect the amount of fuel consumed over a given distance to be directly proportional to the energy content of the fuel, fuel economy should also decrease by 2.2 percent. The test results, however, showed the fuel economy decrease to be only 1.4 percent on average, inferring an efficiency increase of 0.8 percent. The CRC reminds us that the test program was designed to provide independent variation of T50, T90, and ethanol content while holding the other parameters constant. To maintain fixed distillation temperatures while increasing ethanol, for example, heavier hydrocarbons were also added to offset the changes in T50 and T90 that would ordinarily accompany ethanol addition. This changes the volumetric energy content of the fuel to a larger degree than that dictated by the addition of ethanol alone, and complicates this analysis to some extent.

Results from the Auto/Oil Air Quality Improvement Research Program[166] showed a volumetric fuel economy decrease of 2.63 percent ± 0.44 percent (error bars are 95 percent confidence interval) for 10 percent ethanol despite a 3.3 percent decrease in theoretical energy content. On an energy specific fuel economy basis, they found a 0.97 percent ± 0.44 percent increase with E10 compared to the base fuel. These small, but statistically significant, changes in energy specific fuel economy are difficult to explain. One Auto/Oil program hypothesis is that this increase occurs during portions of the FTP when the vehicle is running open loop – during hard accelerations or in the cold start portion of bag 1. They also speculate that the feedback control in these 1983 – 1989 model year vehicles was not sophisticated enough to compensate for the subtle changes seen in stoichiometric A/F with these low level oxygenate blends.

Insufficient data exists to confirm the validity of this slight increase in efficiency with ethanol. Therefore we have maintained the assumption that there is no change in motor vehicle efficiency when operated on gasoline blends with ethanol. However, if additional testing were to confirm a benefit on today's vehicle fleet, it would lower the overall cost estimates of increase ethanol use.

Chapter 8: Agricultural Sector Impacts

Elsewhere in this rulemaking, we have estimated the costs of producing renewable fuel, transporting it to its place of use and absorbing it within the gasoline and diesel fuel pool as a blend stock. In this section we focus on some of the other economic impacts that are likely to result from large expansions in renewable fuel production and use within the United States. In particular, since the vast bulk of this renewable fuel is expected to be produced using feedstock commercially grown in the U.S., we examine the impact of this increasing demand on the agricultural sector.

8.1 Agricultural Sector Impacts

Due to the timing of this NPRM, we were not able to complete a rigorous analysis of the impacts of renewable fuel expansion scenarios in time to be included in this notice. Subsection 1 below gives basic estimates for impacts of renewable fuel on crop and land use, while Subsection 2 outlines the more detailed modeling analysis we are undertaking to be done in time for the final rulemaking package.

8.1.1 Estimates of Land Impacts Based on Available Data

8.1.1.1 Corn Ethanol Land Requirements

Using information from USDA and other sources, we made an estimate of corn and land use requirements for recent years as well as 2012 with production of 7.2 billion gallons of ethanol per year (7.2 BGY).[PPP,167] We repeated the calculations for the case of 9.6 BGY, but due to the fact that USDA's modeling does not consider this level of ethanol production, we did not attempt to estimate any additional corn acreage that might planted. Section 8.1.3 contains more discussion of agricultural sector modeling underway for the final rulemaking.

This work assumed corn was the only feedstock being used to produce ethanol, and would contribute the sole land use impact. Net imports were the only other ethanol source we considered, as others were not expected to have a significant impact on the results. To simplify calculations, the split-year figures given in agricultural sources were assumed to equate to the first calendar year of the pair (i.e. 2005/6 agricultural data is used directly with 2005 ethanol data).

The total land area required for the annual ethanol production requirement was back-calculated using the ethanol production yield in gallons per bushel, and the average corn yield per acre. The figures used are given in Table 8.1-1. Ethanol yield was taken as 2.7 gallons of ethanol per bushel. Before performing the calculation, the ethanol consumption figure was

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[PPP] Through personal communication with USDA in July 2006 we learned that their projections assumed 7.5 BGY of ethanol production in 2012 rather than 7.2 BGY. However, we did not attempt to adjust the results because the difference is small (4%) and because we were uncertain of the level of influence of ethanol volume on corn production.

reduced by subtracting net imports where available, taken from F.O. Licht.[168] The results of this analysis suggest that for the 7.2 BGY case, approximately 21% of corn will be used to produce ethanol in 2012, up from 13% in 2005. Assuming no additional corn is planted in response to the industry producing 9.6 BGY, we estimate that 28% of corn will be required for ethanol production. This figure should be seen as an upper limit, since it is likely that additional acres would be planted as more corn is demanded. More details of the results are given in Table 8.1-2. The result for 2012 (7.2 BGY case) is in reasonable agreement with figures published by the Farm and Agricultural Policy Research Institute (FAPRI), given in Table 8.1-3.

Table 8.1-1. Inputs to Land Use Calculations

Year	Bushels per Acre[a]	Million Bushels Produced[a]	Net Imports (million gals)	Total Ethanol (million gals)[c]
2004	160	11,807	172[b]	3,410
2005	148	11,032	127[b]	4,000
2006	148	10,810	0 (not available)	4,900
2012	159	12,315	300[b]	7,200
2012	159	12,315[d]	300[b]	9,600

[a] USDA Baseline Report OCE-2006-1
[b] F.O. Licht, World Ethanol Markets - The Outlook to 2015 (2006)
[c] RFA website and Chapter 1of this DRIA
[d] This calculation assumes no additional corn is planted for the 9.6 BGY case.

Table 8.1-2. Cropland Allocation Results

Year	Total Ethanol Production (billion gals)	Total Corn Acres Planted (millions)	Corn Acres Required for Ethanol Production (millions)[a]	Ethanol Requirement as % of Corn Acres
2004	3.4	73.6	7.5	10.2
2005	4.0	74.3	9.7	13.0
2006	4.9	73.2	12.3	16.8
2012	7.2	77.7	16.1	20.8
2012	9.6	77.7[b]	21.7	28.0

[a] The 2012 volume is for 7.2 billion gallons minus imports of 300 million gallons.
[b] This calculation assumes no additional corn is planted for the 9.6 BGY case.

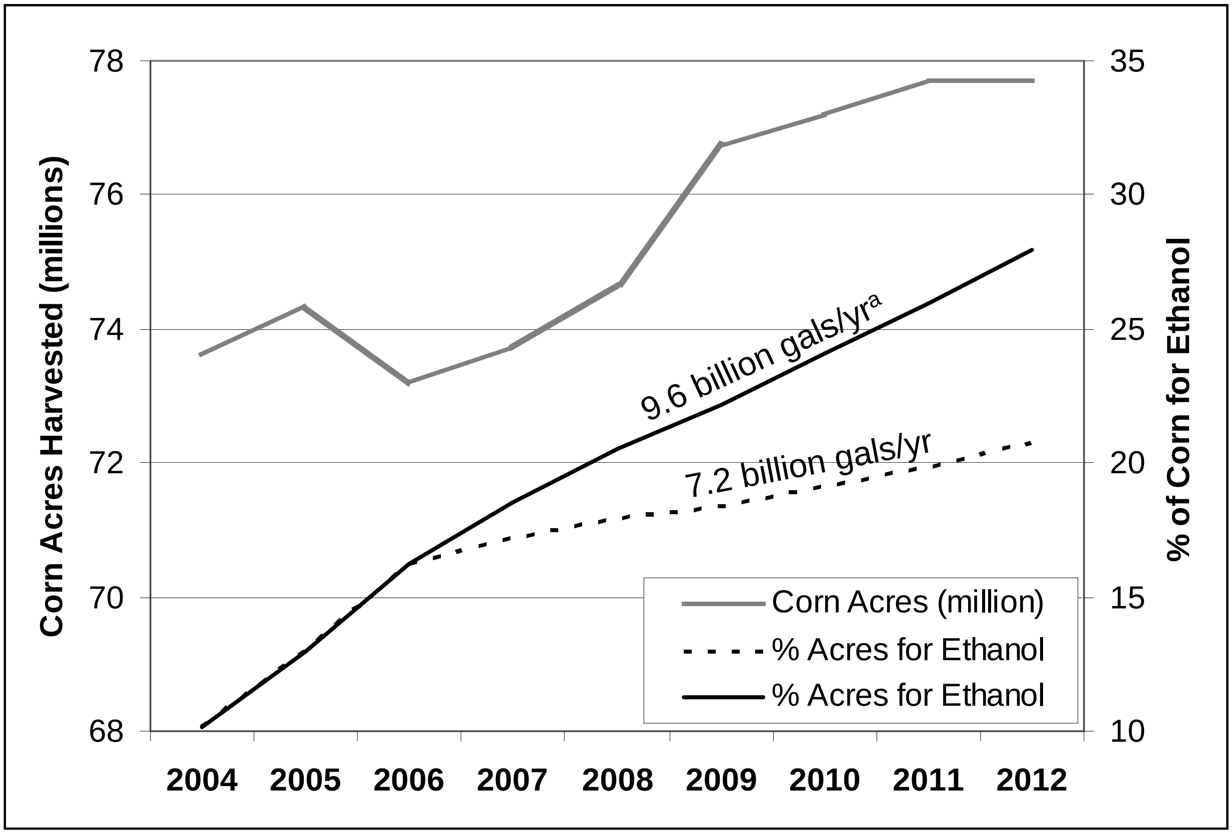
Table 8.1-3. FAPRI Data on Corn Production and Use (Assumes 7.5 BGY RFS)

Year	Ethanol Production[a] (billion gals)	Million Bushels Produced[a]	Million Bushels Used for Ethanol Production[a]	Ethanol Requirement as % of Corn Production
2005	3.9	11,112	1,576	14.2
2006	4.6	10,714	1,800	16.8
2012	7.7	12,431	2,749	22.1

[a] Taken from FAPRI 2006 U.S. and World Agricultural Outlook, Staff Report 06-FSR-1, page 83.

USDA projects that the yield per acre remains essentially flat between now and 2012, while the number of corn acres planted rises by about 6%, resulting in a similar increase in total corn production. However, this increase in corn production is not sufficient to offset the demand by ethanol plants, indicated by the steep increase in percentage of total corn being used for ethanol production. Figure 8.1-1 below shows these trends. Between now and 2012, USDA also forecasts corn prices to rise by about 20 cents per bushel (assuming 7.5 BGY of ethanol). Higher corn price is a driving force for planting more acres, a trend that we expect will be further enhanced at the 9.6 BGY ethanol production level. However, in that situation we still expect a significantly higher percentage of all corn produced to go to ethanol production. In this work, we did not specifically analyze whether fallow acres would be planted with corn as a result of ethanol production, or whether land occupied by other crops would be planted with corn instead.

Figure 8.1-1. Trends in Corn Harvest and Use for Ethanol Production



[a] Assumes no additional corn acres are planted for 9.6 billion gallon per year case.

8.1.1.2 Biodiesel Land Requirements

Based on EIA's current projected biodiesel volumes for years 2006-2012, biodiesel fuel produced from virgin vegetable oils will have a negligible impact on the utilization of farm crop land. EIA's projections forecast biodiesel demand to nearly quadruple by year 2007, based on last years demand, and then remain fairly stable. While this is a large percentage increase, it is still relatively small in terms of absolute volume. Furthermore, these projections assume that about half of biodiesel will be produced from virgin soy bean oil and the remaining from yellow grease feedstocks. New biodiesel plant announcements in the trade journals indicate, however, that in addition to soy oil, other types of virgin vegetable oils may be used in the future. These virgin stocks will probably only make up a small fraction of the feedstocks for making biodiesel. For our analysis, we assume that soy bean oil is the primary virgin oil vegetable feedstock use to manufacture biodiesel, along with yellow grease. Additionally, we use soy bean growth and oil content projections based on current USDA forecast to determine the land acreage impacted by biodiesel fuel derived from virgin vegetable oils.

Biodiesel yields are generally proportional to the oil content of the seeds used as a feedstock. Soy beans have one of the lowest oil concentrations of all oil seeds, currently at about 18.9% by weight and projected to remain at this level in the future[169] Even though the oil content is low, soy oil derived from crushing soy beans is still the primary feedstock used to produce biodiesel fuel in the U.S.[170] This is because U.S. farm policies encourage the growth of soy beans, which are then processed to produce soy meal and soy oil. This increases the supply of soy oil which makes the price economically attractive for producing biodiesel. Current biodiesel yields are averaging about 1.6 gallons per bushel of soy beans, with yield values unlikely to change in the future as the upper yield amount is limited by the soy bean seed oil content. Additionally, for our analysis, a bushel of soy beans is assumed to contain 60 pounds of soy beans. Using these criteria, along with EIA's volume of soy oil derived bio-diesel, we project the total tons of soy beans needed to produce biodiesel volumes projected under the RFS program, shown in Table 8.1-4.

Soy bean yields (bushels per acre) have experienced a slight upward trend in recent years, though the level of improvement has leveled off. The USDA projects that the current yield level will continue in future years under phase-in of the RFS program, see Table 8.1-5. Based on current USDA soy bean yields per acre, and soy oil yields from soy beans, we estimate the amount of land required to produce soy bean oil to satisfy biodiesel demand is 2.04 MM (million) acres in 2006 and 2.27 MM acres in 2012, under the RFS scenario. (See Table 8.1-6) These estimates are based on EIA projections of biodiesel produced from soy bean oil and do not include biodiesel from yellow grease or other virgin vegetable oil stocks. Thus, the amount of biodiesel generated under the RFS programs years, utilizes a modest amount of farm land and is not expected to have a major impact.

Table 8.1-4. Tons of Soy Beans for Biodiesel

Year	**Soy bean (MM tons/ year)**
2004[a]	0.46
2005[a]	1.67
2006	2.61
2012	2.91
2015	2.91

[a] From Table 7, Selected Supply , Use and Price for Major Field Crops, Baseline projections, page 35 USDA report. Soy oil yield was assumed to be 18% in 2004 /2005 and 18.9 % in years 2006 and later.

Table 8.1-5. USDA Soy Bean Yields Per Acre[a]

Year	Yields, Bushels/Acre
2001	39.6
2002	38.0
2003	33.9
2004	42.2
2005	42.7
2006	42.7
2012	42.7
2015	43.9

[a] Years 2005 to 2015 from USDA Outlook 2006 Table 7, Selected Supply, Use and Price for Major Field Crops, Baseline projections. Data for years 2001-2004, from "Oil Crops Situation and Outlook Yearbook", by USDA, Appendix Table 2 Soy beans Acreage Planted, Harvested, Yield, production and Loan rates, U.S., 1960-2005

Table 8.1-6. Cropland Allocation for Soy Beans

Year	Total Soy beans Acres, MM	Soybean Acres for Biodiesel Production, MM[a]	Biodiesel Percent of Total Soy bean Acres, %
2004	75.2	0.4	0.5
2005	72.2	1.3	1.8
2006	73.5	2.04	2.8
2012	71.0	2.27	3.2
2015	70.5	2.27	3.2

[a] MM is million, 2012 and 2015 data based on EIA AEO 2006 projections for soy bean oil derived biodiesel. 2004-2006 data from the National Biodiesel Board (NBB), for 2006, the estimate of 150 MM gallons is NBB's forecast volume. Values for 2004-2006 assume that soy bean oil is the feedstock used to produce 90% of nations total biodiesel supply.

8.1.3 Agricultural Sector Impact Modeling for Final Rulemaking

This section describes work underway to evaluate the impacts of renewable fuel production on the U.S. agricultural sector for the final rulemaking. Here we will outline our methodologies and critical assumptions, as well as some anticipated results.

The RFS program attempts to spur the increased use of renewable transportation fuels made principally from agricultural feed stock produced in the U.S. As a result, there will be impacts on the U.S. agricultural sector. Economic theory suggests that an increase in demand for a good will likely increase both its supply and price. In the case of renewable fuels, production of ethanol from corn for example will create a new use for corn, expanding corn's market value and likely expanding the supply of corn to meet the higher demand.

It is anticipated that almost all of the renewable fuel used to fulfill the requirements of the RFS program will come from agricultural feedstock produced within the U.S. While it is feasible that feedstock could be imported to supply domestic production facilities, it is likely to be more economical to procure feedstock in the general location of the renewable fuel production facility rather than incur substantial feedstock transportation and other costs in shipping feedstock in the large quantities necessary to support a renewable fuel production facility. Furthermore, a joint study by the USDA and DOE has estimated that there will be ample domestic supplies of feedstock to meet the levels of renewable fuel production being evaluated in this rulemaking (although the mix of feedstock sources may be constrained by the economically available land to grow corn for corn-based ethanol and soy beans for soy-based biodiesel).[171] Thus, for the purpose of the analyses of impacts on the U.S. agricultural sector, given that renewable fuel imports to the U.S. are predicted to be relatively small, we are assuming that the feedstock necessary to meet the 7.5 billion gallons of renewable fuel required in 2012 by the RFS will be made from feedstock grown within the U.S. borders. Similarly, for the 9.9 billion gallons of renewable fuel predicted by EIA to be used in 2012, we will again model agricultural sector impacts assuming the necessary feedstock is supplied by the U.S.

To analyze the impacts of the RFS on the U.S. agricultural sector, EPA has selected the Forest and Agricultural Sector Optimization Model (FASOM) developed by Professor Bruce McCarl, Texas A&M University and others over the past thirty years. FASOM is a dynamic, nonlinear programming model of the agriculture and forestry sectors of the U.S. Its objective function is to maximize the present discounted value of producer and consumer surplus across the U.S. agricultural and forestry sectors. (For this analysis, we will be focusing upon the agriculture portion of the model.) The model is constrained by land use balances (e.g., increased corn production could require acres which would otherwise be used to produce soy beans), and commodity competition across domestic consumption, processing, livestock feeding and exports (e.g., increased use of corn for biofuels causes alterations in exports, livestock feeding and livestock herd size). The strength of this model is its consideration of the full direct and indirect impacts of a shift in production of an agricultural commodity. For example, the model assesses not only the impacts of increased demand for corn on acres devoted to corn production but also where the incremental corn will be produced, what other crops will be displaced and how corn is allocated among competing uses. Shifts in crop production will likely impact the price of corn and other crop prices. In addition, the model can estimate the impacts of increased renewable fuel use on animal feed costs, animal production and costs to consumers. Similarly, FASOM can estimate effects on U.S. farm employment and income (broken down by region, and farm sector such as corn farmers versus soy bean producers versus the livestock industry, for example). Corn prices and distillers dried grain values from FASOM and other farm factors will provide inputs to the ethanol cost modeling which, in turn, will impact estimates derived from the refinery model.

While the model has broad capability to estimate such parameters as feedstock prices, we will constrain the model by fixing some of these external values. For feedstock prices, we will use a model version that closely tracks USDA predictions from their report, “USDA Agricultural

Baseline Projections to 2015"[172] . To estimate the amounts of feedstock required for the various renewable fuels, we are assuming in the RFS case the volumes of fuel estimated by EIA for biodiesel from soy and biodiesel from yellow grease (to represent non-soy feedstock) totaling 300 million gallons for 2012. For ethanol, we are assuming the RFS will encourage 250 million gallons of cellulose-based ethanol and 6.95 billion gallons of ethanol from corn in 2012. In a second case, which represents the amount of renewable fuels projected by EIA, we are assuming 9.35 billion gallons of corn-derived ethanol, 250 million gallons of cellulosic ethanol and 300 million gallons for biodiesel from soy and biodiesel from yellow grease.

As mentioned above, the FASOM model has broad capability to assess impacts resulting from changes to the U.S. agricultural sector. While we expect to have the model assess a very wide set of possible outcomes, we realize that models are an abstraction of reality and will also do independent analyses on a number of factors. At a minimum, however, we expect to be able to assess the direct impact on U.S. farm income and farm employment, shifts in crop production and the impacts on commodity prices, including animal feed costs and how changes in feed costs may impact production levels and prices of beef, chicken and other food products within the U.S. As part of this assessment, we will include the value of by-products of ethanol and biodiesel production including, the value of distillers dried grains, corn gluten feed and corn gluten meal which are valuable co-products of dry and wet mill ethanol production from corn and the soy meal by-product resulting from soy oil extraction which is part of soy-based biodiesel production. We will also estimate the potential impacts on exports of crops and animal products as these represent significant sources of income to U.S. farmers.

Chapter 9: Small-Business Flexibility Analysis

This chapter presents our Small Business Flexibility Analysis (SBFA) which evaluates the potential impacts of the proposed rule 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.

9.1 Requirements of the Regulatory Flexibility Act

When proposing and promulgating rules subject to notice and comment under the Clean Air 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.

In developing this proposed rule, we concluded that the RFS program under consideration would not have a significant impact on a substantial number of small entities. We based this 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 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 proposed rule are located in the preamble to the proposed 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 a 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 Definition and Description of Small Entities

Small entities include small businesses, small organizations, and small governmental jurisdictions. For the purposes of assessing the impacts of the proposed 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 9-1 provides an overview of the primary SBA small business categories potentially affected by this regulation.

Table 9.3-1. Small Business Definitions

Industry	Defined as small entity by SBA if:	NAICS Codes [a]
Gasoline refiners	≤1,500 employees <u>and</u> a crude capacity of ≤125,000 bpcd	324110

[a] North American Industrial Classification System

9.4 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 proposed rule "Control of Hazardous Air Pollutants from Mobile Sources" (71 FR 15804, Wednesday, March 29, 2006), we performed an industry characterization 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 used to determine which refiners would also meet the SBA definition of a small refiner under this proposal. From the industry characterization, we determined that there were 20 gasoline refiners 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 under the final RFS program could be different from this initial 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 include 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 stated above in Table 9-1, a small refiner is a small business that employs less than or equal to 1,500 employees and has an annual crude capacity of less than or equal to 125,000 bpcd. A small refinery, per the Energy Policy Act, is a small-capacity refinery and could be owned by a larger refiner that exceeds SBA’s small entity size standards; 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 17 of these refineries were owned by small refiners. Therefore, 17 of the 20 small refiners owned refineries that also met the Energy Policy Act’s definition of a small refinery. As a result, all but three small refiners would automatically be granted relief by implementing the provisions specified in the Energy Policy Act.

9.5 Related Federal Rules

We are not aware of any area where the regulations under consideration would directly duplicate or overlap with the existing federal, state, or local regulations; however, several small refiners are also subject to the gasoline sulfur, highway diesel sulfur, and nonroad diesel sulfur control requirements. In addition, some of these small refiners will also be subject to the upcoming mobile source air toxics (MSAT2) requirements for benzene in gasoline.

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 the proposed RFS program are fairly consistent with those currently in place for other 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 report detailing and tracking a refiner's RINs
- Recordkeeping consisting 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 proposed rule.

9.7 Projected Effects of the Proposed Rulemaking on Small Entities

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 shown in Table III.D.3.c-2, located in the preamble to this proposed rule, the annual projections of ethanol production are greater than the annual renewable fuel volumes required by the Act. In 2011, when the 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 potentially affected small entities, and the projected RIN availability, we do not believe that this program will impose a significant economic impact on a substantial number of small entities.

9.8 Regulatory Alternatives

Though we do not believe that this proposed rule will have a significant economic impact on a substantial number of small entities, we still believe that small refiners generally lack the resources available to larger companies. As discussed in section XII.C of the preamble to the proposed rule, we find it necessary to extend the small refinery temporary exemption, as set out in the Energy Policy Act, to all small qualified small refiners. In addition, past fuels rulemakings have included a provision that, to qualify for EPA's small refiner flexibilities, a refiner must have no more than 1,500 total corporate employees and have a crude capacity of no more than

155,000 bpcd (slightly higher than SBA's crude capacity limit of 125,000 bpcd). To be consistent with these previous rules, we are also proposing to allow those refiners that meet these criteria to be considered small refiners for this rulemaking. Lastly, we are proposing that small refiners may separate RINs from batches and trade or sell these RINs prior to 2011 if the small refiner operates as an oxygenate blender.

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