**ENVIRONMENTAL PROTECTION AGENCY**

**40 CFR Part 80**

[EPA–HQ–OAR–2005–0161; FRL–8299–9]

**RIN 2060–AN76**

**Regulation of Fuels and Fuel Additives: Renewable Fuel Standard Program**

**AGENCY:** Environmental Protection Agency (EPA).

**ACTION:** Final rule.

**SUMMARY:** Under the Clean Air Act, as amended by Section 1501 of the Energy Policy Act of 2005, the Environmental Protection Agency is required to promulgate regulations implementing a renewable fuel program. The statute specifies the total volume of renewable fuel that the regulations must ensure is used in gasoline sold in the U.S. each year, with the total volume increasing over time. In this context, this program is expected to reduce dependence on foreign sources of petroleum, increase domestic sources of energy, and help transition to alternatives to petroleum in the transportation sector. The increased use of renewable fuels such as ethanol and biodiesel is also expected to have the added effect of providing an expanded market for agricultural products such as corn and soybeans. Based on our analysis, we believe that the expanded use of renewable fuels will provide reductions in carbon dioxide emissions that have been implicated in climate change. Also, there will be some reductions in air toxics emissions such as benzene from the transportation sector, while some other emissions such as oxides of nitrogen are expected to increase.

This action finalizes regulations designed to ensure that refiners, blenders, and importers of gasoline will use enough renewable fuel each year so that the total volume requirements of the Energy Policy Act are met. Our rule describes the standard that will apply to these parties and the renewable fuels that qualify for compliance. The regulations also establish a trading program that will be an integral aspect of the overall program, allowing renewable fuels to be used where they are most economical while providing a flexible means for obligated parties to comply with the standard.

**DATES:** This final rule is effective on September 1, 2007. The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of September 1, 2007.

**ADDRESSES:** EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2005–0161. All documents in the docket are listed in the *www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, e.g., confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *www.regulations.gov* or in hard copy at the EPA Docket Center, EPA/DC, EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC. This Docket Facility is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744 and the telephone number for the EPA Docket Center is (202) 566–1742.

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**SUPPLEMENTARY INFORMATION:**

**I. General Information**

Entities potentially affected by this action include those involved with the production, distribution and sale of gasoline motor fuel or renewable fuels such as ethanol and biodiesel. Regulated categories and entities could include:

| Category | NAICS [1] codes | SIC [2] codes | Examples of potentially regulated entities |
|---|---|---|---|
| Industry ........................ | 324110 | 2911 | Petroleum Refineries. |
| Industry ........................ | 325193 | 2869 | Ethyl alcohol manufacturing. |
| Industry ........................ | 325199 | 2869 | Other basic organic chemical manufacturing. |
| Industry ........................ | 424690 | 5169 | Chemical and allied products merchant wholesalers. |
| Industry ........................ | 424710 | 5171 | Petroleum bulk stations and terminals. |
| Industry ........................ | 424720 | 5172 | Petroleum and petroleum products merchant wholesalers. |
| Industry ........................ | 454319 | 5989 | Other fuel dealers. |

[1] North American Industry Classification System (NAICS).
[2] Standard Industrial Classification (SIC) system code.

This table is not intended to be exhaustive, but provides a guide for readers regarding entities likely to be regulated by this action. This table lists the types of entities that EPA is now aware could potentially be affected by this action. Other types of entities not listed in the table could also be affected. To decide whether your organization might be affected by this action, you should carefully examine today's notice and the existing regulations in 40 CFR part 80. If you have any questions regarding the applicability of this action to a particular entity, consult the persons listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

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## I. Introduction

Through today's final rule, we are putting in place a compliance and enforcement program that implements the renewable fuel program, also known as the Renewable Fuel Standard (RFS) program. This program accomplishes the statutory goal of increasing the volume of renewable fuels that are required to be used in vehicles in the U.S. as required in Section 211(o) of the Clean Air Act (CAA) enacted as part of the Energy Policy Act of 2005 (the Energy Act or the Act). This final rule resulted from a collaborative effort with stakeholders, including refiners, renewable fuel producers, and distributors, who together helped to design a program that is simple, flexible, and enforceable.

As a result of the favorable economics of renewable fuels in comparison to conventional gasoline and diesel, renewable fuel volumes are expected to exceed the requirements of the RFS

program. We have evaluated the impacts of a range of renewable fuel volumes as high as 10 billion gallons in 2012. This represents a significant increase over the volume of renewable fuel used in 2004 which was approximately 3.5 billion gallons, and this increase is estimated to produce a number of significant effects. For instance, we estimate that the transition to renewable fuels will reduce petroleum consumption by 2.0 to 3.9 billion gallons or approximately 0.8 to 1.6 percent of the petroleum that would otherwise be used by the transportation sector.

The increased use of renewable fuels is also expected to produce reductions in some regulated pollutants. Carbon monoxide emissions from gasoline powered vehicles and equipment will be reduced by 0.9 to 2.5 percent and emissions of benzene (a mobile source air toxic) will be reduced by 1.8 to 4.0 percent.[1] At the same time, other emissions may increase. Nationwide, we estimate between a 41,000 and 83,000 ton increase in VOC + $NO_X$ emissions. However, the effects will vary significantly by region with some major metropolitan areas experiencing small emission benefits, while other areas may see an increase in VOC emissions from 4 to 5 percent and an increase in $NO_X$ emissions from 6 to 7 percent from gasoline powered vehicles and equipment.

The use of renewable fuel will likewise reduce greenhouse gas emissions such as carbon dioxide by 8.0 to 13.1 million metric tons, about 0.4 to 0.6 percent of the anticipated greenhouse gas emissions from the transportation sector in the United States in 2012. Greenhouse gas emissions contribute to climate change, and thus, increased renewable use is an important step in addressing this issue.

Finally, we estimate that increases in the use of renewable fuels will increase net farm income and the nation's energy security. Net U.S. farm income is estimated to increase by between $2.6 and $5.4 billion through transfers from users of gasoline and consumers of agricultural products used to produce ethanol. However, as feedstocks used in the production of renewable fuels expand beyond the corn and soybeans that are most common today, the renewable fuels industry is expected to continue to diversify and grow in its ability to benefit the nation's environment and economy.

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[1] These reductions are relative to the Mobile Source Air Toxics (MSAT) standards in effect. Additional benzene emission reductions will occur as a result of the recently finalized MSAT2 standards (72 FR 8428, February 26, 2007).

### A. The Role of Renewable Fuels in the Transportation Sector

Renewable fuels have been an important part of our nation's transportation fuel supply for many years. Following the CAA amendments of 1990, the use of renewable fuels, particularly ethanol, increased dramatically. Several key clean fuel programs required by the CAA established new market opportunities for ethanol. A very successful mobile source control strategy, the reformulated gasoline (RFG) program, was implemented in 1995. This program set stringent new controls on the emissions performance of gasoline, which were designed to significantly reduce summertime ozone precursors and year round air toxics emissions. The RFG program also required that RFG meet an oxygen content standard. Several areas of the country began blending ethanol into gasoline to help meet this new standard, such as Chicago and St. Louis. Another successful clean fuel strategy required certain areas exceeding the national ambient air quality standard for carbon monoxide to also meet an oxygen content standard during the winter time to reduce harmful carbon monoxide emissions. Many of these areas, such as Denver and Phoenix, also blended ethanol during the winter months to help meet this new standard.

Today, the role and importance of renewable fuels in the transportation sector continue to expand. In the past several years as crude oil prices have soared above the lower levels of the 1990's, the relative economics of renewable fuel use have improved dramatically. In addition, since the vast majority of crude oil produced in or imported into the U.S. is consumed as gasoline or diesel fuel in the U.S., concerns about our dependence on foreign sources of crude oil have renewed interest in renewable transportation fuels. The emergence of more in-depth understanding of the impacts of human activities on climate change has also focused attention on the various ways that renewable fuels can reduce the consumption of fossil fuels. The passage of the Energy Policy Act of 2005 demonstrated a strong commitment on the part of U.S. policymakers to consider additional means of supporting renewable fuels as a supplement to petroleum-based fuels in the transportation sector. The RFS program is one such means.

The RFS program was debated by the U.S. Congress over several years before finally being enacted through passage of the Energy Policy Act of 2005. The RFS program is first and foremost designed

to increase the use of renewable fuels in motor vehicle fuel consumed in the U.S. In this context, it is expected to simultaneously reduce dependence on foreign sources of petroleum, increase domestic sources of energy, and diversify our energy portfolio to help transition to alternatives to petroleum in the transportation sector. Based on our analysis, we also believe that the expanded use of renewable fuels will provide reductions in carbon dioxide emissions that contribute to climate change and in air toxics emissions such as benzene from the transportation sector, while other emissions such as hydrocarbons and oxides of nitrogen are projected to increase. The increased use of renewable fuels such as ethanol and biodiesel is also expected to have the added effect of providing an expanded market for agricultural products such as corn and soybeans. The expected increase in cellulosic ethanol production will also expand the market opportunities to a wider array of feedstocks.

The requirement for use of a specified volume of renewable fuels complements other provisions of the Energy Act. In particular, the required volume of renewable fuel use will offset any possible loss in demand for renewable fuels occasioned by the Act's repeal of the oxygen content mandate in the RFG program while allowing greater flexibility in how renewable fuels are blended into the nation's fuel supply. The RFS program also creates a specific annual level for minimum renewable fuel use which increases over time, ensuring overall growth in the demand and opportunity for renewable fuels.

Because renewable fuels such as ethanol and biodiesel are not new to the U.S. transportation sector, the expansion of their use is expected to follow distribution and blending practices already in place. For instance, the market already has the necessary production and distribution mechanisms in place in many areas and the ability to expand these mechanisms into new markets. Recent spikes in ethanol use resulting first from the state MTBE bans, and now the virtual elimination of MTBE from the marketplace, have tested the limits of the ethanol distribution system. However, future growth is expected to move in a more orderly fashion since the use of renewable fuels will not be geographically constrained and, given EIA volume projections, investment decisions can follow market forces rather than regulatory mandates. In addition, the increased production volumes of ethanol and the expanded penetration of ethanol in new markets

may create new opportunities for blending of E85, a blend of 85 percent ethanol and 15 percent gasoline, in the long run. The increased availability of E85 will mean that more flexible fueled vehicles (FFV) can use this fuel. Of the approximately 5 million FFVs currently in use in the U.S, most are currently fueled with conventional gasoline rather than E85, in part due to the limited availability of E85.

Given the ever-increasing demand for petroleum-based products in the transportation sector, the RFS program also moves the nation in the direction of replacing part of this demand with renewable energy. The RFS program provides the certainty that at least a minimum amount of renewable fuel will be used in the U.S., which in turn provides some certainty for investment in production capacity of renewable fuels. However, it should be understood that the RFS program is not the only factor currently impacting demand for ethanol and other renewable fuels. As Congress was developing the RFS program in the Energy Act, several large states were adopting and implementing bans on the use of MTBE in gasoline. As a result, refiners supplying reformulated gasoline (RFG) in those states switched to ethanol to satisfy the oxygen content mandate for their RFG, causing a large, sudden increase in demand for ethanol. Even more importantly, with the removal of the oxygen content mandate for RFG, refiners elected to remove essentially all MTBE from the gasoline supply in the U.S. during the spring of 2006. In order to accomplish this transition quickly, while still maintaining gasoline volume, octane, and gasoline air toxics performance standards, refiners elected to blend ethanol into virtually all reformulated gasoline nationwide. This caused a second dramatic increase in demand for ethanol, which in the near term was met by temporarily shifting large volumes of ethanol out of conventional gasoline and into the RFG areas.

Perhaps the largest impact on renewable fuel demand, however, has been the increase in the cost of crude oil. In the last few years, both crude oil prices and crude oil price forecasts have increased dramatically. This has resulted in a large economic incentive for the use of ethanol and biodiesel. The Energy Information Administration (EIA) and others are currently projecting renewable fuel demand to exceed the minimum volumes required under the RFS program by a substantial margin. In this context, the effect of the RFS program is to provide a minimum level of demand to support ongoing investment in renewable fuel

production. However, market demand for renewable fuels is expected to exceed the statutory minimums. We believe that the program we are finalizing today will operate effectively regardless of the level of renewable fuel use or market conditions in the energy sector.

*B. Requirements in the Energy Policy Act*

Section 1501 of the Energy Policy Act amended the Clean Air Act and provides the statutory basis for the RFS program in Section 211(o). It requires EPA to establish a program to ensure that the pool of gasoline sold in the contiguous 48 states contains specific volumes of renewable fuel for each calendar year starting with 2006. The required overall volumes for 2006 through 2012 are shown in Table I.B–1 below.

TABLE I.B–1.— APPLICABLE VOLUMES OF RENEWABLE FUEL UNDER THE RFS PROGRAM

| Calendar year | Billion gallons 2006 |
|---|---|
| 2006 ............................................ | 4.0 |
| 2007 ............................................ | 4.7 |
| 2008 ............................................ | 5.4 |
| 2009 ............................................ | 6.1 |
| 2010 ............................................ | 6.8 |
| 2011 ............................................ | 7.4 |
| 2012 ............................................ | 7.5 |

In order to ensure the use of the total renewable fuel volume specified for each year, the Agency must set a standard for each year representing the amount of renewable fuel that each refiner, blender, or importer must use, expressed as a percentage of gasoline sold or introduced into commerce. This yearly percentage standard is to be set at a level that will ensure that the total renewable fuel volumes shown in Table I.B–1 will be used based on gasoline volume projections provided by the Energy Information Administration (EIA). The standard for each year must be published in the **Federal Register** by November 30 of the previous year. Starting with 2013, EPA is required to establish the applicable national volume, based on the criteria contained in the statute, which must require at least the same overall percentage of renewable fuel use as was required in 2012.

The Act defines renewable fuels primarily on the basis of the feedstock. In general, renewable fuel must be a motor vehicle fuel that is produced from plant or animal products or wastes, as opposed to fossil fuel sources. The Act

specifically identifies several types of motor vehicle fuels as renewable fuels, including cellulosic biomass ethanol, waste-derived ethanol, biogas, biodiesel, and blending components derived from renewable fuel.

The standard set annually by EPA is to be a single percentage applicable to refiners, blenders, and importers, as appropriate. The percentage standard is used by obligated parties to determine a volume of renewable fuel that they are responsible for introducing into the domestic gasoline pool for the given year. The percentage standard must be adjusted such that it does not apply to multiple parties for the same volume of gasoline. The standard must also take into account the use of renewable fuel by small refineries that are exempt from the program until 2011.

Under the Act, the required volumes in Table I.B–1 apply to the contiguous 48 states. However, Alaska and Hawaii can opt into the program, in which case the pool of gasoline used to calculate the standard, and the number of regulated parties, would change. In addition, other states can request a waiver of the RFS program under certain conditions, which would affect the national quantity of renewable fuel required under the program.

The Act requires the Agency to promulgate a credit trading program for the RFS program whereby an obligated party may generate credits for over-complying with their annual obligation. The obligated party can then use these credits to meet their requirements in the following year or trade them for use by another obligated party. Thus the credit trading program allows obligated parties to comply in the most cost-effective manner by permitting them to generate, transfer, and use credits. The trading program also permits renewable fuels that are not blended into gasoline, such as biodiesel, to participate in the RFS program.

The Agency must determine who can generate credits, under what conditions credits may be traded, how credits may be transferred from one party to another, and the appropriate value of credits for different types of renewable fuel. If a party is not able to generate or purchase sufficient credits to meet their annual obligation, they are allowed to carry over the deficit to the next annual compliance period, but must achieve full compliance in that following year.

## C. Development of the RFS Program

Section 1501 of the Energy Act prescribed the RFS program, including the required total volumes, the timing of the obligation, the parties who are obligated to comply, the definition of renewable fuel, and the general framework for a credit trading program. Various aspects of the program require additional development by the Agency beyond the specifications in the Act. The Agency must develop regulations to ensure the successful implementation of the RFS program, based on the framework spelled out in the statute.

Under the RFS program the trading provisions comprise an integral element of compliance. Many obligated parties do not have access to renewable fuels or the ability to blend them, and so must use credits to comply. The RFS trading program is also unique in that the parties liable for meeting the standard (refiners, importers, and blenders of gasoline) are not generally the parties who make the renewable fuels or blend them into gasoline. This creates the need for trading mechanisms that ensure that the means to demonstrate compliance will be readily available for use by obligated parties.

The first step we took in developing the proposed program was to seek input and recommendations from the affected stakeholders. There were initially a wide range of thoughts and views on how to design the program. However, there was broad consensus that the program should satisfy a number of guiding principles, including, for example, that the compliance and trading program should provide certainty to the marketplace and minimize cost to the consumers; that the program should preserve existing business practices for the production, distribution, and use of both conventional and renewable fuels; that the program should be designed to accommodate all qualifying renewable fuels; that all renewable volumes produced are made available to obligated parties for compliance; and that the Agency should have the ability to easily verify compliance to ensure that the volume obligations are in fact met. These guiding principles and the comments we received on our Notice of Proposed Rulemaking (NPRM) helped to move us toward the program in today's final rule.

We published a Notice of Proposed Rulemaking on September 22, 2006 (71 FR 55552) which described our proposed approach to compliance and the trading program, as well as preliminary analyses of the environmental and economic impacts of increased use of renewable fuels. The program finalized today largely mirrors the proposed program, with some revisions reflecting continued input from stakeholders during the formal comment period.

## II. Overview of the Program

Today's action establishes the final requirements for the RFS program, as well as our assessment of the environmental and economic impacts of the nation's transition to greater use of renewable fuels. This section provides an overview of our program and renewable fuel impacts assessment. Sections III through V provide the details of the structure of the program, while Sections VI through X describe our assessment of the impacts on emissions of regulated pollutants and greenhouse gases, air quality, fossil fuel use, energy security, economic impacts in the agricultural sector, and cost from the expanded use of renewable fuels.

### A. Impacts of Increased Reliance on Renewable Fuels

In a typical major rulemaking, EPA would conduct a full assessment of the economic and environmental impacts of the specific rule that it is promulgating. However, as discussed in Section I.A., the replacement of MTBE with ethanol and the extremely favorable economics for renewable fuels brought on by the rise in crude oil prices are causing renewable fuel use to far exceed the RFS requirements. Given these circumstances, it is important to assess the impacts of this larger increase in renewable use and the related changes occurring to gasoline. For this reason we have carried out an assessment of the economic and environmental impacts of the broader changes in fuel quality resulting from our nation's transition to greater utilization of renewable fuels, as opposed to an assessment that is limited to the RFS program itself.

To carry out our analyses, we elected to use 2004 as the baseline from which to compare the impacts of expanded renewable use. We chose 2004 as a baseline primarily due to the fact that all the necessary refinery production data, renewable fuel production data, and fuel quality data were already in hand at the time we needed to begin the analysis. We did not use 2005 as a baseline year because 2005 may not be an appropriate year for comparison due to the extraordinary impacts of hurricanes Katrina and Rita on gasoline production and use. To assess the impacts of anticipated increases in renewable fuels, we elected to look at what they would be in 2012, the year the statutorily-mandated renewable fuel volumes will be fully phased in. By conducting the analysis in this manner, the impacts include not just the impact of expanded renewable fuel use by itself, but also the corresponding decrease in the use of MTBE, and the

potential for oxygenates to be removed from RFG due to the absence of the RFG oxygenate mandate. Since these three changes are all inextricably linked and are occurring simultaneously in the marketplace, evaluating the impacts in this manner is both necessary and appropriate.

We evaluated the impacts of expanded renewable fuel use and the corresponding changes to the fuel supply on fuel costs, consumption of fossil fuels, and some of the economic impacts on the agricultural sector and energy security. We also evaluated the impacts on emissions, including greenhouse gas emissions that contribute to climate change, and the corresponding impacts on nationwide and regional air quality. Our analyses are summarized in this section.

1. Renewable Fuel Volume Scenarios Analyzed

As shown in Table I.B–1, the Act stipulates that the nationwide volumes of renewable fuel required under the RFS program must be at least 4.0 billion gallons in 2006 and increase to 7.5 billion gallons in 2012. However, we expect that the volume of renewable fuel will actually exceed the required volumes by a significant margin. Based on economic modeling in 2006, EIA projected renewable fuel demand in 2012 of 9.6 billion gallons for ethanol, and approximately 300 million gallons for biodiesel using crude oil prices forecast at $48 per barrel.[2] Therefore, in

assessing the impacts of expanded use of renewable fuels, we evaluated two comparative scenarios, one representing the statutorily required minimum, and another reflecting the higher levels projected by EIA. Although the actual renewable fuel volumes produced in 2012 may differ from both the required and projected volumes, we believe that these two volume scenarios together represent a reasonable range for analysis purposes.[3]

The Act also stipulates that at least 250 million gallons out of the total volume required in 2013 and beyond must meet the definition specified for cellulosic biomass ethanol. As described in Section VI, there are a number of companies already making plans to produce ethanol from cellulosic feedstocks and/or waste-derived energy sources that could potentially meet the definition of cellulosic biomass ethanol. Accordingly, we anticipate a ramp-up in production of cellulosic biomass ethanol production in the coming years, and for analysis purposes we have assumed that 250 million gallons of cellulosic biomass ethanol will be used in 2012.

As discussed in Section VI, we chose 2004 to represent current baseline conditions. However, a direct comparison of the fuel quality impacts on emissions and air quality that are expected to occur once the RFS program is fully phased in required that changes in overall fuel volume, fleet characterization, and other factors be

constant. Therefore, we created a 2012 reference case from the 2004 base case for use in the emissions and air quality analysis that maintained current fuel quality parameters while incorporating forecasted increases in vehicle miles traveled and changes in fleet demographics. The 2012 fuel reference case was developed by growing out the 2004 renewable fuel baseline according to EIA's forecasted energy growth rates between 2004 and 2012.

For the analyses, we created two 2012 scenarios representing expanded renewable fuel production. The ''RFS Case'' represents volume levels designed to exactly meet the requirements of the RFS program, and includes the effects of higher credit values for cellulosic ethanol and biodiesel. Since higher credit values mean that one gallon of renewable fuel counts as more than one gallon for compliance purposes, less than 7.5 billion gallons of renewable fuel is needed to meet the 7.5 billion gallon statutory requirement, but credits equivalent to 7.5 billion gallons of renewable fuel would still be available for compliance purposes. The ''EIA Case'' represents volume levels based on EIA projections. A summary of the assumed renewable fuel volumes for the scenarios we evaluated is shown in Table II.A.1–1. Details of the calculations used to determine these volumes are given in Chapter 2 of the Regulatory Impact Analysis (RIA) in the docket for this rulemaking.

TABLE II.A.1–1.—RENEWABLE FUEL VOLUME SCENARIOS (BILLION GALLONS)

| | 2004 base case | 2012 | | |
| --- | --- | --- | --- | --- |
| | | Reference case | RFS case | EIA case |
| Corn-ethanol | 3.548 | 3.947 | 6.421 | 9.388 |
| Cellulosic ethanol | 0 | 0 | 0.25 | 0.25 |
| Biodiesel | 0.025 | 0.030 | 0.303 | 0.303 |
| Total volume | 3.573 | 3.977 | 6.974 | 9.941 |

2. Emissions

We evaluated the impacts of increased use of ethanol and biodiesel on emissions and air quality in the U.S. relative to the reference case. We estimated that nationwide VOC emissions in 2012 from gasoline vehicles and equipment will increase by about 0.3% in the RFS Case and about 0.7% in the EIA Case. For NO$_X$, we estimated that nationwide annual

emissions in 2012 will increase about 0.9% for the RFS Case and 1.6% for the EIA Case. These increases are equivalent to an additional 18,000 to 43,000 tons of VOC per year, and an additional 23,000 to 40,000 tons of NO$_X$ per year.

We also estimated the change in emissions in those areas which are projected to experience a significant change in ethanol use; i.e., where the market share of ethanol blends was projected to change by 50 percent or

more. We focused on July emissions since these are most relevant to ozone formation and modeled 2015 because our ozone model is based upon a 2015 emissions inventory (though we would expect similar results in 2012). Finally, we developed separate estimates for RFG areas, low RVP areas (i.e., RVP standards less than 9.0 RVP), and conventional gasoline areas with a summer 9.0 RVP standard. For areas with a significant change in ethanol use,

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[2] $48/barrel from Annual Energy Outlook 2006, Energy Information Administration, Department of Energy.

[3] Subsequent to the analysis for this final rule, EIA has released its 2007 AEO forecasts for ethanol

use, which increase the projection to 11.2 billion gallons by 2012.

compared to the reference case, VOC emissions in RFG areas increased by up to 2.3%, while $NO_X$ emissions increased by up to 1.6%. In low RVP areas, VOC emissions increased by up to 4.6%, while $NO_X$ emissions increased by up to 6.2%. In 9.0 RVP areas, VOC emissions increased by up to 4.6%, while $NO_X$ emissions increased by up to 7.3%.

Unlike VOC and $NO_X$, emissions of CO and benzene from gasoline vehicles and equipment were estimated to decrease in 2012 when the use of renewable fuels increased. Reductions in emissions of CO varied from 0.9% percent to as high as 2.5% percent for the nation as a whole, depending on the renewable fuel volume scenario. Similarly, benzene emissions from gasoline vehicles and equipment were estimated to be reduced from 1.8% to 4.0% percent.

We do not have sufficient data to predict the effect of ethanol use on levels of either directly emitted particulate matter (PM) or secondarily formed PM. The increased $NO_X$ emissions are expected to lead to increases in secondary nitrate PM, but at the same time reduced aromatics resulting from ethanol blending are likely to lead to a decrease in secondary organic PM, as discussed in Section VIII.C. In addition, biodiesel use is expected to result in some reduction in direct PM emissions, though small in magnitude due to the relatively small volumes.

The emission impact estimates described above are based on the best available data and models. However, it must be highlighted that most of the fuel effect estimates are based on very limited or old data which may no longer be reliable in estimating the emission impacts on vehicles in the 2012 fleet with advanced emission controls.[4] As such, these emission estimates should be viewed as preliminary. EPA hopes to conduct significant new testing in order to better estimate the impact of fuel changes on emissions from both highway vehicles and nonroad equipment, including those fuel changes brought about by the use of renewable fuels. We hope to be able to incorporate the data from such additional testing into the analyses for other studies required by the Energy Act, and into a subsequent rule to set the RFS program standard for 2013 and later.

We used the Ozone Response Surface Model (RSM) to estimate the impacts of the increased use of ethanol on ozone

levels for both the RFS Case and the EIA Case. The ozone RSM approximates the effect of VOC and $NO_X$ emissions in a 37-state eastern area of the U.S. Using this model, we projected that the changes in VOC and $NO_X$ emissions could produce a very small increase in ambient ozone levels. On average, population-weighted ozone design value concentrations increased by about 0.05 ppb, which represents 0.06 percent of the standard. Even for areas expected to experience a significant increase in ethanol use, population-weighted ozone design value concentrations increased by only 0.15 to 0.18 ppb, about 0.2 percent of the standard. These ozone impacts do not consider the reductions in CO emissions mentioned above, or the change in the types of compounds comprising VOC emissions. Directionally, both of these factors may mitigate these ozone increases.

We investigated several other issues related to emissions and air quality that could affect our estimates of the impacts of increased use of renewable fuels. These are discussed in Section VIII and in greater detail in the RIA. For instance, our current models assume that recent model year vehicles are insensitive to many fuel changes. However, a limited amount of new test data suggest that newer vehicles may be just as sensitive as older model year vehicles. Our sensitivity analysis suggests that if this is the case, VOC emissions could decrease by as much as 0.3%, instead of increasing by up to 0.7%. $NO_X$ emissions could increase by up to 4.2%, up from a 1.6% increase. We also evaluated the emissions from the production of both ethanol and biodiesel fuel and determined that they will also increase with increased use of these fuels. Nationwide, emissions related to the production and distribution of ethanol and biodiesel fuel are projected to be of the same order of magnitude as the emission impacts related to the use of these fuels in vehicles.

Finally, a lack of emission data and atmospheric modeling tools prevented us from making specific projections of the impact of renewable fuels on ambient PM levels. As mentioned, however, ethanol use may affect ambient PM levels due to the increase in $NO_X$ emissions and the reduction in the aromatic content of gasoline, which should reduce aromatic VOC emissions. All of these issues will be the subject of further study and analysis in the future.

### 3. Economic Impacts

In Section VII of this preamble, we estimate the cost of producing the extra volumes of renewable fuel anticipated

through 2012. For corn ethanol, we estimate the per gallon cost of ethanol to range from $1.26 per gallon in 2012 (2004 dollars) in the RFS Case to $1.32 per gallon in the EIA Case. These costs take into account the cost of the feedstock (corn), plant equipment and operation and the value of any co-products (distiller's dried grain and solubles, for example). For biodiesel, we estimate the per gallon cost to be between $1.89 and $2.06 per gallon if produced using soy bean oil, and less if using yellow grease ($1.11 to $1.56 per gallon) or other relatively low cost or no-cost feedstocks. The price paid for ethanol, however, is reduced by the $0.51 per gallon federal tax subsidy as well as any state subsidies that might apply. Similarly the price paid for biodiesel is reduced due to the $1.00 per gallon federal tax subsidy biodiesel produced from soy bean oil and $0.50 per gallon tax subsidy for biodiesel produced from yellow grease. We also note that these costs represent the production cost of the fuel and not the market price. In recent years, the prices of ethanol and biodiesel have tended to track the prices of gasoline and diesel fuel, in some cases even exceeding those prices.

These renewable fuels are then blended in gasoline and diesel fuel. While biodiesel is typically just blended with typical petroleum diesel, additional efforts are sometimes necessary and/or economically advantageous at the refiner level when adding ethanol to gasoline. For example, ethanol's high octane reduces the need for other octane enhancements by the refiner, whereas offsetting the volatility increase caused by ethanol may require removal of other highly volatile components. Section VII examines these fuel cost impacts and concludes that the net cost to society in 2012 in comparison to the reference case will range from an estimate of 0.5 cent to 1.0 cent per gallon of gasoline due to the increased use of renewable fuels and their displacement of MTBE. The resulting total nationwide costs in 2012 are $823 million per year for the RFS case and $1,739 million per year for the EIA case. This total excludes the effects of the 51 cent/gal federal excise tax credit as well as state tax subsidies.

Our estimates of fuel impacts do not consider other societal benefits. For example, the displacement of petroleum-based fuel (largely imported) by renewable fuel (largely produced in the United States), should reduce our use of imported oil and fuel. We estimate that 95 percent of the lifecycle petroleum reductions resulting from the use of renewable fuel will be met

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[4] Advanced emission controls include close-coupled, high-density catalysts and their associated electronic control systems for light-duty vehicles, and $NO_X$ adsorbers and PM traps for heavy-duty engines.

through reductions in net petroleum imports. In Section IX of this preamble we estimate the value of the decrease in imported petroleum at about $2.6 billion in 2012 for the RFS Case and $5.1 billion for the EIA Case, in comparison to our 2012 reference case. Total petroleum import expenditures in 2012 are projected to be about $698 billion.

Furthermore, the above estimate on reduced petroleum import expenditures only partly assess the economic impacts. 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 a potential disruption in supply reflected in the price volatility of a particular energy source are reduced. As indicated in the proposal, EPA has worked with researchers at Oakridge National Laboratory to update a study they previously published and which has been used or cited in several government actions impacting oil consumption. A draft report is being made available in the docket at this time for further consideration. This analysis only looks at the impact of reduced petroleum imports on energy security. Other energy security issues could arise with the wider use of biofuels. For example, ethanol's production and costs are determined by the availability of corn as a feedstock. Corn production, in turn, is weather-dependent. Also, the use of biofuels may increase the use of natural gas. A full integrated analysis of the energy security implications of the wider use of biofuels has yet to be undertaken.

While increased use of renewable fuel will reduce expenditures on imported oil, it will also increase expenditures on renewable fuels and in-turn, on the sources of those renewable fuels. The RFS program attempts to spur the increased use of renewable transportation fuels made principally from agricultural crops produced in the U.S. As a result, it is important to analyze the consequences of the transition to greater renewable fuel use in the U.S. agricultural sector. To perform this analysis, EPA selected the Forest and Agricultural Sector Optimization Model (FASOM) developed by Professor Bruce McCarl of 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. (For this analysis, we focused on the agriculture portion of the model.)

Due to the greater demand for corn as a feedstock for ethanol production, corn prices are estimated to increase in 2012 by 18 cents per bushel for the RFS Case and 39 cents per bushel of corn for the EIA Case from $2.32 (in 2004 dollars) in the Reference Case. Although soybean prices are expected to rise slightly, the increased cost is likely due to higher input costs, such as land prices. We estimate a price increase of 18 cents (RFS Case) to 21 cents (EIA Case) per bushel of soybeans from a Reference Case price of $5.26 per bushel. These higher commodity prices are predicted to also result in higher U.S. farm income. Our analysis predicts that farm income will increase by $2.6 billion annually by 2012 for the RFS Case and $5.4 billion for the EIA Case, roughly a 5 to 10 percent increase.

Due to higher corn prices, U.S. exports of corn are estimated to decrease by $573 million in the RFS Case and by $1.29 billion in the EIA Case in 2012. With higher commodity prices, we would expect some upward pressure on food costs as the higher cost of corn and soybeans is passed along to consumers. We estimate a relatively modest increase in annual household food costs associated with the higher price commanded by corn and soybeans. For the RFS Case, annual per capita wholesale food cost are estimated to increase by approximately $7, while the higher renewable fuel volumes anticipated by the EIA Case will result in a $12 annual increase in the per capita wholesale food cost. This equates to roughly a $2.1 to $3.6 billion increase in nationwide food costs in 2012.

## 4. Greenhouse Gases and Fossil Fuel Consumption

There has been considerable interest in the impacts of fuel programs on greenhouse gases implicated in climate change and on fossil fuel consumption due largely to concerns about dependence on foreign sources of petroleum. Therefore, in this rulemaking we have undertaken an analysis of the greenhouse gas and fossil fuel consumption impacts of a transition to greater renewable fuel use. This is the first analysis of its kind in a high profile rule, and as such it may guide future work in this area.

As a result of the transition to greater renewable fuel use, some petroleum-based gasoline and diesel will be directly replaced by renewable fuels. Therefore, consumption of petroleum-based fuels will be lower than it would be if no renewable fuels were used in transportation vehicles. However, a true measure of the impact of greater use of renewable fuels on petroleum use, and

indeed on the use of all fossil fuels, accounts not only for the direct use and combustion of the finished fuel in a vehicle or engine, but also includes the petroleum use associated with production and transportation of that fuel. For instance, fossil fuels are used in producing and transporting renewable feedstocks such as plants or animal byproducts, in converting the renewable feedstocks into renewable fuel, and in transporting and blending the renewable fuels for consumption as motor vehicle fuel. Likewise, fossil fuels are used in the production and transportation of petroleum and its finished products. In order to estimate the true impacts of increases in renewable fuel use on fossil fuel use, we must take these steps into account. Such analyses are termed lifecycle analyses.

There is also no consensus on the most appropriate approach for conducting such lifecycle analyses. We have chosen to base our lifecycle analysis on Argonne National Laboratory's GREET model for the reasons described in Section IX. However, there are other lifecycle models in use. The choice of model inputs and assumptions all have a bearing on the results of lifecycle analyses, and many of these assumptions remain the subject of debate among researchers.

With these caveats, we compared the lifecycle impacts of renewable fuels to the petroleum-based gasoline and diesel fuels that they replace. This analysis allowed us to estimate not only the overall impacts of renewable fuel use on petroleum use, but also on emissions of greenhouse gases such as carbon dioxide from all fossil fuels. In comparison to the reference case, we estimate that the increased use of renewable fuels in the RFS and EIA cases will reduce transportation sector petroleum consumption by about 0.8 and 1.6 percent, respectively, in the transportation sector in 2012. This is equivalent to 2.0–3.9 billion gallons of petroleum in 2012. We also estimated that greenhouse gases from the transportation sector will be reduced by about 0.4 and 0.6 percent for the RFS and EIA cases, respectively, equivalent to about 8–13 million metric tons. These reductions are projected to continue to increase beyond 2012 since crude oil prices have been projected by EIA to continue to be high relative to the prices of the 1990's, and as a result there is expected to be an economic advantage to using renewable fuels beyond 2012. These greenhouse gas emission reductions are also highly dependent on the expectation that the majority of the future ethanol use will be produced

from corn. If advances in the technology for converting cellulosic feedstocks into ethanol allow cellulosic ethanol use to exceed the levels assumed in our analysis, then even greater greenhouse gas reductions may result.[5]

5. Post 2012 RFS Standards

The Energy Policy Act of 2005, in addition to setting the standards to be adopted through 2012, requires EPA, in coordination with the Departments of Agriculture and Energy, to determine the applicable volume for the renewable fuel standard for the year 2013 and subsequent calendar years. This determination is to be based on a review of the program's implementation in 2006 through 2012 as well as review of the impact of renewable fuels on the environment, air quality, energy security, job creation, rural economic development and the expected annual rate of renewable fuel production, including production of cellulosic ethanol.

In today's final rulemaking, we do not suggest any specific renewable fuel volumes for 2013 and beyond that may be appropriate under the statutory criteria. However, we would note that the President, in his State of the Union address this January, set specific goals reducing the amount of gasoline usage in the United States by 20 percent in the next 10 years. This would be accomplished by reforming and modernizing fuel economy standards for cars and setting mandatory fuels standard equivalent to requiring use of 35 billion gallons of renewable and alternative [6] fuels in 2017. Therefore, given the necessity to address the post-2013 period under the Energy Act and the prospect of continued attention by the Administration and Congress to this issue, EPA will continue to devote attention to the issue of renewable and alternative fuel volumes in the post-2013 period.

From a program structure perspective, we believe that what we are putting in place today will remain useful as part of a 2013 and later program. For example, EPA considers that the identification of renewable fuel via a Renewable Identification Number (RIN), the determination of liable parties, the averaging, banking and trading system and the recordkeeping and reporting

system would all be elements of a post-2013 program. Depending on the structure of any final legislation approved by Congress and signed into law, such elements could also be incorporated into an expanded renewable and alternative fuels program.

*B. Program Structure*

The RFS program being finalized today requires refiners, importers, and blenders (other than oxygenate blenders) to show that a required volume of renewable fuel is used in gasoline. The required volume is determined by multiplying their annual gasoline production by a percentage standard specified by EPA. Compliance is demonstrated through the acquisition of unique Renewable Identification Numbers (RINs) assigned by the producer or importer to every batch of renewable fuel produced or imported. The RIN shows that a certain volume of renewable fuel was produced or imported. Each year, the refiners, blenders and importers obligated to meet the renewable volume requirement (referred to as "obligated parties") must acquire sufficient RINs to demonstrate compliance with their volume obligation. RINs can be traded, thereby functioning as the credits envisioned in the Act. A system of recordkeeping and electronic reporting for all parties that have RINs ensures the integrity of the RIN pool. This RIN-based system will both meet the requirements of the Act and provide several other important advantages:
• Renewable fuel production volumes can be easily verified.
• RIN trading can occur in real time as soon as the renewable fuel is produced rather than waiting to the end of the year when an obligated party would determine if it had exceeded the standard.
• Renewable fuel can continue to be produced, distributed, and blended in those markets where it is most economical to do so.
• Instances of double-counting of renewable fuel claimed for compliance purposes can be identified based on electronically reported data.

Our RIN-based trading program is an essential component of the RFS program, ensuring that every obligated party can comply with the standard while providing the flexibility for each obligated party to use renewable fuel in the most economical ways possible.

1. What Is the RFS Program Standard?

EPA is required to convert the aggregate national volumes of renewable fuel specified in the Act into

corresponding renewable fuel standards expressed as a percent of gasoline production or importation. The renewable volume obligation that will apply to an individual obligated party will then be determined based on this percentage and the total gasoline production or import volume in a calendar year, January 1 through December 31. EPA will publish the percentage standard in the **Federal Register** each November for the following year based on the most recent EIA gasoline demand projections. However, for compliance in 2007 we are publishing the percentage standard in today's action. The standard for 2007 is 4.02 percent. Section III.A describes the calculation of the standard.

2. Who Must Meet the Standard?

Under our program, any party that produces or imports gasoline for consumption in the U.S., including refiners, importers, and blenders (other than oxygenate blenders), will be subject to a renewable volume obligation that is based on the renewable fuel standard. These obligated parties will determine the level of their obligation by multiplying the percentage standard by their annual volume of gasoline production or importation. The result will be the renewable fuel volume which each party must ensure is blended into gasoline consumed in the U.S., with credit for certain other renewable fuels that are not blended into gasoline.

For 2007, we are requiring that the renewable fuel volume obligation be determined by multiplying the percentage standard by the volume of gasoline produced or imported prospectively from September 1, 2007 until December 31, 2007. While the standard will not apply to all of 2007 gasoline production, we are nevertheless confident that the total volume of renewable fuel used in all of 2007 will still exceed the volume specified in the Act due to expectations that the demand for renewable fuel will exceed the RFS requirements.

In determining their annual gasoline production volume, obligated parties must include all of the finished gasoline which they produced or imported for use in the contiguous 48 states, and must also include reformulated blendstock for oxygenate blending (RBOB), and conventional blendstock for oxygenate blending (CBOB). For refiners and importers this includes unfinished gasoline produced or imported that will become gasoline upon addition of an oxygenate downstream of the refiner. Other producers of gasoline, such as blenders,

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[5] Cellulosic ethanol is estimated to provide a comparable petroleum displacement as corn derived ethanol on a per gallon basis, though the impacts on total energy and greenhouse gas emissions differ.

[6] While the RFS program is specific to renewable fuels, the president's goal of 35 billion gallons by 2017 would include not only renewable fuels, but also other types of alternatives fuels.

will count as their gasoline production only the volumes of blendstocks which become gasoline upon their addition to finished gasoline, unfinished gasoline, or other blendstocks. Renewable fuels blended into gasoline by any party will not be counted as gasoline for the purposes of calculating the annual gasoline production volume.

Small refiners and small refineries are exempt from meeting the renewable fuel requirements through 2010. All gasoline producers located in Alaska, Hawaii, and noncontiguous U.S. territories and parties who import gasoline into these areas will be exempt indefinitely. However, if Alaska, Hawaii or a noncontiguous territory opts into the RFS program, all of the refiners (except for exempt small refiners and refineries), importers, and blenders located in the state or territory will be subject to the renewable fuel standard.

Section III.A provides more details on the standard that must be met, while Section III.C describes the parties that are obligated to meet the standard.

3. What Qualifies as a Renewable Fuel?

We have designed the program to cover the range of renewable fuels produced today as well as any that might be produced in the future, so long as they meet the Act's definition of renewable fuel and have been registered and approved for use in motor vehicles. In this manner, we believe that the program provides the greatest possible encouragement for the development, production, and use of renewable fuels to reduce our dependence on petroleum as well as to reduce the carbon dioxide emissions that contribute to climate change. In general, renewable fuels must be produced from plant or animal products or wastes, as opposed to fossil fuel sources. Valid renewable fuels include ethanol made from starch seeds, sugar, or cellulosic materials, biodiesel (mono-alkyl esters), non-ester renewable diesel, and a variety of other products. Both renewable fuels blended into conventional gasoline or diesel and those used in their neat (unblended) form as motor vehicle fuel will qualify. Section III.B provides more details on the renewable fuels that will be allowed to be used for compliance with the standard under our program.

4. Equivalence Values of Different Renewables Fuels

One question that we faced in developing the program was what value to place on different renewable fuels and on what basis should that value be determined. The Act specifies that each gallon of cellulosic biomass ethanol and waste-derived ethanol be treated as if it

were 2.5 gallons of renewable fuel for compliance purposes, but does not specify the values for other renewable fuels. Although in the NPRM we considered a range of options including straight volume, energy content, and requested comment on the merit and basis for setting "Equivalence Values" on several metrics including lifecycle energy or greenhouse gas emissions, for this final rule we are requiring that the "Equivalence Values" for the different renewable fuels be based on their energy content in comparison to the energy content of ethanol, and adjusted as necessary for their renewable content. The result is an Equivalence Value for corn ethanol of 1.0, for biobutanol of 1.3, for biodiesel (mono alkyl ester) of 1.5, for non-ester renewable diesel of 1.7, and for cellulosic ethanol and waste-derived ethanol of 2.5. The proposed methodology can be used to determine the appropriate Equivalence Value for any other potential renewable fuel as well. Section III.B.4 provides details of the determination of Equivalence Values.

5. How Will Compliance Be Determined?

Under our program, every gallon of renewable fuel produced or imported into the U.S. must be assigned a unique RIN. A block of RINs would be assigned to any batch of renewable fuel that is valid for compliance purposes under the RFS program. These RINs must be transferred with renewable fuel as ownership of a volume of renewable fuel is initially transferred through the distribution system. Once the renewable fuel is obtained by an obligated party or actually blended into a motor vehicle fuel, the RIN can be separated from the batch of renewable fuel and then either used for compliance purposes, held, or traded.

RINs represent proof of production which is then taken as proof of consumption as well, since all but a trivial quantity of renewable fuel produced or imported will be either consumed as fuel or exported. For instance, ethanol produced for use as motor vehicle fuel is denatured specifically so that it can only be used as fuel. Similarly, biodiesel is produced only for use as fuel and has no other significant uses. An obligated party demonstrates compliance with the renewable fuel standard by accumulating sufficient RINs to cover their individual renewable volume obligation. It will not matter whether the obligated party used the renewable fuel themselves. An obligated party's obligation will be to ensure that a certain amount of renewable fuel was

used, either by themselves or by someone else, and the RIN is evidence that this occurred for a certain volume of renewable fuel. Exporters of renewable fuel will also be required to acquire RINs in sufficient quantities to cover the volume of renewable fuel exported. RINs claimed for compliance purposes by obligated parties will thus represent renewable fuel actually consumed as motor vehicle fuel in the U.S.

RINs are valid for compliance purposes for the calendar year in which they are generated, or the following calendar year. This approach to RIN life is consistent with the Act's prescription that credits be valid for compliance purposes for 12 months as of the date of generation, where credits are generated at the end of a year when compliance is determined. An obligated party can either use RINs to demonstrate compliance, or can transfer RINs to any other party. If an obligated party is not able to accumulate sufficient RINs for compliance in a given year, it can carry a deficit over to the next year so long as the full deficit and obligation is covered in the next year.

In order to ensure that previous year RINs are not used preferentially for compliance purposes in a manner that would effectively circumvent the limitation that RINs be valid for only 12 months after the year generated, we are setting a cap on the use of RINs generated the previous year when demonstrating compliance with the renewable volume obligation for the current year. The cap will mean that no more than 20 percent of a current year obligation can be satisfied using RINs from the previous year. In this manner there is no ability for excess renewable fuel use in successive years to cause an accumulation of RINs to significantly depress renewable fuel demand in any future year. In keeping with the Act, excess RINs not used in the year they are generated or in the subsequent year will expire.

Section III.D provides more details on how obligated parties must use RINs for compliance purposes.

6. How Will the Trading Program Work?

Renewable fuel producers and importers will be required to generate RINs when they produce or import a batch of renewable fuel (unless, for importers, the RINs have been assigned by a foreign producer registered with EPA). They will then be required to transfer those RINs along with the renewable fuel batches that they represent whenever they transfer ownership of the batch to another party. Likewise any other non-obligated party

that takes ownership of a volume of renewable fuel with RINs will be required to transfer those RINs with a volume of renewable fuel. The RIN can be separated from renewable fuel only by obligated parties (at the point when they take ownership of the batch) or a party that converts the renewable fuel into motor vehicle fuel (such as upon blending with gasoline or diesel).

Once a RIN is separated from a volume of renewable fuel, it can be used for compliance purposes, banked, or traded to another party. Separated RINs can be transferred to any party any number of times. Recordkeeping and reporting requirements will apply to any party that takes ownership of RINs, whether through the ownership of a batch of renewable fuel or through the transfer of separated RINs.

Thus obligated parties can acquire RINs directly through the purchase of renewable fuel with assigned RINs or through the open market for RINs that is allowed under this proposal. Section III.E provides more details on how our RIN trading program will work.

7. How Will the Program Be Enforced?

As in all EPA fuel regulations, there is a system of registration, recordkeeping, and reporting requirements for obligated parties, renewable producers and importers (RIN generators), and any parties that procure or trade RINs either as part of their renewable purchases or separately. In most cases, the recordkeeping requirements are not significantly different from what these parties might be doing already as a part of normal business practices. The lynch pin to the compliance program, however, is the unique RIN number itself coupled with an electronic reporting system where RIN generation, RIN use, and RIN transactions will be reported and verified. Thus, EPA, as well as industry can have confidence that invalid RINs are not generated and that there is no double counting.

*C. Voluntary Green Labeling Program*

In the proposal EPA asked for comments on the idea of creating a voluntary labeling program to encourage the adoption and use of practices that minimize the environmental concerns associated with renewable fuel production. The proposal suggested adding a ''G'' (for green) to the end of the RIN of a fuel to indicate that a gallon of renewable fuel was produced with the combination of best farming practices and environmentally friendly production methods and facilities. EPA received a number of comments on this idea.

The majority of respondents were very supportive of voluntary labeling and encouraged EPA to establish this program through this final rulemaking. Two commenters opposed the labeling concept, telling EPA that the number and complexity of issues associated with fuel production, and particularly with farming practices, would make such a program impractical and difficult to implement. EPA also was told that it would be hard to audit such a program. Most commenters agreed that using the RIN to host the label makes sense, however the use of ''G'' for green fuel is insufficient to capture the full range of environmental impacts of renewable fuel production and that it would be difficult for EPA to establish an appropriate cut-off point for determining which fuel qualified for a ''G'' designation. Several respondents suggested that EPA instead use a more continuous scale based on energy or lifecycle greenhouse gas emissions.

A well designed voluntary labeling program could permit producers and blenders to distinguish their fuels in the marketplace and allow consumers to express preferences for ''green'' products through their fuel purchases. While such a program could be valuable to producers, blenders, and consumers, given the range of comments received on the topic, we believe it is important first to continue the dialogue with the various stakeholders to ensure that the program adequately addresses the issues raised prior to putting any such program in place. Thus we are not finalizing a voluntary labeling program. We will continue to investigate the issues surrounding a voluntary labeling program and the various ways in which it could be designed. In particular we are interested in further exploring methods to incorporate lifecycle impacts into a voluntary labeling program and consumer expectations for such ''green'' labeling.

**III. Complying With the Renewable Fuel Standard**

According to the Energy Act, the RFS program places obligations on individual parties such that the renewable fuel volumes shown in Table I.B–1 are used as motor vehicle fuel in the U.S. each year. To accomplish this, the Agency must calculate and publish a standard by November 30 of each year which is applicable to every obligated party. On the basis of this standard each obligated party determines the volume of renewable fuel that it must ensure is consumed as motor vehicle fuel. In addition to setting the standard, we must clarify who the obligated parties are and what volumes of gasoline are

subject to the standard. Obligated parties must also know which renewable fuels are valid for RFS compliance purposes, and the relative values of each type of renewable fuel in terms of compliance. This section discusses how the annual standard is determined and which parties and volumes of gasoline will be subject to the requirements.

Because renewable fuels are not produced or distributed evenly around the country, some obligated parties will have easier access to renewable fuels than others. As a result, the RFS program depends on a robust trading program. This section also describes all the elements of our trading program.

*A. What Is the Standard That Must Be Met?*

1. How Is the Percentage Standard Calculated?

Table I.B–1 shows the required total volume of renewable fuel specified in the Act for 2007 through 2012. The renewable fuel standard is based primarily on (1) the 48-state gasoline consumption volumes projected by EIA (as the Act exempts Hawaii and Alaska, subject to their right to opt-in, as discussed in Section III.C.4), and (2) the volume of renewable fuels required by the Act for the coming year. The renewable fuel standard will be expressed as a volume percentage of gasoline sold or introduced into commerce in the U.S., and will be used by each refiner, blender or importer to determine their renewable volume obligation. The applicable percentage is set so that if each regulated party meets the percentage and total gasoline consumption does not fall short of EIA projections then the total amount of renewable fuel used will meet the total renewable fuel volume specified in Table I.B–1.

In determining the applicable percentage for a calendar year, the Act requires EPA to adjust the standard to prevent the imposition of redundant obligations on any person and to account for the use of renewable fuel during the previous calendar year by exempt small refineries, defined as refineries that process less than 75,000 bpd of crude oil. As a result, in order to be assured that the percentage standard will in fact result in the volumes shown in Table I.B–1, we must make several adjustments to what is otherwise a simple calculation.

As stated, the renewable fuel standard for a given year is basically the ratio of the amount of renewable fuel specified in the Act for that year to the projected 48-state non-renewable gasoline volume

for that year. While the required amount of total renewable fuel for a given year is provided by the Act, the Act requires EPA to use an EIA estimate of the amount of gasoline that will be sold or introduced into commerce for that year. The level of the percentage standard is reduced if Alaska, Hawaii, or a U.S. territory choose to participate in the RFS program, as gasoline produced in or imported into those states or territories would then be subject to the standard. Should any of these states or territories opt into the RFS program, the projected gasoline volume would increase above that consumed in the 48 contiguous states.

In the proposal, we stated that EIA had indicated that the best estimation of the coming year's gasoline consumption is found in Table 5a (U.S. Petroleum Supply and Demand: Base Case) of the October issue of the monthly EIA publication Short-Term Energy Outlook which publishes quarterly energy projections. Commenters on this issue supported the use of the October issue of EIA's Short-Term Energy Outlook (STEO), Table 5a, for the purpose of estimating the next year's gasoline consumption, and we have used the October 2006 STEO values for estimating 2007 gasoline consumption for this final rule.

The gasoline volumes in the STEO include renewable fuel use. As discussed below in Section III.C.1, the renewable fuel obligation does not apply to renewable blenders. Thus, the gasoline volume used to determine the standard must be the non-renewable portion of the gasoline pool, in order to achieve the volumes of renewables specified in the Act. In order to get a total non-renewable gasoline volume, we must subtract the renewable fuel volume from the total gasoline volume. EIA has indicated that the best estimation of the coming year's renewable fuel consumption is found in Table 11 (U.S. Renewable Energy Use by Sector: Base Case) of the October issue of the STEO. As with the gasoline projections discussed above, we have used the October 2006 STEO values for estimating 2007 renewable fuel values for this final rule.

The Act exempts small refineries [7] from the RFS requirements until the 2011 compliance period. As discussed

in Section III.C.3.a, as proposed, EPA is also exempting small refiners [8] from the RFS requirements until 2011, and is treating small refiner gasoline volumes the same as small refinery gasoline volumes. Since small refineries and small refiners are exempt from the program until 2011, EPA is excluding their gasoline volumes from the overall non-renewable gasoline volume used to determine the applicable percentage. EPA believes this is appropriate because the percentage standard should be based only on the gasoline subject to the renewable volume obligation. Because small refineries and small refiners are exempt (unless they waive exemption) only through the 2010 compliance period when the exemption ends, calculation of the standard for calendar year 2011 and beyond will include small refinery and small refiner volumes.[9] Using information from gasoline batch reports submitted to EPA, EIA data, and input from the California Air Resources Board regarding California small refiners, we are finalizing a small refiner exemption adjustment to the standard of a constant 13.5%,[10] consistent with the proposal.

The Act requires that the small refinery adjustment also account for renewable fuels used during the prior year by small refineries that are exempt and do not participate in the RFS program. Accounting for this volume of renewable fuel would reduce the total volume of renewable fuel use required of others, and thus directionally would reduce the percentage standard. However, as discussed in the proposal, there are no such data available, the amount of renewable fuel that would qualify (i.e., that was used by exempt small refineries and small refiners but not used as part of the RFS program) is expected to be very small and would not significantly change the resulting percentage standard. Because whatever renewables small refiners and small refineries blend will be reflected as RINs available in the market, there is no need for a separate accounting of their renewable fuel use in the equation used to determine the standard. We thus proposed that this value be zero, and we are finalizing the equation as such.

We also proposed not to include renewable fuel used in Alaska, Hawaii, or U.S. territories when subtracting

renewable fuel volumes from the anticipated total gasoline volumes in EIA projections. The Act requires that the renewable fuel be consumed in the contiguous 48 states unless Alaska, Hawaii, or a U.S. territory opt-in. However, because renewable fuel produced in Alaska, Hawaii, and U.S. territories is unlikely to be transported to the contiguous 48 states, including their renewable fuel volumes in the calculation of the standard would not serve the purpose intended by the Act of ensuring that the statutorily required renewable fuel volumes are consumed in the 48 contiguous States. We are finalizing the exclusion of these areas' renewable fuel use as proposed.

We stated that any deficit carryover from 2006 would increase the 2007 standard. Since renewable fuel use in 2006 exceeded the 2.78 percent default standard, there is no deficit to carry over to 2007. Beginning with the 2007 compliance period, when annual individual party compliance replaces collective compliance, any deficit is calculated for an individual party and is included in the party's Renewable Volume Obligation (RVO) determination, as discussed in Section III.A.4.

In summary, the total projected non-renewable gasoline volumes from which the annual standard is calculated is based on EIA projections of gasoline consumption in the contiguous 48 states, adjusted by a constant percentage of 13.5% to account for small refinery/refiner volume, with built-in correction factors to be used when and if non-contiguous states and territories opt-in to the program. If actual gasoline consumption were to exceed the EIA projection, the result would be that renewable fuel volumes will exceed the statutory requirements. Conversely, if actual gasoline consumption was less than the EIA projection for a given year, theoretically a renewable fuel shortfall could occur. However, our projections of renewable fuel use due to market demand would make a shortfall extremely unlikely regardless of the error in gasoline consumption projections.

The following formula will be used to calculate the percentage standard:

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[7] Under the Act, small refineries are those with 75,000 bbl/day or less average aggregate daily crude oil throughput.

[8] Small refiners are those entities who produced gasoline from crude oil in 2004, and who meet the crude processing capability (no more than 155,000

barrels per calendar day, bpcd) and employee (no more than 1500 people) criteria as specified in previous EPA fuel regulations.

[9] As discussed in section III.C.3.a of this preamble, the small refinery exemption may be

extended under 211(o)(9)(A)(ii) or (B) of the Clean Air Act as amended by the Energy Policy Act.

[10] ''Calculation of the Small Refiner/Small Refinery Fraction for the Renewable Fuel Program,'' memo to the docket from Christine Brunner, ASD, OTAQ, EPA September 2006.

$$RFStd_i = 100 \times \frac{RFV_i - Cell_i}{(G_i - R_i) + (GS_i - RS_i) - GE_i}$$

Where:

RFStd$_i$ = Renewable Fuel standard in year i, in percent.

RFV$_i$ = Annual volume of renewable fuels required by section 211(o)(2)(B) of the Act for year i, in gallons.

G$_i$ = Amount of gasoline projected to be used in the 48 contiguous states, in year i, in gallons.

R$_i$ = Amount of renewable fuel blended into gasoline that is projected to be consumed in the 48 contiguous states, in year i, in gallons.

GS$_i$ = Amount of gasoline projected to be used in Alaska, Hawaii, or a U.S. territory in year i if the state or territory opts-in, in gallons.

RS$_i$ = Amount of renewable fuel blended into gasoline that is projected to be consumed in Alaska, Hawaii, or a U.S. territory in year i if the state or territory opts-in, in gallons.

GE$_i$ = Amount of gasoline projected to be produced by exempt small refineries and small refiners in year i, in gallons (through 2010 only unless exemption extended under §§ 211(o)(9)(A)(ii) or (B)). Equivalent to $0.135*(G_i - R_i)$.

Cell$_i$ = Beginning in 2013, the amount of renewable fuel that is required to come from cellulosic sources, in year i, in gallons (250,000,000 gallons minimum).

After 2012 the Act requires that the applicable volume of required renewable fuel specified in Table I.B–1 include a minimum of 250 million gallons that are derived from cellulosic biomass. As shown in Table III.A.2–1 below, we have estimated this value (250 million gallons) as a percent of an obligated party's production for 2013. Thus, an obligated party will be subject to two standards in 2013 and beyond, a non-cellulosic standard and a cellulosic standard. We are therefore also finalizing the following formula for

calculating the cellulosic standard that is required beginning in 2013:

$$RFCell_i = 100 \times \frac{Cell_i}{(G_i - R_i) + (GS_i - RS_i)}$$

Where, except for RFCell$_i$, the variable descriptions are as discussed above. The definition of RFCell$_i$ is:

RFCell$_i$ = Renewable Fuel Cellulosic Standard in year i, in percent

Note that after 2012 cellulosic RINs cannot be used to satisfy the non-cellulosic RFS standard (RFStd$_i$). The amount of renewable fuel that is required to come from cellulosic sources (Cell$_i$) is a fixed amount.

We are not finalizing regulations that would specify the criteria under which a state could petition the EPA for a waiver of the RFS requirements, nor the ramifications of Agency approval of such a waiver in terms of the level or applicability of the standard. As discussed in the proposal, there was no clear way to include such a provision in the context of the program being finalized. As a result, the formula for the standard shown above does not include any components to account for Agency approval of a state petition for a waiver of the RFS requirements. Should EPA grant such a waiver in the future, it will determine at that time what adjustments to make to the standard.

2. What Are the Applicable Standards?

As discussed in the proposal, EPA will set the percentage standard for each upcoming year based on the most recent EIA STEO projections, and using the other sources of information as noted above. EPA will publish the standard in

the **Federal Register** by November 30 of the preceding year. The standards are used to determine the renewable volume obligation based on an obligated party's total gasoline production or import volume in a calendar year, January 1 through December 31. The percentage standards do not apply on a per gallon basis. An obligated party will calculate its Renewable Volume Obligation (discussed in Section III.A.4) using the annual standard.

In the NPRM, we estimated the standards for 2007 and later using data available at the time and the formulas discussed above.[11] We have revised these values based on more recent data, and using EIA's October 2006 STEO gasoline and renewable fuel consumption projections.[12] In the proposal, we had used the lower heating value of ethanol for converting from Btu to gallons of ethanol for the purpose of calculating the standard. However, for this final rule, we have used the higher heating value of ethanol as recommended by commenters, to be consistent with EIA practices.[13] [14] Variables related to state or territory opt-ins were set to zero since we do not have any information related to their participation at this time. As mentioned earlier, we estimate the small refinery and small refiner fraction to be 13.5%. The exemption for small refineries and small refiners ends at the end of the 2010 compliance period, unless extended as discussed in Section III.C.3.a. Based on all of these factors, the standard for 2007 is 4.02%. Projected values of the standard for 2008 and beyond are shown in Table III.A.2–1.

TABLE III.A.2–1.—PROJECTED STANDARDS

| Year | Projected standard | Cellulosic standard |
|------|-------------------|---------------------|
| 2008 | 4.63% | Not applicable. |
| 2009 | 5.21% | Not applicable. |
| 2010 | 5.80% | Not applicable. |
| 2011 | 5.38% | Not applicable. |
| 2012 | 5.42% | Not applicable. |
| 2013+ | 5.24% min. (non-cellulosic) | 0.18% min. |

[11] "Calculation of the Renewable Fuel Standard" memo to the docket from Christine Brunner, ASD, OTAQ, EPA, September 2006.

[12] "Calculation of the Renewable Fuel Standard—Revised" memo to the docket from Christine Brunner, ASD, OTAQ, EPA, April 2007.

[13] The higher (or gross or upper) heating value is used in all Btu calculations for EIA's Annual Energy Review and in related EIA publications (see discussion in EIA's Annual Energy Review, Appendix A, Thermal Conversion Factors).

[14] The lower heating value (LHV) is used to represent energy content in the context of setting Equivalence Values as described in Section III.B.4 because it more accurately reflects the energy available in the fuel to produce work.

As discussed in Section II.A.5, for calendar year 2013 and thereafter, the applicable volumes will be determined in accordance with separate statutory provisions that include EPA coordination with the Departments of Agriculture and Energy, and a review of the program during calendar years 2006 through 2012. The Act specifies that this review consider the impact of the use of renewable fuels on the environment, air quality, energy security, job creation, and rural economic development, and the expected annual rate of future production of renewable fuels, including cellulosic ethanol. We intend to conduct another rulemaking as we approach the 2013 timeframe that would include our review of these factors. That rulemaking will present our conclusions regarding the appropriate applicable volume of renewable fuel for use in calculating the renewable fuel standard for 2013 and beyond. The program finalized by today's rule will continue to apply after 2012, though some elements may be modified in the rulemaking setting the standards for 2013 and beyond. Today's rule does not contain a mechanism for establishing a post-2012 standard.

3. Compliance in 2007

The Energy Act requires that EPA promulgate regulations to implement the RFS program, and if EPA did not issue such regulations then a default standard for renewable fuel use would apply in 2006. On December 30, 2005 we promulgated a direct final rule to interpret and implement the application of the statutory default standard of 2.78 percent in calendar year 2006 (70 FR 77325). However, the Act provides no default standard for any other year.

In the NPRM we stated our expectation that, due to the limited time available for this rulemaking, we would be unable to publish the final rule and have it become effective by January 1, 2007. We discussed several ways that we could specify how, and for what time periods, the applicable standard and other program requirements would apply to regulated parties for gasoline produced during 2007. We discussed a collective compliance approach similar to that applied in 2006, as well as a ''full year'' approach that would have based the renewable volume obligation for each obligated party on all gasoline produced starting on January 1, 2007 regardless of the effective date of the rule. However, due to a number of issues with these approaches, we proposed a ''prospective'' approach in which the renewable fuel standard would be applied to only those volumes of gasoline produced after the effective

date of the final rule. Essentially the renewable volume obligation for 2007 would be based on only those volumes of gasoline produced or imported by an obligated party prospectively from the effective date of the rulemaking forward, and renewable producers would not have to begin generating RINs and maintaining the necessary records until this same date.

We received no comments supporting the alternative ''full year'' approach to 2007 compliance. However, several parties expressed a preference for either a collective compliance approach for 2007, or if not that then delaying implementation of the comprehensive program to January 1, 2008. They argued that regulated parties needed additional time to put into place the sophisticated RIN tracking systems that would be required. The additional time would also allow regulated parties to debug the systems, train personnel, and put support programs into place. The American Coalition for Ethanol also argued that the prospective approach did not guarantee that the total renewable fuel volumes required by the Act for 2007 would actually be used in 2007, whereas a collective compliance approach would. Parties in favor of a collective compliance approach argued that EPA has the authority to implement such an approach despite the fact that the Act does not explicitly give EPA this authority, and also argued that there was no need to include any form of credit carryover under a collective compliance approach.

However, a number of refiners and their associations opposed a collective compliance approach to 2007 and expressed strong support for the proposed prospective approach. They argued that a start date at least 60 days from the date of publication of the final rule would provide sufficient time to obligated parties for making the necessary adjustments for compliance. They also argued that they should be afforded the opportunity to participate as soon as possible in the trading program, which the collective compliance approach used for 2006 would preclude for 2007.

We continue to believe that a collective compliance approach is not appropriate for 2007. The Energy Act requires us to promulgate regulations that provide for the generation of credits by any person who over complies with their obligation. It also stipulates that a person who generates credits must be permitted to use them for compliance purposes, or to transfer them to another party. These credit provisions have meaning only in the context of an individual obligation to meet the

applicable standard. Delaying a credit program until 2008 would mean the credit provisions have no meaning at all for 2007, since under a collective compliance approach no individual facility or company would be liable for meeting the applicable standard. Including a ''collective'' credit or deficit carryforward as part of a collective compliance program would also not fully implement the credit provisions of the Act. The prospective compliance approach, in contrast, not only provides obligated parties with the opportunity to generate credits, but also provides the industry with the certainty they need to comply and is relatively straightforward to implement.

Rather than requiring the program to begin on the effective date of the rule as proposed (60 days following publication in the **Federal Register**), we are finalizing a start date of September 1, 2007. From this date forward, the renewable fuel standard will be applicable to all gasoline produced or imported, and all renewable fuels produced or imported will have to be assigned a RIN. All regulated parties must be registered by this date, and the recordkeeping responsibilities will also begin. By setting such a date, industry will be able to plan with confidence to start complying upon signature of the rule, rather than having the start date depend upon the timing of publication of this final rule in the **Federal Register**. We recognize the concerns expressed in comments that time is needed to prepare Information Technology (IT) systems to comply with the program. However, we believe that a September 1, 2007 start date will provide sufficient time. The final rule is in most respects consistent with the NPRM, and based on discussions with industry, plans for implementation are already underway. Furthermore, a September 1, 2007 start date will likely provide regulated parties some additional time to prepare in comparison to simply setting the start date as 60 days following publication of the rule.

As stated in the NPRM, we recognize that the prospective approach to 2007 compliance will not guarantee by regulation that the total renewable fuel volumes required by the Act for 2007 would actually be used in 2007. However, current projections from the Energy Information Administration (EIA) on the volume of renewable fuel expected to be produced in 2007 indicate that the Act's required volumes will be exceeded by a substantial margin due to the relative economic value of renewable fuels in comparison to gasoline. We are confident that the combined effect of the regulatory

requirements for 2007 and the expected market demand for renewable fuels will lead to greater renewable fuel use in 2007 than is called for under the Act. Current renewable production already exceeds the rate required for all of 2007, and as discussed in Section VI, capacity is expected to continue to grow. Furthermore, refiners and importers are not required to meet any requirements under the Act until EPA adopts the regulations, and EPA is authorized to consider appropriate lead time in establishing the regulatory requirements.[15] Under this option we believe there will be reasonable lead-time for regulated parties to meet their 2007 compliance obligations. While no option before us is perhaps totally consistent with all of the provisions of the Act, we believe the rule as adopted does the best job possible given the circumstances of implementing all of the provisions of the Act for 2007.

4. Renewable Volume Obligations

In order for an obligated party to demonstrate compliance, the percentage standards described in Section III.A.2 which are applicable to all obligated parties must be converted into the volume of renewable fuel each obligated party is required to satisfy. This volume of renewable fuel is the volume for which the obligated party is responsible under the RFS program, and is referred to here as its Renewable Volume Obligation (RVO).

The calculation of the RVO requires that the standard shown in Table III.A.2–1 for a particular compliance year be multiplied by the gasoline volume produced by an obligated party in that year. To the degree that an obligated party did not demonstrate full compliance with its RVO for the previous year, the shortfall is included as a deficit carryover in the calculation. The equation used to calculate the RVO for a particular year is shown below:

$$RVO_i = Std_i \times GV_i + D_{i-1}$$

Where:

$RVO_i$ = The Renewable Volume Obligation for the obligated party for year i, in gallons.
$Std_i$ = The RFS program standard for year i, in percent.
$GV_i$ = The non-renewable gasoline volume produced by an obligated party in year i, in gallons.
$D_{i-1}$ = Renewable fuel deficit carryover from the previous year, in gallons.

[15] The statutory default standard for 2006 is the one exception to this, since it directly establishes a renewable fuel obligation applicable to refiners and importers in the event that EPA does not promulgate regulations.

The Energy Act only permits a deficit carryover from one year to the next if the obligated party achieves full compliance with its RVO including the deficit carryover in the second year. Thus deficit carryovers could not occur two years in succession. They could, however, occur as frequently as every other year for a given obligated party.

The calculation of an obligated party's RVO is necessarily retrospective, since the total gasoline volume that it produces in a calendar year will not be known until the year has ended. However, the obligated party will have an incentive to project gasoline volumes, and thus the RVO, throughout the year so that it can spread its efforts to comply across the entire year. Most refiners and importers will be able to project their annual gasoline production volumes with a minimum of uncertainty based on their historical operations, capacity, plans for facility downtimes, knowledge of gasoline markets, etc. Even if unforeseen circumstances (e.g., hurricane, unit failure, etc.) significantly reduced the production volumes in comparison to their projections, their RVO will likewise be reduced proportionally and their ability to comply with the RFS requirements will be only minimally affected. Each obligated party's projected RVO for a given year becomes more accurate as that year progresses, but the obligated party should nevertheless have a sufficiently accurate estimate of its RVO at the beginning of the year to allow it to begin its efforts to comply.

*B. What Counts as a Renewable Fuel in the RFS Program?*

Section 211(o) of the Clean Air Act defines "renewable fuel" and specifies many of the details of the renewable fuel program. The following section provides EPA's views and interpretations on issues related to what fuels may be counted towards compliance with the RVO, and how they are counted.

1. What Is a Renewable Fuel That Can Be Used for Compliance?

The statutory definition of renewable fuel includes cellulosic ethanol and waste derived ethanol. It includes biodiesel, as defined in the Energy Act.[16] It also includes all motor vehicle fuels that are produced from biomass material such as grain, starch, oilseeds,

[16] As discussed below, for purposes of this rulemaking, the regulations separate "biodiesel" as defined in the Energy Act, into biodiesel (diesels that meet the Energy Act's definition and are a mono-alkyl ester) and renewable diesel (other diesels that meet the Energy Act's definition but are not mono-alkyl esters).

animal, or fish materials including fats, greases and oils, sugarcane, sugar beets, tobacco, potatoes or other biomass (such as bagasse from sugar cane, corn stover, and algae and seaweed). In addition, it includes motor vehicle fuels made using a feedstock of natural gas if produced from a biogas source such as a landfill, sewage waste treatment plant, feedlot, or other place where decaying organic material is found.

According to the Act, the motor vehicle fuels must be used "to replace or reduce the quantity of fossil fuel present in a fuel mixture used to operate a motor vehicle." Some motor vehicle fuels can be used in both motor vehicles or nonroad engines or equipment. For example, highway gasoline and diesel fuel are often used in both highway and off-highway applications. Compressed natural gas can likewise be used in either highway or nonroad applications. For purposes of the renewable fuel program, EPA considers a fuel to be a "motor vehicle fuel" and to be "a fuel mixture used to operate a motor vehicle," based on its potential for use in highway and nonroad vehicles, without regard to whether it, in fact, is used in a highway vehicle application. EPA does not believe that the much more complex and costly regulatory scheme that would be needed to track motor vehicle fuel use versus off-road fuel use would be justified. (As discussed further below, heaters and boilers are not considered highway or nonroad engine applications and renewable fuel produced or imported specifically for use in such equipment is not valid for compliance purposes under the RFS program.) If it is a fuel that could be used in highway vehicles, it will satisfy these parts of the definition of renewable fuel, whether it is later used in highway or nonroad applications. This will allow a motor vehicle fuel that otherwise meets the definition to be counted towards a party's RVO without the need to track it to determine its actual application in a highway vehicle, and provided only that the producer does not know that the fuel will be used for a purpose other than highway and nonroad engine applications. This is also consistent with the requirement that EPA base the renewable fuel obligation on estimates of the entire volume of gasoline consumed, without regard to whether it is used in highway or nonroad applications.

Renewable fuel as defined, may be made from a number of different types of feedstocks. For example, the Fisher-Tropsch process can use methane gas from landfills as a feedstock, to produce diesel or gasoline. Vegetable oil made

from oilseeds such as rapeseed or soybeans can be used to make biodiesel or renewable diesel. Methane, made from landfill gas (biogas) can be used to make methanol, or can be used directly as a fuel in vehicles with engines designed to run on compressed natural gas. Also, some vegetable oils or animal fats can be processed in distillation columns in refineries to make gasoline; as such, the renewable feedstock serves as a ''renewable crude,'' and the resulting gasoline or diesel product would be a renewable fuel. This last example is discussed in further detail in Section III.B.3 below.

As this discussion shows, the definition of renewable fuel in the Act is broad in scope, and covers a wide range of fuels. While ethanol is used primarily in combination with gasoline, the definition of renewable fuel in the Act is not limited to fuels that can be blended with gasoline. Various fuels that meet the definition of renewable fuel can be used in their neat form, such as ethanol, biodiesel, methanol or natural gas. Others, including ethanol may be used to produce a gasoline blending component (such as ETBE). At the same time, the RFS regulatory program is to ''ensure that gasoline sold or introduced into commerce * * * contains the applicable volume of renewable fuel.'' This applicable volume is specified as a total volume of renewable fuel on an aggregate basis. Congress also clearly specified that one renewable fuel, biodiesel, could be counted towards compliance even though it is not a gasoline component, and does not directly displace or replace gasoline. The Act is unclear on whether other fuels that meet the definition of renewable fuel, but are not used in gasoline, could also be used to demonstrate compliance towards the aggregate national use of renewable fuels.

EPA interprets the Act as allowing regulated parties to demonstrate compliance based on any fuel that meets the statutory definition for renewable fuel, whether it is directly blended with gasoline or not. This would include neat alternative fuels such as ethanol, methanol, and natural gas that meet the definition of renewable fuel. This is appropriate for several reasons. First, it promotes the use of all renewable fuels, which will further the achievement of the purposes behind this provision. Congress did not intend to limit the program to only gasoline components, as evidenced by the provision for biodiesel, and the broad definition of renewable fuel evidences an intention to address more renewable fuels than those used with gasoline. Second, in practice

EPA expects that the overwhelming volume of renewable fuel used to demonstrate compliance with the renewable fuel obligation would still be ethanol blended with gasoline. Finally, as discussed later, EPA's compliance program is based on assigning volumes at the point of production, and not at the point of blending into motor vehicle fuel. This interpretation avoids the need to track renewable fuels downstream to ensure they are blended with gasoline and not used in their neat form; the gasoline that is used in motor vehicles is reduced by the presence of renewable fuels in the gasoline pool whether they are blended with gasoline or not. Comments received on this interpretation were favorable towards it. EPA continues to believe, therefore, that this approach is consistent with the intent of Congress and is a reasonable interpretation of the Act. One commenter indicated that a logical extension of this reasoning would provide that renewable fuel that could be used in motor vehicles is still a renewable fuel under the Act when used by renewable fuel producers in a boiler or heater. EPA disagrees. The term ''renewable fuel'' means ''motor vehicle fuel that * * * is used to replace or reduce the quantity of fossil fuel present in a fuel mixture used to operate a motor vehicle.'' We believe that all but a trivial quantity of renewable fuels that can be used in motor vehicles will ultimately be used as motor vehicle fuel. Producers of ethanol biodiesel and other products that can be used as motor vehicle fuel can generally assume, therefore, that their products will be used in that way, and can assign RINs to their product without tracking its ultimate use. However, renewable fuel used onsite in a boiler or heater by a renewable fuel producer clearly is not a motor vehicle fuel used to replace or reduce the quantity of fossil fuel present in a fuel mixture used to operate a motor vehicle.

Under the Act, renewable fuel includes ''cellulosic biomass ethanol'' and ''waste derived ethanol'', each of which is defined separately. Ethanol can be cellulosic biomass ethanol in one of two ways, as described below.

### a. Ethanol Made From a Cellulosic Feedstock

The simplest process of producing ethanol is by fermenting sugar in sugar cane or beets, but ethanol can also be produced from starch in corn and other feedstocks by first converting the starch to sugar. Ethanol can also be produced from complex carbohydrates, such as the cellulosic portion of plants or plant products. The cellulose is first

converted to sugars (by hydrolysis); then the same fermentation process is used as for sugar to make ethanol. Cellulosic feedstocks (composed of cellulose and hemicellulose) are currently more difficult and costly to convert to sugar than are starches. While the cost and difficulty are a disadvantage, the cellulosic process offers the advantage that a wider variety of feedstocks can be used. Ultimately with more feedstocks available from which to make ethanol more volume of ethanol can be produced.

The Act provides the definition of cellulosic biomass ethanol, which states:

''The term 'cellulosic biomass ethanol' means ethanol derived from any lignocellulosic or hemicellulosic matter that is available on a renewable or recurring basis, including:
(i) Dedicated energy crops and trees;
(ii) Wood and wood residues;
(iii) Plants;
(iv) Grasses;
(v) Agricultural residues;
(vi) Animal wastes and other waste materials, and
(viii) Municipal solid waste.''

Examples of cellulosic biomass source material include rice straw, switch grass, and wood chips. Ethanol made from these materials would qualify under the definition as cellulosic ethanol. In addition to the above sources of feedstocks for cellulosic biomass ethanol, the Act's definition also includes animal waste, municipal solid wastes, and other waste materials. ''Other waste materials'' generally includes waste material such as sewage sludge, waste candy, and waste starches from food production, but for purposes of the definition of cellulosic ethanol discussed in III.B.1.b below, it can also mean waste heat obtained from an off-site combustion process.

Although the definitions of ''cellulosic biomass ethanol'' and ''waste derived ethanol'' both include animal wastes and municipal solid waste in their respective lists of covered feedstocks, there remains a distinction between these types of ethanol. If the animal wastes or municipal solid wastes contain cellulose or hemicellulose, the resulting ethanol can be termed ''cellulosic biomass ethanol.'' If the animal wastes or municipal solid wastes do not contain cellulose or hemicellulose, then the resulting ethanol is labeled ''waste derived ethanol.'' This is discussed further in Section III.B.1.c below.

b. Ethanol Made From Any Feedstock in Facilities Using Waste Material To Displace 90 Percent of Normal Fossil Fuel Use

The definition of cellulosic biomass ethanol in the Act also provides that ethanol made at any facility—regardless of whether cellulosic feedstock is used or not—may be defined as cellulosic if at such facility "animal wastes 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." The statutory language suggests that there are two methods through which "animal and other waste materials" may be considered for displacing fossil fuel. The first method is the digestion of animal wastes or other waste materials. EPA has interpreted the term "digestion" to mean the conversion of animal or other wastes into methane, which can then be combusted as fuel. We base our interpretation on the practice in industry of using anaerobic digesters to break down waste products such as manure into methane. Anaerobic digestion refers to the breakdown of organic matter by bacteria in the absence of oxygen, and is used to treat waste to produce renewable fuels. We note also that the digestion of animal wastes or other waste materials to produce the fuel used at the ethanol plant does not have to occur at the plant itself. Methane made from animal or other wastes offsite and then purchased and used at the ethanol plant would also qualify.

The second method is suggested by the term "otherwise used" which we interpret to mean (1) the direct combustion of the waste materials as fuel at an ethanol plant, or (2) the use of thermal energy that itself is a waste product; e.g., waste heat that is obtained from an off-site combustion process such as a neighboring plant that has a furnace or boiler from which the waste heat is captured. With respect to the first meaning, "other waste materials" includes but is not limited to waste materials from tree farms (tops, branches, limbs, etc.), or waste materials from saw mills (sawdust, shavings and bark) as well as other vegetative waste materials such as corn stover, or sugar cane bagasse, that could be used as fuel for gasifier/boiler units at ethanol plants. Since these materials are not also used as a feedstock to starch-based ethanol plants, they are truly waste materials. Although these waste materials conceivably could be feedstocks to a cellulosic ethanol plant, their use in that manner is sufficiently challenging at the current time that EPA

believes that such use does not subvert the intent of the definition.[17] Since corn kernels can readily be used as a feedstock in a typical ethanol production facility, their use as a fuel for gasified/boiler units at a corn ethanol plant would not be considered use of "other waste material" for purposes of the definition of cellulosic biomass ethanol.

Regarding the use of waste heat as a source of thermal energy, we note that there may be situations in which an off-site furnace, boiler or heater creates excess or waste heat that is not used in the process for which the thermal energy is employed. For example, a glass furnace generates a significant amount of waste heat that often goes unused. We have therefore included in the regulatory definition of cellulosic biomass ethanol waste heat generated from off-site sources in the definition of "other waste materials" that can be used to displace 90% of the fossil fuel otherwise used at an ethanol production facility.

Several commenters argued that because the source of the waste heat is ultimately a fossil fuel in most cases that it should not be considered an "other waste material". The Agency recognizes that fossil fuel is ultimately the source of most waste heat, but it is also the case that waste heat that is uncaptured represents a loss of energy that could otherwise displace fossil fuel use elsewhere. Specifically, waste heat used at an ethanol plant would result in displacement of fossil fuel use at the plant. In writing the proposed rule, we were aware of the concern raised by the commenters and therefore proposed to restrict waste heat to off-site sources only. We believe that this approach minimizes the concern. We disagree with another commenter that such restriction would create a perverse incentive for facilities near ethanol plants to oversize its combustion units to sell waste heat to the neighboring ethanol facilities where it would be used to displace fossil fuel. It is highly unlikely that businesses would incur the additional expense of building an oversized combustion unit for the sale of waste heat. Also, the 2.5 gallon value given for one gallon of cellulosic ethanol as provided by the Act extends only through 2012. Any additional

market value for waste heat used to qualify ethanol as cellulosic would therefore be of relatively short duration and not likely to warrant investment in oversized combustion units.[18]

The term "fossil fuel normally used in the production of ethanol" means fossil fuel used at the facility in the ethanol production process itself, rather than other phases such as trucks transporting product, and fossil fuel used to grow and harvest the feedstock. Therefore the diesel fuel that trucks consume in hauling wood waste from sawmills to the ethanol facility would not be counted in determining whether the 90% displacement criterion has been met. We are interpreting it in this way because we believe the accounting of fuel use associated with transportation and other life cycle activities would be extremely difficult and in many cases impossible.[19]

Based on the operation of ethanol plants, we are viewing this definition to apply to waste materials used to produce thermal energy rather than electrical energy. Electrical usage at ethanol plants is used for lights and equipment not directly related to the production of ethanol. Also, the calculation of fossil fuel used to generate such electrical usage would be difficult because it is not always possible to track the source of electricity that is purchased off-site. Therefore, the final regulations consider displacement of 90 percent of fossil fuels at the ethanol plant to mean those fuels consumed on-site and that are used to generate thermal energy used to produce ethanol.

One commenter suggested that electricity from cogeneration (i.e., combined heat and power) units be considered in determining the percentage of fossil fuel use that is displaced. The commenter claims that allowing consideration of electricity use would provide an incentive for cogeneration to be used at ethanol plants. Our findings regarding the use of electricity at ethanol plants remain the same—that is, it is not used as part of

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[17] On the other hand, wood from plants or trees that are grown as an energy crop may not qualify as a waste-derived fuel in an ethanol facility because such wood would not qualify as waste materials under this portion of the definition. Under the definition of renewable fuels and cellulosic biomass ethanol, however, such wood material could serve as a feedstock in a cellulosic ethanol plant, since these definitions do not restrict such feedstock to waste materials only.

[18] The term "other waste materials" is also included in the portions of the definitions of "cellulosic biomass ethanol" and "waste-derived ethanol" that identify feedstocks. The inclusion of off-site generated waste heat in the definition of "other waste materials", however, applies only to the portion of the definition of cellulosic biomass ethanol that relates to displacement of fossil fuels, and does not apply to the term "other waste materials" as otherwise used in these definitions.

[19] In Section IX of today's preamble we discuss our analysis of the lifecycle fuel impacts of the RFS rule, with respect to greenhouse gas (GHG) emissions. While we do account for fuel used in hauling materials to ethanol plants in our analysis, we are using average nationwide values, rather than data collected for individual plants.

the heat source in ethanol production for economic reasons. We note also that the commenter did not present any evidence to the contrary. As such, we continue to maintain that electricity is not ''normally used in the production of ethanol'' and we are therefore only considering the displacement of fossil fuels associated with thermal energy at the plant.

Owners who claim their product qualifies as cellulosic biomass ethanol based on the 90 percent fossil fuel displacement through the use of waste materials (i.e., animal wastes, and other waste materials) are required under today's rule to keep records of fuel (waste-derived and fossil fuel) used for thermal energy for verification of their claims. They will also be required to track the fossil fuel equivalent of any off-site generated waste heat that is captured and which displaces fossil fuel used in the ethanol production process. Since such waste heat would typically be purchased through agreement with the off-site owner, we do not feel it burdensome for owners to track such information. Owners will therefore calculate the amount of energy in Btu's associated with waste-derived fuels (including the fossil fuel equivalent waste heat), and divided by the total energy in Btus used to produce ethanol in a given year. Ethanol produced from such facilities will get the benefit of the 2.5 ratio. (Section III.D.3.e discusses the requirements for owners of facilities that claim to have produced cellulosic ethanol under the 90 percent displacement provision, but which fail to meet those requirements.)

### c. Ethanol That Is Made From the Non-Cellulosic Portions of Animal, Other Waste, and Municipal Waste

''Waste derived ethanol'' is defined in the Act as ethanol derived from ''animal wastes, including poultry fats and poultry wastes, and other waste materials; * * * or municipal solid waste.'' Both animal wastes and municipal solid waste are also listed as allowable feedstocks for the production of ''cellulosic biomass ethanol.'' When such feedstocks do not contain cellulose, however, the resulting ethanol is waste derived. Both waste-derived and cellulosic ethanol both are considered equivalent to 2.5 gallons of renewable fuel when determining compliance with the renewable volume obligation.

### d. Foreign Producers of Cellulosic and Waste-Derived Ethanol

Some commenters stated that foreign ethanol producers should not be able to have their cellulosic or waste-derived ethanol treated in the same manner as domestic cellulosic or waste-derived ethanol under the RFS program because of the difficulty in verifying their compliance with the provisions discussed above. Today's rule allows such producers to participate, provided they meet the requirements discussed in Section IV.D.2. of the preamble. The requirements for foreign producers of cellulosic or waste-derived ethanol are different than for domestic producers and allow for verification of compliance.

### 2. What Is Biodiesel?

The Act states that ''The term 'renewable fuel' includes * * * biodiesel (as defined in section 312(f)) of the Energy Policy Act of 1992.'' This definition, as modified by Section 1515 of the Energy Act states:

The term ''biodiesel'' means a diesel fuel substitute produced from nonpetroleum renewable resources that meets the registration requirements for fuels and fuel additives established by the Environmental Protection Agency under section 7545 of this title, and includes biodiesel derived from animal wastes, including poultry fats and poultry wastes, and other waste materials, or municipal solid waste and sludges and oils derived from wastewater and the treatment of wastewater.

This definition of biodiesel would include both mono-alkyl esters which meet the current ASTM specification D–6751–07 [20] (the most common meaning of the term ''biodiesel'') that have been registered with EPA, and any non-esters that are intended for use in engines that are designed to run on conventional, petroleum-derived diesel fuel, have been registered with the EPA, and are made from any of the feedstocks listed above.

To implement the above definition of biodiesel in the context of the RFS rulemaking while still recognizing the unique history and role of mono-alkyl esters meeting ASTM D–6751, we have divided the Act's definition of biodiesel into two separate parts: Biodiesel (mono-alkyl esters) and non-ester renewable diesel. The combination of ''biodiesel (mono-alkyl esters)'' and ''non-ester renewable diesel'' in the regulations fulfills the Act's definition of biodiesel. Commenters supported EPA's approach in defining biodiesel in this manner.

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[20] In the event that the ASTM specification D–6751 is succeeded with an updated specification in the future, EPA may revise the regulations accordingly at such time. Regulations cannot be promulgated that only reference ''the most recent version'' of an ASTM standard, since doing so would place the American Society for Testing and Materials in the position of a regulatory body.

### a. Biodiesel (Mono-Alkyl Esters)

Under today's rule, the term ''biodiesel (mono-alkyl esters)'' means a motor vehicle fuel which: (1) Meets the registration requirements for fuels and fuel additives established by the Environmental Protection Agency under section 7545 of this title (Clean Air Act Section 211); (2) is a mono-alkyl ester; (3) meets ASTM specification D–6751–07; (4) is intended for use in engines that are designed to run on conventional, petroleum-derived diesel fuel, and (5) is derived from nonpetroleum renewable resources.

### b. Non-Ester Renewable Diesel

The term ''non-ester renewable diesel'' means a motor vehicle fuel which: (1) Meets the registration requirements for fuels and fuel additives established by the Environmental Protection Agency under section 7545 of this title (Clean Air Act Section 211); (2) is not a mono-alkyl ester; (3) is intended for use in engines that are designed to run on conventional, petroleum-derived diesel fuel, and (4) is derived from nonpetroleum renewable resources. Current examples of a non-ester renewable diesel include: ''Renewable diesel'' produced by the Neste or UOP process, or diesel fuel produced by processing fats and oils through a refinery hydrotreating process.

### 3. Does Renewable Fuel Include Motor Fuel That Is Made From Coprocessing a Renewable Feedstock With Fossil Fuels?

Renewable fuels can be produced by processing biologically derived wastes such as animal fats, as well as other nonpetroleum based feedstocks in a traditional refinery—that is, a refinery that normally uses crude oil or other fossil fuel-based blendstocks as feeds to processing units. Such wastes are pre-processed so that they are in liquid form to enable their further processing in units at a traditional refinery. In the proposed rule, we defined such feedstocks as ''biocrudes'' and included a discussion on how the fuels resulting from these feedstocks should be counted. Our basic approach remains the same. We have changed the term ''biocrudes'' to ''renewable crudes'', since we believe it is more accurate. We are providing additional discussion in this preamble on how renewable fuels are made from renewable crudes.

The fuels resulting from the co-processing of the pre-processed liquid form of these renewable crudes (i.e., those feedstocks listed in the definition of ''renewable fuel'' and, for biodiesel, in the statutory definition of ''biodiesel'') in a traditional refinery are

themselves indistinguishable from the gasoline and diesel products produced from crude oil. As such, the treatment of any resulting renewable fuel presents a particular complication in terms of RFS program compliance—namely, if such fuels are indistinguishable from gasoline and diesel produced from crude oil feedstocks, how are the volumes to be measured? Also, some renewable feedstocks are used to produce renewable diesel (discussed in Section III.B.2 above). In other circumstances renewable feedstocks are processed in dedicated facilities or units—that is, in either (1) facilities other than refineries that process fossil fuels, (2) equipment located within a traditional refinery but which is dedicated to renewable feedstocks, or (3) equipment located within a traditional refinery that processes renewable and conventional feedstocks but solely for the production of motor vehicle fuels.

The processing approach for the renewable feedstock dictates whether the resulting fuel is distinguishable from crude oil-based fuels by virtue of its being made and stored separately from fossil fuels as discussed in further detail below. Therefore, our method for counting renewable fuels made from renewable feedstocks differ based on how the renewable feedstock is processed

a. Definition of ''Renewable Crudes'' and ''Renewable Crude-Based Fuels''

Under some circumstances renewable feedstocks can be preprocessed into a liquid that is similar to petroleum-based feedstocks used in traditional refineries. We are classifying such liquids as ''renewable crudes,'' and any motor vehicle fuel that is made from such liquids is defined broadly as ''renewable crude-based fuel''.

There are three approaches that can be taken to making renewable fuels from renewable crudes. The first would include gasoline or diesel products resulting from the processing of renewable crudes in production units within refineries that simultaneously process crude oil and other petroleum based feedstocks. In these cases, the final product consists of a mixture of renewable fuel and fossil-based fuel, and may include both motor vehicle fuel and non-motor vehicle fuel. The second approach would include diesel and other products resulting from processing renewable crudes at a stand-alone facility that does not process any fossil fuels, or at a facility dedicated to renewable crudes within a traditional

refinery.[21] In this case, a batch of renewable crude used as feedstock to a production unit would replace crude oil or other petroleum based feedstocks which ordinarily would be the feedstock in that process unit. The third approach would be non-ester renewable diesel fuel produced by processing fats and oils through a refinery hydrotreating process. All three approaches can produce renewable fuel that is valid for compliance purposes under the RFS program, but the measurement of volumes produced and/or their associated Equivalence Values may differ.

b. How Are Renewable Crude-Based Fuel Volumes Measured?

As discussed above, some renewable feedstocks are processed in facilities other than refineries, or in equipment located within a traditional refinery but which is dedicated to renewable feedstocks. The resulting product is ''renewable diesel'' (and such units may in the future also produce ''renewable gasoline'' though none is currently made in such dedicated facilities). In other situations, renewable crudes are coprocessed along with crude oils in traditional refineries, resulting in gasoline or diesel products that may be combinations of renewable and non-renewable fuels.

In the case of renewable crude coprocessed with fossil fuels in refineries, we are assuming that all of the renewable crude used as a feedstock in a refinery unit will end up as a renewable crude-based fuel that is valid for RFS compliance purposes. We are taking this approach because renewable crudes that are processed through distillate hydrotreaters are first pre-processed so that they are in liquid form, and such liquid produces diesel fuel in volumes approximately equal to the amount that is input to the hydrotreater. We are assuming that renewable crudes could also be processed in other process units at refineries to make gasoline. The renewable crude processed at a refinery is functionally equivalent to crude oil, and the end products (gasoline and/or diesel) are indistinguishable from products made from crude oil. Thus, rather than requiring the refiner to document what portion of the renewable crude-based fuel is renewable fuel, we are requiring that the volume of the renewable crude itself count as the volume of renewable fuel produced for the purposes of determining the volume

block codes that are in the RIN (discussed in further detail in Section III.D).[22] The general counting procedure for renewable crude-based fuels that are not derived through coprocessing with fossil fuels is that the volumes of renewable fuel produced are measured directly, and an appropriate Equivalence Value is assigned according to the methodology discussed in Section III.B.4.

4. What Are ''Equivalence Values'' for Renewable Fuel?

One question that EPA needed to address in developing the regulations was how to count volumes of renewable fuel in determining compliance with the renewable volume obligation. The Act stipulates that every gallon of waste-derived ethanol and cellulosic biomass ethanol should count as if it were 2.5 gallons for RFS compliance purposes. The Act does not stipulate similar values for other renewable fuels, but as described below we believe it is appropriate to do so.

We are requiring that the ''Equivalence Values'' for renewable fuels other than those for which specific values are set forth in the Act be based on their energy content in comparison to the energy content of ethanol, adjusted as necessary for their renewable content. The result is an Equivalence Value for corn ethanol of 1.0, for biobutanol of 1.3, for biodiesel (mono alkyl ester) of 1.5, and for non-ester renewable diesel of 1.7. However, the methodology can be used to determine the appropriate equivalence value for any other potential renewable fuel as well.

This section describes why the use of the Equivalence Value approach in today's rule is appropriate under the Act, and our conclusions regarding the possible future use of lifecycle analyses as the basis of Equivalence Values.

a. Authority Under the Act To Establish Equivalence Values

We are requiring that Equivalence Values be assigned to every renewable fuel to provide an indication of the number of gallons that can be claimed for compliance purposes for every physical gallon of renewable fuel. An Equivalence Value of 1.0 means that every physical gallon of renewable fuel counts as one gallon for RFS compliance purposes. An Equivalence Value greater than 1.0 means that every physical gallon of renewable fuel counts as more than one gallon for RFS compliance

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[21] Renewable crude-based fuels will need to be registered under the provisions contained in 40 CFR 79 Part 4 before they can be sold commercially.

[22] We are considering the volumes of renewable crude itself, not the feedstocks that are made into renewable crude.

purposes, while a value less than 1.0 counts as less than one gallon.

We have interpreted the Act as allowing us to develop Equivalence Values according to the methodology discussed below. We believe that the use of Equivalence Values based on energy content in comparison to the energy content of ethanol is consistent with the intent of Congress to treat different renewable fuels differently in different circumstances, and to provide incentives for use of renewable fuels in certain circumstances, as evidenced by those specific circumstances addressed by Congress. The Act has several provisions that provide for mechanisms other than straight volume measurement to determine the value of a renewable fuel in terms of RFS compliance. For example, 1 gallon of cellulosic biomass or waste derived ethanol is to be treated as 2.5 gallons of renewable fuel. EPA is also required to establish an ''appropriate amount of credits'' for biodiesel, and to provide for ''an appropriate amount of credit'' for using more renewable fuels than are required to meet your obligation. EPA is also to determine the ''renewable fuel portion'' of a blending component derived from a renewable fuel. These statutory provisions provide evidence that Congress did not limit this program solely to a straight volume measurement of gallons in the context of the RFS program.

In response to the NPRM, some commenters supported our view that the Act provides sufficient context and direction to permit the use of Equivalence Values, while other commenters opposed this view. Some parties commented that the methodology proposed in the NPRM did not go far enough. These parties argued that instead of energy content, EPA should be using lifecycle impacts to set the Equivalence Values. Lifecycle analyses are discussed in more detail in Section III.B.4.c.

Parties that opposed our proposed approach to Equivalence Values argued that since the Act did not explicitly give EPA the authority to set Equivalence Values for renewable fuels other than cellulosic biomass ethanol and waste-derived ethanol, EPA had no authority to do so. In their view, the explicit inclusion of a 2.5 credit value for cellulosic and waste-derived ethanol and the omission of any credit values for other renewables fuels should be taken as evidence that Congress intended all other renewable fuels to have Equivalence Values of 1.0.

We disagree that our discretion is so strictly limited. The Act specifically gave EPA the authority to determine an ''appropriate'' credit for biodiesel, and also establishes a 2.5 value for cellulosic biomass ethanol and waste-derived ethanol. As ethanol and biodiesel were likely the two primary renewable fuels envisioned in the near-term under the Act, it would seem normal for Congress to have focused on these. However, Congress also clearly allowed for other renewable fuels to participate in the RFS program, and it is appropriate for EPA to consider how they should be treated under the Act. Furthermore, in addition to the Act's direction that EPA determine an appropriate level of credit for biodiesel, the Act also directs EPA to determine the ''appropriate'' amount of credit for renewable fuel use in excess of the required volumes, and to determine the ''renewable fuel portion'' of a blending component derived from a renewable fuel. These statutory provisions lend further support to our belief that Congress did not limit the RFS program solely to a straight volume measurement of gallons. Having concluded that it is appropriate to determine an appropriate level of credit for biodiesel based on energy content as compared to ethanol, EPA is using a consistent approach for other types of renewable fuels for which a specific statutory credit value is not prescribed.

Another reason given by parties opposing our approach to Equivalence Values was that Equivalence Values higher than 1.0 would result in actual volumes of renewable fuel being less than the volumes required by the Act. Although it is true that the Act specifies the annual volumes of renewable fuel that the program must require and directs EPA to promulgate regulations ensuring that gasoline sold each year ''contains the applicable volume of renewable fuel,'' the Act also contains language that makes the achievement of those volumes imprecise. For instance, the deficit carryover provision allows any obligated party to fail to meet its RVO in one year if it meets the deficit and its RVO in the next year. If many obligated parties took advantage of this provision, it could result in the nationwide total volume obligation for a particular calendar year not being met. In addition, the calculation of the renewable fuel standard is based on projected nationwide gasoline volumes provided by EIA (see Section III.A). If the projected gasoline volume falls short of the actual gasoline volume in a given year, the standard will fail to create the demand for the full renewable fuel volume required by the Act for that year. The Act contains no provision for correcting for underestimated gasoline volumes, and as a result the volumes

required by the Act may not be consumed in use.

Some commenters disagreed with our belief that there will only be very limited additional situations where an Equivalence Value other than 1.0 is used. They expressed concern that the provision for Equivalence Values will interfere with meeting the total national volume goals for usage of renewable fuel.

While in the long term we agree that renewable fuels with an Equivalence Value greater than 1.0 may grow to become a larger portion of the renewable fuel pool, we do not believe that this is likely to be the case before 2013, the time period when the statute specifies the overall national volumes. EPA will be issuing a new rule prior to 2013, and can reconsider its approach to Equivalence Values for renewable fuel at that time if it is appropriate to do so. For instance, EIA projects that biodiesel volumes will reach 300 million gallons by 2012. With the Equivalence Value of 1.5 that we are finalizing today, this means that the 7.5 billion gallons required by the Act for 2012 could be met with 7.35 billion gallons of renewable fuel. However, this result is well within the variability in actual volumes resulting from the other statutory provisions described above, and would still result in 7.5 billon gallons of ethanol-equivalent (in terms of energy content) renewable fuel being consumed. Congress explicitly recognized the expected use of credits for biodiesel, as it did for cellulosic ethanol. By requiring or authorizing EPA to assign credit values for such products, Congress recognized that the national volumes specified in the Act would not necessarily be met on a gallon per gallon basis. For the very limited number of other renewable fuels not covered by these express statutory provisions, assigning an equivalence value is consistent with this overall approach. Moreover, EIA is projecting that the total volume of renewable fuel will exceed the Act's requirements by a substantial margin due primarily to the favorable economics of ethanol in comparison to gasoline. Under such projections, the existence of renewable fuels with Equivalence Values higher than 1.0 will have no impact on the demand for renewable fuel.

Finally, the Act also contains language indicating that EPA has flexibility in determining how various renewable fuels should count towards meeting the required annual volumes. For instance, valid renewable fuels are defined as those that ''replace or reduce the quantity of fossil fuel present in a fuel mixture used to operate a motor

vehicle.'' Fossil fuels such as gasoline or diesel are only replaced or reduced to the degree that the energy they contain is replaced or reduced. We do not believe it would be appropriate to treat a renewable fuel with very low volumetric energy content as being equivalent to a renewable fuel with very high volumetric energy content, since the impact on motor vehicle fossil fuel use is very different for these two renewable fuels. The use of Equivalence Values based on volumetric energy content helps to achieve this goal.

A case in point would be butanol. It is produced from the same feedstocks as ethanol (i.e., starch crops such as corn) in a similar process. However, it results in an alcohol with a higher volumetric energy content than ethanol. If we were to give butanol an Equivalence Value of 1.0, it would provide an economic disincentive for corn to be used to produce butanol instead of ethanol.

As a result, we continue to believe that the assignment of Equivalence Values other than 1.0 to some renewable fuels is a reasonable way for the RFS program to establish ''appropriate'' credit values while also ensuring that the Act's volume obligations, read together with the Act's directions regarding credit values towards fulfillment of that obligation, are satisfied. This approach is consistent with the way Congress treated the various specific circumstances noted above, and thus is basically a continuation of that process.

b. Energy Content and Renewable Content as the Basis for Equivalence Values

To appropriately account for the different energy contents of different renewable fuels as well as the fact that some renewable fuels actually contain some non-renewable content, we are requiring that Equivalence Values be calculated using both the renewable content of a renewable fuel and its energy content. This section describes the calculation methodology for Equivalence Values.

In order to take the energy content of a renewable fuel into account when calculating the Equivalence Values, we must identify an appropriate point of reference. Ethanol is a reasonable point of reference as it is currently the most prominent renewable fuel in the transportation sector, and it is likely that the authors of the Act saw ethanol as the primary means through which the required volumes would be met in at least the first years of the RFS program. By comparing every renewable fuel to ethanol on an equivalent energy content basis, each renewable fuel is assigned an Equivalence Value that precisely accounts for the amount of petroleum in motor vehicle fuel that is reduced or replaced by that renewable fuel in comparison to ethanol. To the degree that corn-based ethanol continues to dominate the pool of renewable fuel, this approach allows actual volumes of renewable fuel to be consistent with the volumes required by the Act.

Equivalence Values also account for the renewable content of renewable fuels, since the presence of any non-renewable content impairs the ability of the renewable fuel to replace or reduce the quantity of fossil fuel present in a fuel mixture used to operate a motor vehicle. The Act specifically states that only the renewable fuel portion of a blending component should be considered part of the applicable volume under the RFS program. As described in more detail below, we have interpreted this to mean that every renewable fuel should be evaluated at the molecular level to distinguish between those molar fractions that were derived from a renewable feedstock, versus those molar fractions that were derived from a fossil fuel feedstock. Along with energy content in comparison to ethanol, the relative energy fraction of renewable versus non-renewable content is thus used directly as the basis for the Equivalence Value.

We are requiring that the calculation of Equivalence Values simultaneously take into account both the renewable content of a renewable fuel and its energy content in comparison to denatured ethanol. To accomplish this, we are requiring the following formula:

$$EV = (R_{RF} / R_{Eth}) \times (EC_{RF} / EC_{Eth})$$

Where:

$EV$ = Equivalence Value for the renewable fuel.
$R_{RF}$ = Renewable content of the renewable fuel, in percent of molecular energy.
$R_{Eth}$ = Renewable content of denatured ethanol, in percent of molecular energy.
$EC_{RF}$ = Energy content of the renewable fuel, in Btu per gallon (LHV).
$EC_{Eth}$ = Energy content of denatured ethanol, in Btu per gallon (LHV).

Instead of the higher heating value, the lower heating value (LHV) is used to represent energy content because it more accurately reflects the energy available in the fuel to produce work.

$R$ is a measure of that portion of the renewable fuel molecules which can be considered to have come from a renewable source. Since $R$ (that is, $R_{RF}$ and $R_{Eth}$) is being combined with relative energy content in the formula above, the value of $R$ cannot be based on the weight fraction of the atoms in the molecule which came from a renewable feedstock (the ''renewable atoms''), but rather must be based on the energy inherent in that portion of the molecules comprised of renewable atoms. To identify the renewable atoms within the molecules that comprise the renewable fuel, we must examine the chemical process through which the renewable fuel was produced. A detailed explanation of calculations for $R$ and several examples are given in a technical memorandum in the docket.[23]

In the case of ethanol, denaturants are added to preclude the ethanol's use as food. Denaturants are generally a fossil-fuel based, gasoline-like hydrocarbon in concentrations of 2–5 volume percent, with 5 percent being the most common historical level. One commenter argued that the Equivalence Value of ethanol must be specified as 0.95 for this very reason. However, as described in the NPRM, we believe that the Equivalence Value for ethanol should be specified as 1.0 despite the presence of a denaturant. First, as stated above, ethanol is expected to dominate the renewable fuel pool for at least the next several years, and it is likely that the authors of the Act recognized this fact. Thus it seems likely that it was the intent of the authors of the Act that each physical gallon of denatured ethanol be counted as one gallon for RFS compliance purposes. Second, the accounting of ethanol has historically ignored the presence of the denaturant. For instance, under Internal Revenue Service (IRS) regulations the denaturant can be counted as ethanol by parties filing claims to the IRS for the federal excise tax credit. Also, EIA reporting requirements for ethanol producers allow them to include the denaturant in their reported volumes. The commenter arguing for the use of an Equivalence Value of 0.95 for ethanol provided no additional information to counter these arguments.

Since we are requiring that denatured ethanol be assigned an Equivalence Value of 1.0, this must be reflected in the values of $R_{Eth}$ and $EC_{Eth}$. We have calculated these values to be 93.1 percent and 77,550 Btu/gal, respectively. Details of these calculations can be found in the aforementioned technical memorandum to the docket. The final equation to be used for calculation of Equivalence Values is therefore:

$$EV = (R / 0.931) * (EC / 77,550)$$

Where:

$EV$ = Equivalence Value for the renewable fuel.

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[23] ''Calculation of equivalence values for renewable fuels under the RFS program'', memo from David Korotney to EPA Air Docket OAR–2005–0161.

R = Renewable content of the renewable fuel, expressed as a percent, on an energy basis, of the renewable fuel that comes from a renewable feedstock.

EC = Energy content of the renewable fuel, in Btu per gallon (lower heating value).

For the specific case of biogas which cannot be measured in volumetric units, we are specifying that 77,550 Btu of biogas will be considered to be the equivalent of one gallon of renewable fuel.

The calculation of the Equivalence Value for a particular renewable fuel can lead to values that deviate only slightly from 1.0, and/or can have varying degrees of precision depending on the uncertainty in the value of R or $EC_{RF}$. In the NPRM we proposed several simplifications to streamline the application of Equivalence Values in the context of the RFS program. These included the use of pre-specified bins, rounding, and the use of an Equivalence Value of 1.0 when the calculated value was close to 1.0. We received some comments suggesting that these three simplifications unnecessarily complicated the determination of Equivalence Values. Based on comments received, we have determined for the final rule to simplify the application of Equivalence Values by only requiring the calculated values be rounded to the first decimal place. Also, based on consideration of comments received on how such products should be counted, for renewable diesel produced by processing fats and oils through a refinery hydrotreating process, we have determined that the default Equivalence Value should be 1.7 consistent with renewable diesel produced through other processes. This approach recognizes that hydrotreating produces a product consistent with our definition of non-ester renewable diesel. Furthermore, based on comments received, the volume of the final product is expected to be comparable to the volume of the input renewable crude. Therefore, the volume of renewable crude will be used as a surrogate for the volume of the final product. With the exception of renewable diesel produced through hydroteating fats or oils which is identical to renewable diesel, none of the specific Equivalence Values proposed in the NPRM have changed as a result of this simplification. The final values are shown in the table below.

TABLE III.B.4–1.—EQUIVALENCE VALUES FOR SOME RENEWABLE FUELS

| | Equiva-lence value (EV) |
|---|---|
| Cellulosic biomass ethanol or waste-derived ethanol [24] .......... | 2.5 |
| Ethanol from corn, starches, or sugar ......................................... | 1.0 |
| Biodiesel (mono alkyl ester) ......... | 1.5 |
| Non-ester renewable diesel and hydrotreated renewable crudes | 1.7 |
| Butanol ......................................... | 1.3 |
| Renewable crude-based fuels ...... | 1.0 |

Consistent with the NPRM, the Equivalence Value for renewable crude-based fuels is 1.0. Although some renewable crude-based fuels might warrant a higher value based on their energy content, it is also likely that some of the renewable crude does not end up as a motor vehicle fuel. Rather than requiring the refiner to document what portion of the biocrude-based renewable fuel is other than diesel or gasoline (e.g., jet fuel), we are combining the Equivalence Value of 1.0 with a requirement that the volume of the renewable crude itself count as the volume of renewable fuel produced for the purposes of determining the volume block codes that are in the RIN (discussed in further detail in Section III.D). While this approach may result in some products such as jet fuel being counted as renewable fuel, we believe the majority of the products produced will be motor vehicle fuel because we assume refiners who elect to use biocrudes would do so to help meet the requirements of this rule. Furthermore, both diesel and gasoline presently make up about 85 percent of the product slate of refineries on average. This amount that has been steadily increasing for over time, and we expect that the percentage will continue to increase as demand for gasoline and diesel increases. Thus the designation of an Equivalence Value of 1.0 balances out the potentially higher energy content of renewable crude-based fuels with the potential for lower yields of renewable fuel produced as motor vehicle fuel. We received no comment on this issue and are finalizing it as proposed.

Since there are a wide variety of possible renewable fuels that could qualify under the RFS program, there may be cases in which a party produces a renewable fuel not shown in Table III.B.4–1. A party may also produce a renewable fuel listed in the above table,

[24] The 2.5 value is specified by the Energy Act, and is not based on the EV formula discussed earlier.

but which has a different renewable content or energy content than the values assumed for our calculations. For such cases we have created a regulatory mechanism through which the producer may submit a petition to the Agency describing the renewable fuel, its feedstock and production process, and the calculation of its Equivalence Value. The Agency will review the petition and approve an appropriate Equivalence Value based on the information provided. We will publish newly assigned Equivalence Values in the **Federal Register** at the same time as the annual standard is published each November.

In the NPRM, we also described an additional approach to setting the Equivalence Value for biodiesel (mono alkyl esters). Since ethanol derived from waste products such as animal wastes and municipal solid waste will be assigned an Equivalence Value of 2.5 based on a requirement in the Act, we pointed out that it might be appropriate to create a parallel provision for biodiesel made from wastes. Under this approach, biodiesel made from waste products would have been assigned an Equivalence Value of 2.5 through 2012. Supporters of 2.5 Equivalence Value argued that it would place the treatment of waste-derived biodiesel on the same level as waste-derived ethanol, and that it would be good Agency policy to encourage and reward parties that turn materials that would otherwise be wasted into usable motor vehicle fuel. While some of these arguments may have merit, we nevertheless believe that it is most appropriate to maintain the general methodology applicable to renewable fuels at this time and reserve the 2.5:1 valuation for just the fuel specified by Congress. Therefore, we have not finalized a 2.5 Equivalence Value for waste-derived biodiesel.

For the specific case of ETBE, we have chosen for this final rule to eliminate a uniquely determined Equivalence Value. As described in Section III.D.2.b, ETBE is generally made from ethanol to which RINs will have already been assigned. An ETBE producer, therefore, would need only assign the RINs received with the ethanol to the ETBE made from that ethanol. In this case, there will be no need to generate new RINs, and therefore no need for a separate Equivalence Value.

Except for cellulosic biomass ethanol and waste-derived ethanol, the Equivalence Values shown in Table III.B.4–1, or any others approved through the petition process, will be applicable for all years. However, beginning in 2013, the 2.5 to 1 ratio no longer applies for cellulosic biomass

ethanol. The Act is unclear about whether the 2.5 to 1 ratio for waste-derived ethanol will apply after 2012, though it might be appropriate to treat cellulosic biomass ethanol and waste-derived ethanol in a consistent manner. Nevertheless, in the subsequent rulemaking mentioned above, we will address this issue explicitly. In today's final rule we are only specifying the ratio for cellulosic biomass and waste-derived ethanol prior to 2013.

c. Lifecycle Analyses as the Basis for Equivalence Values

In the NPRM we also described an alternative approach in which Equivalence Values for renewable fuels would be based on lifecycle analyses. We described both the merits and challenges associated with such an approach and requested comment. Based on the comments received we continue to believe that lifecycle analyses could provide a means of reflecting the relative benefits of one renewable fuel in comparison to another. However, we are not, in this action, establishing Equivalence Values on a lifecycle basis. Rather, we intend to continue evaluating and updating the tools and assumptions associated with lifecycle analyses in a collaborative effort with stakeholders. This rulemaking makes no determination and should not be interpreted to make any determination regarding whether EPA has the legal authority under section 1501 of the Energy Act, as incorporated in section 211(o) of the Clean Air Act, to use lifecycle analysis in establishing Equivalence Values in general or Equivalence Values specifically related to greenhouse gas or carbon dioxide emissions. This section describes some of the comments we received on the use of lifecycle analyses and our responses.

Lifecycle analyses involve an examination of fossil fuel used, and emissions generated, at all stages of a renewable fuel's life. A typical lifecycle analysis examines production of the feedstock, its transport to a conversion facility, the conversion of the feedstock into renewable motor vehicle fuel, and the transport of the renewable fuel to the consumer. At each stage, every activity that consumes fossil fuels or results in emissions is quantified, and these energy consumption and emission estimates are then summed over all stages. By accounting for every activity associated with renewable fuels over their entire life, we can assess renewable fuels in terms of not just their impact within the transportation sector, but across all sectors and thus for the nation as a whole. In this way, lifecycle analyses provide a more complete

picture of the potential impacts of different fuels or different fuel sources. While the use of energy content to establish Equivalence Values is an improvement over a simple gallon-for-gallon approach, a lifecycle basis would provide a further level of sophistication in assessing the net energy input and output of fuels and the emissions associated with the use of different fuels.

Supporters of the use of lifecycle analyses for setting the Equivalence Values of different renewable fuels pointed to several advantages of this approach. First, doing so could create an incentive for obligated parties to choose renewable fuels having a greater ability to reduce fossil fuel use or resulting emissions, since such renewable fuels would have higher Equivalence Values and thus greater value in terms of compliance with the RFS requirements. The preferential demand for renewable fuels having higher Equivalence Values could in turn spur additional growth in production of these renewable fuels. Second, using lifecycle analyses as the basis for Equivalence Values could orient the RFS program more explicitly towards reducing petroleum use, fossil fuel use or emissions.

However, the use of lifecycle analyses to establish the Equivalence Values for different renewable fuels also raises a number of issues, generally acknowledged by supporters of the use of lifecycle analyses. For instance, lifecycle analyses can be conducted using several different metrics, including total fossil fuel consumed, petroleum energy consumed, regulated pollutant emissions (e.g., VOC, NO$_X$, PM), carbon dioxide emissions, or greenhouse gas emissions. Each metric would result in a different set of Equivalence Values. At the present time there is no consensus on which metric would be most appropriate for this purpose or the purposes of the Act.

There is also no consensus on the approach to lifecycle analyses themselves. Although we have chosen to base our lifecycle analyses on Argonne National Laboratory's GREET model for the reasons described in Section IX, there are a variety of other lifecycle models and analyses available. The choice of model inputs and assumptions all have a bearing on the results of lifecycle analyses, and many of these assumptions remain the subject of debate among researchers. Lifecycle analyses must also contend with the fact that the inputs and assumptions generally represent industry-wide averages even though energy consumed and emissions generated vary widely from one facility or process to another.

There currently exists no organized, comprehensive dialogue among stakeholders about the appropriate tools and assumptions behind any lifecycle analyses. We will be initiating more comprehensive discussions about lifecycle analyses with stakeholders in the near future.

Another issue related to using lifecycle analyses as the basis for Equivalence Values pertains to the ultimate impact that the RFS program would have on petroleum use, fossil fuel use, regulated pollutant emissions, and/or emissions of GHGs. With a fixed volume of renewable fuel required under the RFS program, any renewable fuel with an Equivalence Value greater than 1.0 would necessarily mean that fewer actual gallons would be needed to meet the RFS standard. Thus, the advantage per gallon may be offset with fewer overall gallons, resulting in no overall additional benefit under the chosen metric for using fuels with higher Equivalence Values unless the RFS standard was simultaneously adjusted by Congress.

Based on comments received in response to our NPRM, we continue to believe that the current state of scientific inquiry surrounding lifecycle analyses is not sufficiently robust to warrant its use to set Equivalence Values in this final rule. Since renewable fuel use is expected to far exceed the standards being finalized today, a higher equivalence value for those renewables with greater lifecycle benefits will likely do little to stimulate their use. However, if in the future the RFS standard more closely matches renewable demand, this could be important. We are committed to continuing our investigations into lifecycle analyses.

*C. What Gasoline Is Used To Calculate the Renewable Fuel Obligation and Who Is Required To Meet the Obligation?*

1. What Gasoline Is Used To Calculate the Volume of Renewable Fuel Required To Meet a Party's Obligation?

The Act requires EPA to promulgate regulations designed to ensure that "gasoline sold or introduced into commerce in the United States (except in noncontiguous states or territories)" contains on an annual average basis, the applicable aggregate volumes of renewable fuels as prescribed in the Act.[25] To implement this provision, today's final rule provides that the volume of gasoline used to determined the renewable fuel obligation must include all finished gasoline (RFG and

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[25] CAA Section 211(o)(2)(A)(i), as added by Section 1501(a) of the Energy Policy Act of 2005.

conventional) produced or imported for use in the contiguous United States during the annual averaging period and all unfinished gasoline that becomes finished gasoline upon the addition of oxygenate blended downstream from the refinery or importer. This would include both unfinished reformulated gasoline, called ''reformulated gasoline blendstock for oxygenate blending,'' or ''RBOB,'' and unfinished conventional gasoline designed for downstream oxygenate blending (e.g. sub-octane conventional gasoline), called ''CBOB.'' The volume of any other unfinished gasoline or blendstock, such as butane, is not included in the volume used to determine the renewable fuel obligation, except where the blendstock is combined with other blendstock or finished gasoline to produce finished gasoline, RBOB, or CBOB. Where a blendstock is blended with other blendstock to produce finished gasoline, RBOB, or CBOB, the total volume of the gasoline blend is included in the volume used to determine the renewable fuels obligation for the blender. Where a blendstock is added to finished gasoline, only the volume of the blendstock is included, since the finished gasoline would have been included in the compliance determinations of the refiner or importer of the gasoline.

Gasoline produced or imported for use in a noncontiguous state or U.S. territory [26] is not included in the volume used to determine the renewable fuel obligation (unless the noncontiguous state or territory has opted-in to the RFS program), nor is gasoline, RBOB or CBOB exported for use outside the United States.

For purposes of this preamble, the various gasoline products (as described above) that are included in the volume of gasoline used to determine the renewable fuel obligation are collectively called ''gasoline.''

The final rule excludes the volume of renewable fuels contained in gasoline from the volume of gasoline used to determine the renewable fuels obligation. In implementing the Act's renewable fuels requirement, our primary goal was to design a program that is simple, flexible and enforceable. If the program were to include renewable fuels in the volume of gasoline used to determine the renewable fuel obligation, then every blender that blends ethanol downstream from the refinery or importer would be

subject to the renewable fuel obligation for the volume of ethanol that they blend. There are currently approximately 1,200 such ethanol blenders. Of these blenders, only those who blend ethanol into RBOB are regulated parties under current fuels regulations. Designating all of these ethanol blenders as obligated parties under the RFS program would greatly expand the number of regulated parties and increase the complexity of the RFS program beyond that which is necessary to carry out the renewable fuels mandate under the Act.

The Act provides that the renewable fuel obligation shall be ''applicable to refiners, blenders, and importers, as appropriate.'' [27] For the reasons discussed above, we believe it is appropriate to exclude downstream renewable fuel blenders from the group of parties subject to the renewable fuel obligation and to exclude renewable fuels from the volume of gasoline used to determine the renewable fuel obligation. This exclusion applies to any renewable fuels that are blended into gasoline at a refinery, contained in imported gasoline, or added at a downstream location. Thus, for example, any ethanol added to RBOB or CBOB downstream from the refinery or importer would be excluded from the volume of gasoline used to determine the obligation. Any non-renewable fuel added downstream, however, would be included in the volume of gasoline used to determine the obligation. This approach has no impact on the total volume of renewable fuels required (which is specified in the Act and must be met regardless of the approach taken here), but merely on the number of obligated parties. As discussed earlier, this volume of renewable fuel is likewise excluded from the calculation performed each year by EPA to determine the applicable percentage.

The NPRM was unclear with regard to whether obligated parties are to determine their renewable fuel obligation based on the gasoline production of all of their facilities in the aggregate, or each facility individually. As discussed above, EPA has discretion under the Energy Act to determine the renewable fuels obligation applicable to parties, ''as appropriate.'' We believe that allowing obligated parties to determine their obligation based on either their facilities in the aggregate or individually is appropriate, since allowing this flexibility will not affect compliance with the RFS. Although some commenters expressed concern

that obligated parties with multiple facilities could gain an economic advantage over obligated parties with only a single facility if aggregate compliance is allowed, we do not believe that this will be the case given the unrestricted trading allowed under our program. We also believe that clarification in the regulations regarding the basis on which the obligation may be determined is a necessary and logical outgrowth of the proposal. As a result, the regulations have been modified in the final rule to clarify that the renewable fuels obligation may be determined based on the gasoline production of all of an obligated party's facilities in the aggregate, or each facility individually.

We received comment that EPA should clarify when obligated parties must include imported gasoline that is used as ''gasoline treated as blendstock'', or GTAB, in the volume of gasoline used to determine the party's renewable fuel obligation. As stated in the preamble to the proposed rule, GTAB is to be treated as a blendstock with regard to the RFS rule. Where the GTAB is blended with other blendstock (other than only renewable fuel) to produce gasoline, the total volume of the gasoline blend, including the GTAB, is included in the volume of gasoline used to determine the renewable fuel obligation. Where the GTAB is blended with finished gasoline, only the GTAB volume is included in the volume of gasoline used to determine the renewable fuel obligation (since the finished gasoline will already be included in the RFS calculations of the refiner of that gasoline). For purposes of compliance demonstrations, the RFS rule treats GTAB in a manner that is consistent with the reformulated gasoline (RFG) and conventional gasoline (CG) regulations. Under the RFG/CG regulations, importers who designate imported gasoline as GTAB must be registered with EPA as both an importer and a refiner. The importer submits separate compliance reports to EPA, one in its capacity as an importer, and one in its capacity as a refiner. The GTAB is blended by the importer and included in the importer's compliance calculations in its capacity as a refiner of the GTAB, and is excluded from the importer's compliance calculations in its capacity as an importer. The RFS rule treats GTAB in a similar manner; i.e., the importer includes the GTAB in the volume of gasoline used to determine the renewable fuel obligation of the importer in its capacity as a refiner of the GTAB, and excludes the GTAB in the volume of gasoline used to

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[26] The noncontiguous states are Alaska and Hawaii. The territories are the Commonwealth of Puerto Rico, the U.S. Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Marianas.

[27] CAA Section 211(o)(3)(B), as added by Section 1501(a) of the Energy Policy Act of 2005.

determine the renewable fuel obligation of the importer in its capacity as an importer. The regulations have been clarified with regard to how GTAB is used to determine the GTAB importer's renewable fuels obligation.

We received comment that EPA should clarify that the terms RBOB and CBOB include "blendstocks for oxygenate blending" that are designed to comply with state fuels requirements, such as CARBOB (California), AZRBOB (Arizona), and LVBOB (Las Vegas). As discussed in Section III.C.1, all gasoline, and all unfinished gasoline that becomes finished gasoline upon the addition of oxygenate, that is produced or imported for use in the contiguous United States is included in the volume of gasoline used to determine an obligated party's renewable fuels obligation. As such, any finished gasoline, or unfinished gasoline that becomes finished gasoline upon the addition of oxygenate, that is produced or imported to comply with state fuels programs must also be included in the volume of gasoline used to determine an obligated party's renewable fuels obligation. The regulations have been clarified in this regard.

2. Who Is Required To Meet the Renewable Fuels Obligation?

Under the final rule, any person who meets the definition of refiner under the fuels regulations, which includes any blender who produces gasoline by combining blendstocks or blending blendstocks into finished gasoline, is subject to the renewable fuels obligation. Any person who brings gasoline into the 48 contiguous states from a foreign country or from an area that has not opted-in to the RFS program, or brings gasoline from a foreign country or an area that has not opted-in to the RFS program into an area that has opted-in to the RFS program, is considered an importer under the RFS program and is subject to the renewable fuels obligation. As noted above, a blender who only blends renewable fuels downstream from the refinery or importer is not subject to the renewable fuel obligation. Any person that is required to meet the renewable fuels obligation is called an "obligated party." We generally refer to all of the obligated parties as refiners and importers, since the covered blenders are all refiners under the regulations.

A refiner or importer located in a noncontiguous state or U.S. territory is not subject to the renewable fuel obligation and thus is not an obligated party (unless the noncontiguous state or territory opts-in to the RFS program). A party located within the contiguous 48 states is an obligated party if it "imports" into the 48 states any gasoline produced or imported by a refiner or importer located in a noncontiguous state or territory.

We received comment that EPA should clarify how the RFS rule applies to transmix processors and blenders. Transmix processors and blenders are treated like any other blenders under the RFS rule. Transmix processors are parties that separate the gasoline portion of the transmix from the transmix and either sell the gasoline portion as finished gasoline or blend it with other components to produce gasoline. Transmix processors exclude the gasoline portion of the transmix from the volume that is used to determine the party's renewable fuel obligation, since the gasoline portion of the transmix would have been included in the volume used to determine the renewable fuels obligation of the refiner or importer of the gasoline. In calculating the volume used to determine its renewable fuel obligation, the transmix processor would include any blendstocks (other than renewable fuels) that are added to the gasoline separated from the transmix. Where the transmix processor combines the gasoline portion of the transmix with purchased finished gasoline, both the gasoline portion of the transmix and the finished gasoline would be excluded, since the finished gasoline would have been included in the volume used to determine the renewable fuels obligation of the refiner or importer of the finished gasoline. Transmix blenders are parties that blend small amounts of unprocessed transmix into gasoline. Transmix blenders are not obligated parties if they only blend transmix into finished gasoline. If the transmix blender adds blendstocks to the transmix, the transmix blender would be an obligated party with regard to the volume of blendstocks added. The regulations have been clarified with regard to how the RFS rule applies to transmix processors and blenders.

3. What Exemptions Are Available Under the RFS Program?

a. Small Refinery and Small Refiner Exemption

The Act provides an exemption from the RFS standard for small refineries during the first five years of the program. The Act defines small refinery as "a refinery for which the average aggregate daily crude oil throughput for a calendar year (as determined by dividing the aggregate throughput for the calendar year by the number of days in the calendar year) does not exceed 75,000 barrels." [28] Thus, any gasoline produced at a refinery that qualifies as a small refinery under this definition is not counted in determining the renewable fuel obligation of a refiner until January 1, 2011. Where a refiner complies with the renewable fuel obligation on an aggregate basis for multiple refineries, the refiner may exclude from its compliance calculations gasoline produced at any refinery that qualifies as a small refinery under the RFS program. This exemption applies to any refinery that meets the definition of small refinery stated above regardless of the size of the refining company that owns the refinery. Based on information currently available to us we expect 42 small refineries to qualify for this exemption. Beginning in 2011, small refineries will be required to meet the same renewable fuel obligation as all other refineries, unless their exemption is extended pursuant to § 80.1141(e).

In addition to small refineries as defined in the Act, we proposed to extend this relief to refiners who, during 2004: (1) Produced gasoline at a refinery by processing crude oil through refinery processing units; (2) employed an average of no more than 1,500 people, including all employees of the small refiner, any parent company and its subsidiary companies; and (3) had a total average crude oil processing capability for all of the small refiner's refineries of 155,000 barrels per calendar day (bpcd). These size criteria were established in prior rulemakings and were the result of our analyses of small refiner impacts. Based on information currently available to us, we believe that there are only three gasoline refineries owned by small refiners that meet these criteria and that currently exceed the 75,000 bpcd crude oil processing capability defined by the Act.

We received comments supporting the proposed extension of the small refinery exemption to small refiners, and we also received comments opposing the proposed provision. Commenters that supported the provision generally stated that they believe that a small refiner exemption is necessary as those entities (i.e., companies) that would qualify as small refiners are generally at an economic disadvantage due to their company size—whereas the Act only recognizes facilities, based on the size of each location. These commenters also stated that they have concerns with the cost and the availability of credits under this program, and believe that provisions for small refiners are

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[28] CAA Section 211(o)(a)(9), as added by Section 1501(a) of the Energy Policy Act of 2005.

necessary to help mitigate any significant adverse economic impact on these entities. Commenters that opposed the provision stated that they believe that EPA exceeded its discretionary authority, that there appears to be no basis on which the Agency can legitimately expand this statutory exemption to add small refiners, and that Congress ''clearly did not intend that the exemption be broadened to also include small refiners.'' One commenter also stated that it does not believe that small refiner provisions are necessary because this rule does not require costly capital investments like previous fuel regulations.

As stated in the proposal, we believe that we have discretion in determining an appropriate lead-time for the start-up of this program, as well as discretion to determine the regulated refiners, blenders and importers, ''as appropriate.'' We continue to believe that some refiners, due to their size, generally face greater challenges compared to larger refiners. The Small Business Regulatory Enforcement Fairness Act (SBREFA) also recognizes this and requires agencies, during promulgation of new standards, to assess the potential impacts on small businesses (as defined by the Small Business Administration (SBA) at 13 CFR 121.201). For those instances where the Agency cannot certify that a rule will not have a significant economic impact on a substantial number of small entities, we are required to convene a SBREFA Panel. A SBREFA Panel process—which generally takes at least six months to complete—entails performing outreach with entities that meet the definition of a small business to develop ways to mitigate potential adverse economic impacts on small entities, in consultation with SBA and the Office of Management and Budget (OMB).

''Small refiners'' have historically been recognized in EPA fuel regulations as those refiners who employ no more than 1,500 employees and have an average crude oil capacity of 155,000 bpcd. These refiners generally have greater difficulty in raising and securing capital for investing in capital improvements and in competing for engineering resources and projects. This rulemaking does not require that refiners make capital improvements, however there are still significant costs associated with meeting the standard. While we were not required to assess the impacts on small businesses under the Energy Policy Act, we are required to do so under SBREFA. Based on our own analysis and outreach with small refiners, our assessment is that this rule

will not impose a significant adverse economic impact on small refiners if they are given the small refinery exemption. Further, as noted above, we believe that no more than three additional refiners that do not meet the Energy Policy Act's definition of a small refinery will qualify as small refiners for this rule. Therefore, we are finalizing the proposed provision that the small refinery exemption will be provided to qualified small refiners. This exemption does not mean that less renewable fuel will be used than is required in the Energy Policy Act; rather, it just means that small refiners will not be obligated to ensure that those volumes are attained during the period of their exemption.

We also proposed to allow foreign refiners to apply for a small refinery or small refiner exemption under the RFS program. We requested comment on the provision and related aspects, and we received some comments in which commenters stated that they believe that there is no reason to extend the small refinery exemption to these refiners. One commenter even stated that it believes that such an allowance would be unlawful. We proposed this provision for consistency with prior gasoline-related fuel programs (anti-dumping, MSAT, and gasoline sulfur) which allowed foreign refiners to receive such exemptions, and we are finalizing the provision in this action. Under this provision, foreign small refiners and foreign small refineries can apply for an exemption from the RFS standards such that importers would not count the small refiner or small refinery gasoline volumes towards the importer's renewable volume obligation. The Energy Policy Act does not prohibit EPA from granting this avenue of relief to foreign entities, and EPA believes it is consistent with the spirit of international trade agreements to provide it.

In the proposal we stated that applications for a small refinery exemption must be received by EPA by September 1, 2007 for the exemption to be effective in 2007 and subsequent calendar years. We proposed that the application should include documentation that the small refinery's average aggregate daily crude oil throughput for calendar year 2004 did not exceed 75,000 barrels; and that eligibility would be based on 2004 data (rather than 2005). Further, we proposed that the small refinery exemption would be effective 60 days after receipt of the application by EPA unless EPA notifies the applicant that the application was not approved or that additional documentation is required. We received

comments on this provision in which commenters stated that requiring small refinery applications was inconsistent with the language set out in the Act. The commenters stated that small refineries should not be obligated parties in 2007 even if they do not submit a small refinery application by September 1, 2007. We agree with these statements, and believe that the Energy Policy Act did in fact intend to provide this exemption without the need for small refineries to submit applications. However, in order to ensure that this provision is not being misused, we believe that it is necessary for refiners to verify that their refineries meet the definition set out in the Act. Therefore, we are finalizing that the small refinery exemption will become active immediately upon the effective date of the rule. Refiners will only be required to send a letter to EPA verifying their status as a small refinery. We did not receive any comments on our proposal to base eligibility on 2004 data, nor did we receive comments on whether a multiple-year average should be used. We believe that eligibility should be based on 2004 data rather than on 2005 data, since it was the first full year prior to passage of the Energy Act. In addition, some refineries' production may have been affected by Hurricanes Katrina and Rita in 2005. We are thus finalizing our proposed approach to base eligibility on 2004 data.

As discussed above, we proposed that refiners that do not qualify for a small refinery exemption under the 75,000 bpcd criteria, but nevertheless meet the criteria of a small refiner may apply for small refiner status under the RFS rule. We proposed that the applications must be received by EPA by September 1, 2007 for the exemption to be effective in 2007 and subsequent calendar years (similar to the small refinery exemption). We also proposed that small refiner status would be determined based on documentation submitted in the application which demonstrates that the refiner met the criteria for small refiner status during the calendar year 2004 and that EPA would notify a refiner of approval or disapproval of small refiner status by letter.

The final rule provides that qualified small refiners receiving the small refinery exemption will also receive the exemption immediately upon the effective date of the rule. These refiners must also submit a verification letter showing that they meet the small refiner criteria. This letter will be similar to the small refiner applications required under other EPA fuel programs (and must contain all the required elements

specified in the regulations at § 80.1142), except the letter will not be due prior to the program. Small refiner status verification letters for this rule that are later found to contain false or inaccurate information will be void as of the effective date of these regulations. Unlike the case for small refineries, small refiners who subsequently do not meet all of the criteria for small refiner status (i.e., cease producing gasoline by processing crude oil, employ more than 1,500 people or exceed the 155,000 bpcd crude oil capacity limit) as a result of a merger with or acquisition of or by another entity are disqualified as small refiners, except in the case of a merger between two previously approved small refiners. As in other EPA programs, where such disqualification occurs, the refiner must notify EPA in writing no later than 20 days following the disqualifying event.

The Act provides that the Secretary of Energy must conduct a study for EPA to determine whether compliance with the renewable fuels requirement would impose a disproportionate economic hardship on small refineries. If the study finds that compliance with the renewable fuels requirements would impose a disproportionate economic hardship on a particular small refinery, EPA is required to extend the small refinery's exemption for a period of not less than two additional years (i.e., to 2013). The Act also provides that a refiner with a small refinery may at any time petition EPA for an extension of the exemption for the reason of disproportionate economic hardship. In accordance with these provisions of the Act, we are finalizing the provision that refiners with small refineries may petition EPA for an extension of the small refinery exemption. As provided in the Act, EPA will act on the petition not later than 90 days after the date of receipt of the petition. Today's regulations do not provide a comparable opportunity for an extension of the small refinery exemption for small refiners. Therefore, all parties temporarily exempted from the RFS program on the basis of qualifying as a small refiner, rather than a small refinery, must comply with the program beginning January 1, 2011 (unless they waive their exemption prior to this date).

During the initial exemption period for small refineries and small refiners and any extended exemption periods for small refineries, the gasoline produced by exempted small refineries and refineries owned by approved small refiners will not be subject to the renewable fuel standard.

We proposed that the automatic exemption to 2011 and any small refinery extended exemptions may be waived upon notification to EPA; and we are finalizing this provision. Gasoline produced at a refinery which waives its exemption will be included in the RFS program and will be included in the gasoline used to determine the refiner's renewable fuel obligation. If a refiner waives the exemption for its small refinery or its exemption as a small refiner, the refiner will be able to separate and transfer RINs like any other obligated party. If a refiner does not waive the exemption, the refiner could still separate and transfer RINs, but only for the renewable fuel that the refiner itself blends into gasoline (i.e. the refinery operates as an oxygenate blender facility). Thus, exempt small refineries and small refiners who blend ethanol can separate RINs from batches without opting in to the program in the same manner that an oxygenate blender is allowed to do.

b. General Hardship Exemption

In recent rulemakings, we have included a general hardship exemption for parties that are able to demonstrate severe economic hardship in complying with the standard. We proposed not to include provisions for a general hardship exemption in the RFS program. Unlike most other fuels programs, the RFS program includes inherent flexibility since compliance with the renewable fuels standard is based on a nationwide trading program, without any per gallon requirements, and without any requirement that the refiner or importer produce the renewable fuel. By purchasing RINs, obligated parties will be able to fulfill their renewable fuel obligation without having to make capital investments that may otherwise be necessary in order to blend renewable fuels into gasoline. We believe that sufficient RINs will be available and at reasonable prices, given that EIA projects that far greater renewable fuels will be used than required. Given the flexibility provided in the RIN trading program, including the provisions for deficit carry-over, and the fact that the standard is proportional to the volume of gasoline actually produced or imported, we continue to believe a general hardship exemption is not warranted. As a result, the final rule does not contain provisions for a general hardship exemption.

c. Temporary Hardship Exemption Based on Unforeseen Circumstances

In recent rulemakings, we have included a temporary hardship exemption based on unforeseen circumstances. We proposed not to include such an exemption in the RFS program. The need for such an exemption would primarily be based on the inability to comply with the renewable fuels standard due to a natural disaster, such as a hurricane. However, in the event of a natural disaster, we believe it is likely that the volume of gasoline produced by an obligated party would also drop, which would result in a reduction in the renewable fuel requirement. We, therefore, reasoned in the NPRM that unforeseen circumstances, such as a hurricane or other natural disaster, would not result in a party's inability to obtain sufficient RINs to comply with the applicable renewable fuels standard.

We received several comments regarding the inclusion of a temporary hardship exemption based on unforeseen circumstances. One commenter believes it would be of value to have a mechanism for selectively waiving or modifying the RFS downward on a temporary basis in the event of unforeseen circumstances such as significant drought affecting potential crop production. The commenter believes that crop shortages could have an impact on a national level, or a major disaster may impact logistics of renewable fuel distribution regionally, necessitating a more rapid response from EPA than is provided in the Energy Act. Another commenter believes that a temporary hardship exemption based on unforeseen circumstances should be included in the rule since it is impossible to predict how the RFS program will impact small refiners. Another commenter believes that, given the variety of potentially challenging unforeseen events during the last several years, it is not inconceivable that man-made or natural circumstances could adversely impact the RFS program. A natural disaster in the agricultural section, for example, may make it difficult to meet the renewable fuels mandate which, in turn, could drive the price of RINs high enough to disrupt the gasoline market. The commenter believes that a mechanism built into the program from the outset would provide a more flexible and less disruptive way to address unforeseen circumstances than the more time-consuming waiver process provided in the Energy Act.

Under other EPA fuels programs, compliance is based on a demonstration that the fuel meets certain component or emissions standards. Unforeseen circumstances, such as a natural disaster, may affect an individual refiner's or importer's ability to produce or import fuel that complies with the

standards. As a result, we have included in other fuels programs provisions for a temporary hardship exemption from the standards in the event of an unforeseen natural disaster that affects a party's ability to produce gasoline that complies with the standards. Unlike most other fuels programs, compliance under the RFS program is based on a demonstration that a party has fulfilled its individual renewable fuels obligation on an annual basis, as compared to meeting specific gasoline content requirements. The renewable fuels obligation can be met through the use of purchased RINs, and there is a deficit carry forward provision allowing compliance to be shown over more than one year. In the event of a natural disaster, the volume of gasoline produced by an obligated party is also likely to drop, which would result in a reduction in the party's renewable fuel obligation. As a result, we believe that an individual party would be able to meet its renewable fuel obligation even in the event of a natural disaster that affects the party's refinery or blending facility. Therefore, unlike other fuels programs, we do not believe there is a need to include a temporary hardship exemption in the RFS rule to address an individual party's inability to comply with its renewable fuels obligation due to unforeseen circumstances.

Most of the concerns raised by the commenters relate to problems that would have a more regional or national effect, as compared to affecting one or a few individuals. In the event that unforeseen circumstances do occur which result in a shortage of renewable fuel and available RINs, we believe that Congress provided an adequate mechanism for addressing such situations in the Energy Act.[29] The Energy Act provides that on petition by one or more States, EPA, in consultation with the Departments of Agriculture and Energy, may waive the required aggregate renewable fuels volume obligation in whole or in part upon a sufficient showing of economic or environmental harm, or inadequate supply. As a result, we believe that a renewable fuel supply problem that affects all parties can be addressed using this statutory provision. We have carefully considered the comments; however, we do not believe that the comments provide a compelling rationale for providing a temporary hardship exemption from the RFS obligation based on unusual circumstances that goes beyond the provisions that Congress included in the

Energy Act. As a result, the final rule does not contain provisions for a temporary hardship exemption based on unforeseen circumstances.

4. What Are the Opt-in and State Waiver Provisions Under the RFS Program?

a. Opt-in Provisions for Noncontiguous States and Territories

The Act provides that, upon the petition of a noncontiguous state or U.S. territory, EPA may apply the renewable fuels requirements to gasoline produced in or imported into that noncontiguous state or U.S. territory at the same time as, or any time after the promulgation of regulations establishing the RFS program.[30] In granting such a petition, EPA may issue or revise the RFS regulations, establish applicable volume percentages, provide for generation of credits, and take other actions as necessary to allow for the application of the RFS program in a noncontiguous state or territory. We believe that approval of the petition does not require a showing other than a request by the Governor of the State or the equivalent official of a Territory to be included in the program.

Today's final rule will implement this provision of the Act by providing a process whereby the governor of a noncontiguous state or territory may petition EPA to have the state or territory included in the RFS program. The petition must be received by EPA on or before November 1 for the noncontiguous state or territory to be included in the RFS program in the next calendar year. A noncontiguous state or territory for which a petition is received after November 1 would not be included in the RFS program in the next calendar year, but would be included in the RFS program in the subsequent year. For example, if EPA receives a petition on September 1, 2007, the noncontiguous state or territory would be included in the RFS program beginning on January 1, 2008. If EPA receives a petition on December 1, 2007, the noncontiguous state or territory would be included in the RFS program beginning January 1, 2009. We believe that requiring petitions to be received by November 1 is necessary to allow EPA time to make any adjustments in the applicable standard. The method for calculating the renewable fuels standard to reflect the addition of a state or territory that has opted into the RFS program is discussed in Section III.A. Because today's regulations make EPA approval of an opt-in petition automatic if it is signed by the appropriate authority and

properly delivered to EPA, EPA does not envision providing an opportunity to comment on an opt-in request, although we will provide notice in the publication of the standard for the following year.

We received several comments regarding when a noncontiguous state or territory should be able to opt-in to the RFS program. One commenter supported the approach in this final rule that EPA use the EIA Short-term Energy Outlook published each October to assist in determining the percentage standard and therefore a state can only opt-in beginning with the first full compliance period of 2008. Another commenter believed we should include a provision to allow noncontiguous states or territories to opt-in to the first compliance period which starts September 1, 2007. While we see the merits of allowing a noncontiguous state or territory to opt-in to the first compliance period, we intend to maintain the current approach and allow noncontiguous states and territories to opt-in beginning with the 2008 compliance year. The statute clearly states that the program may apply to noncontiguous states and territories (that have petitioned EPA) at any time after these regulations have been promulgated. Given the short period of time between publication of the final rule and the effective date of the program, the need for a state and regulated parties to discuss opting-in with knowledge of the final version of the rule, and the requirement for EPA to notify obligated parties with sufficient lead time to any change in the standard, EPA believes 2008 is the earliest practical date for an opt-in to be effective. In addition, EPA notes that none of the noncontiguous states or territories indicated a strong interest in opting-in for the remainder of the 2007 compliance period.

Where a noncontiguous state or territory opts-in to the RFS program, producers and importers of gasoline for that state or territory will be obligated parties subject to the renewable fuel requirements. All refiners and importers who produce or import gasoline for use in a state or territory that has opted-in to the RFS program will be required to comply with the renewable fuel standard and will be able to separate RINs from batches of renewable fuels in the same manner as other obligated parties.

Once a petition to opt-in to the RFS program is approved by EPA, the state or territory would remain in the RFS program and be treated as any of the 48 contiguous states. We received a comment asserting that once a state or

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[29] CAA section 211(o)(7), as added by Section 1501(a) of the Energy Policy Act of 2005.

[30] CAA Section 211(o)(2)(A)(ii), as added by Section 1501(a) of the Energy Policy Act of 2005.

territory opts-in, they should be required to remain in the program for at least 5 years. As stated earlier, EPA will recognize a state or territory that opts-in to the program as identical to any of the 48 states. The current regulations do not allow a state to opt-out and the only form of relief from the program is a waiver, in whole or in part, of the national renewable fuel volume requirement. Noncontiguous states and territories should be aware of the obligations of the program and should only choose to opt-in if they expect to meet those obligations for the indefinite future. If in the future a state believes EPA should change its regulations and allow an opt-out the state could petition EPA to change the regulations. As in other situations where a party petitions EPA to revise its regulations, EPA would be in a position at that point to consider the concerns raised by the state as well as other interested stakeholder and to determine whether it would be appropriate to revise the regulations.

b. State Waiver Provisions

The Energy Act provides that EPA, in consultation with the U.S. Department of Agriculture (USDA) and the Department of Energy (DOE), may waive the renewable fuels requirements in whole or in part upon a petition by one or more states by reducing the national quantity of renewable fuel required under the Act.[31] The Act also outlines the basic requirements for such a waiver, such as a demonstration that implementation of the renewable fuels requirements would severely harm the economy or environment of a state, a region, or the United States or that there is an inadequate domestic supply of renewable fuel.

If EPA, after public notice and opportunity for comment, approves a state's petition for a waiver of the RFS program, the Act stipulates that the national quantity of renewable fuel required (Table I.B–1) may be reduced in whole or in part. This reduction could reduce the percentage standard applicable to all obligated parties. However, there is no provision in the Act that would permit EPA to reduce or eliminate any obligations under the RFS program specifically for parties located within the state that petitioned for the waiver. Thus all refiners, importers, and blenders located in the state would still be obligated parties if they produce gasoline. In addition, an approval of a state's petition for a waiver may not have any impact on renewable fuel use in that state since it would not be a

prohibition on the sale or consumption of renewable fuels in that state. In fact, the Act prohibits the regulations from restricting the geographic areas in which renewable fuels may be used.[32] Renewable fuel use in the state in question would thus continue to be driven by natural market forces and, perhaps if the economics of ethanol blending were less favorable than today, the nationally-applicable renewable fuel standard.

Given that state petitions for a waiver of the RFS program appear unlikely to affect renewable fuel use in that state, we have not finalized regulations providing more specificity regarding the criteria for a waiver or the ramifications of Agency approval of such a waiver in terms of the level or applicability of the standard. However, states can still submit petitions to the Agency for a waiver of the RFS requirements under the provision in the Energy Act and such petitions will be addressed by EPA on a case-by-case basis.

We received several comments objecting to the decision to not propose regulations detailing the waiver process and our rationale for not doing so. One commenter stated that nothing in the statute prevents relief from being directed toward a state which has requested the waiver by reducing the renewable fuel obligation of refiners, blenders, and importers who market gasoline in the affected state. Contrary to the commenter's assertion, the statute states that, "[t]he Administrator * * * may waive the requirements * * * by reducing the national quantity of renewable fuel required".[33] Congress's clear intent was to limit EPA's authority to provide relief under the state waiver provision of section 211(o)(7). Relief under that provision is limited to reducing the total national volume required under the RFS program. Thus, the renewable volume obligation for regulated parties would be reduced, but the reduced obligation would still apply to all obligated refiners, blenders and importers, including those in the state that requested the waiver. This may provide some relief to the part of the country submitting the petition, but EPA is not authorized to grant other more targeted relief such as reducing the percentage for some refiners and not others or refusing to count towards compliance renewable fuel that is produced or used in certain parts of the country. It should be noted here that this approach holds true for states or

territories which have opted-in to the program as well. Once a state or territory has opted-in to the program, they will be treated as identical to any other state and specific relief will not be provided to regulated parties serving these areas after the approval of a waiver. Noncontiguous states and territories should consider this in discussions with regulated parties before opting-in to the program.

Another commenter stated that EPA should publish regulations outlining specific criteria that will be considered in reviewing a petition, so that the public would have a more meaningful opportunity to participate in the process. While EPA realizes that the criteria provided by the statute are quite general, the rationales of severe environmental or economic harm or inadequate domestic supply are sufficient for a basic framework upon which a petition can be built and evaluated. Each situation in which a waiver may be requested will be unique, and promulgating a list of more specific criteria in the abstract may be counter-productive. Communication between the petitioning state(s), EPA, DOE, USDA, and public and industry stakeholders should begin early in the process, well before a waiver request is submitted. This communication will supply these federal agencies with a knowledgeable background of the situation prompting the potential waiver request. The waiver request may even prove unnecessary after an initial investigation and analysis of the situation. If not, and if the state continues to believe that a valid basis for submission of a petition exists, federal agencies can instruct the state(s) as to what more detailed information is needed for waiver approval. Petitions will be published in the **Federal Register**, as required by statute, to provide public notice and opportunity for comment.

A third commenter raised the point that there is no provision in the Act that would permit EPA to waive any obligations for specific entities in a state that has petitioned for a waiver, and in the case of an emergency, such as a natural disaster, specific relief may be warranted. The commenter is correct in the observation that EPA cannot waive obligations for specific entities or locations. However, the Act does authorize EPA to waive the obligations of the program as it applies to all obligated parties, in whole or in part, depending on the severity of the situation.

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[31] CAA Section 211(o)(7), as added by Section 1501(a) of the Energy Policy Act of 2005.

[32] CAA Section 211(o)(2)(iii), as added by Section 1501(a) of the Energy Policy Act of 2005.

[33] CAA Section 211(o)(7), as added by Section 1501(a) of the Energy Policy Act of 2005.

*D. How Do Obligated Parties Comply With the Standard?*

Under the Act, EPA is to establish a renewable fuel standard annually, expressed as a percentage of gasoline sold or introduced into commerce, that will ensure that overall a specified total national volume of renewable fuels will be used in gasoline in the U.S. The Act does not require each obligated party to necessarily do the blending themselves in order to comply with this obligation. Rather, under the credit trading program required by the Act, each obligated party is allowed to satisfy its obligations either through its own actions or through the transfer of credits from others who have more than satisfied their individual requirements.

This section describes our final compliance program. It is based on the use of unique renewable identification numbers (RINs) assigned to batches of renewable fuel by renewable fuel producers and importers. These RINs can then be sold or traded, and ultimately used by any obligated party to demonstrate compliance with the applicable standard. Excess RINs serve the function of the credits envisioned by the Act and also provide additional benefits, as described below. We believe that our approach is consistent with the language and intent of the Act and preserves the natural market forces and blending practices that will keep renewable fuel costs to a minimum.

1. Why Use Renewable Identification Numbers?

Once renewable fuels are produced or imported, there is very high confidence that all but de minimus quantities will in fact be blended into gasoline or otherwise used as motor vehicle fuels, except for exports. Renewable fuels are not used for food, chemicals, or as feedstocks to other production processes. In fact the denaturant that must be added to ethanol is designed specifically to ensure that the ethanol is primarily used as motor vehicle fuel. In discussions with stakeholders prior to release of the NPRM, it became clear that other renewable fuels, including biodiesel and renewable fuels used in their neat (unblended) form, likewise are not used in appreciable quantities for anything other than motor vehicle fuel. Therefore if a refiner ensures that a certain volume of renewable fuel has been produced, in effect they have also ensured that this volume will be blended into gasoline or otherwise used as a motor vehicle fuel. Focusing on production of renewable fuel as a surrogate for use of such fuel has many benefits as far as streamlining the

program and minimizing the influence that the program has on the operation of the market.

In order to implement a program that is based on production of a certain volume of renewable fuels, we are finalizing a system of volume accounting and tracking of renewable fuels. We are requiring that this system be based on the assignment of unique numbers to each batch of renewable fuel. These numbers are called Renewable Identification Numbers or RINs, and are assigned to each batch by the renewable fuel producer or importer.

The use of RINs allows the Agency to measure and track renewable fuel volumes starting at the point of their production rather than at the point when they are blended into conventional fuels. Although an alternative approach would be to measure renewable fuel volumes as they are blended into conventional gasoline or diesel, measuring renewable fuel volumes at the point of production provides more accurate measurements that can be easily verified. For instance, ethanol producers are already required to report their production volumes to EIA through Monthly Oxygenate Reports. These data provide an independent source for verifying volumes. The total number of batches and parties involved are also minimized in this approach. The total number of batches is smallest at the point of production, since batches are commonly split into smaller ones as they proceed through the distribution system to the place where they are blended into conventional fuel. The number of renewable fuel producers is also far smaller than the number of blenders. Currently there just over 100 ethanol plants and 85 biodiesel plants in the U.S., compared with approximately 1200 blenders [34] based on IRS data.

The assignment of RINs to batches of renewable fuel at the point of their production also allows those batches to be identified according to various categories important for compliance purposes. For instance, the RIN will contain a component that specifies whether a batch of ethanol was made from cellulosic feedstocks. This RIN component will be of particular importance for 2013 and beyond when the Act specifies a national volume requirement for cellulosic biomass ethanol. The RIN will also identify the Equivalence Value of the renewable fuel which will often only be known at the

point of its production. Finally, the RIN will identify the year in which the batch was produced, a critical element in determining the applicable time period within which RINs are valid for compliance purposes.

Although production volumes of renewable fuels intended for blending into gasoline are a reasonably accurate surrogate for volumes ultimately blended into gasoline, changes can occur at various times throughout the year in the volumes of renewable fuel that are in storage. These stock changes involve the temporary storage of renewable fuel during times of excess and can affect the length of time between production and ultimate use. While there may be seasonal fluctuations in stocks due to seasonal demand, these stock changes always have a net change of zero over the long term since there is no economic benefit to stockpiling renewable fuels. As a result there is no need to account for stock changes in our program.

Exports of renewable fuel represent the only significant distribution pathway that could impair the use of production as a surrogate for renewable fuel blending into gasoline or other use as a motor vehicle fuel. However, our approach accounts for exports through an explicit requirement placed upon exporters (discussed in Section III.D.4 below). As a result, we are confident that our approach satisfies the statutory obligation that our regulations impose obligations on refiners and importers that will ensure that gasoline sold or introduced into commerce in the U.S. each year will contain the volumes of renewable fuel specified in the Act. By tracking the amount of renewable fuel produced or imported and subtracting the amount exported, we will have an accurate accounting of the renewable fuel actually consumed as motor vehicle fuel in the U.S. Exports of renewable fuel are discussed in more detail in Section III.D.4.

a. RINs Serve the Purpose of a Credit Trading Program

According to the Act, we must promulgate regulations that include provisions for a credit trading program. The credit trading program allows a refiner that overcomplied with its annual RVO to generate credits representing the excess renewable fuel. The Act stipulates that those credits can then be used within the ensuing 12 month period, or transferred to another refiner that had not blended sufficient renewable fuel into its gasoline to satisfy its RVO. In this way the credit trading program permits current blending practices to continue wherein

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[34] Those blenders who add ethanol to RBOB are already regulated under our reformulated gasoline regulations.

some refiners purchase a significant amount of renewable fuel for blending into their gasoline while others do little or none, thus providing a means for all refiners to economically comply with the standard.

Our RIN-based program fulfills all the functions of a credit trading program and thus meets the Act's requirements. If at the end of a compliance period a party had more RINs than it needed to show compliance with its renewable volume obligation, these excess RINs would serve the function of credits and could be used or traded in the next compliance period. RINs can be transferred to another party in an identical fashion to a credit. However, our program provides additional flexibility in that it permits all RINs to be transferred between parties before they are deemed to be in excess of a party's annual RVO at the end of the year. This is because a RIN serves two functions: It is direct evidence of compliance and, after a compliance year is over, excess RINs serve the function of credits for overcompliance. Thus the RIN approach has the advantage of allowing real-time trading without having to wait until the end of the year to determine excess.

As in other motor vehicle fuels credit programs, we are also requiring that any renewable producer that generates RINs must use an independent auditor to conduct annual reviews of the party's renewable production, RIN generation, and RIN transactions. These reviews are called ''attest engagements,'' because the auditor is asked to attest to the validity of the regulated party's credit transactions. For example, the reformulated gasoline program requires attest engagements for refiners and importers, and downstream oxygenate blenders to verify the underlying documentation forming the basis of the required reports (40 CFR part 80, subpart F). In the case of RIN generation, the auditor is required to verify that the number of RINs generated matched the volume of renewable fuels produced, that any extra value RINs are appropriately generated, and that RIN numbers are properly transferred with the renewable fuel as required by the regulations.

b. Alternative Approach to Tracking Batches

If we had not implemented a RIN-based system for uniquely identifying, measuring, and tracking batches of renewable fuel, the RFS program would necessarily require that we measure renewable fuel volumes at the point in the distribution system where they are actually blended into conventional gasoline or diesel or used in their neat form as motor vehicle fuel. The NPRM described a number of significant problems that this approach would create, including the potential for double-counting, increasing the number of parties subject to enforcement provisions, and the loss of a distinction between cellulosic ethanol and other forms of ethanol. We concluded that a blender-based approach to tracking volumes of renewable fuel was inferior to our proposed program focusing on the point of production and importation. We did not receive any comments supporting a blender-based approach and, consistent with the rationale provided in the proposed rule, have decided not to implement it.

2. Generating RINs and Assigning Them to Batches

a. Form of Renewable Identification Numbers

Each RIN is generated by the producer or importer of the renewable fuel and uniquely identifies not only a specific batch, but also every gallon in that batch. The RIN consists of a 38-character code having the following form:

RIN: KYYYYCCCCFFFFFBBBBBRRD SSSSSSSSEEEEEEEE

Where:
K = Code distinguishing assigned RINs from separated RINs.
YYYY = Calendar year of production or import.
CCCC = Company ID.
FFFFF = Facility ID.
BBBBB = Batch number.
RR = Code identifying the Equivalence Value.
D = Code identifying cellulosic biomass ethanol.
SSSSSSSS = Start of RIN block.
EEEEEEEE = End of RIN block.

In response to the NPRM, one commenter requested that the full RIN generation date, not just the year, be included in the RIN. We believe that this is unnecessary and would unduly lengthen the RIN. Compliance with the standard is determined on a calendar year basis, and the year of RIN generation is necessary in order to ensure that RINs are used for compliance purposes only in the calendar year generated or the following year. See Section III.D.3.b. The full RIN generation date, while a potentially useful piece of information in the context of potential enforcement activities, is not necessary as a component of the RIN since recordkeeping requirements contain this same information and can be consulted in the enforcement context.

The company and facility IDs are assigned by the EPA as part of the registration process as described in Section IV.B. Company IDs will be used primarily to determine compliance, while the inclusion of facility IDs allows the assignment of batch numbers unique to each facility. The use of both company and facility IDs is also consistent with our approach in other fuel programs. The batch number is chosen by the producer and includes five digits to allow for facilities that produce up to a hundred thousand batches per year. In the NPRM we proposed that batch numbers be sequential values starting with 00001 at the beginning of each year. Following release of the NPRM, some stakeholders expressed the desire to be able to align RIN batch numbers with numbers used in other aspects of their business. As a result, we have determined that the requirement that the batch numbers be sequential is not necessary so long as each batch number is unique within a given calendar year. Batches are described more fully in Section III.E.1.a.

The RR, D, and K codes together describe the nature of the renewable fuel and the RINs that are generated to represent it. The RR code simply represents the Equivalence Value for the renewable fuel, multiplied by 10 to eliminate the decimal place inherent in Equivalence Values. Equivalence Values form the basis for the total number of RINs that can be generated for a given volume of renewable fuel, and are described in Section III.B.4.

The D code identifies cellulosic biomass ethanol batches as such. Since the Act requires that a minimum of 250 million gallons of cellulosic biomass ethanol be consumed starting in 2013, obligated parties will need to be able to distinguish RINs representing cellulosic biomass ethanol from RINs representing other types of renewable fuel. This requirement is discussed in more detail in Section III.A.

In the NPRM, the K code served to distinguish between standard-value RINs and extra-value RINs, and it was placed in the middle of the RIN. As described more fully in Section III.E.1.a, our final rule eliminates the need for a distinction between standard-value RINs and extra-value RINs, but requires a distinction between RINs that must be transferred with a volume of renewable fuel (assigned RINs) and RINs that can be transferred without renewable fuel (separated RINs). Thus for the final rule we have changed the purpose of the K code. As described in Section III.E.2, we are requiring that RINs separated from volumes of renewable fuel be identified as such, by changing the K code from a value of 1 to a value of 2. Placing the K code at the beginning of the RIN

makes this process more straightforward for obligated parties and oxygenate blenders who will be responsible for changing the K code after separating a RIN from renewable fuel.

The RIN also contains two codes SSSSSSSS and EEEEEEEE that together identify the ''RIN block'' which demarcates the number of gallons of renewable fuel that the batch represents in the context of compliance. Depending on the Equivalence Value, this may not necessarily be the same as the actual number of gallons in the batch. The methodology for designating the SSSSSSSS and EEEEEEEE values is described in Section III.D.2.b below.

In the NPRM we assigned six digits to the RIN block codes to allow batches up to a million gallons in size. Based on comments received, we have decided to expand the number of digits to eight to accommodate batches up to 100 million gallons in size. Although it is highly unlikely that a single tank would hold this volume, we are adding a definition of ''batch'' to our final regulations that would allow this high volume to be counted as a single batch for the purposes of generating RINs.

In the NPRM we pointed out that ''RIN'' can refer to either the number representing an entire batch or the number representing one gallon of renewable fuel in the context of compliance. In order to make the distinction clear, we are defining the latter as a gallon-RIN, and a batch-RIN will represent multiple gallon-RINs. In the case of a gallon-RIN, the values of SSSSSSSS and EEEEEEEE will be identical. A batch-RIN, on the other hand, will generally have different values for SSSSSSSS and EEEEEEEE, representing the starting and ending values of a batch of renewable fuel. Examples of RINs are presented in the next section.

b. Generating RINs

As described in Section III.E.1.a, we have eliminated the distinction between standard-value RINs and extra-value RINs for this final rule. Instead, all gallon-RINs must be assigned to batches of renewable fuel by the producer or importer. Consistent with the NPRM, each gallon-RIN will continue to represent one gallon of renewable fuel in the context of compliance.

Also consistent with the NPRM, we are requiring that RIN generation begin at the same time that the renewable fuel standard becomes applicable to obligated parties. Thus RINs must be generated for all renewable fuel produced or imported on or after September 1, 2007. Since many producers and importers will have

renewable fuel in inventory at the start of the program that was produced prior to September 1, 2007, we are also allowing them to generate RINs for such renewable fuel. This provision ensures that every gallon that a producer or importer sells starting on September 1, 2007 can have an assigned RIN, and obligated parties that take ownership of renewable fuel directly from a producer or importer will have greater assurance of having access to RINs at the start of the program. Other volumes of ethanol in inventory in the distribution system on September 1, 2007 will continue to be sold and distributed without RINs.

In order to determine the number of gallon-RINs that must be generated and assigned to a batch by a producer or importer, the actual volume of the batch must be multiplied by the Equivalence Value to determine an applicable ''RIN volume'':

$$V_{RIN} = EV \times V_s$$

Where:

$V_{RIN}$ = RIN volume, in gallons, representing the number of gallon-RINs that must be generated (rounded to the nearest whole gallon).
EV = Equivalence value for the renewable fuel.
$V_s$ = Standardized volume of the batch of renewable fuel at 60 °F, in gallons.

When RINs are first assigned to a batch of renewable fuel by its producer or importer, the RIN block start for that batch will in general be 1 (i.e., SSSSSSSS will have a value of 00000001). The RIN block end value EEEEEEEE will be equal to the RIN volume calculated above. The batch-RIN then represents all the gallon-RINs assigned to the batch. Table III.D.2.b–1 provides some examples of the number of gallon-RINs that would be assigned to a batch under different circumstances.

TABLE III.D.2.B–1.—EXAMPLES OF BATCH-RINS [35]

Batch volume: 2000 gallons corn ethanol.
Equivalence value: 1.0.
Gallon-RINs: 2000.
Batch-RIN: 1–2007–1234–12345–00001–10–2–00000001–00002000.

Batch volume: 2000 gallons biodiesel.
Equivalence value: 1.5.
Gallon-RINs: 3000.
Batch-RIN: 1–2007–1234–12345–00002–15–2–00000001–00003000.

Batch volume: 2000 gallons cellulosic ethanol.
Equivalence value: 2.5.
Gallon-RINs: 5000.
Batch-RIN: 1–2007–1234–12345–00003–25–1–00000001–00005000.

The RIN block will often represent the actual number of gallons in the batch, for cases where the Equivalence Value is 1.0. In other cases, the RIN block start and RIN block end values in the batch-RIN will not exactly correspond to the volume of the batch. For instance, in cases where the Equivalence Value is larger than 1.0, the number of gallon-RINs generated will be larger than the number of gallons in the batch. In such cases the batch will have a greater value in terms of compliance than a batch with the same volume but an Equivalence Value equal to 1.0. Likewise, a batch with an Equivalence Value less than 1.0 will have a smaller value in terms of compliance than a batch with the same volume but an Equivalence Value equal to 1.0. In the context of our modified approach to RIN distribution as described in Section III.E.1, however, the transfer of RINs with batches will be straightforward regardless of the number of gallon-RINs assigned to a particular volume of renewable fuel, as every gallon-RIN will always have the capability of covering one gallon of an obligated party's RVO.

In response to the NPRM, some obligated parties requested that fractional RINs be used for cases in which the Equivalence Value is less than 1.0. Under this approach, every gallon in a batch would still have an assigned gallon-RIN, but those gallon-RINs would represent only a fraction of a gallon for compliance purposes. The commenters also argued that our proposed system in which RINs are assigned to only a portion of a batch would be unworkable given the need to ensure that RINs remain assigned to batches as they travel through the distribution system.

We continue to believe that the most straightforward system calculates the number of gallon-RINs representing a batch as the product of the Equivalence Value and the actual volume of the batch. Then every gallon-RIN will have the capability of covering one gallon of an obligated party's RVO, and thus every gallon-RIN has the same value. This is true both for renewable fuels with Equivalence Values less than 1.0, and renewable fuels with Equivalence Values greater than 1.0. Also, as described in Section III.E.1, we have modified our approach to the distribution of RINs assigned to volumes of renewable fuel. As a result, the batch-splitting and batch-merging protocols have become largely irrelevant, and thus the transfer of renewable fuels having an

[35] RIN codes have been separated by hyphens in this table for demonstrative purposes only. In actual use, no hyphens would be present in the RIN.

Equivalence Value less than 1.0 has become greatly simplified. We are therefore finalizing our proposed approach in which renewable fuels having an Equivalence Value less than 1.0 result in fewer assigned gallon-RINs than gallons in a batch.

Following release of the NPRM, we also identified some cases in which the generation of RINs for a partially renewable fuel or blending component would result in double-counting of RINs generated. For instance, ethyl tertiary butyl ether (ETBE) is made from combining ethanol with isobutylene. The ethanol is generally from corn, and the isobutylene is generally from petroleum. The ETBE producer may purchase ethanol from another source, and that ethanol may already have RINs assigned to it. In such cases it would not be appropriate for the ETBE producer to generate additional RINs for the ETBE made from that ethanol. Even if the ETBE producer purchased ethanol without assigned RINs, our program design ensures that either RINs were generated for the ethanol and separated prior to purchase by the ETBE producer, or RINs were legitimately not assigned to the ethanol. The NPRM did not address the potential for generating RINs twice for the same renewable fuel in these cases. Therefore, we are finalizing a provision prohibiting a party from generating RINs for a partially renewable fuel or blending component that it produces if the renewable feedstock used to make the renewable fuel or blending component was acquired from another party. Any RINs acquired with the renewable feedstock (e.g. ethanol) must be assigned to the product made from that feedstock (e.g. ETBE). This approach is consistent with comments submitted by Lyondell Chemical Company.

c. Cases in Which RINS Are Not Generated

Although in general every batch of renewable fuel produced or imported must have an assigned batch-RIN, there are several cases in which a RIN may not be assigned to a batch by a producer or importer. For instance, if the renewable fuel was consumed within the confines of the production facility where it was made, it would not be acquired by either an obligated party or a gasoline blender. In such cases, the RIN could not be separated from the batch and transferred separately since producers do not have this right. A RIN is assigned to renewable fuel when ownership of the renewable fuel is transferred to another party. Since no such transfer would occur in this case, no RIN should be generated.

A second case in which some renewable fuel would not have an assigned RIN would occur for small volume producers. We are allowing renewable fuel producers who produce less than 10,000 gallons in a year to avoid the requirement to generate RINs and assign them to batches. Such producers would not contribute meaningfully to the nationwide pool of renewable fuel, and we do not believe that the very small business operations involved should be subject to the burden of recordkeeping and reporting. Although two commenters disagreed that these small volume producers should be exempt from the requirement to generate RINs, they did not provide compelling evidence that the exemption would create a problem in the distribution system or provide an unfair advantage to small producers. As a result we are finalizing this provision as proposed. Note that if a small producer chooses to register as a renewable fuel producer under the RFS program, they will be subject to all the regulatory provisions that apply to all producers, including the requirement to assign RINs to batches.

In the NPRM we proposed that a renewable fuel producer which also operated as an exporter would not be required to generate and assign a RIN to any renewable fuel that it produced and exported. However, one commenter pointed out that this approach could lead to confusion regarding which gallons should have an assigned RIN and which should not, given the complex nature of tracking volumes of renewable fuel. As a result we have determined that this provision should be eliminated. Our final regulations require that producers assign RINs to all renewable fuel, regardless of whether it is exported. Exports of renewable fuel are discussed further in Section III.D.4.

3. Calculating and Reporting Compliance

Under our program, RINs form the basis of the volume accounting and tracking system that allows each obligated party to demonstrate that they have met their renewable fuel obligation each year. This section describes how the compliance process using RINs works. Our approach to the distribution and trading of RINs is covered separately in Section III.E below.

a. Using RINs To Meet the Standard

Under our program, each obligated party must determine its Renewable Volume Obligation (RVO) based on the applicable percentage standard and its annual gasoline volume as described in Section III.A.4. The RVO represents the volume of renewable fuel that the obligated party must ensure is used in the U.S. in a given calendar year. Since the nationwide renewable fuel volumes shown in Table I.B–1 are required by the Act to be consumed in whole calendar years, each obligated party must likewise calculate its RVO on an annual basis.

Since our program uses RINs as a measure of the amount of renewable fuel used as motor vehicle fuel that is sold or introduced into commerce within the U.S., obligated parties must meet their RVO through the accumulation of RINs. In so doing, they will effectively be causing the renewable fuel represented by the RINs to be consumed as motor vehicle fuel. Obligated parties are not required to physically blend the renewable fuel into gasoline or diesel fuel themselves. The accumulation of RINs is the means through which each obligated party shows compliance with its RVO and thus with the renewable fuel standard.

For each calendar year, each obligated party is required to submit a report to the Agency documenting the RINs it acquired and showing that the sum of all gallon-RINs acquired is equal to or greater than its RVO. This reporting is discussed in more detail in Section IV. In the context of demonstrating compliance, all gallon-RINs have the same compliance value. The Agency can then verify that the RINs used for compliance purposes are valid by simply comparing RINs reported by producers to RINs claimed by obligated parties. We can also verify simply that any given gallon-RIN was not double-counted, i.e., used by more than one obligated party for compliance purposes. In order to be able to identify the cause of any double-counting, however, additional information is needed on RIN transactions as discussed in Section IV.

If an obligated party has acquired more RINs than it needs to meet its RVO, then in general it can retain the excess RINs for use in complying with its RVO in the following year or transfer the excess RINs to another party. The conditions under which this is allowed are determined by the valid life of a RIN, described in more detail in Section III.D.3.b below. If, alternatively, an obligated party has not acquired sufficient RINs to meet its RVO, then under certain conditions it can carry a deficit into the next year. Deficit carryovers are discussed in more detail in Section III.D.3.d.

The regulations prohibit any party from creating or transferring invalid RINs. Invalid RINs cannot be used in demonstrating compliance regardless of

the good faith belief of a party that the RINs are valid. These enforcement provisions are necessary to ensure the RFS program goals are not compromised by illegal conduct in the creation and transfer of RINs.

As in other motor vehicle fuel credit programs, the regulations address the consequences if an obligated party is found to have used invalid RINs to demonstrate compliance with its RVO. In this situation, the refiner or importer that used the invalid RINs will be required to deduct any invalid RINs from its compliance calculations. The refiner or importer will be liable for violating the standard if the remaining number of valid RINs is insufficient to meet its RVO, and the obligated party may be subject to additional monetary penalties if it used invalid RINs in its compliance demonstration. See Section V of this preamble for further discussion regarding liability for use of invalid RINs.

Just as for RIN generators, we are also requiring that obligated parties conduct attest engagements for the volume of gasoline they produce and the number of RINs procured to ensure compliance with their RVO. In most cases, this should amount to little more than is already required under existing EPA gasoline regulations. In the case of renewable fuel exporters, the attest engagement will verify the volume of renewable fuel exported and therefore the magnitude of their RVO. Attest engagement reports must be submitted to the party that commissioned the engagement and to EPA. See Section IV of this preamble for further discussion of the attest engagement requirements.

b. Valid Life of RINs

The Act requires that renewable fuel credits be valid for showing compliance for 12 months as of the date of generation. This section describes our interpretation of this provision in the context of our program wherein excess RINs fulfill the Act's requirements regarding credits.

As discussed in Section III.D.1.a, we interpret the Act such that credits would represent renewable fuel volumes in excess of what an obligated party needs to meet their annual compliance obligation. Given that the renewable fuel standard is an annual standard, obligated parties will determine compliance shortly after the end of the year, and credits would be identified at that time. Obligated parties will typically demonstrate compliance by submitting a compliance demonstration to EPA. Given the 12-month life of a credit as stated in the Act, we interpret this provision as

meaning that credits would only be valid for compliance purposes for the following compliance year. Hence if a refiner or importer overcomplied with their 2007 obligation they would generate credits that could be used to show compliance with the 2008 compliance obligation, but the credits could not be used to show compliance for later years. Since RINs fulfill the role of credits, the statutory provisions regarding credits apply to RINs

The Act's limit on credit life helps balance the risks between the needs of renewable fuel producers and obligated parties. Producers are currently making investments in expanded production capacity on the expectation of a statutorily guaranteed minimum quantity demanded. Under the market conditions we are experiencing today that make ethanol use more economically attractive, the annual volume requirements in the RFS program will not drive consumption of renewable fuels. However, if the price of crude oil dropped significantly or the use of ethanol in gasoline became otherwise less economically attractive, obligated parties could use stockpiled credits to comply with the program requirements. As a result, demand for renewable fuel could fall well below the RFS program requirements, and many producers could end up with a stranded investment. The 12 month valid life limit for credits minimizes the potential for this type of result.

For obligated parties, the Act's 12 month valid life for credits provides a window within which parties who do not meet their renewable fuel obligation through their own physical use of renewable fuel can obtain credits from other parties who have excess. This critical aspect of the trading system allows the renewable fuels market to continue operating according to natural market forces, avoiding the possibility that every single refiner would need to purchase renewable fuel for blending into its own gasoline. But the 12 month life also provides a window within which banking and trading can be used to offset the negative effects of fluctuations in either supply of or demand for renewable fuels. For instance, if crude oil prices were to drop significantly and natural market demand for ethanol likewise fell, the RFS program would normally bring demand back up to the minimum required volumes shown in Table I.B–1. But in this circumstance, the use of ethanol in gasoline would be less economically attractive, since demand for ethanol would not be following price but rather the statutorily required minimum volumes. As a result, the

price of credits as represented by RINs, and thus ethanol blends, could rise above the levels that would exist if no minimum required volumes existed. The 12 month valid life creates some flexibility in the market to help mitigate price fluctuations. The renewable fuels market could also experience a significant drop in supply if, for instance, a drought were to limit the production of the feedstocks needed to produce renewable fuel. Obligated parties could use banked credits to comply rather than carry a deficit into the next year.

In the context of our RIN-based program, we have been able to accomplish the same objective as the Act's 12 month life of credits by allowing RINs to be used to show compliance for the year in which the renewable fuel was produced and its associated RIN first generated or for the following year. RINs not used for compliance purposes in the year in which they were generated will by definition be in excess of the RINs an obligated party needed in that year, making excess RINs equivalent to the credits referred to in the Energy Act. Excess RINs are valid for compliance purposes in the year following the one in which they initially came into existence.[36] RINs not used within their valid life will expire. This approach satisfies the Act's 12 month duration for credits.

Thus we are requiring that every RIN be valid for the calendar-year compliance period in which it was generated or the following year. If a RIN was created in one year but was not used by an obligated party to meet its RVO for that year, the RIN can be used for compliance purposes in the next year (subject to certain provisions to address RIN rollover as discussed below). If, however, a RIN was created in one year and was not used for compliance purposes in that year or in the next year, it will expire. In response to the NPRM, this approach was supported by a number of obligated parties and their representative associations. These commenters agreed that allowing RINs to be used for the year generated or the following year was not only supported by the statutory language, but was also an element of program flexibility that would be critical for offsetting the negative effects of potential fluctuations in either supply of or demand for renewable fuels.

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[36] The use of previous-year RINs for current year compliance purposes will also be limited by the 20 percent RIN rollover cap under today's final rule. However, as discussed in the next section, we believe that this cap will still provide a significant amount of flexibility to obligated parties.

However, in response to our NPRM, other commenters said that the Energy Act's 12-month credit life provision should be interpreted as applying retrospectively, not prospectively. Under this approach, the 12-month timeframe in the Act would be interpreted to refer to the full calendar year within which a credit was generated. Under this alternative approach no RINs could be used for compliance purposes beyond the calendar year in which they originally came into existence. As discussed below, we do not believe that this approach is appropriate.

Commenters who supported the retrospective approach to the Act's 12-month credit life provision argued that the Energy Act could have been written to explicitly allow a valid life of multiple years if that had been Congress' intent. In response, the Act explicitly indicates that obligated parties may either use the credits they have generated or transfer them. For a party to be able to use credits generated, such credit use must necessarily occur in a compliance year other than the one in which the credit was generated. Thus we do not believe that a retrospective approach to the Act's 12-month credit life provision is consistent with the explicit credit provisions of the Act. In addition, we believe that an interpretation leading to a valid life of one year after the year in which the RIN was generated is most consistent with the program as a whole. In comparison to a single-year valid life for RINs, our approach provides some additional compliance flexibility to obligated parties as they make efforts to acquire sufficient RINs to meet their RVOs each year. This flexibility will have the effect of keeping fuel costs lower than they would otherwise be.

In the comments we received on the NPRM, one objection to our proposed approach was that the use of RINs generated in one compliance period to satisfy obligations in a subsequent compliance period could result in less renewable fuel used in a given year than is set forth in the statute. While this is true, we believe this approach is most consistent with the Act, as described above. The Act clearly set up a credit program with a credit life, meaning Congress intended parties to use credits in some cases instead of blending renewable fuel. The Act is best read to harmonize all of its provisions. In addition, we note that other provisions of the Act may lead to less renewable fuel use in a given year than the statutorily-prescribed volumes, but Congress adopted them and intended that they could be used. For instance,

the deficit carryover provision allows any obligated party to fail to meet its RVO in one year if it meets the deficit and its RVO in the next year. If several obligated parties took advantage of this provision, it could result in the nationwide total volume obligation for a particular calendar year not being met. In a similar fashion, the statutory requirement that every gallon of cellulosic biomass ethanol be treated as 2.5 gallons for the purposes of compliance means that the annually required volumes of renewable fuel could be met in part by virtual, rather than actual, volumes. Finally, the calculation of the renewable fuel standard is based on projected nationwide gasoline volumes provided by EIA (see Section III.A). If the projected gasoline volume falls short of the actual gasoline volume in a given year, the standard will fail to create the demand for the full renewable fuel volume required by the Act for that year. The Act contains no provision for correcting for underestimated gasoline volumes. Additional responses to the issues raised by commenters on RIN life can be found in the S&A document.

c. Cap on RIN Use To Address Rollover

As described in Section III.D.3.b above, RINs are valid for compliance purposes for the calendar year in which they are generated or the following year. We believe that this approach is most consistent with the Act's prescription that credits be valid for compliance purposes for 12 months as of the date of generation. Our approach is intended to address both the risk taken by producers expecting a guaranteed demand to cover their expanded production capacity investments and the risk taken by obligated parties who need a guaranteed supply in order to meet their regulatory obligations under this program.

However, the use of previous year RINs to meet current year compliance obligations does create an opportunity for effectively circumventing the valid life limit for RINs. This can occur in situations wherein the total number of RINs generated each year for a number of years in a row exceeds the number of RINs required under the RFS program for those years. The excess RINs generated in one year could be used to show compliance in the next year, leading to the generation of new excess RINs in the next year, causing the total number of excess RINs in the market to accumulate over multiple years despite the limit on RIN life. The NPRM included examples of how this "rollover" might occur. The rollover issue would in some circumstances essentially make the applicable valid

life for RINs virtually meaningless in practice.

RIN rollover also undermines the ability of a limit on credit life to guarantee a market for renewable fuels. As described in Section III.D.3.b, if the natural market demand for ethanol was higher than the volumes required under the RFS program for several years in a row, as may occur in practice, obligated parties could amass RINs that, in the extreme, could be used entirely in lieu of actually demanding ethanol in some subsequent year.

As described in the NPRM, we believe that the rollover issue must be addressed. The Act's provision regarding the valid life of credits is clearly intended to obtain the benefits associated with a limited credit life. Any program structure in which some RINs effectively have an infinite life, regardless of the technical life of individual RINs, does not appropriately achieve the benefits expected from the Act's provision regarding the 12-month life of credits. The authority to establish a credit program and to implement a limited life for credits includes the authority to limit actions that have the practical effect of circumventing this limited credit life.

To be consistent with the Act, we believe that the rollover issue should be addressed in our regulations. However, we also believe that the limits to preclude such unhindered rollovers should not preclude all previous-year RINs from being used for current-year compliance. To accomplish this, we must restrict the number of previous-year RINs that can be used for current year compliance. To this end, we proposed a 20 percent cap on the amount of an obligated party's Renewable Volume Obligation (RVO) that can be met using previous-year RINs. After review of the comments we received on the NPRM, we have decided to finalize this provision. Thus each obligated party will be required to use current-year RINs to meet at least 80 percent of its RVO, with a maximum of 20 percent being derived from previous-year RINs. Any previous-year RINs that an obligated party may have that are in excess of the 20 percent cap can be traded to other obligated parties that need them. If the previous-year RINs in excess of the 20 percent cap are not used by any obligated party for compliance, they will expire. The net result will be that, for the market as a whole, no more than 20 percent of a given year's renewable fuel standard can be met with RINs from the previous year.

As described in the NPRM, we believe that the 20 percent cap provides the

appropriate balance between, on the one hand, allowing legitimate RIN carryovers and protecting against potential supply shortfalls that could limit the availability of RINs, and on the other hand ensuring an annual demand for renewable fuels as envisioned by the Act. We believe this approach also provides the certainty all parties desire in implementing the program. The same cap will apply equally to all obligated parties, and the cap will be the same for all years, providing certainty on exactly how obligated parties must comply with their RVO going out into the future. A 20 percent cap will be readily enforceable with minimal additional program complexity, as each obligated party's annual report will simply provide separate listings of previous-year and current-year RINs to establish that the cap has not been exceeded. A 20 percent cap will have no impact on who could own RINs, their valid life, or any other regulatory provision regarding compliance.

Some NPRM commenters did not perceive a problem with the RIN rollover issue and argued for no rollover cap or at least for a more flexible one. They pointed to the need for maximum flexibility in responding to fluctuations in the market, and they were primarily concerned about potential supply problems. For instance, if a drought were to reduce the availability of corn for ethanol production, there may simply not be sufficient RINs available for compliance purposes. A drought situation actually occurred in 1996, and as a result 1996 ethanol production was 21% less than it had been in 1995. In 1997, production had not yet returned to the 1995 levels. Moreover, there is no guarantee that future droughts, should they occur, would result in a reduction in ethanol production of only 21 percent. As a result, in the NPRM we requested comment on whether a higher cap, such as 30 percent, would be more appropriate. A number of refiners and refinery associations commented that 30 percent would indeed provide them with the additional flexibility they would need in the case of a significant market disruption. Some requested a cap of 40 percent or even no cap at all. These parties also expressed concern that, although the Agency has the authority to waive the required renewable fuel volumes in whole or in part in the event of inadequate domestic supply, this can occur only on petition by one or more states and then only after consultation with both the Department of Agriculture and the Department of Energy. Some obligated parties expressed concern that such a

waiver would not occur in a timely fashion. The availability of excess previous-year RINs would thus provide compliance certainty in the event that the supply of current-year RINs falls below the RFS program requirements and the Agency does not waive any portion of the program requirements.

In contrast to obligated parties, renewable fuel producers provided comments on the NPRM indicating that 10 percent would be more appropriate. They argued that a 10 percent cap was closer to their preferred approach to RIN life in which the Act's 12-month life of a credit is interpreted as allowing RINs to be used for compliance purposes only in the year in which they are generated.

We continue to believe that a cap set at 20 percent is appropriate, and the comments submitted in response to the NPRM did not provide compelling evidence to the contrary. The level of 20 percent is consistent with past ethanol market fluctuations. As described above, the largest single-year drop in ethanol supply occurred in 1996 and resulted in 21% less ethanol being produced than in 1995. While future supply shortfalls may be larger or smaller, the circumstances of 1996 provide one example of their potential magnitude.

We believe that a cap of 20 percent is a reasonable way to limit RIN rollover and provide some assurances to renewable fuel producers regarding demand for renewable fuel. A cap of 20 percent also ensures that many previous-year RINs can still be used for current year compliance, providing some flexibility in the event of market disruptions.

Given the competing needs expressed by renewable fuel producers and refiners, a rollover cap of 20 percent also balances the risk taken by producers of renewable fuels expecting a guaranteed quantity demanded to cover their production capacity investments and the risk taken by obligated parties who need a guaranteed supply in order to meet their regulatory obligations under this program. We are therefore finalizing a rollover cap of 20 percent.

In the NPRM we also considered an alternative approach whereby we would set the cap annually based on the actual excess renewable fuel production. We did not propose this approach, and commenters did not support it. We have determined that fixing the cap at 20 percent both provides certainty to the RIN market and ensures that some minimum level of flexibility exists for individual obligated parties even in a market without excess RINs.

We also requested comment on whether the Agency should adopt a

provision allowing the cap to be raised in the event that supply shortfalls overwhelmed the 20 percent cap. Under this conditional provision, the Agency would monitor standard indicators of agricultural production and renewable fuel supply to determine if sufficient volumes of renewable can be produced to meet the RFS program requirements in a given year. Prior to the end of a compliance period, if the Agency determined that a supply shortfall was imminent, it could raise the cap to permit a greater number of previous-year RINs to be used for current-year compliance. Although this approach would not change the required volumes, it could create some additional temporary flexibility. However, we did not propose this provision, and commenters did not address it. We do not believe it is necessary, and thus we have not finalized it.

Finally, the cap is designed to prevent the rollover of RINs generated two years ago from being used for compliance purposes in the current year. No RINs were generated in 2006 when the default standard of 2.78 percent was in effect on a collective basis, so the first year in which RINs will be generated is 2007. Consequently, the first year in which there could be rollover would be 2009. Therefore, we proposed that the cap would not be effective until compliance year 2009. Two commenters pointed out that this approach could under some scenarios lead to a situation in which more than 20 percent of the RINs used for compliance purposes in 2008 were actually generated in the previous year, 2007. EPA believes that implementing the rollover cap in 2008 would, indeed, prevent the initiation of an excess buildup of past RINs. In addition, it would simplify the regulations, since there would be no need for an exception from the RIN cap for 2008. Consequently we are finalizing the 20 percent cap to apply to all years, including 2008.

### d. Deficit Carryovers

The Energy Act also contains a provision allowing an obligated party to carry a deficit forward from one year into the next if it cannot comply with its RVO. However, deficits cannot be carried over two years in a row.

Deficit carryovers are measured in gallons of renewable fuel, just as for RINs and RVOs. If an obligated party does not acquire sufficient RINs to meet its RVO in a given year, the deficit is calculated by subtracting the total number of RINs an obligated party has acquired from its RVO. There are no volume penalties, discounts, or other factors included when calculating a

deficit carryover. As described in Section III.D.1, the deficit is then added to the RVO for the next year. The calculation of the RVO as described in Section III.A.4 shows how a deficit would be carried over into the next year:

$$RVO_i = (Std_i \times GV_i) + D_{i-1}$$

Where:

$RVO_i$ = The Renewable Volume Obligation for the obligated party for year i, in gallons.

$Std_i$ = The RFS program standard for year i, in percent.

$GV_i$ = The non-renewable gasoline volume produced by an obligated party in year i, in gallons.

$D_{i-1}$ = Renewable fuel deficit carryover from the previous year, in gallons.

If an obligated party does not acquire sufficient RINs to meet its RVO in year i-1, the obligated party must procure sufficient RINs to cover the full RVO for year i including the deficit. There are no provisions allowing for another year of carryover. If the obligated party does not acquire sufficient RINs to meet its RVO for that year plus the deficit carryover from the previous year, it will be in noncompliance.

The Act indicates that deficit carryovers are to occur due to ''inability'' to generate or purchase sufficient credits. We believe that obligated parties will make a determined effort to satisfy their RVO on an annual basis and that a deficit will demonstrate that they were unable to do so. Thus, we did not propose that any particular demonstration of ''inability'' be a prerequisite to the ability of obligated parties to carry deficits forward. However, one commenter requested that we should establish some sort of standard or threshold that obligated parties must meet before they would be allowed to use the deficit carryover provision. Although the commenter provided no suggestions regarding how such a threshold could be established, he indicated that in the absence of such a threshold obligated parties could potentially use the deficit carryover provision to undermine the amount of actual renewable fuel used in a given year.

We agree that the deficit carryover provision could result in less renewable fuel being consumed in a given year than is required by the Act, especially if several obligated parties took advantage of it at the same time. However, in any given year some parties may be making up deficits from a prior year, while other parties might be generating deficits. This fact will tend to reduce the net effect in any given year, and regardless, the deficit in demand in one year will by regulatory requirement

be made up in the following year. Finally, any threshold we could set to demonstrate an obligated party's inability to generate or purchase sufficient credits would likely require a comprehensive investigation of their opportunities to acquire RINs. Such investigations would consume Agency resources that would be better spent, in terms of ensuring that the goals of the Act are met, on other compliance enforcement matters. Therefore, we have not set any thresholds in the final rule.

4. Provisions for Exporters of Renewable Fuel

As described in Section III.D.2.a, we believe that U.S. consumption of renewable fuel as motor vehicle fuel can be measured with considerable accuracy through the tracking of renewable fuel production and importing records. This is the basis for our RIN-based system of compliance. However, exports of renewable fuel must be accounted for under this approach. For instance, if a gallon of ethanol is produced in the U.S. but consumed outside of the U.S., the RIN associated with that gallon is not valid for RFS compliance purposes since the RFS program is intended to require a specific volume of renewable fuel to be consumed in the U.S. Exports of renewable fuel currently represent about 5 percent of U.S. production, though the exact value varies each year.

To ensure that renewable fuels exported from the U.S. cannot be used by an obligated party for RFS compliance purposes, the RINs associated with that exported renewable fuel must be removed from circulation. For this final rule we have concluded that it should be the exporter's responsibility to account for exported renewable fuel in our RIN-based program. We are therefore requiring that an RVO be assigned to each exporter that is equal to the annual volume of renewable fuel it exported. Just as for obligated parties, then, the exporter is required to acquire sufficient gallon-RINs to meet its RVO. If the exporter purchases renewable fuel directly from a producer, that renewable fuel will come with associated gallon-RINs which can then be applied to its RVO under our program. In this circumstance, the exporter will not need to acquire RINs from any other source. If, however, the exporter receives renewable fuel without the associated RINs, it will need to acquire RINs from some other source in order to meet its RVO.

In the NPRM we presented an alternative approach which would have increased the obligation placed on refiners and importers of gasoline based

on the volume of renewable fuel exported. One commenter supported this alternative approach, explaining that the proposed approach of requiring the exporter to acquire sufficient RINs to offset an RVO equal to the exported volume would place a significant recordkeeping burden on exporters. This commenter also expressed concern that exporters would receive no value in return for compliance with an RVO. We do not believe that these are compelling reasons to place the burden for exported renewable fuel on obligated parties. Not only would this alternative approach have required an estimate of the volume of renewable fuel exported in the next year, but would also mean that every obligated party would share in accumulating RINs to cover the activities of other parties not under their control.

In the NPRM we pointed out that in specific circumstances involving exports of renewable fuels, the need for RINs might not be necessary. For instance, if the exporter was wholly owned by a renewable fuel producer, there would be no need to generate RINs for the exported product. We therefore proposed to allow exported product to be excluded from the exporter's RVO if the exporter was also the producer and no RINs were generated for that product. However, one commenter pointed out that this approach could lead to confusion regarding which gallons should have an assigned RIN and which should not, given the complex nature of tracking volumes of renewable fuel. As a result we have determined that this provision should be eliminated. Our final regulations require producers to assign RINs to all renewable fuel, regardless of whether it is exported. In this case the renewable producer would merely use these RINs to cover its obligation as an exporter.

As described in Section III.D.2, there are cases in which there is not a one-to-one correspondence between gallons in a batch of renewable fuel and the gallon-RINs generated for that batch. If the RVO assigned to the exporter were based strictly on the actual volume of the exported product, it would not necessarily capture all the gallon-RINs which were generated for that exported volume. Thus we are requiring that the RVO assigned to an exporter be based not on the actual volume of renewable fuel exported, but rather on a volume adjusted by the Equivalence Value assigned to each batch. The Equivalence Value is represented by the RR code within the RIN as described in Section III.D.2.a. Thus the exporter must multiply the actual volume of a batch by

that batch's Equivalence Value to obtain the volume used to calculate the RVO.

In cases wherein an exporter obtains a batch of renewable fuel whose RIN has already been separated by an obligated party or blender, the exporter may not know the Equivalence Value. We are requiring that for such cases the exporter use the equivalence value applicable to that type of renewable fuel (e.g., 1.5 for biodiesel). However, in the case of ethanol, the same product could have been produced as corn ethanol or cellulosic ethanol. Thus, in the case of ethanol, if the exporter does not know the equivalence value we are requiring that the exporter use the actual volume of the batch to calculate its RVO. This will introduce some small error into the calculation of the RVO for cases in which the ethanol had in fact been assigned an Equivalence Value of 2.5. However, we believe that the potential impact of this on the overall program will be exceedingly small.

5. How Will the Agency Verify Compliance?

The primary means through which the Agency will verify an obligated party's compliance with its RVO will be the annual compliance demonstration reports. These reports will include a variety of information required for compliance and enforcement, including the demonstration of compliance with the previous calendar year's RVO, a list of all transactions involving RINs, and the tabulation of the total number of RINs owned, used for compliance, transferred, retired and expired. Reporting requirements for obligated and non-obligated parties are covered in detail in Section IV.

In its annual reports, an obligated party will be required to include a list of all RINs held as of the reporting date, divided into a number of categories. For instance, a distinction must be made between current-year RINs and previous-year RINs as follows:

*Current-year RINs:* RINs that came into existence during the calendar year for which the report is demonstrating compliance.

*Previous-year RINs:* RINs that came into existence in the calendar year preceding the year for which the report is demonstrating compliance.

The report must also indicate which RINs have been used for compliance with the RVO including any potential deficit, which current-year RINs have not been used for compliance and are therefore valid for compliance the next year, and which previous-year RINs have not been used for compliance and therefore expire. The report must also include a demonstration that the

obligated party had not exceeded the 20 percent cap to address RIN rollover, as described in Section III.D.3.c.

In order to verify compliance for each obligated party, the primary Agency activity will involve the validation of RINs. The Agency will perform the following four basic elements of RIN validation:

(1) RINs used by an obligated party to comply with its RVO will be checked to ensure that they are within their two-year valid life. The RIN itself will contain the year of generation, so this check involves only an examination of the listed RINs.

(2) All RINs owned by an obligated party will be cross-checked with reports from renewable fuel producers to verify that each RIN had in fact been generated.

(3) All RINs used by an obligated party for compliance purposes will be cross-checked with annual reports from other obligated parties to ensure that no two parties used the same RIN to comply.

(4) Previous-year RINs used for compliance purposes will be checked to ensure that they do not exceed 20 percent of the obligated party's RVO.

In cases where a RIN is highlighted under suspicion of being invalid, the Agency will then need to take additional steps to resolve the issue. In general this will involve a review of RIN transfer records submitted quarterly to the Agency by all parties in the distribution system that held the RINs. RIN transfers will be recorded through EPA's Central Data Exchange as described in Section IV. These RIN transfer records will permit the Agency to identify all transaction(s) involving the RINs in question. The Agency can then contact liable parties and take appropriate steps to formally invalidate a RIN improperly claimed by a particular party. Additional details of the liabilities and prohibitions attributed to parties in the distribution system are discussed in Section V.

*E. How Are RINs Distributed and Traded?*

Under our final program structure, a Renewable Identification Number (RIN) must (with certain exceptions) be generated for all renewable fuel produced or imported into the U.S., and RINs must be acquired by obligated parties for use in demonstrating compliance with the RFS requirements. However, as described in the NPRM, there are a variety of ways in which RINs could theoretically be transferred from the point of generation by renewable fuel producers to the obligated parties that need them.

EPA's final program was developed in light of the somewhat unique aspects of the RFS program. As discussed earlier, under this program the refiners and importers of gasoline are the parties obligated to comply with the renewable fuel requirements. At the same time, refiners and importers do not generally produce or blend renewable fuels at their facilities and so are dependent on the actions of others for the means of compliance. Unlike EPA's other fuel programs, the actions needed for compliance largely center on the production, distribution, and use of a product by parties other than refiners and importers. In this context, we believe that the RIN transfer mechanism should focus primarily on facilitating compliance by refiners and importers and doing so in a way that imposes minimum burden on other parties and minimum disruption of current mechanisms for distribution of renewable fuels.

Our final program does this by relying on the current market structure for ethanol distribution and use and avoiding the need for creation of new mechanisms for RIN distribution that are separate and apart from this current structure. Our program basically requires RINs to be transferred with renewable fuel until the point at which the renewable fuel is purchased by an obligated party or is blended into gasoline or diesel fuel by a blender. This approach allows the RIN to be incorporated into the current market structure for sale and distribution of renewable fuel, and avoids requiring refiners to develop and use wholly new market mechanisms. While the development of new market mechanisms to distribute RINs is not precluded under our program, it is also not required.

In the NPRM the Agency also evaluated several options for distributing RINs other than the option incorporated into today's rule. We are not finalizing these alternatives because they tend to require the development of new market mechanisms, as compared to relying on the current market structure for distribution of ethanol, and they are less focused on facilitating compliance for the obligated parties.

1. Distribution of RINs With Volumes of Renewable Fuel

We are requiring that RINs be transferred with volumes of renewable fuel as they move through the distribution system, until ownership of those volumes is assumed by an obligated party, exporter, or a party that converts the renewable fuel into motor vehicle fuel. At such time, RINs can be

separated from the volumes and freely traded. This approach places certain requirements on anyone who takes ownership of renewable fuels, including renewable fuel producers, importers, marketers, distributors, blenders, and terminal operators.

a. Responsibilities of Renewable Fuel Producers and Importers

The initial generation of RINs and their assignment to batches of renewable fuel will be the sole responsibility of renewable fuel producers and renewable fuel importers. As described in Section III.D.1, volumes of renewable fuel can be measured most accurately and be more readily verified at these originating locations.

The final rule defines a batch of renewable fuel as a volume that has been assigned a unique batch-RIN. This simple and flexible definition of a batch allows renewable fuel producers and importers to construct each batch-RIN based on the particular circumstances associated with the batch. In this context, a batch is not confined to the volume that can be held in a tank, but instead can include a significantly larger volume. However, we are placing two limits on the volumes of renewable fuel that are identified as a single batch. First, the RIN contains only enough digits to permit the assignment of 99,999,999 gallon-RINs to a single batch. For corn-ethanol with an Equivalence Value of 1.0, this means that a single batch can be comprised of up to 99,999,999 gallons of ethanol. In contrast, for biodiesel with an Equivalence Value of 1.5, a single batch can contain up to 66,666,666 gallons of biodiesel. Second, in order to provide more clarity in the event that an investigation of a party's volume and RIN generation records is conducted, we are also limiting a batch to the maximum volume that is produced or imported by the renewable fuel producer or importer within a calendar month. Within these two limits, producers and importers can define batches of renewable fuel according to their own discretion and practices, including using individual tankfulls to represent each batch. These parties must designate a unique serial number for each batch (RIN code BBBBB) and specify its Equivalence Value. The batch-RIN will identify all the gallon-RINs assigned to the batch. See Section III.D.2.a for details on the format for RINs.

In the NPRM, we proposed different approaches to the assignment of standard-value RINs and extra-value RINs. Under the proposal, extra-value RINs could be generated by the renewable fuel producer in cases where the renewable fuel in question had an Equivalence Value greater than 1.0. We proposed that all standard-value RINs must be assigned to volumes of renewable fuel, but that producers should have the option of whether to assign extra-value RINs to batches. We took this approach in part out of concern that the assignment of extra-value RINs to volumes would mean that the number of gallon-RINs assigned to a batch could be greater than the number of gallons in that batch. This was of particular concern for ethanol, since a tank could contain both corn-ethanol and cellulosic ethanol. When volume was withdrawn from the tank, it would have been unclear whether the volume should be assigned the extra-value RINs or not. In the process of designing the proposed program structure to accommodate such situations, however, the program became more complicated than it needed to be.

In response to the NPRM, some commenters requested that extra-value RINs be treated just like standard-value RINs. Specifically, some obligated parties, as well as gasoline marketers and distributors, argued that all RINs, be they standard-value or extra-value, should be required to travel with volumes of renewable fuel so that they will all be equally available to the obligated parties that need them for compliance. These commenters expressed concern that some producers may not release extra-value RINs, if given the choice, in an effort to drive up demand for renewable fuel.

After further consideration, we have determined that in most cases there is no need to treat extra-value RINs differently from standard-value RINs in terms of whether each should be assigned to batches of renewable fuel by the producer or importer. Therefore, for most renewable fuels we are finalizing a requirement that all RINs be assigned to batches of renewable fuel by the producer or importer. Since each renewable fuel with a different Equivalence Value is a distinct fuel, producers and importers will still receive the added value of extra-value RINs that are assigned to volumes of renewable fuel if those volumes are priced appropriately in comparison to other renewable fuels with different Equivalence Values. The only exception to this is cellulosic biomass and waste-derived ethanol. Producers of such ethanol may have difficulty marketing their product at prices different than that for corn ethanol given the fungible distribution system for ethanol. The added value of the extra-value RINs may not be reflected in the price and as a result the producer may not receive any economic benefit from them. Therefore, for the case of cellulosic biomass and waste-derived ethanol we are maintaining the ability of the producer, should they so choose, to retain the extra value and not assign these RINs to the renewable fuel that they represent. In such cases, the producer of the cellulosic biomass or waste-derived ethanol would be required to change the K code from 1 to 2 in order to designate these extra RINs as separated RINs.

This approach is also consistent with one of the primary motivations for the approach described in our NPRM, namely that each gallon-RIN be allowed to have a value of 1.0 to facilitate trading. Even though different renewable fuels will have different Equivalence Values and therefore different numbers of gallon-RINs per gallon, each gallon-RIN will still count as one gallon of renewable fuel for RFS compliance purposes.

However, the distinction between standard-value RINs and extra-value RINs is no longer necessary. The total number of gallon-RINs that can be generated for a given batch of renewable fuel will be determined directly by its Equivalence Value as described in Section III.D.2.b, and all such gallon-RINs will be summarized in a single batch-RIN assigned to a batch. In cases where the Equivalence Value is greater than 1.0, there will be more gallon-RINs assigned to a batch of renewable fuel than gallons in that batch. Once again, in the context of the changes we are making to the RIN distribution program structure as described in Section III.E.1.b below, we do not believe that this will in any way complicate the process of distributing RINs with renewable fuel. For the specific case of cellulosic biomass or waste-derived ethanol with an Equivalence Value of 2.5, producers will be required to assign only one gallon-RIN to each gallon of ethanol, each of which has a K code value of 1. The additional 1.5 gallon-RINs that can be generated for each gallon can remain unassigned, and thus be assigned a K code value of 2.

In addition to cases where the Equivalence Value is greater than 1.0, there are several other cases in which the gallon-RINs assigned to a batch will not exactly correspond to the number of gallons in that batch. First, if a renewable fuel has an Equivalence Value less than 1.0, then there will be fewer gallon-RINs than gallons in the batch. Such potential circumstances are described in Section III.D.2.c. RINs may also not correspond exactly to gallons if the density of the batch changes due to changes in temperature. For instance,

under extreme changes in temperature, the volume of a batch of ethanol can change by 5 percent or more. For this reason we are requiring that all batch volumes be corrected to represent a standard condition of 60 °F prior to the assignment of a RIN. For ethanol,[37] we are requiring that the correction be done as follows:[38]

$$V_{s,e} = V_{a,e} \times (-0.0006301 \times T + 1.0378)$$

Where:

$V_{s,e}$ = Standard volume of ethanol at 60 °F, in gallons.
$V_{a,e}$ = Actual volume of ethanol, in gallons.
$T$ = Actual temperature of the batch, in °F.

Since batches of ethanol are generally sold using standard volumes rather than actual volumes, this approach to assigning RINs to batches is consistent with current practices and will maintain the one-to-one correspondence between the volume block in the batch-RIN and the standardized volume of the batch. We are requiring a similar approach for biodiesel, where the volume correction must be calculated using the following equation:[39]

$$V_{s,b} = V_{a,b} \times (-0.0008008 \times T + 1.0480)$$

Where:

$V_{s,b}$ = Standard volume of biodiesel at 60 °F, in gallons.
$V_{a,b}$ = Actual volume of biodiesel, in gallons.
$T$ = Actual temperature of the batch, in °F.

Consistent with the NPRM, we are requiring that RIN generation begin at the same time that the renewable fuel standard becomes applicable to obligated parties. Thus RINs must be generated for all renewable fuel produced or imported on or after September 1, 2007. Since many producers and importers will have renewable fuel in inventory at the start of the program that was produced prior to September 1, 2007, we are also allowing them to generate RINs for any renewable fuel that they own on September 1, 2007. This provision ensures that every gallon that a producer or importer sells starting on September 1, 2007 can have an assigned RIN, and obligated parties that take ownership of renewable fuel directly from a producer or importer will have greater assurance of receiving RINs at the start of the program. Since RINs are not assigned to volumes until those volumes are transferred to another party, this approach also provides

producers and importers of renewable fuel the flexibility to determine which of the volumes they own on September 1, 2007 constitute production as of the start of the program.

Although a RIN is generated when renewable fuel is produced or imported, we do not define the point of production. However, the RIN must be assigned to a batch no later than the point in time when ownership of the batch is transferred from the producer or importer to another party. If ownership of the batch is retained by the producer or importer after the batch leaves the originating facility, the RIN need not be transferred along with the batch on product transfer documents identifying transfer of custody.

The means through which RINs are transferred with volumes of renewable fuel will in some respects be left to the discretion of the renewable fuel producer or importer. The primary requirement would be that the RIN transfer be recorded on a product transfer document (PTD). The PTD can be included in any form of standard documentation that is already associated with or used to identify title to the volume or can be a separate document as described below. In many cases an invoice could serve this purpose. As in other fuels programs, we believe the PTD requirement can be met by including the required information generated and transferred in the normal course of business.

RINs are transferable in the context of the RFS program and initially must be transferred along with ownership of a volume of renewable fuel. The approach that a producer or importer takes to the transfer or sale of RINs and volumes would be at their discretion, under the condition that the RIN and volume be transferred or sold on the same day and to the same party. Based on comments received, we are also permitting the transfer of RINs to be done in a separate PTD from the PTD used to transfer ownership of the volume of renewable fuel. This will provide some additional flexibility to parties who take ownership of renewable fuel with assigned RINs, permitting IT systems managing RIN transfers to be more easily incorporated into existing business management systems. Thus a party may use two separate PTDs, one for the volume and another for the RINs. However, transfer of the RINs must occur on the same day that transfer of the volume occurred, and the two PTDs must contain sufficient information to uniquely cross–reference them. In many cases an electronic transfer will suffice if sufficient information about the transfer is recorded. In the case of such parallel

PTDs, we are also requiring that the PTD transferring ownership of the volume must indicate whether RINs are being transferred and the number of gallon–RINs being transferred, though it need not list the actual RINs.

As described in Section III.E.1.b below, while assigned RINs must always be transferred to another party with a volume of renewable fuel, we are allowing any party that received assigned RINs with renewable fuel to thereafter transfer anywhere from zero to 2.5 gallon-RINs with each gallon of renewable fuel. This provision provides the flexibility to transfer more assigned RINs with some volumes and less assigned RINs with other volumes depending on the business circumstances of the transaction and the number of RINs that the seller has available. However, for producers and importers of renewable fuel, this level of flexibility could contribute to short-term hoarding that was the primary concern expressed by obligated parties during development of the proposed program. Therefore we are also finalizing a provision that requires producers and importers to transfer assigned gallon-RINs with gallons such that the ratio of assigned gallon-RINs to gallons is equal to the equivalence value for the renewable fuel. Since this is not possible for exempt small volume producers, or when a producer or importer obtains renewable fuel from another party without assigned RINs, exceptions are made in these cases.

We received comment that EPA should require a purchaser of imported gasoline who subsequently blends renewable fuel into the imported gasoline to transfer the RINs associated with the renewable fuel back to the importer of the gasoline. The commenter suggested that this requirement would ensure that the importer of the gasoline obtains all the RINs associated with the renewable fuel blended into that gasoline in cases where the importer has a long-term contractual agreement with the party that purchases the gasoline and adds the renewable fuel. However, we do not believe that such a provision is warranted. The RFS program places the renewable fuels obligation on parties based on ownership of the gasoline at the refiner or importer level. We believe this approach is the most effective way to implement and enforce the renewable fuels requirement. We also believe it is appropriate to allow parties who add the renewable fuel to gasoline, including blenders, to separate RINs from the renewable fuel volume and to have the right to sell those RINs to any party. Individual parties may agree that,

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[37] An appropriate temperature correction for other renewable fuels must likewise be used.

[38] Derived from ''Fuel Ethanol Technical Information,'' Archer Daniels Midland Company, v1.2, 2003.

[39] Derived from R.E. Tate et al., ''The densities of three biodiesel fuels at temperatures up to 300 °C,'' Fuel 85 (2006) 1004–1009, Table 1 for soy methyl ester.

in certain situations, it would be appropriate for the RINs to be transferred from the renewable fuels blender to the importer of the gasoline. In such cases, the parties may make contractual arrangements for the transfers. We do not believe it would be appropriate or workable for EPA to require such transfers.

The NPRM did not specify whether RINs should be generated for and assigned to renewable fuel that is already contained in imported gasoline (for example, a blend of 10 percent ethanol and 90 percent gasoline). Since the renewable fuel contained in imported gasoline is part of the total volume of renewable fuel in gasoline sold or introduced into commerce in the U.S., we believe it is appropriate to treat it as any other imported renewable fuel. Thus, we believe it would be appropriate for importers to assign RINs to renewable fuel contained in imported gasoline. However, the volume of renewable fuel contained in imported gasoline is very small in comparison to the volume requirements of the RFS program. If an importer of gasoline containing renewable fuel imports less than 10,000 gallons per year of renewable fuel, then that party is not required to generate RINs. But a small volume importer that chooses to generate and assign RINs to any volume of renewable fuel in imported gasoline is required to fulfill all of the requirements that apply to renewable fuel importers under the RFS rule, in addition to all of the requirements that apply to gasoline importers as obligated parties. An importer that assigns RINs to the renewable fuel in imported gasoline may separate the RINs from the renewable fuel, since the renewable fuel has been blended into gasoline.

Regardless of a small volume importer's decision to generate and assign RINs to renewable fuel contained in imported gasoline, an importer that imports any gasoline containing renewable fuel must include the gasoline portion of the imported product in the volume used to determine the importer's renewable fuel obligation (and exclude the renewable fuel portion of the batch). RINs must be assigned to imported renewable fuels that are not contained in gasoline at the time of importation, unless less than 10,000 gallons of renewable fuel are imported per year.

b. Responsibilities of Parties That Buy, Sell, or Handle Renewable Fuels

Volumes of renewable fuel can be transferred between many different types of parties as they make their way from the production or import facilities

where they originated to the places where they are blended into conventional gasoline or diesel. Some of these parties take custody but not ownership of these volumes, storing and transmitting them on behalf of those who retain ownership. Other parties take ownership but not custody, such as a refiner who purchases ethanol and has it delivered directly to a blending facility. Thus prior to blending, each volume of renewable fuel can be owned or held by any number of parties including marketers, distributors, terminal operators, and refiners.

In the NPRM, we proposed that in general all parties that assume ownership of any volume of renewable fuel would be required to transfer all RINs assigned to that volume to another party to whom ownership of the volume is being transferred. The only exceptions to the requirement that RINs be transferred with volumes would be for parties who are obligated to meet the renewable fuel standard and parties who convert the renewable fuel into motor vehicle fuel. Commenters overwhelmingly supported this approach to the distribution of RINs assigned to volumes of renewable fuel, and as a result we are adopting this approach in our final program. In this context, we are also clarifying that parties taking custody of a volume of renewable fuel but not ownership of that volume would have no responsibilities with regard to the transfer of RINs.

However, in response to the NPRM, several stakeholders apprised us of certain aspects of our proposed program that would limit the intended fungibility of RINs assigned to volumes of renewable fuel. While the goal of our proposed program was to permit RINs to be interchangeable with one another and to permit one assigned RIN to be exchanged with another RIN, our proposed regulations did not sufficiently capture this level of fungibility. Instead, the proposed regulations effectively required that a specific RIN assigned to a specific gallon of renewable fuel must remain assigned to that specific gallon as it travels through the distribution system. This approach was taken in order to accommodate the legitimate existence of some volumes of renewable fuel without assigned RINs, and some assigned RINs that have no corresponding volume. These situations can occur in the distribution system for several reasons, such as the following:

• RINs can be separated from renewable fuel by obligated parties or blenders, and the renewable fuel re-introduced into the distribution system.

• Small volume producers are exempt from generating and assigning RINs to their product.

• At the start of the program, some parties may have renewable fuel in their inventories that have not been assigned a RIN.

• Batches of renewable fuels with Equivalence Values less than 1.0 will have fewer gallon-RINs than gallons.

• Batch volumes can swell or shrink due to temperature changes.

• Batch volumes can shrink due to evaporation, spillage, leakage, or accidents.

• Volume metering imprecision.

Indeed, if the program could be designed such that every gallon in the distribution system always had an assigned RIN, the complete fungibility of RINs would be straightforward. However, this is not the case.

In order to make assigned RINs more fungible, we are finalizing a modified version of our proposed approach. Consistent with the NPRM, no party will be permitted to change a RIN assigned to a volume of renewable fuel into an unassigned (separated) RIN except for those parties explicitly given the right to do so (for example, obligated parties and oxygenate blenders). Also consistent with the NPRM, any party not authorized to separate an assigned RIN that takes ownership of a RIN assigned to a volume of renewable fuel cannot transfer ownership of that RIN to another party without simultaneously transferring an appropriate volume of renewable fuel.

However our final regulations allow any party to transfer a volume of renewable fuel without assigned RINs, or with a different number of assigned RINs than were received with the renewable fuel, as long as the number of assigned gallon-RINs held by that party at the end of a quarter is no higher than the number of gallons it owns at the end of the quarter. This will provide parties with the flexibility to decide which RINs are transferred with which volumes, and to transfer some volumes without RINs if the party took ownership of some volumes without assigned RINs. Our final regulations require only that the number of gallon-RINs held by a party at the end of a quarter be no higher than the number of gallons held by that party, adjusted by their Equivalence Value. Aside from spillage, evaporation, or volume metering imprecision, the only way that the number of gallon-RINs that are held by a party could be higher than the number of gallons held (adjusted for their Equivalence Value) is if that party transferred some volume without RINs. In such a case the excess RINs held

would be deemed to have been separated from renewable fuel, in violation of the prohibition against separating RINs.

While this approach creates more flexibility for parties that hold assigned RINs, it requires three additional changes to the proposed regulations. First, we are requiring parties that hold assigned RINs to also report the volumes of renewable fuel held at the end of each quarter. While the NPRM did not propose that volumes held be reported, we believe that the additional burden on parties holding assigned RINs will be minimal. The NPRM proposed that the recordkeeping requirements include information on all renewable fuel volumes transferred, so under the proposal parties holding assigned RINs would in general already have the information available. In addition, we are not requiring that all volumes held at any time during the quarter be reported, nor are we requiring that all volumes transferred be reported. Rather, parties will be required only to report the total volume of renewable fuel and the total number of gallon-RINs held on the last day of a quarter, in addition to other information regarding RINs held and transferred.

Second, our modified approach requires that we distinguish between RINs assigned to renewable fuel and RINs that have already been separated from renewable fuel, since only assigned RINs would be subject to the end-of-quarter comparison of RINs held and volumes held. We have chosen to use the K code in the RIN for this purpose, since it no longer serves the purpose of distinguishing between standard-value and extra-value RINs. The K code has also been moved to the beginning of the RIN to make its value more prominent. RINs assigned to renewable fuel must have a K code of 1. Parties who legally separate a RIN from renewable fuel must change the K code for that RIN to a value of 2. The RIN then formally becomes an unassigned RIN that can be transferred independent of renewable fuel volumes. The end-of-quarter comparisons between RINs held and volumes held apply only to RINs with a K value of 1.

Third, we are requiring quarterly reporting in addition to annual reports for RINs held and transferred. In the NPRM we took comment on requiring quarterly reporting for various reasons. We received both comments supporting and opposing quarterly reporting. As discussed further in Section IV, we are requiring quarterly reporting in this final rule. Under our modified program structure, quarterly reporting will be necessary to ensure that RINs are

available for obligated parties' annual compliance. Quarterly reports will provide us with the ability to monitor the activities of marketers and distributors in real time to ensure that they are transferring RINs with renewable fuel, and to address potential violations as soon as they arise.

As discussed in Section III.E.1.a above, we are requiring that producers and importers of renewable fuel assign all RINs to volumes of renewable fuel, consistent with our proposed approach to standard-value RINs. As a result, downstream parties can legitimately hold more gallon-RINs than gallons if some of the renewable fuel has an Equivalence Value greater than 1.0. In the context of our modified approach to RIN distribution, this fact must be taken into account in the end-of-quarter comparison of gallon-RINs held and gallons held. Thus the following equation must be satisfied at the end of each quarter by each party that has taken ownership of any assigned RINs:

$$\Sigma(RIN)_D \leq \Sigma(V_{si} \times EV_i)_D$$

Where:

D = Last day of a quarter (Jan–Mar, Apr–Jun, Jul–Sep, Oct–Dec).

$\Sigma(RIN)_D$ = Sum of all assigned gallon-RINs with a K code of 1 that are owned on the last day of the quarter.

$(V_{si})_D$ = Volume i of renewable fuel owned on the last day of the quarter, standardized to 60 °F, in gallons.

$EV_i$ = Equivalence Value representing volume i.

$\Sigma(V_{si} \times EV_i)_D$ = Sum of all volumes of renewable fuel owned on the last day of the quarter, multiplied by their respective equivalence values.

Under our fungible distribution system, the RINs received with a volume of renewable fuel may not be the RINs originally generated to represent that particular volume. Thus the Equivalence Value for a volume of renewable fuel cannot be based on the RR code of associated RINs, but instead should be determined from the composition of the renewable fuel. If the Equivalence Value for a volume of renewable fuel cannot be determined from its composition, it should be assumed to be 1.0. However, in the specific case of ethanol the owner may not know if a volume can be categorized as cellulosic biomass ethanol or waste-derived ethanol. Thus for volumes of ethanol held at the end of a quarter, the Equivalence Value should be assumed to be 2.5 to ensure that a party can legitimately hold more RINs than gallons.

The above equation ensures that the total number of gallon-RINs that can be held by a party at the end of a quarter is no greater than the number of gallon-

RINs he could have received given the volume of renewable fuel that he owns. Parties that do not satisfy the above equation are deemed to be in violation of the prohibition against separating RINs from volumes.

Under our modified approach to RIN distribution, it might be possible for a party who owns volumes of renewable fuel with assigned RINs to hold onto all the RINs until near the end of a quarter while selling volume without RINs. Then, in order to comply with the above equation, the party could transfer all assigned RINs with a single volume of renewable fuel prior to the last day of the quarter. This approach would amount to short-term hoarding. To prevent it, we are also placing a cap on the maximum number of gallon-RINs that can be transferred with any gallon of renewable fuel. The cap is dictated by the maximum number of gallon-RINs that a party could receive with a volume of renewable fuel, which is 2.5 in the case of cellulosic biomass ethanol or waste-derived ethanol. For a party that took ownership of these types of renewable fuel, we must allow them to transfer up to 2.5 gallon-RINs with each gallon.

We are also aware that there are situations in which the volume transferred to another party might be smaller than the volume originally received. This could occur due to fuel evaporation, spillage, leakage, or volume metering imprecision, and would have the effect of raising the ratio of gallon-RINs held to gallons held. For spillage/leakage involving significant volumes, we have developed a mechanism for formally retiring the RINs associated with the lost volume. See Section IV. Smaller volume losses can be accommodated by a RIN transfer cap of 2.5, which would in general allow RINs associated with lost volume to be transferred with remaining volume. In the rare case that a party takes ownership of only cellulosic biomass ethanol or waste-derived ethanol and experiences some small volume loss, he can take ownership of a small volume of some other form of renewable fuel with an Equivalence Value less than 2.5. This will permit him to transfer RINs associated with lost volume to another party while still meeting the RIN transfer cap of 2.5.

Our program is designed to allow RIN transfer and documentation to occur as part of normal business practices in the context of renewable fuel distribution. Thus the incremental costs of transferring RINs with volumes is expected to be minimal. Marketers and distributors must simply add the RIN to product transfer documents such as

invoices, and record the RINs in their records of volume purchases and sales.

Finally, the final rule also provides that a foreign entity may apply to EPA for approval to own RINs. As an approved foreign RIN owner, the foreign entity will be able to obtain, sell, transfer and hold both assigned and separated RINs. An approved foreign RIN owner will be required to comply with all requirements that apply to domestic RIN owners under the RFS rule. In addition, similar to other fuels programs, an approved foreign RIN owner will be required to comply with additional requirements designed to ensure that enforcement of the RFS regulations at the foreign RIN owner's place of business will not be compromised.

c. Batch Splits and Batch Mergers

In the RIN distribution approach proposed in the NPRM, RINs assigned to a given volume of renewable fuel remained assigned to that volume as it moved through the distribution system. In that context, batch splits and batch mergers required special treatment. We discussed the need for protocols to ensure that RINs assigned to parent batches were appropriately distributed among daughter batches, and that RINs assigned to batches that were merged were all re-assigned to the new combined batch. The proposed regulations included some restrictions on how parent batch RINs were to be apportioned to daughter batches during splits, but fell short of prescribing a detailed batch split protocol. Nevertheless, commenters by and large did not address these protocols in their comments.

The need for protocols for batch splits and batch mergers was directly related to the NPRM's approach to the distribution of RINs with volumes of renewable fuel. As described in Section III.E.1.b above, we are modifying our approach to permit assigned RINs to be more fungible. As a result, there is no need for the regulations to specify any batch splitting or batch merging protocols.

Under our final regulations, parties taking ownership of volumes of renewable fuel with assigned RINs will simply retain an inventory of all assigned RINs owned. As volumes of renewable fuel are then transferred to other parties, an appropriate number of gallon-RINs are withdrawn from the party's inventory and transferred along with the renewable fuel. There is no need for the party to determine which RINs were originally assigned to the volume being transferred. For parties handling both ethanol and biodiesel, it

would be reasonable to transfer RINs with volumes in a manner consistent with the Equivalence Value of the renewable fuel, but this would not be required under our final regulations in which the number of assigned gallon-RINs transferred with each gallon of renewable fuel can be anywhere between zero and 2.5. In addition, volumes of renewable fuel can be split or merged any number of times while remaining under the ownership of a single party, with no impact on RINs. It is only when ownership of a volume of renewable is transferred to another party that an appropriate number of gallon-RINs need to be withdrawn from the party's inventory and assigned to the transferred volume, subject to the flexibility associated with the quarterly average as discussed above.

2. Separation of RINs From Volumes of Renewable Fuel

Separation of a RIN from a volume of renewable fuel means that the RIN is no longer included on the PTD and can be traded independently from the volume to which it had originally been assigned. In general commenters supported our proposed approach of limiting the parties that can separate a RIN from a batch, and the associated conditions under which separation can occur.

In designing the regulatory program, we structured it around facilitating compliance by obligated parties with their renewable fuel obligation, with the intention of giving obligated parties the power to market the renewable fuel separately from the RIN originally assigned to it. Our final program therefore requires a refiner or importer to separate the RIN from renewable fuel as soon as he assumes ownership of that renewable fuel. In the case of ethanol blended into gasoline at low concentrations ($\leq$ 10 volume percent), stakeholders have informed us that a large volume of the ethanol is purchased by refiners directly from ethanol producers, and is then passed to blenders who carry out the blending with gasoline. Therefore, in many cases RINs assigned to renewable fuel will pass directly from the producers who generated them to the obligated parties who need them.

However, significant volumes of ethanol are also blended into gasoline without first being purchased by a refiner. In some cases, the blender itself purchases the ethanol. In other cases, a downstream customer purchases the ethanol and contracts with the blender to carry out the blending. Regardless, the ethanol may never be held or owned by an obligated party before it is blended into gasoline. Thus we are also

requiring a blender to separate the RIN from the renewable fuel if he takes ownership of the renewable fuel and actually blends it into gasoline (or, in the case of biodiesel, into diesel fuel). This would only apply to volumes where the RIN had not already been separated by an obligated party. Since blenders will in general not be obligated parties under our program, blenders who separate RINs from renewable fuel will have no need to hold onto those RINs and thus can transfer them to an obligated party for compliance purposes or to any other party.

There may be occasions in which a retailer downstream of a blender actually owns the volume of renewable fuel when it is blended into gasoline or diesel. In such cases the blender will have custody but not ownership of the renewable fuel. In today's final rule we are requiring the RIN to be separated from the volume of renewable fuel when that volume is blended into gasoline, but the RIN can only be separated by the party that owns that volume of renewable fuel at the time of blending. In the case of a blender and a downstream customer who might both lay claim to the right to separate any assigned RINs (for instance, if transfer of ownership occurred simultaneous with blending), these two parties would need to come to agreement between themselves regarding which party will own the separated RINs.

As described in Section III.B, many different types of renewable fuel can be used to meet the RFS volume obligations placed upon refineries and importers. Currently, ethanol is the most prominent renewable fuel and is most commonly used as a low level blend in gasoline at concentrations of 10 volume percent or less. However, some renewable fuels can be used in neat form (i.e. not blended with conventional gasoline or diesel). The two RIN separation situations described above would capture any renewable fuel for which ownership is assumed by an obligated party or a party that blends the renewable fuel into gasoline or diesel. However, renewable fuels which are used in their neat (unblended) form as motor vehicle fuel would not be captured. This would include such renewable fuels as neat biodiesel (B100) or renewable diesel, methanol for use in a dedicated methanol vehicle or biogas for use in a CNG vehicle.

Under our final program, producers and importers must assign a RIN to all renewable fuels produced or imported, including neat renewable fuels. To avoid the possibility that the RIN assigned to neat renewable fuel would never become available to an obligated

party for RFS compliance purposes, in the NPRM we proposed to more broadly define the right to separate a RIN from renewable fuel. In addition to obligated parties and blenders, we proposed that any producer holding a volume of renewable fuel for which the RIN has not been separated could separate the RIN from that volume if the party designates it for use only as a motor vehicle fuel in its neat form and it is in fact only used as such. This approach would recognize that the neat form of the renewable fuel is valid for compliance purposes under the RFS program, as described in Section III.B. In effect, it would place neat fuel producers in the same category as blenders, in that they are producing motor vehicle fuel. We did not receive any negative comments on this proposal, and thus are finalizing this provision as proposed.

As discussed above, under our final rule, obligated parties must separate RINs from volumes of renewable fuel. This applies to all volumes of renewable fuel that an obligated party owns. The requirement to separate a RIN from the renewable fuel is intended to apply to refiners, blenders and importers for whom the production or importation of gasoline is a significant part of their overall business operations. Parties that are predominately renewable fuel producers or importers, but which must be designated as obligated parties due to the production or importation of a small amount of gasoline, should not be able to separate RINs from all renewable fuels that they own. For example, we believe it would be inappropriate to permit an ethanol producer to separate RINs from all volumes that they own simply because the producer imported, for example, a single truckload of gasoline from Canada or Mexico. As a result, the final rule prohibits obligated parties from separating RINs from volumes of renewable fuel that they produce or import that are in excess of their RVO. However, obligated parties must separate any RINs from volumes of renewable fuel that they own if that volume was produced or imported by another party.

As described in Section III.B.2, RINs can be generated for renewable fuels made from renewable crude which is treated as if it were a petroleum-derived crude oil or derivative, and is used as a feedstock in a traditional refinery processing unit. Whether the renewable crude is coprocessed with petroleum derivatives or is processed in a facility or unit dedicated to the renewable crude, the final product is generally a motor vehicle fuel. In such cases the refinery will have the responsibility of

generating RINs for the renewable fuel produced. But since renewable crude is generally processed in a traditional refinery, the refiner will be an obligated party and can therefore immediately separate those RINs from the renewable fuel and transfer them to another party. As described in III.E.1.a above, cellulosic and waste-derived ethanol producers will also be permitted to separate the RINs associated with the extra 1.5 value of their ethanol production.

Once a RIN is separated from a volume of renewable fuel, the PTD associated with that volume can no longer list the RIN. However, in the NPRM we requested comment on whether PTDs should include some notation indicating that the assigned RIN has been removed to avoid concerns about whether RINs assigned to batches have not been appropriately transferred with the batch. One refiner commented that the addition of such a note on a PTD would represent an unnecessary burden, while two commenters representing fuel distribution operations indicated that such a notation would be useful. Based on comments we received, we have determined that such notation on PTDs would not only be useful to parties receiving volumes of renewable fuel, but would also be an important element of our RIN distribution requirements under our modified approach. The requirement will ensure that parties who take ownership of renewable fuel without assigned RINs will know that RINs were originally assigned but subsequently removed. We also believe that such a requirement would be of minimal burden to parties that have separated a RIN from a volume of renewable fuel.

As described in Section III.E.1.b, we have modified the RIN transfer requirements for the final rule to make RINs more fungible and to provide more flexibility to distributors while still requiring RINs to be transferred with volumes of renewable fuel. However, our modified approach requires that we distinguish between RINs assigned to renewable fuel and RINs that have already been separated from renewable fuel. Our final rule thus requires that parties who separate a RIN from renewable fuel must change the K code for that RIN to a value of 2. The RIN then becomes an unassigned RIN that can be transferred independent of renewable fuel volumes.

In the NPRM we also provided a discussion of the unique circumstances regarding biodiesel (mono alkyl

esters) [40] and the conditions under which we believed a RIN should be separated from a volume of such biodiesel. As described in the proposal, biodiesel is one type of renewable fuel that can under certain conditions be used in its neat form. However, in the vast majority of cases it is blended with conventional diesel fuel before use, typically in concentrations of 20 volume percent or less. This approach is taken for a variety of reasons, such as to reduce impacts on fuel economy, to mitigate cold temperature operability issues, to address concerns of some engine owners or manufacturers regarding the impacts of biodiesel on engine durability or drivability, or to reduce the cost of the resulting fuel. Biodiesel (mono alkyl esters) is also used in low concentrations as a lubricity additive and as a means for complying with the ultra-low sulfur requirements for highway diesel fuel. Biodiesel (mono alkyl esters) is occasionally used in its neat form. However, this approach is the exception rather than the rule. Consequently, in the NPRM we proposed that the RIN assigned to a volume of biodiesel could only be separated from that volume if and when the biodiesel was blended with conventional diesel. To avoid claims that very high concentrations of biodiesel count as a blended product, we also proposed that biodiesel must be blended into conventional diesel at a concentration of 80 volume percent or less before the RIN could be separated from the volume.

A number of commenters expressed concern that the 80 volume percent limit put biodiesel at odds with the RIN separation criteria applicable to other renewable fuels, including neat fuels. Upon further consideration, we have determined that the 80 volume percent limit remains a valid means for ensuring that the separation of RINs from biodiesel is consistent with its common use at low blend levels just as for ethanol, and that RINs are generally separated at the point in time when the biodiesel can be deemed to be motor vehicle fuel. However, based on comments received, we are changing the treatment of biodiesel for the final rule in two ways.

First, obligated parties are required to separate RINs from volumes of biodiesel at the point when they gain ownership of the biodiesel, not when they blend biodiesel with conventional diesel fuel. This approach is consistent with our treatment of the RIN separation

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[40] Throughout this Section III.E.2, ''biodiesel'' means mono alkyl esters, not non-ester renewable diesel.

requirements for obligated parties for other renewable fuels. Parties that actually blend biodiesel into conventional diesel fuel at a concentration of 80 volume percent or less would continue to be required to separate the RIN from the biodiesel, as proposed.

Second, we have determined that a biodiesel producer should be allowed to separate a RIN from a volume of biodiesel that it produces if it designates the volume of biodiesel specifically for use as motor vehicle fuel in its neat form, and the neat biodiesel is in fact used as motor vehicle fuel. In general this demonstration would require that the producer track the volume of biodiesel to the point of its final use. However, this approach to the treatment of neat biodiesel is consistent with how we are treating other renewable fuels used in their neat form.

3. Distribution of Separated RINs

In the NPRM, we proposed that RINs become freely transferable once they are separated from a batch of renewable fuel. Each RIN could be held by any party and transferred between parties any number of times. We argued that the unique features of the RFS program warranted more open trading than in past fuel credit programs. In particular, RINs are generated by parties other than obligated parties, and many nonobligated parties will own RINs (for example, oxygenate blenders who have the right to separate RINs from volumes). While recognizing that limiting trading to and between obligated parties might help obligated parties to maintain control of those RINs being traded, such an approach could have the unintended effect of limiting the number of RINs that non-obligated parties contribute to the RIN market. The RFS program must work efficiently not only for a limited number of obligated parties, but a number of non-obligated parties as well.

There was disagreement among commenters about whether an open RIN market was appropriate. Several parties supported our proposed approach, saying that unlimited trading among all interested parties would increase liquidity and transparency in the RIN market. They also argued that increasing the number of participants would facilitate the acquisition of RINs by obligated parties and promote economic efficiency.

However, some commenters disagreed, arguing instead that an open market does not necessarily make the market any more fluid and free. They pointed to past credit programs in which only refiners and importers have

been allowed to transfer credits, and argued that the success of those programs should compel the Agency to use those past credit program structures as the model for the RFS program.

We continue to believe that there is a need to provide for more open trading in the RFS program and that this need warrants a unique approach for this rule. First, unlike other programs where credits generally represent overcompliance with an applicable standard and are thus supplemental to the means of compliance, under the RFS program RINs are the fundamental unit for compliance. There will be many more RINs in the RFS program than credits in other programs, and the trading structure must maximize the fluidity of those RINs. A wider RIN market will make it easier for obligated parties to get access to RINs.

Second, obligated parties are typically not the ones producing the renewable fuels and generating the RINs, nor blending the renewable fuels into gasoline, so there is a need for trades to occur between obligated parties and non-obligated parties. If we prohibited everyone except obligated parties from holding RINs after they have been separated from a batch, non-obligated parties seeking avenues for releasing their RINs would only be able to release them to obligated parties. Having fewer avenues through which they could market their RINs, some non-obligated parties might opt not to transfer their RINs at all rather than participate in the RIN market with the attendant recordkeeping requirements. Furthermore, a potentially large number of oxygenate blenders, many of which will be small businesses, will be looking for ways to market their RINs. Allowing other parties, including brokers, to own and transfer RINs may create a more fluid and free market that would increase the venues for RINs to be acquired by the obligated parties that need them. Limiting RIN trading to and among obligated parties could make it more difficult for RINs to eventually be transferred to the obligated parties that need them.

Some commenters argued that limiting the RIN trading market to and among obligated parties would make the program more enforceable, since there would be fewer parties to track and the sources of RINs would be more reliable. While this may be directionally true, we believe the RFS program will remain sufficiently enforceable under an open RIN market, and as discussed above, the greater need for market fluidity for this program warrants the change. The RIN number, along with the associated electronic reporting mechanism, will

provide us the ability to verify the validity of RINs and the source of any invalid RINs. Since all RINs generated, traded, and used for compliance would be recorded electronically in an Agency database, these types of investigations should be straightforward. The number of RIN trades, and the parties between whom the RINs are being traded, will only have the effect of increasing the size of the database.

Some commenters were concerned that an open RIN market could lead to price volatility and potentially higher prices as non-obligated speculators enter the market expressly to profit from the sale of RINs. According to commenters, these speculators would hold an unfair advantage over obligated parties that must purchase credits for compliance since speculators can hold onto RINs indefinitely, driving up their price. However, by expanding the number of parties that can hold RINs, we minimize the potential for any one party to exercise market power, and thus we do not believe that such activity on the part of speculators is likely to substantively affect the availability of RINs or their price. Moreover, we do not believe that a given party will hold a RIN indefinitely simply to increase profit because RINs have a limited life and new RINs will be generated and will enter the market continuously.

Based on our review of the comments received, we did not find compelling evidence that an open market for RINs would create particular difficulties for obligated parties seeking RINs or would limit the enforceability of the program. As a result we are finalizing a RIN trading program that permits any party to hold RINs and for RINs to be traded any number of times.

As with other credit-trading programs, the business details of RIN transactions, such as the conditions of a sale or any other transfer, RIN price, role of mediators, etc. will be at the discretion of the parties involved. The Agency is concerned only with information such as who holds a given RIN at any given moment, when transfers of RINs occur, who the party to the transfers are, and ultimately which obligated party relies on a given RIN for compliance purposes. This type of information will therefore be the subject of various recordkeeping and reporting requirements as described in Section IV, and these requirements will generally apply regardless of whether a RIN has been separated from a batch.

The means through which RIN trades occur will also be at the discretion of the parties involved. For instance, parties with RINs can create open auctions, contract directly with those

obligated parties who seek RINs, use brokers to identify potential transferees and negotiate terms, or just transfer the RINs to any other party. Brokers involved in RIN transfer can either operate in the role of arbitrator without owning the RINs, or alternatively can take custody of the RINs from one party and transfer them to another. If they are the transferee of any RINs, they will also be subject to the registration, recordkeeping, and reporting requirements. The Agency will not be directly involved in RIN transfers, other than in the role of providing a database within which transfers will be recorded for enforcement purposes.

In order to provide public information that could be helpful in managing and trading RINs as well as understanding how the program is operating, we intend to publish a report each year that summarizes information submitted to us through the quarterly and annual reports required as part of our enforcement efforts (see Section IV). Annual summary reports published by EPA may include such information as the number of RINs generated in each month or in each state, the average number of trades that RINs undergo before being used for compliance purposes, or the frequency of deficit carryovers. However, we will not publish information identifying specific parties.

4. Alternative Approaches to RIN Distribution

In the NPRM, we also described several alternative approaches to the proposed trading and compliance program that were offered by stakeholders. Most of these alternatives recognized the value of a RIN-based system of compliance, but they differed in terms of which parties would be allowed to separate a RIN from a batch and the means through which the RINs would be transferred to obligated parties. We invited comment on all of these alternatives in the NPRM, but received very few. Based on those comments we did receive, we do not believe that any of these alternative approaches should be implemented at this time. In general our responses to comments on the alternatives can be found in the Summary and Analysis of Comments document in the docket, but we have addressed one particular subject area below.

In the NPRM, we described an alternative approach to RIN distribution in which obligated parties would only be able to separate a RIN from a batch of renewable fuel at the point in time when blending actually occurs. In contrast, the approach we are finalizing

today requires an obligated party to separate a RIN from a batch as soon as it gains ownership of that batch. Our final program design is based on the expectation that all but a negligible quantity of renewable fuels will eventually be consumed as motor vehicle fuel, primarily through blending with gasoline or diesel. See further discussion in Section III.D. As a result, we do not believe that it is necessary to verify that blending has actually occurred in order to provide a program that adequately ensures it occurs. The American Petroleum Institute agreed that tracking renewable fuels to the point of blending would represent an unnecessary burden and added that such a requirement could preclude many obligated parties from taking direct steps to obtain RINs to meet their obligations.

The Renewable Fuels Association, however, argued that allowing obligated parties to separate RINs from batches before blending occurred could give rise to RIN hoarding, fraud, and confusion. Most importantly, they noted, the alternative approach would provide direct verification of blending. For the reasons described in Section III.D, we do not believe that a compliance system requiring verification of blending is necessary, given that, with the exception of exports, essentially all renewable fuel produced in the U.S. is used as motor vehicle fuel in the U.S. This is a foundational principle of the use of a RIN-based program design that enjoyed widespread support among stakeholders and widespread recognition that it accurately describes real world practices.

If verification of blending were required before a RIN could be separated from a batch, both obligated parties and blenders would be subject to additional recordkeeping and paperwork burdens. The Agency would be compelled to enforce activities at the blender level, adding about 1200 parties to the list of those subject to enforcement under our final program. Although we agree that the reformulated gasoline program could act as a model from which to construct such a recordkeeping and enforcement system, we continue to believe that such a system would be both unnecessary and burdensome.

The Renewable Fuels Association also argued that our proposed program would result in confusion in the distribution system, since there would be renewable fuel both with and without RINs. However, there are many other reasons that this situation could arise, and none is expected to negatively impact the distribution of renewable

fuels or the business agreements developed by parties transferring renewable fuels. For instance, we are exempting small volume producers from generating RINs, renewable fuels with equivalence values less than 1.0 may have fewer RINs than gallons, and volume swell and metering discrepancies can all contribute to situations in which batches legitimately do not have assigned RINs corresponding to their actual volumes. Parties that sell such batches could choose to price such product differently from product that has assigned RINs with a one-to-one correspondence to product volume. We are also requiring that PTDs associated with transfers of volume include notation indicating whether RINs are being simultaneously transferred to address these types of situations.

Another commenter argued that the alternative approach could limit the potential for one refiner to purchase large volumes of renewable fuel with the intent of separating the RINs and exercising market power in the RIN market. However, the commenter did not provide any information regarding how such market power could be exercised by one refiner in a system where unassigned RINs can be transferred freely between parties any number of times, and access to those RINs is not limited geographically in any way. In addition, RINs that have been separated from their assigned batches by oxygenate blenders represent an additional safety valve in the RIN market, providing additional assurances that no one refiner could exercise market power in the RIN market.

Commenters supporting a requirement that RINs be separated only at the point of blending offered no other arguments that hoarding or fraud could actually occur under our proposed approach. Therefore, we are finalizing an approach that requires obligated parties to separate RINs from batches at the point of ownership.

## IV. Registration, Recordkeeping, and Reporting Requirements

### A. Introduction

Registration, recordkeeping and reporting are necessary to track compliance with the renewable fuels standard and transactions involving RINs. This summarizes these requirements. Our estimates as to the burden associated with registration, recordkeeping and reporting are contained in this **Federal Register** notice in Section XII.B and explained fully in ''OMB–83 Supporting Statement—Renewable Fuels Standard

(RFS) Program (Final Rule)—EPA ICR No. 2242.02,'' which has been placed in the public docket for this rulemaking.

*B. Registration*

1. Who Must Register Under the RFS Program?

Obligated parties (including refiners and importers), exporters of renewable fuels, producers and importers of renewable fuels, and any party who owns RINs must register with EPA. Any party may own RINs including, but not limited to, the above-named parties and marketers, blenders, terminal operators, jobbers, and brokers. Owning RINs, and engaging in any activities regarding RINs, is prohibited as of September 1, 2007 unless the party has registered and received EPA company and facility identification numbers.

Most refiners and importers and many biodiesel producers are already registered with us under various regulations in 40 CFR part 80 related to reformulated (RFG) and conventional gasoline or diesel fuel. Parties who are already registered will not have to take any action to register under the RFS program, because their existing registration will be applied to the RFS program as well.

2. How Do I Register?

Registration is a simple process. We will use the same basic forms for RFS program registration that we use under the reformulated gasoline (RFG) and anti-dumping program. You may download our registration forms at *http://www.epa.gov/otaq/regs/fuels/ rfgforms.htm.* These forms are well known in the regulated community and are very simple to fill out. Information requested includes company and facility names, addresses, and the identification of a contact person with telephone number and e-mail address. Registrations never expire and do not have to be renewed. However, all registered parties are responsible for notifying us of any change to their company or facility information.

3. How Do I Know I Am Properly Registered With EPA?

Upon receipt of a completed registration form, we will provide you with a unique 4-digit company identification number and a unique 5-digit facility identification number. These numbers will appear in compliance reports and, in the case of renewable fuel producers and importers, they will be incorporated in the unique RINs they generate for each batch of renewable fuel. Timely registration is important because you cannot generate

or handle transactions involving RINs until you have registered and received your registration numbers from us. It is advisable to register as soon as possible if you believe you will be engaged in activities that may require registration under the RFS program. Registration can occur any time following signature of this final rule.

If you are already registered under another fuels program, such as RFG and anti-dumping or diesel sulfur, then you do not have to register again. You will use the same company and facility identification number you are currently using for RFS reporting. Parties in this situation may contact the Agency for confirmation or clarification of the appropriate registration numbers to use. As noted above, registrations never expire, but you are responsible for keeping the information we have up to date. If you have previously registered with us but have not had to report until now, then you may wish to contact the person listed on our renewable fuels Web page (*http://www.epa.gov/otaq/ renewablefuels/index.htm*) in order to confirm the information in your registration file.

4. How Are Small Volume Domestic Producers of Renewable Fuels Treated for Registration Purposes?

Small volume domestic producers of renewable fuels are those who produce less than 10,000 gallons per year or who import less than 10,000 gallons per year. These parties are not required to register if they do not wish to generate RINs. If a small volume domestic producer of renewable fuels wishes to generate RINs, then that party must register and comply with all recordkeeping and reporting requirements.

*C. Reporting*

1. Who Must Report Under the RFS Program?

Obligated parties, exporters of renewable fuel, producers and importers of renewable fuel, and any party who owns either assigned or unassigned RINs such as marketers or brokers must submit periodic reports to us covering RIN generation, RIN use, and RIN transactions.

2. What Reports Are Required Under the RFS Program?

There are four basic reports under the RFS program. The first report is an annual compliance demonstration report that is required to be submitted by obligated parties and exporters of renewable fuel. This report provides the RFS compliance demonstration and is required to be submitted on an annual

basis. It is focused on calculating the RVO, indicating RINs used for compliance, and determining any deficit carried over.

The second report is a quarterly RIN generation report that is required to be submitted by producers and importers of renewable fuel. This report is focused on providing information on all batches of renewable fuel produced and imported and all RINs generated.

The third report is a RIN transaction report that is required to be submitted by any party that owns RINs, including RIN marketers and brokers, as well as obligated parties, exporters, and renewable fuel producers and importers. This report is focused on providing information on individual RIN purchases, RIN sales, retired RINs, and expired RINs.[41] A separate RIN transaction report is required to be submitted for each RIN purchase and sale, and for each retired or expired RIN, and must be submitted by the end of the quarter in which the activity occurred. The purpose of the RIN transaction report is to document the ownership and transfer of RINs, and to track expired and retired RINs. This report is necessary because compliance with the RVO is primarily demonstrated through self-reporting of RIN trades and therefore we must be able to link transactions involving each unique RIN in order to verify compliance. We will be able to import reports into our compliance database and match RINs to transactions across their entire journey from generation to use. As with our other 40 CFR part 80 compliance-on-average and credit trading programs, many potential violations are expected to be self-reported.

The fourth report is a quarterly gallon-RIN activity report that also is required to be submitted by *any* party that owns RINs. This report is focused on the total number of gallon-RINs owned at the start and end of the quarter, and the total number of gallon-RINs purchased, sold, retired and expired during the quarter. This report also requires

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[41] In this final rule, we have clearly distinguished expired RINs, which are no longer valid due to the passage of time, from retired RINs, which are RINs no longer valid due to the reportable spillage of their assigned volumes under § 80.1132, RINs used to satisfy an enforcement action, or RINs used to effect an import volume correction under § 80.1166(k). Rather than leaving retired RINs under ''any additional information that the Administrator may require,'' we have specifically addressed them in this final rule. We believe it is useful to specifically distinguish between retired and expired RINs because it will be easier for us to determine whether a report is complete and to quality assure and check reported information by applying a consistent reporting distinction between expired and retired RINs.

information on end-of-quarter renewable fuel volumes.

3. What Are the Specific Reporting Items for the Various Types of Parties Required To Report?

The following table summarizes the information to be submitted in each

type of report by the type of regulated party:

TABLE IV.C.3–1.—INFORMATION CONTAINED IN REPORTS BY REGULATED PARTY *

| Type of report | Obligated parties | Exporters of renewable fuel | Producers and importers of renewable fuel | Other parties who own RINS |
|---|---|---|---|---|
| Annual Compliance Demonstration Report. | • Calculation of RVO ....... <br> • List of RINs used for compliance. <br> • Calculation of deficit carryover. | • Calculation of RVO ....... <br> • List of RINS used for compliance. <br> • Calculation of deficit carryover. | No report ........................... | No report. |
| Quarterly RIN Generation Report. | No report ........................... | No report ........................... | • Volume of each batch produced or imported. <br> • RINs generated for each batch. <br> • Volume of denaturant and applicable equivalence value of each batch. | No report. |
| RIN Transaction Report .... | Separate report for each transaction:. <br> • RIN purchase ................ <br> • RIN sale ........................ <br> • Expired RIN ................... <br> • Retired RIN ................... | Separate report for each transaction:. <br> • RIN purchase ................ <br> • RIN sale ........................ <br> • Expired RIN ................... <br> • Retired RIN ................... | Separate report for each transaction:. <br> • RIN purchase ................ <br> • RIN sale ........................ <br> • Expired RIN ................... <br> • Retired RIN ................... | Separate report for each transaction: <br> • RIN purchase. <br> • RIN sale. <br> • Expired RIN. <br> • Retired RIN. |
| Quarterly gallon-RIN Activity Report. | • Number of gallon-RINs* owned at start of quarter. <br> • Number of gallon-RINs purchased. <br> • Number of gallon-RINs sold. <br> • Number of gallon-RINs retired. <br> • Number of gallon-RINs expired (4th quarter only). <br> • Number of gallon-RINs at end of quarter. <br> • Volume (gals) of renewable fuel owned at end of quarter. | • Number of gallon-RINs owned at start of quarter. <br> • Number of gallon-RINs purchased. <br> • Number of gallon-RINs sold. <br> • Number of gallon-RINs retired. <br> • Number of gallon-RINS expired (4th quarter only). <br> • Number of gallon-RINs at end of quarter. <br> • Volume (gals) of renewable fuel owned at end of quarter. | • Number of gallon-RINs owned at start of quarter. <br> • Number of gallon-RINs purchased. <br> • Number of gallon-RINs sold. <br> • Number of gallon-RINs retired. <br> • Number of gallon-RINs expired (4th quarter only). <br> • Number of gallon-RINs at end of quarter. <br> • Volume (gals) of renewable fuel owned at end of quarter. | • Number of gallon-RINs owned at start of quarter. <br> • Number of gallon-RINs purchased. <br> • Number of gallon-RINs sold. <br> • Number of gallon-RINs retired. <br> • Number of gallon-RINs expired (4th quarter only). <br> • Number of gallon-RINs at end of quarter. <br> • Volume (gals) of renewable fuel owned at end of quarter. |

* A gallon-RIN is a RIN that represents an individual gallon of renewable fuel. See § 80.1101.

4. What Are the Reporting Deadlines?

In the proposed rule, we had requested comment on whether reporting should be annual or quarterly. After consideration of comments received, we have determined that each RIN transaction report must be submitted by the end of the quarter in which the transaction occurred, and the gallon-RIN activity report should be submitted quarterly. Quarterly reporting is better because it provides us with the information necessary to confirm the validity and legitimacy of RINs prior to their use in compliance. Additionally, quarterly reporting enables EPA to enforce the RIN/inventory balance requirements for producers and marketers of renewable fuels.

The annual compliance demonstration for obligated parties must

be submitted by February 28th for the prior calendar year. For the RIN transaction and quarterly gallon-RIN activity reports, the following schedule applies to all reporting parties:

TABLE IV.C.4–1.—QUARTERLY REPORTING SCHEDULE FOR RFS PROGRAM

| Quarter covered by quarterly report | Due date for quarterly report |
|---|---|
| January–March ................ | May 31. |
| April–June ....................... | August 31. |
| July–September .............. | November 30. |
| October–December ......... | February 28. |

In the first year of the RFS program only, obligated parties and exporters are given an extra quarter to submit their list of RINs used to demonstrate

compliance. This information must be reported by May 31, 2008 for calendar year 2007. All other reporting follows the schedule indicated above.

5. How May I Submit Reports to EPA?

We will use a simplified and secure method of reporting via the Agency's Central Data Exchange (CDX). CDX permits us to accept reports that are electronically signed and certified by the submitter in a secure and robustly encrypted fashion. Using CDX will eliminate the need for wet ink signatures and will reduce the reporting burden on regulated parties. Guidance for reporting will be issued before implementation and will contain specific instructions and formats consistent with provisions in this final rule. The guidance will be posted on our renewable fuels Web page: *http://*

*www.epa.gov/otaq/renewablefuels/index.htm.*

We will accept electronic reports generated in virtually all commercially available spreadsheet programs and will even permit parties to submit reports in comma delimited text, which can be generated with a variety of basic software packages.

CDX will confirm delivery of your report. As described below with regard to recordkeeping, you must retain copies of all items submitted to us for five (5) years.

## 6. What Does EPA Do With the Reports it Receives?

In order to permit maximum flexibility in meeting the RFS program requirements, we must track activities involving the creation and use of RINs, as well as any transactions such as purchase or sale of RINs. Reports will be imported into a compliance database managed by EPA's Office of Transportation and Air Quality and will be reviewed for completeness and for potential violations. It is important to keep your company contact updated (this is an item on the registration form), because we may need to speak to that person about any problems with a report submitted. Potential violations will be referred to EPA enforcement personnel.

## 7. May I Claim Information in Reports as CBI and How Will EPA Protect it?

You may claim information submitted to us as confidential business information (CBI). Please be sure to follow all reporting guidance and clearly mark the information you claim as proprietary. We will treat information covered by such a claim in accordance with the regulations at 40 CFR part 2 and other Agency procedures for handling proprietary information.

## 8. How Are Spilled Volumes With Associated Lost RINs To Be Handled in Reports?

Since spills can happen whenever renewable fuel with assigned RINs is held, owners have two options if the spill causes their organization to be out of compliance. The owners of the spilled fuel may either retire RINs lost in reported spills or purchase and sell a volume of renewable fuel equal to the reported volume and not associated with RINs in order to meet compliance. Reportable spills for the purposes of this rule refers to spills of renewable fuel with assigned RINs and a requirement by a federal, state, or local authority to report said spills. The party that owns the spilled renewable fuel must retire a number of gallon-RINs corresponding to the volume of spilled renewable fuel

multiplied by its equivalence value. If the equivalence value for the spilled volume may be determined based on its composition, then the appropriate equivalence value shall be used. If the equivalence value for the spilled volume cannot be determined, the equivalence value is 1.0. In the case that the fuel must be reported in pounds rather than gallons, the party that reported the spill should use the best available conversion for converting the volume into gallons. In the event that volume is spilled in transport, the owner of the RINs will need to request a copy of the spill report from the party that reported the spill.

## D. Recordkeeping

### 1. What Types of Records Must Be Kept?

The recordkeeping requirements for obligated parties and exporters of renewable fuels support the enforcement of the use of RINs for compliance purposes. Records kept by parties are central to tracking individual RINs through the fungible distribution system after those RINs are assigned to batches of renewable fuel. Parties use invoices or other types of product transfer documentation, which are customarily generated and issued in the course of business and which are familiar to parties who transfer or receive fuel. Parties are afforded significant freedom with regard to the form these documents take, although they must travel in some manner (on paper or electronically) with the volume of renewable fuel being transferred. On each occasion any person transfers ownership of renewable fuels subject to this regulation, that transferor must provide the transferee with documents identifying the renewable fuel and containing the identifying information that includes: The name and address of the transferor and transferee, the EPA-issued company identification number of the transferor and transferee, the volume of renewable fuel that is being transferred, the date of transfer, and each associated RIN. These types of documents must be used by all parties in the distribution chain down to the point where the renewable fuel is blended into conventional gasoline or diesel.

Except for transfers to truck carriers, retailers or wholesale purchaser-consumers, product codes may be used to convey the information required, as long as the codes are clearly understood by each transferee. However, the RIN must always appear in its entirety before it is separated from a batch, since it is a unique identification number that

cannot be summarized by a shorter code.

Parties must keep copies of all records for a period of not less than five (5) years. In addition to documentation related to transfers, parties must keep information related to the sale, purchase, brokering and trading of RINs and copies of any reports they submit to us for compliance reports. For example, if a volume of fuel and its associated RINs are reported to us as lost due to spillage, documentation related to that spill must be retained for the five year period. Upon request, parties are responsible for providing records to the Administrator or the Administrator's authorized representative.

### 2. What Recordkeeping Requirements Are Specific to Producers of Cellulosic or Waste-Derived Ethanol?

In addition to the records applicable to all ethanol producers, producers of cellulosic biomass or waste-derived ethanol must keep records of fuel use in order to ensure compliance with, and enforcement of, the definitions of these types of renewable fuel. Producers of cellulosic biomass or waste-derived ethanol must keep records of volume and types of all feedstocks purchased to ensure compliance with, and enforcement of, the feedstock aspect of the definitions of cellulosic biomass and waste-derived ethanol. In addition, producers of cellulosic biomass or waste-derived ethanol are required to arrange for an independent third party to review the ethanol producer's records and verify that the facility is, in fact, a cellulosic biomass or waste-derived ethanol production facility and that the ethanol producer is producing cellulosic biomass or waste-derived ethanol. The independent third party must be a licensed Professional Engineer (P.E.) in the chemical engineering field. Domestic ethanol producers are not required obtain prior approval of the independent third party P.E. or submit the engineering verification to EPA, however, the ethanol producer and the P.E. are required to keep records related to the required engineering verification and to produce them upon request of the Administrator or the Administrator's authorized representative.

A foreign ethanol producer may apply to us to have its cellulosic biomass or waste-derived ethanol treated in the same manner as domestic cellulosic biomass or waste-derived ethanol under the RFS program. A foreign ethanol producer with an approved application will be required to comply with all of the requirements that apply to domestic ethanol producers, including registration, recordkeeping, reporting,

attest engagements, and the independent third party verification discussed above. The attest engagements for a foreign ethanol producer must be conducted by a U.S. auditor (if not a U.S. based auditor, the auditor must be approved in advance by EPA). Similar to other fuels programs, the foreign ethanol producer will be required to comply with additional requirements designed to ensure that enforcement of the regulations at the foreign ethanol facility will not be compromised. The independent third party P.E. conducting the facility verification must be approved by EPA before the foreign entity will be allowed to treat its cellulosic biomass or waste-derived ethanol in the same manner as domestic producers. The foreign ethanol producer must arrange for the P.E. to inspect the facility and submit a report to us which describes the physical plant and its operation and includes documentation of the P.E.'s qualifications. The foreign ethanol producer must agree to provide access to EPA personnel for the purposes of conducting inspections and audits, post a bond, and arrange for an independent inspector to monitor ship loading and offloading records to ensure that volumes of ethanol do not change from port of shipping to port of entry. The independent inspector must be approved by EPA prior to the shipment of any ethanol designated by the foreign ethanol producer as ethanol which is to be treated as cellulosic biomass or waste-derived ethanol. Cellulosic biomass or waste-derived ethanol produced by a foreign ethanol producer must be identified as such on product transfer documents that accompany the ethanol to the importer. (These additional provisions for foreign ethanol producers are contained in § 80.1166.)

The provisions for foreign ethanol producers are optional and are available only to foreign producers of cellulosic biomass or waste-derived ethanol. Ethanol or other renewable fuels produced and exported to the United States by other foreign producers are regulated through the importer. An importer that receives ethanol identified as cellulosic biomass or waste-derived ethanol produced by a foreign producer with an approved application would not assign RINs to the ethanol, as RINs for such ethanol will be assigned by the foreign ethanol producer. The importer, like any other marketer, would transfer the RINs assigned by the foreign producer with a volume of ethanol and report the transactions to us.

*E. Attest Engagements*

1. What Are the Attest Engagement Requirements Under the RFS Program?

Attest engagements are similar to financial audits and consist of an independent, professional review of compliance records and reports. Similar to other fuels programs, the RFS program requires reporting parties to arrange for annual attest engagements to be conducted by an auditor that is "independent" under the criteria specified in the regulations. We believe that the attest engagements provide an appropriate and useful tool for verifying the accuracy of the information reported to us. Attest engagements are performed in accordance with standard procedures and standards established by the American Institute of Certified Public Accountants and the Institute of Internal Auditors. The attest engagement consists of an outside certified public accountant (CPA) or certified independent auditor (CIA) following agreed upon procedures to determine whether underlying records, reported items, and transactions agree, and issuing a report as to their findings. Attest engagements are performed on an annual basis.

2. Who Is Subject to the Attest Engagement Requirements for the RFS Program?

Obligated parties, producers, exporters and importers of renewable fuel, and any party who own RINs are all subject to the attest engagement requirements.

3. How Are the Attest Engagement Requirements in This Final Rule Different From Those Proposed?

We had proposed that obligated parties, exporters, and renewable fuels producers be subject to attest engagement requirements. We received several comments on this proposal. Some commenters suggested that the attest engagements should be required for renewable fuels producers and importers, but not for obligated parties. These commenters believe that attest engagements are needed for renewable fuel producers and importers in order to verify reported production and RIN volumes, whereas we can monitor compliance by obligated parties by cross-checking their reports regarding RIN transactions and use with the reports from other parties. These commenters also believe that the information required by obligated parties under the RFS program is not such that an attest engagement is needed because the rule does not require verification of raw data as with

other fuels programs. We have considered these comments but continue to believe that the attest engagements are an appropriate means of verifying the accuracy of the information reported to us by obligated parties. In addition to documentation of RIN transactions and use, the reports include information on production and import volumes and calculation of the party's RFS obligation. We believe that attest engagements are necessary in order to verify that the underlying data regarding production and import volumes and RFS obligation, as well as the underlying data regarding RIN transactions and use, support the information included in the reports. As a result, the final rule includes an attest engagement requirement for obligated parties.

We also received several comments that the attest engagement auditor should be required to examine only representative samples of the party's RIN transaction documents rather than the documents for each RIN transaction, as required in the proposed regulations. We agree that examination of representative samples of RIN transaction documents would provide sufficient oversight and that the requirement included in the proposed regulations may be unnecessarily burdensome. As a result, the attest engagement provisions have been modified to require the auditor to examine only representative samples of RIN transaction documents. However, in the case of attest engagements applied to RIN generation by producers or importers of renewable fuel, or the use of RINs for compliance purposes by obligated parties or exporters, the auditor must examine documentation for all RINs generated or used. We believe this requirement is necessary to ensure that obligated parties and exporters are meeting their RFS obligation and that ethanol producers and importers are assigning RINs to each batch of renewable fuel produced or imported as required under the regulations.

The proposed attest engagement regulations at § 80.1164(b) did not include importers of renewable fuels. One commenter pointed out these procedures should apply to both renewable fuels producers and importers. Renewable fuel importers have the same reporting requirements as renewable fuel producers, and, therefore, there is the same need for verification of the information given on the reports through attest engagements. It was an inadvertent oversight that renewable fuel importers were not included in the parties required to

comply with the attest engagement procedures in proposed § 80.1164(b), and that applying the requirements in § 80.1164(b) to renewable fuel importers is a logical outgrowth of the proposed regulations. As a result, the regulations have been modified to include renewable fuel importers in the parties required to comply with the attest procedures in § 80.1164(b).

In addition to obligated parties, exporters and renewable fuel producers and importers, we believe that an attest engagement requirement is necessary for any party who takes ownership of a RIN. As discussed above, attest engagements provide an appropriate and useful tool for verifying the accuracy of the information reported to us. Like obligated parties and renewable fuel producers and importers, the final rule requires RIN owners to submit information regarding RIN transaction activity to us. We believe that attest engagement audits are necessary to verify the accuracy of the information included in these reports. Therefore, this final rule includes an attest engagement requirement for RIN owners who are not obligated parties or renewable fuel producers or importers. We believe that inclusion of the requirement in the final rule is a logical outgrowth of the proposed attest engagement requirements for other parties who are required to submit similar information regarding RIN transaction activity to us.

## V. What Acts Are Prohibited and Who Is Liable for Violations?

The prohibition and liability provisions applicable to the RFS program are similar to those of other gasoline programs. The final rule identifies certain prohibited acts, such as a failure to acquire sufficient RINs to meet a party's renewable fuel obligation (RVO), producing or importing a renewable fuel without properly assigning a RIN, creating, transferring or using invalid RINs, improperly transferring renewable fuel volumes without RINs, improperly separating RINs from renewable fuel, retaining more RINs during a quarter than the party's inventory of renewable fuel, or transferring RINs that are not identified by proper RIN numbers. Any person subject to a prohibition will be held liable for violating that prohibition. Thus, for example, an obligated party will be liable if the party fails to acquire sufficient RINs to meet its RVO. A party who produces or imports renewable fuels will be liable for a failure to properly assign RINs to batches of renewable fuel produced or imported. A renewable fuels marketer will be liable

for improperly transferring renewable fuel volumes without RINs or retaining more RINs during a quarter than the party's inventory of renewable fuels. Any party may be liable for creating, transferring, or using an invalid RIN, or transferring a RIN that is not properly identified.

In addition, any person who is subject to an affirmative requirement under the RFS program will be liable for a failure to comply with the requirement. For example, an obligated party will be liable for a failure to comply with the annual compliance reporting requirements. A renewable fuel producer or importer will be liable for a failure to comply with the applicable renewable fuel batch reporting requirements. Any party subject to recordkeeping or product transfer document requirements would be liable for a failure to comply with these requirements. Like other EPA fuels programs, the final rule provides that a party who causes another party to violate a prohibition or fail to comply with a requirement may be found liable for the violation.

The Energy Act amended the penalty and injunction provisions in section 211(d) of the Clean Air Act to apply to violations of the renewable fuels requirements in section 211(o).[42] Accordingly, under the final rule, any person who violates any prohibition or requirement of the RFS program may be subject to civil penalties for every day of each such violation and the amount of economic benefit or savings resulting from the violation. Under the final rule, a failure to acquire sufficient RINs to meet a party's renewable fuels obligation will constitute a separate day of violation for each day the violation occurred during the annual averaging period.

Because there are no standards under the RFS rule that may be measured downstream, we believe that a presumptive liability scheme, i.e., a scheme in which parties upstream from the facility where the violation is found are presumed liable for the violation, would not be applicable under the RFS program. As a result, the RFS rule does not contain such a scheme.

The regulations prohibit any party from creating, transferring or using invalid RINs. These invalid RIN provisions apply regardless of the good faith belief of a party that the RINs are valid. These enforcement provisions are necessary to ensure the RFS program goals are not compromised by illegal

conduct in the creation and transfer of RINs.

Any obligated party that reports the use of invalid RINs to meet its renewable fuels obligation may be liable for a regulatory violation for use of invalid RINs. If the obligated party fails to meet its renewable fuels obligation without the invalid RINs, the party may also be liable for not meeting its renewable fuels obligation. In addition, the transfer of invalid RINs is prohibited, so that any party or parties that transfer invalid RINs may be liable for a regulatory violation for transferring the invalid RINs. In a case where invalid RINs are transferred and used, EPA normally will hold each party that committed a violation responsible, including both the user and the transferor of the invalid RINs. For this reason, obligated parties and RIN brokers should use good business judgment when deciding whether to purchase RINs from any particular seller and should consider including prudent business safeguards in RIN transactions, such as requiring RIN sellers to sign contracts with indemnity provisions to protect the purchaser in the event penalties are assessed because we find the RINs are invalid. Similarly, parties that sell RINs should take steps to ensure any RINs that are sold were properly created to avoid penalties that result from the transfer of invalid RINs.

As in other motor vehicle fuel credit programs, the regulations address the consequences if an obligated party is found to have used invalid RINs to demonstrate compliance with its RVO. In this situation, the obligated party that used the invalid RINs will be required to deduct any invalid RINs from its compliance calculations. As discussed above, the obligated party will be liable for not meeting its renewable fuels obligation if the remaining number of valid RINs is insufficient to meet its RVO, and the obligated party may be subject to monetary penalties if it used invalid RINs in its compliance demonstration. In determining an appropriate penalty, EPA will consider a number of factors, including whether the obligated party did in fact procure sufficient valid RINs to cover the deficit created by the invalid RINs. A penalty may include both the economic benefit of using invalid RINs and a gravity component.

Although an obligated party may be liable for a violation if it uses invalid RINs for compliance purposes, we normally will look first to the generator or seller of the invalid RINs both for payment of penalty and to procure sufficient valid RINs to offset the invalid RINs. However, if EPA is unable to

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[42] Section 1501(b) of the Energy Policy Act of 2005.

obtain relief from that party, attention will turn to the obligated party who may then be required to obtain sufficient valid RINs to offset the invalid RINs.

We received several comments on the prohibition regarding use of invalid RINs. Some commenters believe that an obligated party that uses RINs which are later found to be invalid should be given an opportunity to ''cure'' the shortfall caused by the invalid RINs without penalty. As indicated above, a penalty for a good faith purchaser is not automatic. Where an invalid RIN was created by another party, such as the producer or marketer of the renewable fuel, the party responsible for the existence of the invalid RIN would be liable and would be required to purchase a RIN to make up for the invalid RIN and pay an appropriate penalty. If the responsible party cannot be identified or is out of business, or if EPA is otherwise unable to obtain relief from the party, then the obligated party that used the RIN would be required to purchase a RIN to make up for the invalid RIN. However, any penalty for a good faith purchaser would likely be small, particularly where EPA is able to obtain relief from the party that was responsible for the invalid RIN. Where a RIN was originally believed to be valid but is later found to be invalid, whether a current year RIN may be used to make up for the prior-year invalid RIN would be determined in the context of the enforcement action.

Another commenter suggested that an obligated party should not be liable for

a violation unless the party knowingly used the invalid RINs to demonstrate compliance. Where the suspect RINs are later proved to be valid, the party should be able to use the RINs in the subsequent year regardless of the year of generation or any rollover cap. For the reasons stated above, we believe that it is appropriate to hold an obligated party responsible for using invalid RINs even where the party in good faith believed the RINs to be valid. Normally, suspect RINs will be not be replaced until the RINs are proved to be invalid. In the unlikely circumstance that a RIN is first determined to be invalid and then later found to be valid, the ability to use the RIN in a subsequent year would be determined in the context of the enforcement action.

Finally, parties that are predominately renewable fuel producers or importers, but which must be designated as obligated parties due to the production or importation of a small amount of gasoline, should not be able to separate RINs from all renewable fuels that they own. To address such circumstances, we are prohibiting obligated parties from separating RINs that they generate from volumes of renewable fuel in excess of their RVO. However, obligated parties must separate any RINs generated by other parties from renewable fuel if they own the renewable fuel.

## VI. Current and Projected Renewable Fuel Production and Use

While the definition of renewable fuel 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. This section provides a brief overview of the ethanol and biodiesel industries today and how they are projected to grow into the future.

### A. Overview of U.S. Ethanol Industry and Future Production/Consumption

1. Current Ethanol Production

As of October 2006, there were 110 ethanol production facilities operating in the United States with a combined production capacity of approximately 5.2 billion gallons per year.[43] 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 majority of ethanol (almost 92 percent by volume) is produced exclusively from corn. Another 7 percent comes 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 VI.A.1–1.

TABLE VI.A.1–1.—2006 U.S. ETHANOL PRODUCTION BY FEEDSTOCK

| Plant feedstock | Capacity MMgy | Percent of capacity | Number of plants | Percent of plants |
|---|---|---|---|---|
| Cheese Whey | 8 | 0.1 | 2 | 1.8 |
| Corn [a] | 4,780 | 91.6 | 90 | 81.8 |
| Corn, Barley | 40 | 0.8 | 1 | 0.9 |
| Corn, Milo [b] | 244 | 4.7 | 8 | 7.3 |
| Corn, Wheat | 90 | 1.7 | 2 | 1.8 |
| Milo, Wheat | 40 | 0.8 | 1 | 0.9 |
| Sugars, Starches | 2 | 0.0 | 1 | 0.9 |
| Waste Beverages [c] | 16 | 0.3 | 5 | 4.5 |
| Total | 5,218 | 100.0 | 110 | 100.0 |

[a] Includes two facilities processing seed corn and another facility processing corn which intends to transition to corn stalks, switchgrass, and biomass in the future.
[b] Includes one facility procesisng small amounts of molasses in addition to corn and milo.
[c] Includes two facilities processing brewery waste.

[43] The October 2006 ethanol production capacity baseline was generated based on the June 2006 NPRM plant list and updated on October 18, 2006 based on a variety of data sources including: Renewable Fuels Association (RFA), Ethanol Biorefinery Locations (updated October 16, 2006); Ethanol Producer Magazine (EPM), plant list (downloaded October 18, 2006) and monthly

publications (June 2006 through October 2006); ICF International, Ethanol Industry Profile (September 30, 2006); BioFuels Journal, News & Information for the Ethanol and BioFuels Industries (breaking news posted June 16, 2006 through October 18, 2006); and ethanol producer Web sites. The baseline includes small-scale ethanol production facilities as well as former food-grade ethanol plants that have

since transitioned into the fuel-grade ethanol market. Where applicable, current ethanol plant production levels have been used to represent plant capacity, as nameplate capacities are often underestimated. This analysis does not consider ethanol plants that may be located in the Virgin Islands or U.S. territories.

There are a total of 102 plants processing corn and/or other similarly processed grains. Of these facilities, 92 utilize dry-milling technologies and the remaining 10 plants rely on wet-milling processes. Dry mill ethanol plants grind the entire kernel and produce only one primary co-product: Distillers' grains with solubles (DGS). The co-product is sold wet (WDGS) or dried (DDGS) to the agricultural market as animal feed. In contrast to dry mill plants, wet mill facilities separate the kernel prior to processing and in turn produce other co-products (usually gluten feed, gluten meal, and oil) in addition to DGS. Wet mill plants are generally more costly to build but are larger in size on average. As such, nearly 22 percent of the current overall ethanol production comes from the 10 previously-mentioned wet mill facilities.

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

Ethanol production is a relatively resource-intensive process that requires the use of water, electricity, and steam. Steam needed to heat the process is generally produced onsite or by other dedicated boilers. Of today's 110 ethanol production facilities, 101 burn natural gas, 7 burn coal, 1 burns coal and biomass, and 1 burns syrup from the process to produce steam.[44] Our research suggests that 11 plants currently utilize cogeneration or combined heat and power (CHP) technology, although others may exist. CHP is a mechanism for improving overall plant efficiency. Whether owned by the ethanol facility, their local utility, or a third party; CHP facilities produce their own electricity and use the waste heat from power production for process steam, reducing the energy intensity of ethanol production. A summary of the energy sources and CHP technology utilized by today's ethanol plants is found in Table VI.A.1–2.

TABLE VI.A.1–2.—2006 U.S. ETHANOL PRODUCTION BY ENERGY SOURCE

| Plant energy source | Capacity MMgy | Percent of capacity | Number of plants | Percent of plants | CHP tech. |
|---|---|---|---|---|---|
| Coal | 1,042 | 20.0 | 7 | 6.3 | 2 |
| Coal, Biomass | 50 | 1.0 | 1 | 0.9 | 0 |
| Natural Gas [a] | 4,077 | 78.1 | 101 | 91.8 | 9 |
| Syrup | 48 | 0.9 | 1 | 0.9 | 0 |
| Total | 5,218 | 100.0 | 110 | 100.0 | 11 |

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

The majority of domestic ethanol is currently produced in the Midwest within PADD 2—where most of the corn is grown. Of the 110 U.S. ethanol production facilities, 100 are located in PADD 2. As a region, PADD 2 accounts for 96 percent (or over five billion gallons) of the annual domestic ethanol production, as shown in Table VI.A.1–3.

TABLE VI.A.1–3.—2006 U.S. ETHANOL PRODUCTION BY PADD

| PADD | Capacity MMgy | Percent of capacity | Number of plants | Percent of plants |
|---|---|---|---|---|
| PADD 1 | 0.4 | 0.0 | 1 | 0.9 |
| PADD 2 | 5,012 | 96.0 | 100 | 90.9 |
| PADD 3 | 30 | 0.6 | 1 | 0.9 |
| PADD 4 | 105 | 2.0 | 4 | 3.6 |
| PADD 5 | 71 | 1.4 | 4 | 3.6 |
| Total | 5,218 | 100.0 | 110 | 100.0 |

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

Leading the Midwest in ethanol production are Iowa, Illinois, Nebraska, Minnesota, and South Dakota with a combined capacity of nearly four billion gallons per year. Together, these five states' 70 ethanol plants account for 76 percent of the total domestic product. However, although the majority of ethanol production comes from PADD 2, there are a growing number of plants located outside the traditional corn belt. In addition to the 15 states comprising PADD 2, ethanol plants are currently located in California, Colorado, Georgia, New Mexico, and Wyoming. Some of these facilities ship in feedstocks (namely corn) from the Midwest, others rely on locally grown/produced

feedstocks, while others rely on a combination of both.

The U.S. ethanol industry is currently comprised of a mixture of corporations and farmer-owned cooperatives (co-ops). More than half (or 60) of today's plants are owned by corporations and, on average, these plants are larger in size than farmer-owned co-ops. Accordingly, company-owned plants account for almost 64 percent of the total U.S. ethanol production capacity. Further, more than 50 percent of the total domestic product comes from plants owned by just 6 different companies—Archer Daniels Midland, Broin, VeraSun, Hawkeye Renewables, Global/MGP Ingredients, and Aventine Renewable Energy.[45]

2. Expected Growth in Ethanol Production

Over the past 25 years, domestic fuel ethanol production has steadily increased due to environmental regulation, federal and state tax incentives, and market demand. More recently, ethanol production has soared due to the phase out of MTBE, an increasing number of state ethanol mandates, and elevated crude oil prices. As shown in Figure VI.A.2–1, over the past three years, domestic ethanol production has nearly doubled from 2.1 billion gallons in 2002 to 4.0 billion gallons in 2005. For 2006, the Renewable Fuels Association is anticipating about 4.7 billion gallons of domestic ethanol production.[46]

Figure VI.A.2-1

U.S. Ethanol Production versus Time
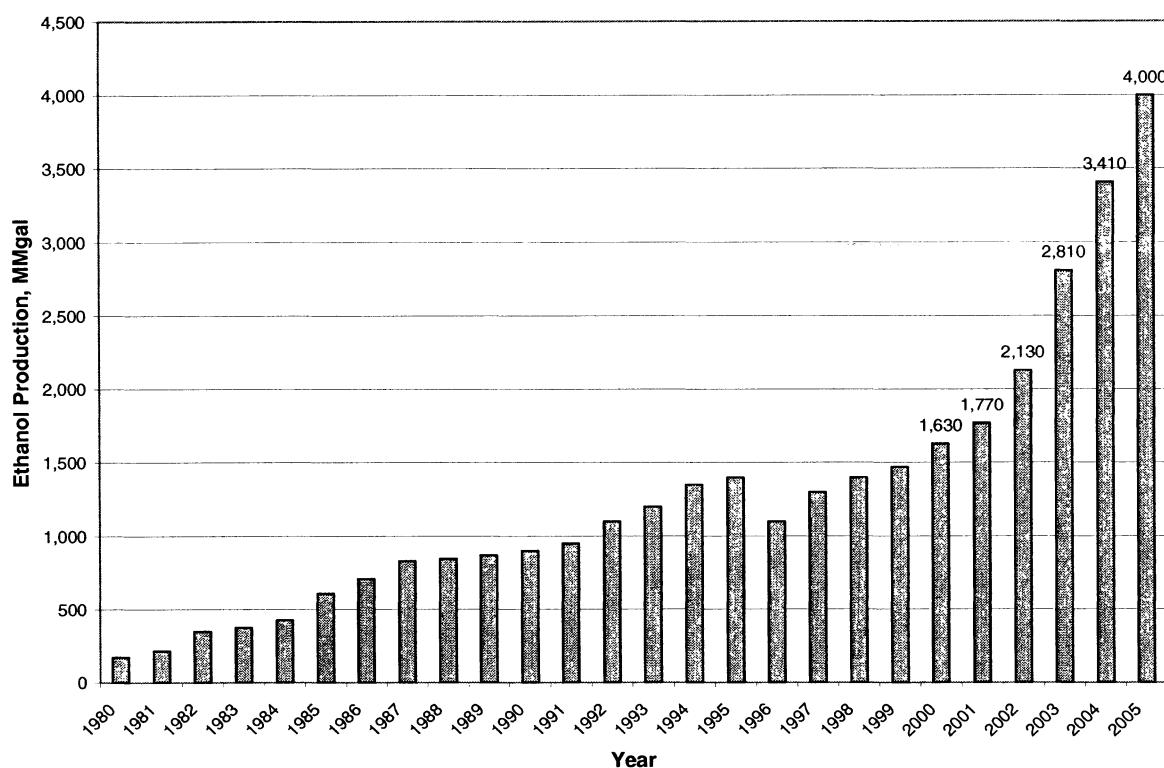


Source: Renewable Fuels Association, From Niche to Nation: Ethanol Industry Outlook 2006

EPA forecasts that domestic ethanol production will continue to grow into the future. In addition to the past

impacts of federal and state tax incentives, as well as the more recent impacts of state ethanol mandates and

the removal of MTBE from all U.S. gasoline, crude oil prices are expected to continue to drive up demand for

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[45] Includes Broin's minority ownership in 18 U.S. ethanol plants.

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

ethanol. As a result, the nation is on track to exceed the renewable fuel volume requirements contained in the Act. Today's ethanol production capacity (5.2 billion gallons) is already exceeding the 2007 renewable fuel requirement (4.7 billion gallons). In addition, there is another 3.4 billion gallons of ethanol production capacity currently under construction.[47] A summary of the new construction and plant expansion projects currently underway (as of October 2006) is found in Table VI.A.2–1.

TABLE VI.A.2–1.—UNDER CONSTRUCTION U.S. ETHANOL PRODUCTION CAPACITY

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

[a] Includes plant expansions.

A select group of builders, technology providers, and construction contractors are completing the majority of the construction projects described in Table VI.A.2–1. 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 VI.A.2–2.[48]

[47] Under construction plant locatons, capacities, feedstocks, and energy sources as well as planned/ proposed plant locations and capacities were derived from a variety of data soruces including Renewable Fuels Association (RFA), Ethanol Biorefinery Locations (updated October 16, 2006); Ethanol Producer Magazine (EPM), under construction plant list (downloaded October 18, 2006) and monthly publications (June 2006 through October 2006); ICF International, Ethanol Industry Profile (September 30, 2006); BioFuels Journal, News & Information for the Ethanol and BioFuels Industries (breaking news posted June 16, 2006 through October 18, 2006); and ethanol producer Web sites. This analysis does not consider ethanol plants under construction or planned for the Virgin Islands or U.S. territories.

[48] Construction timelines based on information obtained from press releases and ethanol producer Web sites.

Figure VI.A.2-2

Estimated Phase-In of Under Construction Plant Capacity
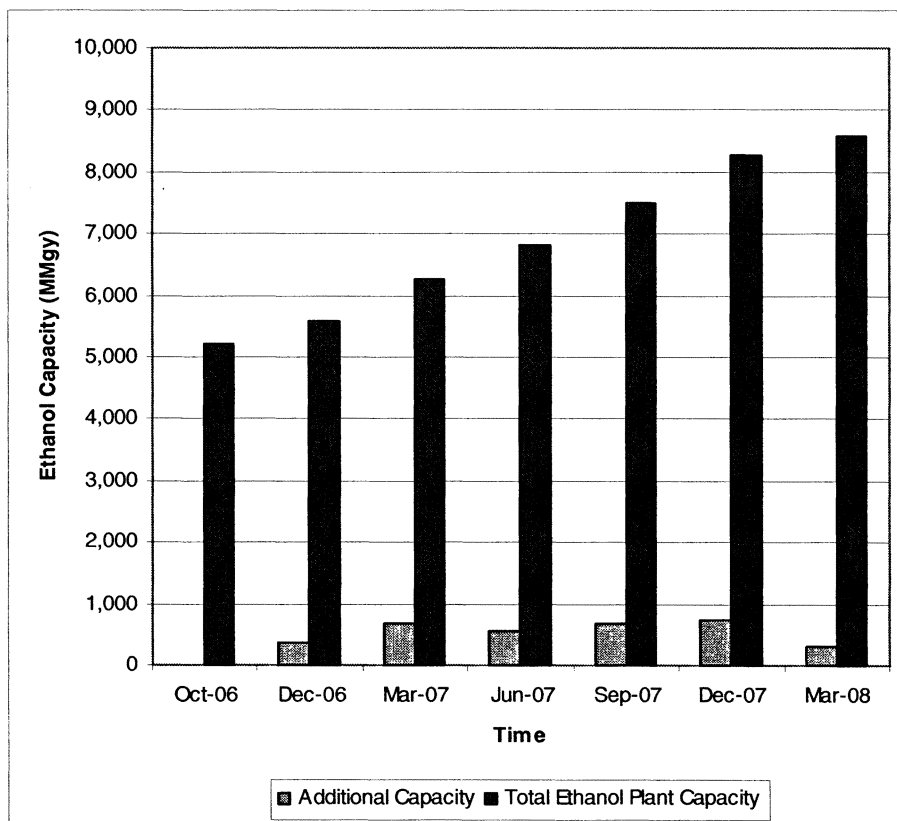


As shown in Table VI.A.2–1 and Figure VI.A.2–2, once all the construction projects currently underway are complete (estimated by March 2008), the resulting U.S. ethanol production capacity would be about 8.6 billion gallons. Without even considering forecasted biodiesel production (described below in Section VI.B.1), this would be more than enough renewable fuel to satisfy the 2012 RFS requirements (7.5 billion gallons). However, ethanol production is expected to continue to grow. There are more and more ethanol projects being announced each day. These potential projects are at various stages of planning from conducting feasibility studies to gaining local approval to applying for permits to financing/fundraising to obtaining contractor agreements. Together these potential projects could result in an additional 21 billion gallons of ethanol production capacity as shown in Table VI.A.2–2.

TABLE VI.A.2–2.—OTHER POTENTIAL U.S. ETHANOL PRODUCTION CAPACITY

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

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

Although there is clearly a great potential for ethanol production growth, it is highly unlikely that all the announced projects would actually reach completion in a reasonable amount of time, or at all, considering the large number of projects moving forward. Since there is no precise way to know exactly which plants will come

to fruition in the future, we have chosen to focus our subsequent discussion on forecasted ethanol production on plants which are likely to be online by 2012.[49] This includes existing plants as well as projects which are under construction (refer to Table VI.A.2–1) or in the final planning stages (denoted as ''planned'' in Table VI.A.2–2). The distinction between ''planned'' versus ''proposed'' is that as of October 2006 planned projects had completed permitting, fundraising/financing, and had builders assigned with definitive construction timelines whereas proposed projects did not.

### TABLE VI.A.2–3.—FORECASTED 2012 ETHANOL PRODUCTION BY PADD

| PADD | Capacity MMgy | Percent of capacity | Number of plants | Percent of plants |
|------|--------------|--------------------|-----------------|-------------------|
| PADD 1 ....................................................................................................... | 663 | 4.6 | 10 | 4.5 |
| PADD 2 ....................................................................................................... | 12,409 | 86.5 | 183 | 82.4 |
| PADD 3 ....................................................................................................... | 510 | 3.6 | 8 | 3.6 |
| PADD 4 ....................................................................................................... | 255 | 1.8 | 6 | 2.7 |
| PADD 5 ....................................................................................................... | 501 | 3.5 | 15 | 6.8 |
| Total ................................................................................................... | 14,339 | 100.0 | 222 | 100.0 |

As shown above in Table VI.A.2–3, once all the under construction and planned projects are complete the resulting ethanol production capacity would be 14.3 billion gallons. The majority of which would still originate from PADD 2. This volume, expected to be online by 2012, exceeds the EIA AEO 2006 demand estimate (9.6 billion gallons by 2012, discussed more in RIA Section 2.1). The forecasted growth would nearly triple today's production capacity and greatly exceed the 2012 RFS requirement (7.5 billion gallons). While our forecast represents ethanol production capacity (actual production could be lower), we believe it is still a good indicator of what domestic ethanol production could look like in the future. In addition, we predict that domestic ethanol production will continue to be supplemented by imports in the future.

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 Caribbean Basin Initiative (CBI), with some direct imports from Brazil during times of shortfall or high price. For more information on ethanol imports, refer to RIA Section 1.5.

Of the 112 forecasted new ethanol plants (47 under construction and 65 planned), 106 would rely on grain-based feedstocks. More specifically, 89 would rely exclusively on corn, 13 would process a blend of corn and/or similarly processed grains (milo or wheat), 3 would process molasses, and 1 would process a combination of molasses and sweet sorghum (milo). Of the remaining six plants (all in the planned stage), four would process cellulosic biomass

feedstocks and two would start off processing corn and later transition to cellulosic materials. Of the four dedicated cellulosic plants, one would process bagasse, one would process a combination of bagasse and wood, and two would process biomass. Of the two transitional corn/cellulosic plants, one would ultimately process a combination of bagasse, rice hulls, and wood and the other would ultimately process wood and other agricultural residues. In addition to the forecasted new plants, an existing corn ethanol plant plans to expand production and transition to corn stalks, switchgrass, and biomass in the future. A summary of the resulting overall feedstock usage (including current, under construction, and planned projects) is found in Table VI.A.2–4.

### TABLE VI.A.2–4.—FORECASTED 2012 U.S. ETHANOL PRODUCTION BY FEEDSTOCK

| Plant feedstock | Capacity MMgy | Percent of capacity | Number of plants | Percent of plants |
|-----------------|--------------|--------------------|-----------------|-------------------|
| Bagasse ...................................................................................................... | 7 | 0.1 | 1 | 0.5 |
| Bagasse, Wood ........................................................................................... | 2 | 0.0 | 1 | 0.5 |
| Bagasse, Wood, Rice Hulls[a] ..................................................................... | 108 | 0.8 | 1 | 0.5 |
| Biomass ....................................................................................................... | 55 | 0.4 | 2 | 0.9 |
| Cheese Whey .............................................................................................. | 8 | 0.1 | 2 | 0.9 |
| Corn[b] .......................................................................................................... | 12,495 | 87.1 | 178 | 80.2 |
| Corn, Barley ................................................................................................ | 40 | 0.3 | 1 | 0.5 |
| Corn, Milo[c] .................................................................................................. | 1,132 | 7.9 | 20 | 9.0 |
| Corn, Wheat ................................................................................................ | 235 | 1.6 | 3 | 1.4 |
| Corn Stalks, Switchgrass, Biomass[a] ......................................................... | 40 | 0.3 | 1 | 0.5 |
| Milo, Wheat ................................................................................................. | 40 | 0.3 | 1 | 0.5 |
| Molasses[d] ................................................................................................... | 52 | 0.4 | 4 | 1.8 |
| Sugars, Starches ........................................................................................ | 2 | 0.0 | 1 | 0.5 |
| Waste Beverages[e] ..................................................................................... | 16 | 0.1 | 5 | 2.3 |
| Wood Agricultural Residues[a] ..................................................................... | 108 | 0.8 | 1 | 0.5 |
| Total ................................................................................................... | 14,339 | 100.0 | 222 | 100.0 |

[a] Facilities plan to start off processing corn.

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

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

Of the 112 forecasted new plants, 100 would burn some amount of natural gas—at least initially. More specifically, 91 plants would rely exclusively on natural gas; 2 would rely on a combination of natural gas, bran and biomass; 1 would burn a combination of natural gas, distillers' grains and syrup; and 6 would start off burning natural gas and later transition to coal. As for the remaining 12 plants, 3 would burn manure-derived methane (biogas); 7 would rely exclusively on coal; 1 would

burn a combination of coal and biomass; and 1 would burn a combination of coal, tires and biomass. In addition to the new ethanol plants, three existing plants currently burning natural gas are predicted to transition to alternate boiler fuels in the future. More specifically, two plants plan to transition to biomass and one plans to start burning coal. Our research suggests that 7 of the new plants would utilize combined heat and power (CHP) technology, although others may exist. Three of the new CHP

plants would burn natural gas, three would burn coal, and one would burn a combination of coal, tires, and biomass. Among the existing CHP plants, two are predicted to transition from natural gas to coal or biomass at this time. Overall, the net number of CHP ethanol plants would increase from 11 to 18. A summary of the resulting overall plant energy source utilization is found below in Table VI.A.2–5.

TABLE VI.A.2–5.—FORECASTED 2012 U.S. ETHANOL PRODUCTION BY ENERGY SOURCE

| Plant energy source | Capacity MMgy | Percent of capacity | Number of plants | Percent of plants | CHP tech. |
|---|---|---|---|---|---|
| Biomass a | 112 | 0.8 | 2 | 0.9 | 1 |
| Coal b | 2,095 | 14.6 | 21 | 9.5 | 6 |
| Coal, Biomass | 75 | 0.5 | 2 | 0.9 | 0 |
| Coal, Biomass, Tires | 275 | 1.9 | 1 | 0.5 | 1 |
| Manure Biogas c | 144 | 1.0 | 3 | 1.4 | 0 |
| Natural Gas | 11,275 | 78.6 | 189 | 85.1 | 10 |
| Natural Gas, Bran, Biomass | 264 | 1.8 | 2 | 0.9 | 0 |
| Natural Gas, Distiller's Grain, Syrup | 50 | 0.3 | 1 | 0.5 | 0 |
| Syrup | 49 | 0.3 | 1 | 0.5 | 0 |
| Total | 14,339 | 100.0 | 222 | 100.0 | 18 |

a Represents two existing natural gas-fired plants that plan to transition to biomass.
b Includes two plants planning on burning lignite coal or coal lines. Includes one existing plant currently burning natural gas that plans to transition to coal. Includes six new plants that will start off burning natural gas and later transition to coal.
c Includes one facility planning on burning cotton gin in addition to manure biogas.

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

As shown in Table VI.A.2–4, there are seven ethanol plants planning to utilize cellulosic feedstocks in the future. These facilities have a combined ethanol production capacity of 320 million gallons per year. It is unclear whether these plants would be online and capable of producing 250 million gallons of ethanol by 2013 to meet the

Act's cellulosic biomass ethanol requirement. However, as shown in Table VI.A.2–5, there are 12 facilities that burn or plan to burn waste materials to power their ethanol plants. Depending on how much fossil fuel is displaced, these facilities (with a combined ethanol production capacity of 969 million gallons per year) could also meet the definition of cellulosic biomass ethanol under the Act. Considering both feedstock and waste energy plants, the total cellulosic ethanol potential could be as high as 1.3 billion gallons. Even if only one fifth of this ethanol were to end up qualifying as cellulosic biomass ethanol or come to fruition by 2013, it would be more than enough to satisfy the 250 million gallon requirement specified in the Act.[50]

[50] 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.

3. Current Ethanol and MTBE Consumption

To understand the impact of the increased ethanol production/use on gasoline properties and in turn 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. As such, in addition to the production analysis presented above, we have completed a parallel consumption analysis comparing current ethanol consumption to future predictions.

In the 2004 base case, 3.5 billion gallons of ethanol[51] and 1.9 billion gallons of MTBE[52] were blended into gasoline to supply the transportation sector with a total of 136 billion gallons of gasoline.[53] A breakdown of the 2004

[51] EIA Monthly Energy Review, June 2006 (Table 10.1: Renewable Energy Consumption by Source, Appendix A: Thermal Conversion Factors).
[52] File containing historical RFG MTBE usage obtained from EIA representative on March 9, 2006.
[53] EIA 2004 Petroleum Marketing Annually (Table 48: Prime Supplier Sales Volumes of Motor
Continued

gasoline and oxygenate consumption by PADD is found below in Table VI–A.3–1.

PADD is found below in Table VI–A.3–1.

TABLE VI.A.3–1.—2004 U.S. GASOLINE & OXYGENATE CONSUMPTION BY PADD

| PADD | Gasoline MMgal | Ethanol | | MTBE [a] | |
|---|---|---|---|---|---|
| | | MMgal | Percent of gasoline | MMgal | Percent of gasoline |
| PADD 1 ................................................................................... | 49,193 | 660 | 1.3 | 1,360 | 2.8 |
| PADD 2 ................................................................................... | 38,789 | 1,616 | 4.2 | 1 | 0.0 |
| PADD 3 ................................................................................... | 20,615 | 79 | 0.4 | 498 | 2.4 |
| PADD 4 ................................................................................... | 4,542 | 83 | 1.8 | 0 | 0.0 |
| PADD 5 [b] ............................................................................. | 7,918 | 209 | 2.6 | 19 | 0.2 |
| California ................................................................................ | 14,836 | 853 | 5.8 | 0 | 0.0 |
| Total ................................................................................ | 135,893 | 3,500 | 2.6 | 1,878 | 1.4 |

[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, 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 is reasonable because California alone accounts for over 10 percent of the nation's total gasoline consumption and all the fuel (both Federal RFG and California Phase 3 RFG) has been assumed to contain ethanol (following their recent MTBE ban) at 5.7 volume percent.[54] The bulk of the remaining ethanol was used in reformulated gasoline (RFG) and winter oxy-fuel areas requiring oxygenated gasoline. Overall, 62 percent of ethanol was used in RFG, 33 percent was used

in CG, and 5 percent was used in winter oxy-fuel.[55]

As shown above in Table VI.A.3–1, 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. Overall, 100 percent of MTBE in 2004 was assumed to be used in reformulated gasoline.[56]

In 2004, total ethanol use exceeded MTBE use. Ethanol's lead oxygenate role is relatively new, however the trend

has been a progression over the past few years. From 2001 to 2004, ethanol consumption more than doubled (from 1.7 to 3.5 billion gallons), while MTBE use (in RFG) was virtually cut in half (from 3.7 to 1.9 billion gallons). A plot of oxygenate use over the past decade is provided below in Figure VI.A.3–1.

The nation's transition to ethanol is linked to states' responses to recent environmental concerns surrounding MTBE groundwater contamination. Resulting 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. A list of the states with MTBE bans is provided in RIA Table 2.1–4.

Gasoline by Grade, Formulation, PAD District, and State).

[54] Current California gasoline regualtions make it very difficult to meet the NO$_X$ emissions performance standard with ethanol content higher than about 6 vol%. For our analysis, all California RFG was assumed to contain 5.7 volume percent

ethanol based on a conversation with Dean Simeroth at California Air Resources Board (CARB).

[55] For the purpose of this analysis, except where noted, the term ''RFG'' pertains to Federal RFG plus California Phase 3 RFG (CaRFG3) and Arizona Clean Burning Gasoline (CBG).

[56] 2004 MTBE consumption was obtained from EIA. The data received was limited to states with RFG programs, thus MTBE use was assumed to be limited to RFG areas for the purpose of this analysis.

Figure VI.A.3-1

U.S. Oxygenate Use Over Time
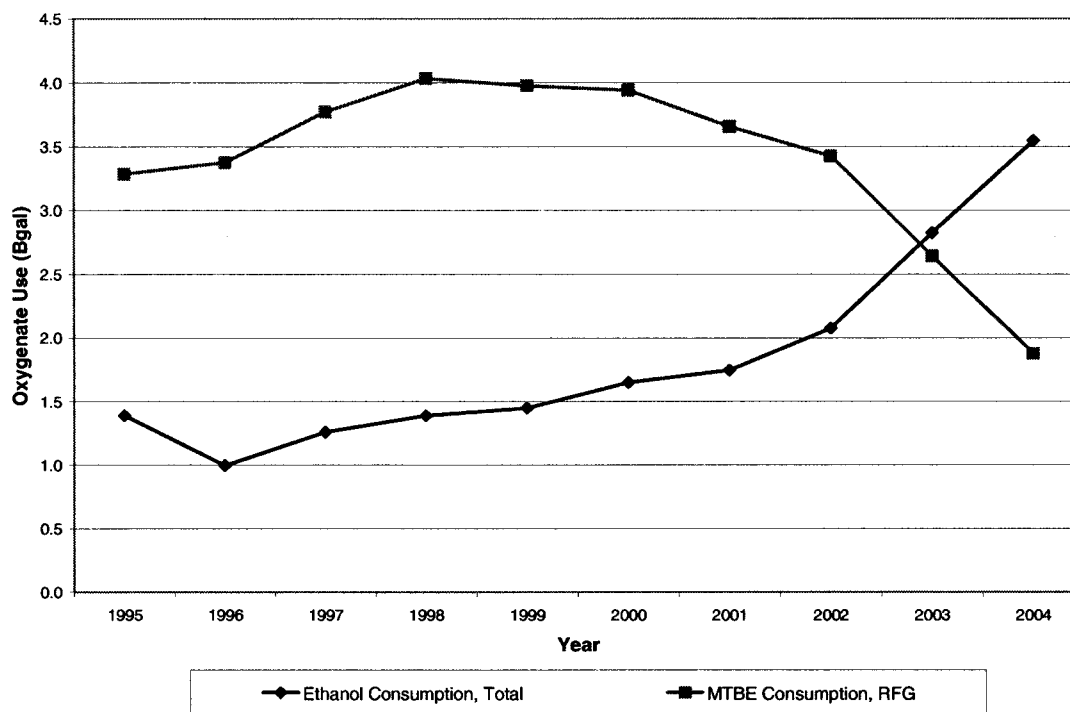


Source: Energy Information Administration

4. Expected Growth in Ethanol Consumption

As mentioned above, ethanol demand is expected to increase well beyond the levels contained in the renewable fuels standard (RFS) under the Act. With the removal of the RFG oxygenate mandate,[57] all U.S. refiners are taking steps to eliminate the use of MTBE as quickly as possible. In order to complete this transition quickly (by 2007 at the latest) while maintaining gasoline volume, octane, and mobile source air toxics emission performance standards, refiners have elected to blend ethanol into virtually all of their RFG.[58] This has caused a dramatic increase in demand for ethanol which, in 2006, was met by temporarily shifting large volumes of ethanol out of conventional gasoline and into RFG areas. By 2012, however, ethanol production will have grown to accommodate the removal of MTBE without the need for such a shift from

conventional gasoline. More important than the removal of MTBE over the long term, however, is the impact that the rise in crude oil price is having on demand for renewable fuels, both ethanol and biodiesel. This has dramatically improved the economics for renewable fuel use, leading to a surge in demand that is expected to continue. In the Annual Energy Outlook (AEO) 2006, EIA forecasted that by 2012, total ethanol use (corn, cellulosic, and imports) would be about 9.6 billion gallons and biodiesel use would be about 0.3 billion gallons at a crude oil price forecast of $48 per barrel.[59] This ethanol projection was not based on what amount the market would demand (which could be higher), but rather on the amount that could be produced by 2012. Others are making similar predictions, and as discussed above in

VI.A.2, production capacity would be sufficient.

In assessing the impacts of expanded renewable fuel use, we have chosen to evaluate two different future ethanol consumption levels, one reflecting the statutory required minimum, and one reflecting the higher levels projected by EIA. For the statutory consumption scenario we assumed 6.7 billion gallons of ethanol use (0.25 billion gallons of which was assumed to be cellulosic) and 0.3 billion gallons of biodiesel. This figure is lower than the 7.2 billion gallons of ethanol we modeled in the proposal because it considers the renewable fuel equivalence values we are finalizing for corn ethanol (1), biodiesel (1.5) and cellulosic ethanol (2.5). For the higher projected renewable fuel consumption scenario, we assumed 9.6 billion gallons of ethanol (0.25 billion gallons of which was assumed to be cellulosic) and 0.3 billion gallons of biodiesel. Although the actual renewable fuel volumes consumed in 2012 may differ from both the required and projected volumes, we believe that

[57] Energy Act Section 1504, promulgated on May 8, 2006 at 71 FR 26691.

[58] Based on discussions with the refining industry.

[59] In AEO 2007, EIA is forecasted an even higher ethanol consumption of 11.2 billion gallons by 2012. The draft report was issued on December 5, 2006 and we could not incorporate it into the refinery modeling used to conduct our analyses.

these two scenarios provide a reasonable range for analysis purposes. For more information on how the renewable fuel usage scenarios we considered, refer to RIA Section 2.1.

To estimate where ethanol would be consumed in 2012, we used a linear programming (LP) refinery cost model (discussed in more detail in Section VII). For both future ethanol consumption scenarios discussed above, the modeling provided us with a summary of ethanol usage by PADD, fuel type, and season. There was some post-processing involved to ensure that all state ethanol mandates and winter oxy-fuel requirements were satisfied. The adjusted results for the 6.7 Bgal RFS case and the 9.6 Bgal EIA case are presented below in Tables VI.A.4–1 and VI.A.4–2, respectively.

### Table VI.A.4–1.—Forecasted 2012 U.S. Ethanol Consumption (MMgal) 6.7 Bgal RFS Case

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

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

### Table VI.A.4–1.—Forecasted 2012 U.S. Ethanol Consumption by Season (MMgal) 9.6 Bgal EIA Case

| PADD | Summer ethanol use | | | Winter ethanol use | | | Total ethanol |
|---|---|---|---|---|---|---|---|
| | CG[a] | RFG[b] | Total | CG[a] | RFG[b] | Total | |
| PADD1 | 610 | 630 | 1,240 | 267 | 973 | 1,240 | 2,481 |
| PADD2 | 1,735 | 185 | 1,919 | 1,631 | 366 | 1,998 | 3,917 |
| PADD3 | 901 | 47 | 949 | 856 | 0 | 856 | 1,805 |
| PADD 4/5[c] | 339 | 0 | 339 | 154 | 0 | 154 | 492 |
| California | 0 | 435 | 435 | 0 | 470 | 470 | 905 |
| Total | 3,584 | 1,298 | 4,882 | 2,908 | 1,809 | 4,718 | 9,600 |

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

As shown above, the LP modeling predicts that the majority of ethanol will be consumed in PADD 2, where most of the ethanol is produced. The results show varying levels of ethanol usage in RFG in response to the removal of the oxygenate requirement. For the higher ethanol consumption scenario, the modeling suggests that the majority of additional ethanol would be absorbed in PADD 3 conventional gasoline. With respect to seasonality, in both cases, the modeling predicts that a greater fraction of ethanol use would occur in the summertime due to the 1psi RVP waiver. For a more detailed discussion on future ethanol consumption, refer to Chapter 2 of the RIA.

### B. Overview of Biodiesel Industry and Future Production/Consumption

1. Characterization of U.S. Biodiesel Production/Consumption

Historically, the cost to make biodiesel was an inhibiting factor to production in the U.S. The cost to produce biodiesel was high compared to the price of petroleum derived diesel fuel, even with the subsidies and credits provided by federal and state programs. Much of the demand occurred as a result of mandates from states and local municipalities, that required the use of biodiesel. However, over the past couple of years biodiesel production has been increasing rapidly. The combination of higher crude oil prices and greater federal tax subsidies has created a favorable economic situation. The Biodiesel Blenders Tax Credit programs and the Commodity Credit Commission Bio-energy Program, both subsidize producers and offset production costs. The Energy Policy Act extended the Biodiesel Blenders Tax Credit program to 2008. This credit 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. The program was started in 2004 under the American Jobs Act, spurring the expansion of biodiesel production and demand. Historical estimates and future forecasts of biodiesel production in the U.S. are presented in Table VI.B.1–1 below.

### Table VI.B.1–1.—Estimated Biodiesel Production

| Year | Million gallons per year |
|---|---|
| 2001 | 5 |
| 2002 | 15 |
| 2003 | 20 |
| 2004 | 25 |
| 2005 | 91 |
| 2006 | 150 |
| 2007 | 414 |
| 2012 | 303 |

Source: 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 *http://www.fsa.usda.gov/daco/bioenergy/2005/FY2005ProductPayments,* Year 2006 data from verbal quote based on projection by NBB in June of 2006. Production data for years 2007 and higher are from EIA's AEO 2006.

With the increase in biodiesel production, there has also been a

corresponding rapid expansion in biodiesel production capacity. Presently, there are 85 biodiesel plants in operation with an annual production capacity of 580 million gallons per year.[60] The majority of the current production capacity was built in 2005

and 2006, and was first available to produce fuel in the later part of 2005 and in 2006. Though the capacity has grown, historically the biodiesel production capacity has far exceeded actual production with only 10–30 percent of this being utilized to make

biodiesel. The excess capacity, though, may be from biodiesel plants that do not operate full time and from production capacity that is primarily devoted to making esters for the ole-chemical markets, see Table VI.B.1–2.

TABLE VI.B.1–2.—U.S. PRODUCTION CAPACITY HISTORY [a]

|  | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 |
|---|---|---|---|---|---|---|
| Plants | 9 | 11 | 16 | 22 | 45 | 85 |
| Capacity (million gal/yr) | 50 | 54 | 85 | 157 | 290 | 580 |

[a] Capacity Data based on surveys conducted around the month of September for most years, though the 2006 information is based on a survey conducted in January 2006.[61]

2. Expected Growth in U.S. Biodiesel Production/Consumption

In addition to the 85 biodiesel plants already in production, as of early 2006, there were 65 plants in the construction

phase and 13 existing plants that are expanding their capacity, which when completed would increase total biodiesel production capacity to over one billion gallons per year. Most of

these plants should be completed by late 2007. As shown in Table VI.B.2–1 if all of this capacity came to fruition, U.S. biodiesel capacity would exceed 1.4 billion gallons.

TABLE VI.B.2–1.—PROJECTED BIODIESEL PRODUCTION CAPACITY

|  | Existing plants | Construction phase |
|---|---|---|
| Number of plants | 85 | 78 |
| Total Plant Capacity, (MM Gallon/year) | 580 | 1,400 |

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 VI.B.1.1). The reference case was computed by taking the 2004 base case and growing it out to 2012 by applying the 2004–2012 EIA diesel fuel growth rate.[62] The resulting 2012 reference case consisted of 30 million gallons of biodiesel. Finally, for the 2012 control case, forecasted biodiesel use was assumed to be 300 million gallons based on EIA's AEO 2006 report (rounded value from Table VI.B.1.1). Unlike forecasted ethanol use, biodiesel use was assumed to be constant at 300 million gallons under both the statutory and higher projected renewable fuel consumption scenarios described in VI.A.4. EIA's projection is based on the assumption that the blender's tax credit is not renewed beyond 2008. If the tax credit is renewed, the projection for biodiesel demand would increase.

*C. Feasibility of the RFS Program Volume Obligations*

This section examines whether there are any feasibility issues associated with the meeting the minimum renewable fuel requirements of the Energy Act. Issues are examined with respect to renewable production capacity, cellulosic ethanol production capacity, and distribution system capability. Land resource requirements are discussed in Chapter 7 of the RIA.

1. Production Capacity of Ethanol and Biodiesel

As shown in Sections VI.A. and VI.B., increases in renewable fuel production capacity are already proceeding at a pace significantly faster than required to meet the 2012 mandate in the Act of 7.5 billion gallons as well as the mandate (starting in 2013) of a minimum of 250 million gallons of cellulosic ethanol. The combination of ethanol and biodiesel plants in existence and planned or under construction is expected to provide a total renewable fuel production capacity of over 9.6 billion gallons by the end of 2012. Production capacity is expected to continue to increase in response to

strong demand. We estimate that this will require a maximum of 2,100 construction workers and 90 engineers on a monthly basis through 2012.

2. Technology Available To Produce Cellulosic Ethanol

There are a wide variety of government and renewable fuels industry research and development programs dedicated to improving our ability to produce renewable fuels from cellulosic feedstocks. In this discussion, we deal with at least three completely different approaches to producing ethanol from cellulosic biomass. The first is based on what NREL refers to as the "sugar platform,"[63] which refers to pretreating the biomass, then hydrolyzing the cellulosic and hemicellulosic components into sugars, and then fermenting the sugars into ethanol.

Corn grain is a nearly ideal feedstock for producing ethanol by fermentation, especially when compared with cellulosic biomass feedstocks. Corn grain is easily ground into small particles, following which the exposed starch which has $\alpha$-linked saccharide polymers is easily hydrolyzed into

[60] NBB Survey September 13, 2006 "U.S. Biodiesel Production Capacity".

[61] From Presentation "Biodiesel Production Capacity," by Leland Tong, National Biodiesel Conference and Expo, February 7, 2006.

[62] EIA Annual Energy Outlook 2006, Table 1.

[63] Enzyme Sugar Platform (ESP), Project Next Steps National Renewable Energy, Dan Schell, FY03 Review Meeting; Laboratory Operated for the U.S. Department of Energy by Midwest Research

Institute • B NREL, Golden, Colorado, May 1–2, 2003; U.S. Department of Energy by Midwest Research Institute • Battelle • Bechtel.

simple, single component sugar which can then be easily fermented into ethanol. By comparison, the biomass lignin structure must be either mechanically or chemically broken down to permit hydrolyzing chemicals and enzymes access to the saccharide polymers. The central problem is that the cellulose/hemicellulose saccharide polymers are β-linked which makes hydrolysis much more difficult. Simple microbial fermentation used in corn sugar fermentation is also not possible, since the cellulose and hemicellulose (6 & 5 carbon molecules, respectively) have not been able to be fermented by the same microbe. We discuss various pretreatment, hydrolysis and fermentation technologies, below. The second and third approaches have nothing to do with pretreatment, acids, enzymes, or fermentation. The second is sometimes referred to as the "syngas" or "gas-to-liquid" approach; we will call it the "Syngas Platform." Briefly, the cellulosic biomass feedstock is steam-reformed to produce syngas which is then converted to ethanol over a Fischer-Tropsch catalyst. The third approach uses plasma technology.

a. Sugar Platform

Plant cell walls are made up of cellulose and hemicellulose polymers embedded in a lignin matrix. This complex structure prevents both the first step, hydrolyzation of the cellulose and hemicellulose polymers, and the second step, fermentation of the hydrolyzed sugars into ethanol.

i. Pretreatment

Those who wish to use cellulosic biomass feedstocks to produce ethanol face several, difficult problems. The lignin sheath, present in all cellulosic materials, prevents, or at the very least, severely restricts hydrolysis. To produce ethanol from cellulosic biomass feedstocks by fermentation, some type of thermo-mechanical, mechanical, chemical or a combination of these pretreatments is always necessary before the cellulosic and hemicellulosic polymers can be hydrolyzed. In effect, the lignin structure must be "opened" to allow efficient and effective strong acid hydrolysis, weak acid hydrolysis, or weak acid enzymatic hydrolysis of the cellulose/hemicellulose to their glucose and xylose sugar components. Over time, many pretreatment methods or combinations of methods have been tried, some with more success than others. Usually, intense physical pretreatments such as steam explosion are required; grasses and forest thinnings usually need to be chipped, prior to chemical or enzymatic

hydrolysis. The most common chemical pretreatments for cellulosic feedstocks are strong acid, dilute acid, caustic, organic solvents, ammonia, sulfur dioxide, carbon dioxide or other chemicals which make the biomass more accessible to the enzymes. Following pretreatment, acidic (dilute and concentrated) and enzymatic hydrolysis are the two process types commonly used to hydrolyze cellulosic feedstocks before fermentation into ethanol.[64]

ii. Dilute Acid Hydrolysis

Dilute acid hydrolysis is the oldest technology for converting cellulose biomass to ethanol. The dilute acid process uses a 1-percent sulfuric acid in a continuous flow reactor at about 420 °F; reaction times are measured in seconds and minutes, which facilitates continuous processing. The process involves two reactions with a sugar conversion efficiency of about 50 percent. The process conditions at which the cellulosic molecules are converted into sugar are also those at which the sugar is almost immediately converted into other chemicals, principally furfural. The rapid conversion to furfural reduces the sugar yield, which along with other by-products inhibits the fermentation process. One way to decrease sugar degradation is to use a two-stage process which takes advantage of the fact that hemicellulose (5-carbon) sugars degrade more rapidly than cellulose (6-carbon) sugars. The first stage is conducted under mild process conditions to recover the 5-carbon sugars, while the second stage is conducted under harsher conditions to recover the 6-carbon sugars. Both hydrolyzed solutions are then fermented to ethanol. Lime is used to neutralize the residual acid before the fermentation stage. Regardless, some sugar degrades to furfural, which naturally limits the net yield of ethanol. The residual cellulose and lignin are used as boiler fuel for electricity or steam production.[65]

iii. Concentrated acid hydrolysis

Concentrated acid hydrolysis uses a 70-percent sulfuric acid solution, followed by water hydrolysis to convert the cellulose into sugar. The process rapidly, and nearly completely, converts

cellulose to glucose (6-carbon) and hemicellulose to xylose (5-carbon) sugar, with little degradation to furfural; the reaction times are typically slower than those of the dilute acid process. The critical factors needed to make this process economically viable are to optimize sugar recovery and cost effectively recover the acid for recycling. The concentrated acid process is somewhat more complicated and requires more time, but it has the primary advantage of yielding up to about 90% of both hemicellulosic and cellulosic sugars.[66] In addition, a significant advantage of the concentrated acid process is that it is carried out at relatively low temperatures, about 212 °F, and low pressure, such that fiberglass reactors and piping can be used.

iv. Enzymatic hydrolysis

Enzymatic hydrolysis is not necessarily a recent discovery. We found reports of research conducted by a variety of companies and government agencies going back to at least 1991. [67][68][69] The enzymatic hydrolysis of cellulose was reportedly discovered when a fungus, *trichoderma reesei*, was identified which produced cellulase enzymes that broke down cotton clothing and tents in the South Pacific during World War II. Since then, generations of cellulases have been developed through genetic modifications of the fungus strain. As in acid hydrolysis, the hydrolyzing enzymes must have access to the cellulose and hemicellulose in order to work efficiently. Although enzymatic hydrolysis requires some kind of pretreatment, purely physical pretreatments are typically not adequate. Furthermore, the chemical method uses dilute sulfuric acid, which is poisonous to the fermentation

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[64] Appendix B, Overview of Cellulose-Ethanol Production Technology; OREGON CELLULOSE-ETHANOL STUDY, *An evaluation of the potential for ethanol production in Oregon using cellulose-based feedstocks*; Prepared by: Angela Graf, Bryan & Bryan Inc., 5015 Red Gulch, Cotopaxi, Colorado 81223; Tom Koehler, Celilo Group, 2208 S.W. First Ave, #320, Portland, Oregon 97204; For submission to: The Oregon Office of Energy.

[65] Ibid.

[66] Ibid.

[67] Technical and Economic Analysis Of An Enzymatic Hydrolysis Based Ethanol Plant, Fuels and Chemicals Research and Engineering Division, Solar Energy Research Institute, Golden CO, 80401, June 1991 • DRAFT • SERI Protected Proprietary Information • Do Not Copy.

[68] Biomass to Ethanol Process Evaluation, A report prepared for National Renewable Energy Laboratory, December 1994; Chem Systems Inc. 303 South Broadway, Tarrytown, New York, 10591.

[69] Lignocellulosic Biomass to Ethanol Process Design and Economics Utilizing Co-Current Dilute Acid Prehydrolysis and Enzymatic Hydrolysis Current and Futuristic Scenarios, July 1999 • NREL/TP–580–26157; Robert Wooley, Mark Ruth, John Sheehan, and Kelly Ibsen, Biotechnology Center for Fuels and Chemicals; Henry Majdeski and Adrian Galvez, Delta-T Corporation; National Renewable Energy Laboratory, 1617 Cole Boulevard, Golden, Colorado 80401–3393; NREL is a U.S. Department of Energy Laboratory Operated by Midwest Research Institute • Battelle • Bechtel; Contract No. DE–AC36–98–GO10337.

microorganisms and must be detoxified. While original enzymatic hydrolysis processes used separate hydrolysis and fermentation steps, recent process improvements integrate saccharification and fermentation by combining the cellulase enzymes and fermenting microbes in one vessel. This results in a one-step process of sugar production and fermentation, referred to as the simultaneous saccharification and fermentation (SSF) process. One disadvantage is that the cellulase enzyme and fermentation organism must operate under the same process conditions, which could decrease the sugar and, ultimately, the ethanol yields. An alternative to the SSF technology is the sequential hydrolysis and fermentation (SHF) process. The separation of hydrolysis and fermentation enables enzymes to operate at higher temperatures in the hydrolysis step to increase sugar production and more moderate temperatures in the fermentation step to optimize the conversion of sugar into ethanol.

Cost-effective cellulase enzymes must also be developed for this technology to be completely successful.[70] Several companies are using variations of these technologies to develop processes for converting cellulosic biomass into ethanol by way of fermentation. A few groups, using recently developed genome modifying technology, have been able to produce a variety of new or modified enzymes and microbes that show promise for use in weak- or dilute-acid enzymatic-prehydrolysis. Another problem with cellulosic feedstocks is, as previously described, that the hydrolysis reactions produce both glucose, the six-carbon sugar, and xylose, the 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 fermenting organisms. Now, glucose and xylose can be co-fermented—hence, the present-day terminology: Weak-acid enzymatic hydrolysis and co-fermentation.

b. Syngas Platform

The second platform for producing cellulosic ethanol is to convert the biomass into a syngas which is then converted into ethanol. A "generic" syngas process is essentially a "steam reformer," which "gasifies" biomass and other carbon based substances including wastes, in a reduced-oxygen environment and reacts them with steam to produce a synthesis gas or

"syngas" consisting primarily of carbon monoxide and hydrogen. The syngas is then passed over in a Fischer-Tropsch catalyst to produce ethanol.

The biomass feedstock is dried to about 15% moisture content and ground small enough to be efficiently burned and reacted in the reformer. The reformer, an important upstream element of the process, is essentially a common solid-fuel gasifier, which with some modification and steam injection becomes what is sometimes referred to as the "primary reformer."

When any fuel is completely burned, all of its potential energy is released as heat which can be recovered for immediate use. In a common gasification process, the partially burned fuel (wood or coal) releases a small amount of heat, but leaves some uncombusted, gaseous products. Ordinarily, the hot product gases are fed directly to a nearby boiler or gas turbine, to do work; it has been reported that for a well-designed system, the overall efficiency may approach that of a solid fuel boiler. However, when steam is injected into the gasifier, it reacts with the burning solid fuel to produce more gaseous product. The primary reaction is between carbon and water which produces hydrogen and carbon monoxide and an inorganic ash. The ash and heavy hydrocarbon-tars are removed from the raw syngas before it is compressed and passed over Fisher-Tropsch catalyst to produce ethanol. Fisher-Tropsch technology has been used for many years in the chemical and refining industries, most notably to produce gasoline and diesel fuel from syngas produced by coal gasification. Whether the Fischer-Tropsch reaction produces diesel or ethanol is primarily the result of changes to process pressure, temperature and in some cases the use of custom catalysts. In most cases, the Fischer-Tropsch process did not produce pure ethanol in the first pass through the system. Rather, a stream of mixed chemicals was produced, including gasoline, diesel, and oxygenated hydrocarbons (alcohol).[71]

c. Plasma Technology

The development of another technology, called plasma, is also

underway for creating a syngas from which ethanol is produced. A plasma "reactor," generates an ionized gas (plasma) which serves as an electrical conductor to transfer intense radiant energy to a biomass or waste material. This intense energy is said to actually breakdown the various materials in the biomass or waste into their atomic components. Anything present in the feed-mass that doesn't gasify, is essentially "vitrified." This vitrified stream is reportedly inert and can be used as aggregate in paving materials. Following gasification, the syngas is cooled, impurities are removed, and the gas is sent to ethanol production as with the syngas platform described above.[72]

d. Feedstock Optimization

Cellulosic biomass can come from a variety of sources. Because the conversion of cellulosic biomass to ethanol has not yet been commercially demonstrated, we cannot say at this time which feedstocks are superior to others. A few of the many resources are: Post-sorted municipal waste, rice and wheat straw,[73] soft-woods, hardwood, switch grass, and bagasse. Regardless, each feedstock requires a specific combination of pretreatment methods and enzyme "cocktails" to optimize the operation and maximize the ethanol yield. One of the many challenges for the cellulose-ethanol industry is to find the best feedstocks and then develop the most cost-effective ways for converting them into ethanol.

3. Renewable Fuel Distribution System Capability

Ethanol and biodiesel blended fuels are currently not shipped by petroleum product pipeline due to operational issues and additional cost factors. 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. In cases where ethanol and biodiesel are produced within 200 miles of a terminal, trucking is often the preferred means of distribution. For longer shipping distances, the preferred

[70] Ibid.

[71] Gridley Ethanol Demonstration Project Utilizing Biomass Gasification Technology: Pilot Plant Gasifier and Syngas Conversion Testing, August 2002–June 2004; February 2005 • NREL/SR–510–37581; TSS Consultants, For the City of Gridley, California, 1617 Cole Boulevard, Golden, Colorado 80401–3393, 303–275–3000 • *http://www.nrel.gov*; Operated for the U.S. Department of Energy Office of Energy Efficiency and Renewable Energy by Midwest Research Institute • Battelle Contract No. DE–AC36–99–GO10337.

[72] Ethanol From Tires Via Plasma Converter Plus Fischer Tropsch, March 15, 2006; *http://thefraserdomain.typepad.com/energy/2006/03/ethanol_from_ti.html.*

[73] Wheat Straw for Ethanol Production in Washington: A Resource, Technical, and Economic Assessment, September 2001, WSUCEEP2001084; Prepared by: James D. Kerstetter, Ph.D., John Kim Lyons, Washington State University Cooperative Extension Energy Program, 925 Plum Street, SE., P.O. Box 43165, Olympia, WA 98504–3165; Prepared for: Washington State Office of Trade and Economic Development.

method of bringing renewable fuels to terminals is by rail and barge.

Modifications to the rail, barge, tank truck, and terminal distribution systems will be needed to support the transport of the anticipated increased volumes of renewable fuels. These modifications include the addition of terminal blending systems for ethanol and biodiesel, additional storage tanks at terminals, additional rail delivery systems at terminals for ethanol and biodiesel, and additional rail cars, barges, and tank trucks to distribute ethanol and biodiesel to terminals. Terminal storage tanks for 100 percent biodiesel will also need to be heated during cold months to prevent gelling. The most comprehensive study of the infrastructure requirements for an expanded fuel ethanol industry was conducted for the Department of Energy (DOE) in 2002.[74] The conclusions reached in that study indicate that the changes needed to handle the anticipated increased volume of ethanol by 2012 will not represent a major obstacle to industry. While some changes have taken place since this report was issued, including an increased reliance on rail over marine transport, we continue to believe that the rail and marine transportation industries can manage the increased growth in demand in an orderly fashion. This belief is supported by the demonstrated ability for the industry to handle the rapid increases and redistribution of ethanol use across the country over the last several years as MTBE was removed. The necessary facility changes at terminals and at retail stations to dispense ethanol containing fuels have been occurring at a record pace. Given that future growth is expected to progress at a steadier pace and with greater advance warning in response to economic drivers, we anticipate that the distribution system will be able to respond appropriately. A discussion of the costs associated making the changes discussed above is contained in Section VII.B of today's preamble.

## VII. Impacts on Cost of Renewable Fuels and Gasoline

This section examines the impact on fuel costs resulting from the growth in renewable fuel use between a base year of 2004 and 2012. We note that based on analyses conducted by the Energy Information Administration (EIA), renewable fuels will be used in gasoline and diesel fuel in excess of the RFS

requirements. As such, the changes in the use of renewable fuels and their related cost impacts are not directly attributable to the RFS rule. Rather, our analysis assesses the broader fuels impacts of the growth in renewable fuel use in the context of corresponding changes to the makeup of gasoline. These fuel impacts include the elimination of the reformulated gasoline (RFG) oxygen standard which has resulted in the refiners ceasing to use the gasoline blendstock methyl tertiary butyl ether (MTBE) and replacing it with ethanol. Thus, in this analysis, we are assessing the impact on the cost of gasoline and diesel fuel of increased use of renewable fuels, the cost savings resulting from the phase out of MTBE and the increased cost due to the other changes in fuel quality that result.

As discussed in Section II, we chose to analyze a range of renewable fuel use. In the case of ethanol's use in gasoline, the lower end of this range is based on the minimum renewable fuel volume requirements in the Act, (the RFS case) and the higher end is based on AEO 2006 (the EIA case). At both ends of this range, we assume that biodiesel consumption will be the level estimated in AEO 2006. We analyzed the projected fuel consumption scenario and associated program costs in 2012, the year that the RFS is fully phased-in. The volumes of renewable fuels consumed in 2012 at the two ends of the range are summarized in Table II.A.1–1.

We have estimated an average corn ethanol production cost of $1.26 per gallon in 2012 (2004 dollars) for the RFS case and $1.32 per gallon for the EIA case. For cellulosic ethanol, we estimate it will cost approximately $1.65 in 2012 (2004 dollars) to produce a gallon of ethanol using corn stover as a cellulosic feedstock. In this analysis, however, we assume that the cellulosic requirement will be met by corn-based ethanol produced by energy sourced from biomass (animal and other waste materials as discussed in Section III.B of today's preamble) and costing the same as corn based ethanol produced by conventional means.

We estimated production costs for soy-derived biodiesel of $2.06 per gallon in 2004 and $1.89 per gallon in 2012. For yellow grease derived biodiesel, we estimate an average production cost of $1.19 per gallon in 2004 and $1.11 in 2012.

For the proposed rule, we estimated the cost of increased use of renewable fuel and other major cost impacts by developing our own cost spreadsheet model. That analysis considered the production cost, distribution cost as well as the cost for balancing the octane

and RVP caused by these fuel changes. That analysis, however, could not properly balance octane and other gasoline qualities. For this final rule, we have therefore used the services of Jacobs Consultancy to run their refinery LP model to estimate the cost impacts of the RFS rule.

The results from the refinery LP model indicate that the impacts on overall gasoline costs from the increased use of ethanol and the corresponding changes to the other aspects of gasoline would be 0.49 cents per gallon for the RFS case. The EIA case would result in increased total cost of 1.03 cents per gallon. The actual cost at the fuel pump, however, will be decreased due to the effect of State and Federal tax subsidies for ethanol. Taking this into consideration results in "at the pump" decreased costs (cost savings) of −0.47 cents per gallon for the RFS case and "at the pump" decreased cost of −0.83 cents per gallon for the EIA case. Section 7 of the RIA contains more detail on the cost analysis used to develop these costs.

### A. Renewable Fuel Production and Blending Costs

#### 1. Ethanol Production Costs

#### a. Corn Ethanol

A significant amount of work has been done in the last decade on surveying and modeling the costs involved in producing ethanol from corn to serve business and investment purposes as well as to try to educate energy policy decisions. Corn ethanol costs for our work were estimated using a model developed by USDA in the 1990s that has been continuously updated by USDA. The most current version was documented in a peer-reviewed journal paper on cost modeling of the dry-grind corn ethanol process, and it produces results that compare well with cost information found in surveys of existing plants.[75][76] We made some minor modifications to the USDA model to allow scaling of the plant size, to allow consideration of plant energy sources other than natural gas, and to adjust for energy prices in 2012, the year of our analysis.

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

[74] "Infrastructure Requirements for an Expanded Fuel Ethanol Industry," Downstream Alternatives Inc., January 15, 2002.

[75] Kwaitkowski, J.R., McAloon, A., Taylor, F., Johnston, D.B., Industrial Crops and Products 23 (2006) 288–296.

[76] Shapouri, H., Gallagher, P., USDA's 2002 Ethanol Cost-of-Production Survey (published July 2005).

represents about 48% of the final per-gallon cost, while utilities, capital and labor comprise about 19%, 9%, and 6%, respectively. For this work, we used corn prices of $2.50/bu and $2.71/bu for the RFS and EIA cases, respectively, with corresponding DDGS prices at $83.35/ton and $85.16/ton (2004 dollars). These estimates are from modeling work done for this rulemaking using the Forestry and Agricultural Sector Optimization Model, which is described in more detail in Chapter 8 of the RIA. Energy prices were derived from historical data and projected to 2012 using EIA's AEO 2006. More details on how the ethanol production cost estimates were made can be found in Chapter 7 of the RIA.

The estimated average corn ethanol production cost of $1.26 per gallon in 2012 (2004 dollars) in the RFS case and $1.32 per gallon in the EIA case represents the full cost to the plant operator, including purchase of feedstocks, energy required for operations, capital depreciation, labor, overhead, and denaturant, minus revenue from sale of co-products. It assumes that 86% of new plants will use natural gas as a thermal energy source, at a price of $6.16/MMBtu (2004 dollars).[77] It does not account for any subsidies on production or sale of ethanol. Note that the cost figure generated here is independent of the market price of ethanol, which has been related closely to the wholesale price of gasoline for the past decade.[78][79]

Under the Energy Act, starch-based ethanol can be counted as cellulosic if at least 90% of the process energy is derived from renewable feedstocks, which include plant cellulose, municipal solid waste, and manure biogas.[80] It is expected that the vast majority of the 250 million gallons per year of cellulosic ethanol production required by 2013 will be made using this provision. While we have been unable to develop a detailed production cost estimate for corn ethanol meeting cellulosic criteria, we assume that the costs will not be significantly different from conventionally produced corn ethanol. We believe this is reasonable because the costs of hauling, storing, and processing this low or zero cost waste material in order to combust it

will be significant, thus making overall production costs at these plants similar to gas-fired ethanol plants. As of the time of this writing, we know of only a few operating plants of this type, and expect the quantity of ethanol produced this way to remain a relatively small fraction of the total ethanol demand. Thus, the sensitivity of the overall analysis to this assumption is also very small.[81] Based on these factors, we have assigned starch ethanol made using this cellulosic criteria the same cost as ethanol produced from corn using conventional means.

b. Cellulosic Ethanol

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 hard-wood chips.[82] Although the 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 and USDA used a modified version of the model 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 the analysis for this rule. Because there were no operating plants that could potentially provide real world process design, construction, and operating data for processing cellulosic ethanol, NREL had considered modeling the plant based on assumptions associated with a first-of-a-kind or pioneer plant. The literature indicates that such models often underestimate actual costs since the high performance assumed for pioneer process plants is generally unrealistic.

Instead, the NREL researchers assumed that the corn stover plant was an Nth generation plant, e.g., not a pioneer plant or first-or-its kind, built after the industry had been sufficiently established to provide verified costs. The corn stover plant was normalized to the corn kernel plant, e.g., placed on a

similar basis.[83] It is also reasonable to expect that the cost of cellulosic ethanol would be higher than corn ethanol because of the complexity of the cellulose conversion process. Recently, process improvements and 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.

We calculated fixed and variable operating costs using percentages of direct labor and total installed capital costs. Following this methodology, we estimate that producing a gallon of ethanol using corn stover as a cellulosic feedstock would cost $1.65 in 2012 (2004 dollars).

2. Biodiesel Production Costs

We based our estimate for the cost to produce biodiesel on the use of USDA's, NREL's and EIA's biodiesel computer models, along with estimates from engineering vendors that design biodiesel plants. Biodiesel fuel can be made from a wide variety of virgin vegetable oils such as canola, corn oil, cottonseed, etc. though, the operating costs (minus the costs of the feedstock oils) for these virgin vegetable oils are similar to the costs based on using soy oil as a feedstock, according to an analysis by NREL Biodiesel costs are therefore determined based on the use of soy oil, since this is the most commonly used virgin vegetable feedstock oil, and the use of recycled cooking oil (yellow grease) as a feedstock. Production costs are based on the process of continuous transesterification, which converts these feedstock oils to esters, along with the ester finishing processes and glycerol recovery. The models and vendors data are used to estimate the capital, fixed and operating costs associated with the production of biodiesel fuel, considering utility, labor, land and any other process and operating requirements, along with the prices for

[77] For more details on fuel sources and costs of production, see RIA Chapter 1.2.2 and 7.1.1.2.

[78] Whims, J., Sparks Companies, Inc. and Kansas State University, ''Corn Based Ethanol Costs and Margins, Attachment 1'' (Published May 2002).

[79] Piel, W.J., Tier & Associates, Inc., March 9, 2006 report on costs of ethanol production and alternatives.

[80] Energy Policy Act of 2005, Section 1501 amending Clean Air Act Section 211(o)(1)(A).

[81] See Table VI.A.1–2 for more details on number of operating ethanol plants and their fuel sources.

[82] Lignocellulosic Biomass to Ethanol Process Design and Economics Utilizing Co-Current Dilute Acid Prehydrolysis and Enzymatic Hydrolysis Current and Futuristic Scenarios, Robert Wooley, Mark Ruth, John Sheehan, and Kelly Ibsen, Biotechnology Center for Fuels and Chemicals, Henry Majdeski and Adrian Galvez, Delta-T Corporation; National Renewable Energy Laboratory, Golden, CO, July 1999, NREL/TP–580–26157.

[83] Determining the Cost of Producing Ethanol from Corn Starch and Lignocellulosic Feedstocks; A Joint Study Sponsored by: USDA and USDOE, October 2000 • NREL/TP–580–28893 • Andrew McAloon, Frank Taylor, Winnie Yee, USDA, Eastern Regional Research Center Agricultural Research Service; Kelly Ibsen, Robert Wooley, National Renewable Energy Laboratory, Biotechnology Center for Fuels and Chemicals, 1617 Cole Boulevard, Golden, CO, 80401–3393; NREL is a USDOE Operated by Midwest Research Institute • Battelle • Bechtel; Contract No. DE–AC36–99–GO10337.

feedstock oils, methanol, chemicals and the byproduct glycerol.

The USDA, NREL and EIA models are based on a medium sized biodiesel plant that was designed to process raw degummed virgin soy oil as the feedstock. Additionally, the EIA model also contains a representation to estimate the biodiesel production cost for a plant that uses yellow grease as a feedstock. In the USDA model, the equipment needs and operating requirements for their biodiesel plant was estimated through the use of process simulation software. This software determines the biodiesel process requirements based on the use of established engineering relationships, process operating conditions and reagent needs. To substantiate the validity and accuracy of their model, USDA solicited feedback from major biodiesel producers. Based on responses, they then made adjustments to their model and updated their input prices to year 2005. The NREL model is also based on process simulation software, though the results are adjusted to reflect NREL's modeling methods, using prices based on year 2002. The output for all of these models was provided in spreadsheet format. We also use engineering vendor estimates as another source to generate soy oil and yellow grease biodiesel production costs. These firms are primarily engaged in the business of designing biodiesel plants.

The production costs are based on an average biodiesel plant located in the Midwest using feedstock oils and methanol, which are catalyzed into esters and glycerol by use of sodium hydroxide. Because local feedstock costs, distribution costs, and biodiesel plant type introduce some variability into cost estimates, we believe that using an average plant to estimate production costs provides a reasonable approach. Therefore, we simplified our analysis and used costs based on an average plant and average feedstock prices since the total biodiesel volumes forecasted are not large and represent a small fraction of the total projected renewable volumes.

The models and vendor estimates are further modified to use input prices for feedstocks, byproducts and energy that reflect the effects of the fuels provisions in the Energy Act. In order to capture a range of production costs, we generated cost projections from all of the models and vendors. We present the details on these estimates in Chapter 7 of the RIA.

For soy oil biodiesel production, we estimate a production cost ranging from $1.89 to $2.15 per gallon in 2012 (in 2004 dollars) using these different

models and sources of information. For yellow grease derived biodiesel, we used the EIA and vendor estimates to generate total production costs which range from $1.11 to $1.56 for year 2012.

With the current Biodiesel Blender Tax Credit Program, producers using virgin vegetable oil stocks receive a one dollar per gallon tax subsidy while yellow grease producers receive 50 cents per gallon, reducing the net production cost to a range of 89 to 115 cents per gallon for soy oil and 61 to 106 cents per gallon for yellow greased derived biodiesel fuel in 2012. This compares favorably to the projected wholesale diesel fuel prices of 138 cents per gallon in 2012, signifying that the economics for biodiesel are positive under the effects of the blender credit program, though the tax credit program will expire in 2008 if it is not extended. Congress may later elect to extend the blender credit program 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.

### 3. Diesel Fuel Costs

Biodiesel fuel is blended into highway and nonroad diesel fuel, which increases the volume and therefore the supply of diesel fuel and thereby reduces the demand for refinery-produced diesel fuel. In this section, we estimate the overall cost impact, considering how much refinery based diesel fuel is displaced by the forecasted production volume of biodiesel fuel. The cost impacts are evaluated considering the production cost of biodiesel with and without the subsidy from the Biodiesel Blenders Tax credit program. Additionally, the diesel cost impacts are quantified with refinery diesel prices as forecasted by Jacob's which is based on EIA's AEO 2006.

We estimate the net effect that biodiesel production has on overall cost for diesel fuel in year 2012 using total production costs for biodiesel and diesel fuel. The costs are evaluated based on how much refinery based diesel fuel is displaced by the biodiesel volumes as forecasted by EIA, accounting for energy density differences between the fuels. The cost impact is estimated from a 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 biodiesel volume is used as

transport fuel, neglecting minor uses in the heating oil market.

For RFS cases, the net effect of biodiesel production on diesel fuel costs, including the biodiesel blenders' subsidy, is a reduction in the cost of transport diesel fuel costs by $114 million per year, which equates to a reduction in fuel cost of about 0.20 cents per gallon.[84] Without the subsidy, the transport diesel fuel costs are increased by $91 million per year, or an increase of 0.16 cents per gallon for transport diesel fuel.

### B. Distribution Costs

#### 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.[85] 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 to meet the requirements of the RFS in 2012. Distribution costs are evaluated here for both the RFS case and for the EIA case. The 2012 reference case against which we are estimating the cost of distributing the additional volume of ethanol needed to meet the requirements of the RFS is 3.9 billion gallons.

#### a. Capital Costs To Upgrade Distribution System for Increased Ethanol Volume

The 2002 DOE study examined two cases regarding the use of renewable fuels for estimating the capital costs for distributing additional ethanol. The first assumed that 5.1 billion gal/yr of ethanol would be used in 2010, and the second assumed that 10 billion gal/yr of ethanol would be used in the 2015 timetable. We interpolated between these two cases to provide the foundation for our estimate of the capital costs to support the use of 6.7 billion gal/yr of ethanol in 2012 for the

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[84] Based on EIA's AEO 2006, 58.9 billion gallons of highway and off-road diesel fuel is projected to be consumed in 2012.

[85] Infrastructure Requirements for an Expanded Fuel Ethanol Industry, Downstream Alternatives Inc., January 15, 2002.

RFS case.[86] The 10 billion gal/yr case examined in the DOE study was used as the foundation in estimating the capital costs under the EIA projected case examined in today's rule of 9.6 billion gal/yr of ethanol.[87] Our estimated capital costs in this final rule differ from those in the proposed rule for several reasons. We adjusted our capital costs from those in the proposal to reflect an increase in the cost of tank cars and barges used to ship ethanol since the DOE study was conducted. In addition, we are assuming an increased reliance on rail transport over that projected in the DOE study.[88]

Table VII.B.1.a–1contains our estimates of the infrastructure changes and associated capital costs for the two ethanol use scenarios examined in today's rule. Amortized over 15 years with a 7 percent cost of capital, the total capital costs equate to approximately 1.4 cents per gallon of ethanol under the RFS case and 1.2 cents per gallon under the EIA case.[89]

TABLE VII.B.1.A–1.—ESTIMATED ETH- ANOL DISTRIBUTION INFRASTRUC- TURE CAPITAL COSTS ($M) *

|  | RFS case 6.7 Bgal/yr | EIA case 9.6 Bgal/yr |
|---|---|---|
| *Fixed Facilities:* |  |  |
| Retail ............. | 20 | 44 |
| Terminals ...... | 115 | 241 |
| *Mobile Facilities:* |  |  |
| Transport |  |  |
| Trucks ........ | 24 | 50 |
| Barges ........... | 21 | 43 |
| Rail Cars ....... | 172 | 297 |
| Total Cap- ital Costs | 352 | 675 |

*Relative to a 3.9 billion gal/yr reference case.

b. Ethanol Freight Costs

The Energy Information Administration (EIA) translated the ethanol freight cost estimates in the DOE study to a census division basis.[90]

For this final rule, we translated the EIA projections into State-by-State and national average freight costs to align with our State-by-State ethanol use estimates. Not including capital recovery, we estimate that the freight cost to transport ethanol to terminals would range from 4 cents per gallon in the Midwest to 25 cents per gallon to the West Coast. On a national basis, this averages to 11.3 cents per gallon of ethanol under the RFS case and 11.9 cents per gallon under the EIA case.[91] We adjusted the estimated ethanol freight costs from those in the proposal by increasing the cost of shipping ethanol to satellite versus hub terminals, by increasing the cost of gathering ethanol for large volume shipments to hub terminals, and by increasing the percentage of ethanol delivered to large volume terminals versus the volume delivered to lesser volume terminals.[92]

Including the cost of capital recovery for the necessary distribution facility changes, we estimate the national average cost of distributing ethanol to be 12.7 cents per gallon under the RFS case and 13.1 cents per gallon under the EIA case.[93] Thus, we estimate the total cost for producing and distributing ethanol to be between $1.39 and $1.45 per gallon of ethanol, on a nationwide average basis. This estimate includes both the capital costs to upgrade the distribution system and freight costs.

2. Biodiesel Distribution Costs

The volume of biodiesel used by 2012 under the RFS is estimated at 300 million gallons per year. The 2012 baseline case against which we are estimating the cost of distributing the additional volume of biodiesel is 30 million gallons.[94]

The capital costs associated with distribution of biodiesel are higher per gallon than those associated with the distribution of ethanol due to the need for storage tanks, blending systems, barges, tanker trucks and rail cars to be insulated and in many cases heated

during the winter months.[95] In the proposal, we estimated that these capital costs would be approximately $50,000,000. We adjusted our estimate of these capital costs for this final rule based on additional information regarding the cost to install necessary storage and blending equipment at terminals and the need for additional rail tank cars for biodiesel.[96] As discussed in the RIA, we now estimate that handling the increased biodiesel volume will require a total capital cost investment of $145,500,000 which equates to about 6 cents per gallon of new biodiesel volume.[97]

In the proposal, we estimated that the freight costs for ethanol may adequately reflect those for biodiesel as well. In response to comments, we sought additional information regarding the freight costs for biodiesel. This information indicates that freight costs for biodiesel are typically 30 percent higher than those for ethanol which translates into an estimate of 15.5 cents per gallon for biodiesel freight costs on a national average basis.[98]

Including the cost of capital recovery for the necessary distribution facility changes, we estimate the cost of distributing biodiesel to be 21.5 cents per gallon. Depending on whether the feedstock is waste grease or virgin oil, we estimate the total cost for producing and distributing biodiesel to be between $1.33 and $2.11 per gallon of biodiesel, on a nationwide average basis.[99] This estimate includes both the capital costs to upgrade the distribution system and freight costs, and the wide range reflects differences in different types of production feedstocks.

C. Estimated Costs to Gasoline

To estimate the cost of increased use of renewable fuels, the cost savings from the phase out of MTBE and the production cost of alkylate, we relied on

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[86] See chapter 7.3 of the Regulatory Impact Analysis associated with today's rule for additional discussion of how the results of the DAI study were adjusted to reflect current conditions in estimating the ethanol distribution infrastructure capital costs under today's rule.

[87] For both the 6.7 bill gal/yr and 9.6 bill gal/yr cases, the baseline from which the DOE study cases were projected was adjusted to reflect a 3.9 bill gal/ yr 2012 baseline.

[88] This increased reliance on rail transport was the subject of a sensitivity analysis conducted for the proposed rule.

[89] These capital costs will be incurred incrementally during the period of 2007–2012 as ethanol volumes increase. For the purpose of this analysis, we assumed that all capital costs were incurred in 2007.

[90] Petroleum Market Model of the National Energy Modeling System, Part 2, March 2006, DOE/EIA–

059 (2006), *http://tonto.eia.doe.gov/FTPROOT/ modeldoc/m059(2006)-2.pdf*.

[91] See Chapter 7.3 of the RIA.

[92] Hub terminals refer to those terminals where ethanol is delivered in large volume shipments such as by unit train (consisting of 70 tank cars or more) or marine barges/tanker. Satellite terminals are those terminals that are either supplied from a hub terminal or receive ethanol shipments in smaller quantities directly from the producer. See Chapter 7 of the RIA regarding how these estimates were adjusted from those in the proposal and the check of our estimates against current ethanol freight rates.

[93] All capital costs were assumed to be incurred in 2007 and were amortized over 15 years at a 7 percent cost of capital.

[94] 2004 baseline of 25 million gallons grown with diesel demand to 2012.

[95] See Chapter 1.3 of the Regulatory Impact Analysis associated with today's rule for a discussion of the special handling requirements for biodiesel under cold conditions.

[96] Biodiesel rail tank cars typically have a capacity of 25,500 gallons as opposed to 30,000 gallons for an ethanol tank car. Thus, additional tank cars are needed to transport a given volume of biodiesel relative to the same volume of ethanol.

[97] Capital costs will be incurred incrementally over the period of 2007–2012 as biodiesel volumes increase. For the purpose of this analysis, all capital costs were assumed to be incurred in 2007 and were amortized over 15 years at a 7 percent cost of capital.

[98] The estimated ethanol freight costs were increased by 30 percent to arrive at the estimate of biodiesel freight costs.

[99] See Section VII.A.2. of this preamble regarding biodiesel production costs. We estimated 2012 production costs of $1.89 per gal for soy-derived biodiesel and $1.11 per gal for yellow grease derived biodiesel.

refinery modeling conducted by Jacob's Consultancy that established baselines based on 2004 volumes, which were then used to project a reference case and 2 control cases for 2012. The contractor developed a five region, U.S. demand model in which specific regional clean product demands are sold at hypothetical regional terminals.

1. Description of Cases Modeled

a. Base Case (2004)

The baseline case was established by modeling fuel volumes for 2004, with data on fuel properties provided to the contractor by EPA. Fuel property data for this base case was built off of 2004 refinery batch reports provided to EPA; however, the base case assumed sulfur standards based on gasoline data in 2004, not with fully phased in Tier 2 gasoline standards at the 30 ppm level. In addition we assumed the phase-in of 15 ppm sulfur standards for highway, nonroad, locomotive and marine diesel fuel. The supply/demand balance for the U.S. was based on gasoline volumes from EIA and the California Air Resources Board (CARB). Our decision to use 2004 rather than 2005 as the baseline year was because of the refinery upset conditions associated with the Gulf Coast hurricanes in 2005.

b. Reference Case (2012)

The reference case was based on modeling the base case, using 2012 fuel prices, and scaling the 2004 fuel volumes to 2012 based on growth in fuel demand. In addition, we scaled MTBE and ethanol upward, in proportion to gasoline growth, and assumed the RFS program would not be in effect. For example, if the PADD 1 gasoline pool MTBE oxygen was 0.5 wt% in 2004, the reference case assumed it should remain at 0.5 wt%. Finally, we assumed the MSAT 1 standards would remain in place as would the RFG oxygen mandate. We assumed the crude slate quality in 2012 is the same as the baseline case.

c. Control Cases (2012)

Two control cases were run for 2012. The assumptions for each of the control cases are summarized below

Control Case 1 (RFS case): 6.7 billion gallons/yr (BGY) of ethanol in gasoline; it reflects the renewable fuel mandate. We have also assumed that 0.3 billion gallons of biodiesel will be consumed as reflected in Table II.A.1–1. In addition,

it is assumed that no MTBE is in gasoline, MSAT1 is in place, the psi waiver for conventional gasoline containing 10 volume percent ethanol is in effect, the RFS is in effect, and there is no RFG oxygenate mandate.

Control Case 2 (EIA case): Same as Control Case 1, except the ethanol volume in gasoline is 9.6 BGY.

2. Overview of Cost Analysis Provided by the Contractor Refinery Model

The estimated cost of increased use of renewable fuels, the cost savings from the phase out of MTBE and the cost of converting some of the former MTBE feedstocks to produce alkylate, isooctane, and isooctene is provided by the output of the refinery model. As described in VII.C.1, the cost analysis was conducted by comparing the 2012 reference case with the two control cases which are assumed to take place in 2012.

The major factors which impact the costs in the refinery model are (1) blending in more ethanol, (2) adjusting the gasoline blending to lower RVP, (3) removing the MTBE, (4) converting MTBE feedstocks to other high quality replacement, and (5) adjusting for the change in gasoline energy density. The first is the addition of ethanol to the gasoline pool. The refinery model estimates the cost impact of increasing the volume of ethanol in the reference case from 3.94 billion gallons to 6.67 and 9.60 billion gallons in the RFS and EIA modeled cases, respectively. The estimated production prices for ethanol for the RFS and EIA cases are provided above in Section VII.A. We also show the results with the federal and state subsidies applied to the production price of ethanol.

The addition of ethanol to wintertime gasoline, and to summertime RFG, will cause an increase of approximately 1 psi in RVP which needs to be offset to maintain constant RVP levels. One method that refiners could choose to offset the increase in RVP is to reduce the butane levels in their gasoline. To some extent, the modeling results showed some occurrences of that, but it also did not report an overall increase in butane sales as a result of the increased use of ethanol.

To convert the captive MTBE over to alkylate, after the rejection of methanol, refiners will need to combine refinery-produced isobutane with the isobutylene that was used as a feedstock for MTBE. The use of the isobutane will

reduce the RVP of the gasoline pool from which it comes, helping to offset the RVP impacts of ethanol. Also, the increased production of alkylate provides a low RVP gasoline blendstock which offsets a portion of the cracked stocks produced by the fluidized catalytic cracker unit. Other means that the refinery model used to offset the high blending RVP of ethanol included purchasing gasoline components with lower RVP, producing more poly gasoline which has low RVP and selling more high-RVP naphtha to petrochemical sales.

3. Overall Impact on Fuel Cost

Based on the refinery modeling conducted for today's rule, we have calculated the costs of these fuels changes that will occur for the RFS and EIA cases. The costs are expressed two different ways. First, we express the cost of the program without the ethanol consumption subsidies in which the costs are based on the total accumulated cost of each of the fuels changes. Second, we express the cost with the ethanol consumption subsidies included since the subsidized portion of the renewable fuels costs will not be represented to the consumer in its fuels costs paid at the pump, but instead by being paid through the state and federal tax revenues. In all cases, the capital costs are amortized at 7 percent return on investment (ROI), and based on 2006 dollars.

a. Cost Without Ethanol Subsidies

Table VII.C.3.a–1 summarizes the costs without ethanol subsidies for each of the two control cases, including the cost for each aspect of the fuel changes, and the aggregated total and the per-gallon costs for all the fuel changes.[100] This estimate of costs reflects the changes in gasoline that are occurring with the expanded use of ethanol, including the corresponding removal of MTBE. These costs include the labor, utility and other operating costs, fixed costs and the capital costs for all the fuel changes expected. The per-gallon costs are derived by dividing the total costs over all U.S. gasoline projected to be consumed in 2012. We excluded federal and state ethanol consumption subsidies which avoids the transfer payments caused by these subsidies that would hide a portion of the program's costs.

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[100] EPA typically assesses social benefits and costs of a rulemaking. However, this analysis is more limited in its scope by examining the average

cost of production of ethanol and gasoline without accounting for the effects of farm subsidies that

tend to distort the market price of agricultural commodities.

TABLE VII.C.3.A–1.—ESTIMATED COST WITHOUT ETHANOL CONSUMPTION SUBSIDIES

[Million dollars and cents per gallon; 7% ROI and 2006 dollars]

| | RFS case 6.8 billion gals incremental to reference case | EIA case 9.6 billion gals incremental to reference case | EIA case 9.6 billion gals incremental to RFS case |
|---|---|---|---|
| Capital Costs ($MM) | −5,878 | −7,311 | −1,433 |
| Amortized Capital Costs ($MM/yr) | −647 | −804 | −158 |
| Fixed Operating Cost ($MM/yr) | −178 | −222 | −43 |
| Variable Operating Cost ($MM/yr) | −201 | −491 | −290 |
| Fuel Economy Cost ($MM/yr) | 1,848 | 3,255 | 1407 |
| Total Cost ($MM/yr) | 823 | 1739 | 915 |
| Capital Costs (c/gal of gasoline) | −0.40 | −0.49 | −0.10 |
| Fixed Operating Cost (c/gal of gasoline) | −0.11 | −0.14 | −0.03 |
| Variable Operating Cost (c/gal of gasoline) | −0.12 | −0.30 | −0.18 |
| Fuel Economy Cost (c/gal of gasoline) | 1.13 | 1.98 | 0.86 |
| Total Cost Excluding Subsidies (c/gal of gasoline) | 0.50 | 1.06 | 0.56 |

Our analysis shows that when considering all the costs associated with these fuel changes resulting from the expanded use of subsidized ethanol that these various possible gasoline use scenarios will increase fuel costs by $820 million or $1,740 million in the year 2012 for the RFS and EIA cases, respectively. Expressed as per-gallon costs, these fuel changes would increase fuel costs by 0.50 to 1.1 cents per gallon of gasoline.

b. Gasoline Costs Including Ethanol Consumption Tax Subsidies

Table VII.C.3.b–1 expresses the total and per-gallon gasoline costs for the two control scenarios with the federal and state ethanol subsidies included. The federal tax subsidy is 51 cents per gallon for each gallon of new ethanol blended into gasoline. The state tax subsidies apply in 5 states and range from 1.6 to 29 cents per gallon. The cost reduction to the fuel industry and consumers is estimated by multiplying the subsidy times the volume of new ethanol estimated to be used in the state. The per-gallon costs are derived by dividing the total costs over all U.S. gasoline projected to be consumed in 2012.

TABLE VII.C.3.B–1.—ESTIMATED COST INCLUDING ETHANOL CONSUMPTION SUBSIDIES

[Million dollars and cents per gallon; 7% ROI and 2006 dollars]

| | RFS case 6.8 billion gals incremental to reference case | EIA case 9.6 billion gals incremental to reference case | EIA case 9.6 billion gals incremental to RFS case |
|---|---|---|---|
| Total Cost ($MM/yr) | 823 | 1739 | 915 |
| Federal Subsidy ($MM/yr) | −1376 | −2865 | −1489 |
| State Subsidies ($MM/yr) | −5 | −31 | −26 |
| Revised Total Cost ($MM/yr) | −558 | −1158 | −600 |
| Per-Gallon Cost Excluding Subsidies (c/gal of gasoline) | 0.50 | 1.06 | 0.56 |
| Federal Subsidy (c/gal of gasoline) | −0.84 | −1.74 | −0.90 |
| State Subsidies (c/gal of gasoline) | −0.003 | −0.02 | −0.02 |
| Total Cost Including Subsidies (c/gal of gasoline) | −0.34 | −0.71 | −0.37 |

The cost including subsidies better represents gasoline's production cost as reflected to the fuel industry as a whole and to consumers "at the pump" because the federal and state subsidies tend to hide a portion of the actual costs. Our analysis estimates that the fuel industry and consumers will see a 0.34 and 0.71 cent per gallon decrease in the apparent cost of producing gasoline for the RFS and EIA cases, respectively.

## VIII. What Are the Impacts of Increased Ethanol Use on Emissions and Air Quality?

In this section, we evaluate the impact of increased production and use of renewable fuels on emissions and air quality in the U.S., particularly ethanol and biodiesel. In performing these analyses, we compare the emissions which would have occurred in the future if fuel quality had remained unchanged from pre-Act levels to those which will be either required under the Energy Policy Act of 2005 (Energy Act or the Act) or exist due to market forces.

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 Energy Act. However, as described in Section II, we expect that total renewable fuel use in the U.S. in 2012 to exceed the Act's requirements even in the absence of the RFS program. Thus, a traditional regulatory impact analysis would have shown no impact on emissions or air quality. This is because, strictly speaking, if the same volume and types of renewable fuels are produced and used with and without the RFS program, the RFS program has no impact on fuel quality and thus, no impact on emissions or air quality. However, levels of renewable fuel use are increasing dramatically relative to both today and the recent past, with corresponding impacts on emissions and air quality. We believe that it is appropriate to evaluate these changes here, regardless of whether they are occurring due to economic forces or Energy Act requirements.

In the process of estimating the impact of increased renewable fuel use, we also include the impact of reduced use of MTBE in gasoline. It is the

increased production and use of ethanol which is facilitating the continued production of RFG which meets both commercial and EPA regulatory specifications without the use of MTBE. Because of this connection, we found it impractical to isolate the impact of increased ethanol use from the removal of MTBE.

*A. Effect of Renewable Fuel Use on Emissions*

1. Emissions From Gasoline Fueled Motor Vehicles and Equipment

Several models of the impact of gasoline quality on motor vehicle emissions have been developed since the early 1990's. We evaluated these models and selected those which were based on the most comprehensive set of emissions data and developed using the most advanced statistical tools for this analysis. 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 vehicle and engine models equipped with the most advanced emission controls. Pending 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. We hope that the results from these test programs will be available for reference in the future evaluations of the emission and air

quality impacts of U.S. fuel programs required by the Act.[101]

The remainder of this sub-section is divided into three parts. The first evaluates the impact of increased ethanol use and decreased MTBE use on gasoline quality. The second evaluates the impact of increased ethanol use and decreased MTBE use on motor vehicle emissions. The third evaluates the impact of increased ethanol use and decreased MTBE use on nonroad equipment emissions.

a. Gasoline Fuel Quality

For the final rulemaking, we estimate the impact of increased ethanol use and decreased MTBE use on gasoline quality using refinery modeling conducted specifically for the RFS rulemaking.[102] In general, adding ethanol to gasoline reduces the aromatic content of conventional gasoline and the mid- and high-distillation temperatures (e.g., T50 and T90). RVP increases except in areas where ethanol blends are not provided a 1.0 RVP waiver of the applicable RVP standards in the summer. With the exception of RVP, adding MTBE directionally produces the same impacts. Thus, the effect of removing MTBE results in essentially the opposite impacts. Neither oxygenate is expected to affect sulfur levels, as refiners control sulfur independently in order to meet the Tier 2 sulfur standards.

The impacts of oxygenate use are smaller with respect to RFG. This is due to RFG's VOC and toxics emission

performance specifications, which limit the range of feasible fuel quality values. Thus, oxygenate type or level does not consistently affect the RVP level and aromatic and benzene contents of RFG.

Table VIII.A.1.a–1 shows the fuel quality of a typical summertime, non-oxygenated conventional gasoline and how these qualities change with the addition of 10 volume percent ethanol. Similarly, the table shows the fuel quality of a typical MTBE RFG blend and how fuel quality might change with either ethanol use or simply MTBE removal. All of these fuels are based, in whole or in part, on projections made by Jacobs in their recent refinery modeling performed for EPA and therefore, represent improvements over the projections made for the NPRM. Please see Chapter 2 of the RIA for a detailed description of the methodologies used to determine the specific changes in projected fuel quality. As discussed there, we use the Jacobs model projections of RFG fuel quality directly in our emission modeling. For conventional gasoline, we use the Jacobs modeling described in Section VII to determine the change in fuel quality due to ethanol use and apply this change to base fuel quality estimates contained in EPA's NMIM emission inventory model. Sulfur is not shown in Table VIII.A.1.a–1, as it is held constant at 30 ppm, which is the average Tier 2 sulfur standard applicable to all gasoline sold in the U.S. in the timeframe of our emission analyses.

### TABLE VIII.A.1.A–1.—TYPICAL SUMMERTIME FUEL QUALITY

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

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

b. Emissions From Motor Vehicles

We use the EPA Predictive Models to estimate the impact of gasoline fuel quality on exhaust VOC and $NO_X$ emissions from motor vehicles. These models were developed in 2000, in

support of EPA's response to California's request for a waiver of the RFG oxygen mandate. These models represent a significant update of the EPA Complex Model. However, they are still based on emission data from Tier 0

vehicles (roughly equivalent to 1990 model year vehicles). We based our estimates of the impact of fuel quality on CO emissions on the EPA MOBILE6.2 model. We base our estimates of the impact of fuel quality

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[101] Subject to funding.

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

on exhaust toxic emissions (benzene, formaldehyde, acetaldehyde, and 1,3-butadiene) primarily on the MOBILE6.2 model, updated to reflect the effect of fuel quality on exhaust VOC emissions per the EPA Predictive Models. Very limited data are available on the effect of gasoline quality on PM emissions. Therefore, the effect of increased ethanol use on PM emissions can only be qualitatively discussed.

In responding to California's request for a waiver of the RFG oxygen mandate in 2000, we found that both very limited and conflicting data were available on the effect of fuel quality on exhaust emissions from Tier 1 and later vehicles.[103] Thus, we assumed at the time that changes to gasoline quality would not affect VOC, CO and NO$_X$ exhaust emissions from these vehicles.[104] Very little additional data have been collected since that time on which to modify this assumption. Consequently, for our primary analysis for today's final rule we have maintained the assumption that changes to gasoline do not affect exhaust emissions from Tier 1 and later technology vehicles.

For the NPRM, we evaluated one recent study by the Coordinating Research Council (CRC) which assessed the impact of ethanol and two other fuel properties on emissions from twelve 2000–2004 model year vehicles (CRC study E–67). Based on comments received on the NPRM, we evaluated four additional studies of the fuel-emission effects of recent model year vehicles. The results of these test

programs indicate that emissions from these late model year vehicles are likely sensitive to changes in fuel properties. However, both the size and direction of the effects are not consistent between the various studies. More testing is still needed before confident predictions of the effect of fuel quality on emissions from these vehicles can be made.

In the NPRM, we developed two sets of assumptions regarding the effect of fuel quality on emissions from Tier 1 and later vehicles to reflect this uncertainty. A primary analysis assumed that exhaust emissions from Tier 1 and later vehicles are not sensitive to fuel quality. This is consistent with our analysis of California's request for a waiver of the RFG oxygen mandate. A sensitivity analysis assumed that the NMHC and NO$_X$ emissions from Tier 1 and later vehicles were as sensitive to fuel quality as Tier 0 vehicles. Only one effect of fuel quality on CO emissions was assumed, that contained in EPA's MOBILE6.2 emission inventory model.

The five available studies of Tier 1 and later vehicles support continuing this approach for exhaust NMHC and NO$_X$ emissions. The assumptions supporting both our primary and sensitivity analyses reasonably bracket the results of the five studies. However, we have decided to perform a sensitivity analysis for CO emissions, as well. In this case, we apply the fuel-emission effects from MOBILE6.2 for Tier 0 vehicles to Tier 1 and later vehicles. This is analogous to the approach taken for exhaust NMHC and NO$_X$ emissions.

We base our estimates of fuel quality on non-exhaust VOC and benzene emissions on the EPA MOBILE6.2 model. The one exception to this is the effect of ethanol on permeation emissions through plastic fuel tanks and elastomers used in fuel line connections. Recent testing has shown that ethanol increases permeation emissions, both by permeating itself and increasing the permeation of other gasoline components. This effect was included in EPA's analysis of California's most recent request for a waiver of the RFG oxygen requirement, but is not in MOBILE6.2.[105] 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 these emissions.

No models are available which address the impact of gasoline quality on PM emissions. Very limited data indicate that ethanol blending might reduce exhaust PM emissions under very cold weather conditions (e.g., −20 °F to 0 °F). Very limited testing at warmer temperatures (e.g., 20 °F to 75 °F) shows no definite trend in PM emissions with oxygen content. Thus, for now, no quantitative estimates can be made regarding the effect of ethanol use on direct PM emissions.

Table VIII.A.1.b–1 presents the average per vehicle (2012 fleet) emission impacts 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 VIII.A.1.B–1.—EFFECT OF RFG ON PER MILE EMISSIONS FROM TIER 0 VEHICLES RELATIVE TO A TYPICAL 9PSI RVP CONVENTIONAL GASOLINE [a]

| Pollutant | Source | Non-Oxy RFG (percent) | 11 Volume percent MTBE | 10 Volume percent ethanol |
|---|---|---|---|---|
| **Exhaust Emissions** | | | | |
| VOC | EPA Predictive Models | −13.4 | −15.3 | −9.7 |
| NO$_X$ | | −2.4 | −1.7 | 7.3 |
| CO | MOBILE6.2 | −22 | −31 | −36 |
| Exhaust Benzene | EPA Predictive and Complex Models | −21.2 | −29.7 | −38.9 |
| Formaldehyde | | −5.9 | 19.4 | 2.3 |
| Acetaldehyde | | −0.2 | −9.5 | 173.7 |
| 1,3-Butadiene | | 20.9 | −29.2 | 6.1 |
| **Non-Exhaust Emissions** | | | | |
| VOC | MOBILE6.2 & CRC E–65 | −30 | −30 | −18 |
| Benzene | MOBILE6.2 & Complex Models | −40 | −43 | −32 |

[a] Average per vehicle effects for the 2012 fleet during summer conditions.

[103] The one exception was the impact of sulfur on emissions from these later vehicles, which is not an issue here due to the fact that renewable fuel use is not expected to change sulfur levels significantly.

[104] An exception is that MOBILE6.2 applies the effect of oxygenate on CO emissions to Tier 1 and later vehicles which are expected to be high emitters based on their age and mileage.

[105] For more information on California's request for a waiver of the RFG oxygen mandate and the Decision Document for EPA's response, see *http://www.epa.gov/otaq/rfg_regs.htm#waiver.*

As can be seen, all three types of RFG produce significantly lower emissions of VOC, CO and benzene than conventional gasoline. The impact of ethanol RFG on non-exhaust VOC emissions is lower than the other two types of RFG due to the impact of ethanol on permeation emissions. The impact of RFG on emissions of $NO_X$ and the other air toxics depends on the type of RFG blend. The most notable effect on toxic emissions in percentage terms is the 173 percent increase in acetaldehyde with the use of ethanol. However, as will be seen below, base acetaldehyde emissions are low relative to the other toxics. While not shown, the total mass emissions of the four toxic pollutants always decreases, as benzene is by far the largest constituent.

It should be noted that these comparisons assume that all gasoline blends meet EPA's Tier 2 gasoline sulfur standard of 30 ppm. Prior to the Tier 2 program, RFG contained less sulfur than conventional gasoline and reduced $NO_X$ emissions to a greater degree compared to conventional gasoline.

Historically, no non-oxygenated RFG was sold, due to the requirement that RFG contain at least 2.0 weight percent oxygen. However, with the Energy Act's removal of this requirement, all three types of RFG blends can be sold today. Increased use of ethanol in RFG would therefore either replace MTBE RFG or non-oxygenated RFG. The former has already occurred in many areas, as MTBE was essentially removed from the U.S. gasoline market by the end of 2006. The impact of using ethanol in RFG in lieu of MTBE or no oxygenate can be seen from comparing the relative impacts of the various RFG blends shown in Table VIII.A.1.b–1.

Blending RFG with ethanol instead of MTBE or no oxygenate will increase VOC and $NO_X$ emissions and decrease CO emissions. Exhaust benzene and formaldehyde emissions will decrease, but non-exhaust benzene, acetaldehyde, and 1,3-butadiene emissions will increase. All of these impacts are on a per vehicle basis and apply to Tier 0 vehicles only. The overall impact of increased ethanol use on total emissions of these various pollutants is described below.

Table VIII.A.1.b–2 presents the effect of blending either MTBE or ethanol into conventional gasoline while matching octane.

TABLE VIII.A.1.B–2.—EFFECT OF MTBE AND ETHANOL IN CONVENTIONAL GASOLINE ON TIER 0 VEHICLE EMISSIONS RELATIVE TO A TYPICAL NON-OXYGENATED CONVENTIONAL GASOLINE [a]

| Pollutant | Source | 11 Volume percent MTBE | 10 Volume percent ethanol [b] |
|---|---|---|---|
| Exhaust VOC | EPA Predictive Models | −9.2 | −7.4 |
| $NO_X$ | | −2.6 | 7.7 |
| CO [c] | MOBILE6.2 | −6/−11 | −11/−19 |
| Exhaust Benzene | EPA Predictive and Complex Models | −22.8 | −24.9 |
| Formaldehyde | | +21.3 | +6.7 |
| Acetaldehyde | | +0.8 | +156.8 |
| 1,3-Butadiene | | −3.7 | −13.2 |
| Non-Exhaust VOC | MOBILE6.2 | Zero | +30 |
| Non-Exhaust Benzene | MOBILE6.2 & Complex Models | −9.5 | +15.8 |

[a] Average per vehicle effects for the 2012 fleet during summer conditions.
[b] Assumes a 1.0 psi RVP waiver for ethanol blends.
[c] The first figure shown applies to normal emitters; the second applies to high emitters.

Use of either oxygenate reduces exhaust VOC and CO emissions, but increases $NO_X$ emissions. The ethanol blend increases non-exhaust VOC emissions due to the commonly granted 1.0 psi waiver of the RVP standard, as well as increased permeation emissions. Both oxygenated blends reduce exhaust benzene and 1,3-butadiene emissions. As above, ethanol increases non-exhaust benzene and acetaldehyde emissions. While small amounts of MTBE may have still been used in CG in 2004, for our reference case we have assumed that all MTBE use was in RFG. Therefore, we are not predicting any emissions impact related to removing MTBE from conventional gasoline. Increased use of conventional ethanol blends will be in lieu of non-oxygenated conventional gasoline. Thus, the more relevant column in Table VII.A.1.b–2 for our modeling is the last column, which shows the emission impact of a 10 volume percent ethanol blend relative to non-oxygenated gasoline.

The exhaust emission effects shown above for VOC and $NO_X$ emissions only apply to Tier 0 vehicles in our primary analysis. For example, MOBILE6.2 estimates that 34 of exhaust VOC emissions and 16 of $NO_X$ emissions from gasoline vehicles in 2012 come from Tier 0 vehicles. In the sensitivity analysis, these effects are extended to all gasoline vehicles. The effect of RVP and permeation on non-exhaust VOC emissions is temperature dependent. The figures shown above are based on the distribution of temperatures occurring across the U.S. in July.

We received several comments related to the effect of ethanol on emissions from onroad vehicles. None of the comments led us to change the basic approach taken to estimating the impact of changing fuel quality described above. Several comments suggested that we expand our discussion of the uncertainty in these fuel effects (as well as the effects of fuel quality on emissions from nonroad equipment and diesels described below). While such an expanded discussion might be generally desirable, the lack of relevant emission data from late model vehicles and equipment prevents this. We believe that we have adequately described the uncertainty in the emission estimates presented below and our plans to obtain more data in order to improve these estimates in the near future.

c. Nonroad Equipment

To estimate the effect of gasoline quality on emissions from nonroad equipment, we used EPA's NONROAD emission model. We used the 2005 version of this model, NONROAD2005, which includes the effect of ethanol on permeation emissions from most nonroad equipment.

Only sulfur and oxygen content affect exhaust VOC, CO and $NO_X$ emissions in NONROAD. Since sulfur level is assumed to remain constant, the only difference in exhaust emissions between conventional and reformulated gasoline is due to oxygen content. Table VIII.A.1.c–1 shows the effect of adding

11 volume percent MTBE or 10 volume percent ethanol to non-oxygenated gasoline on these emissions.

TABLE VIII.A.1.C–1.—EFFECT MTBE AND ETHANOL ON NONROAD EXHAUST EMISSIONS RELATIVE TO A TYPICAL NON-OXYGENATED GASOLINE

| Base fuel | 4-Stroke engines | | 2-Stroke engines | |
|---|---|---|---|---|
| | 11 Volume percent MTBE | 10 Volume percent ethanol | 11 Volume percent MTBE | 10 Volume percent ethanol |
| Exhaust VOC | −9 | −16 | −1 | −2 |
| Non-Exhaust VOC | 0 | 26 | 0 | 26 |
| CO | −13 | −22 | −13 | −23 |
| NO$_X$ | +23 | +40 | +37 | +65 |

As can be seen, higher oxygen content reduces exhaust VOC and CO emissions significantly, but also increases NO$_X$ emissions. However, NO$_X$ emissions from these engines tend to be fairly low to start with, given the fact that these engines run much richer than stoichiometric. Thus, a large percentage increase of a relative low base value can be a relatively small increase in absolute terms.

Evaporative emissions from nonroad equipment are impacted by only RVP, and permeation by ethanol content. Both the RVP increase due to blending of ethanol and its permeation effect cause non-exhaust VOC emissions to increase with the use of ethanol in nonroad equipment. The 26 percent effect represents the average impact across the U.S. in July for both 2-stroke and 4-stroke equipment. We updated the NONROAD2005 hose permeation emission factors for small spark-ignition engines and recreational marine watercraft to reflect the use of ethanol.

For nonroad toxics emissions, we base our estimates of the impact of fuel quality on the fraction of exhaust VOC emissions represented by each toxic on MOBILE6.2 (i.e., the same effects predicted for onroad vehicles). The National Mobile Inventory Model (NMIM) contains estimates of the fraction of VOC emissions represented by the various air toxics based on

oxygenate type (none, MTBE or ethanol). However, estimates for nonroad gasoline engines running on different fuel types are limited, making it difficult to accurately model the impacts of changes in fuel quality. In the recent final rule addressing mobile air toxic emissions, EPA replaced the toxic-related fuel effects contained in NMIM with those from MOBILE6.2 for onroad vehicles.[106] We follow the same methodology here. Future testing could significantly alter these emission impact estimates.

2. Diesel Fuel Quality: Biodiesel

EPA assessed the impact of biodiesel fuel on emissions in 2002 and published a draft report summarizing the results.[107] This report included a technical analysis of biodiesel effects on regulated and unregulated pollutants from diesel powered vehicles and concluded that biodiesel fuels improved PM, HC and CO emissions of diesel engines while slightly increasing their NO$_X$ emissions.

While the conclusions reached in the 2002 EPA report relative to biodiesel effects on VOC, CO and PM emissions have been generally accepted, the magnitude of the B20 effect on NO$_X$ remains controversial due to conflicting results from different studies. Significant new testing is being planned with broad stakeholder participation and support in order to better estimate

the impact of biodiesel on NO$_X$ and other exhaust emissions from the in-use fleet of diesel engines. We hope to incorporate the data from such additional testing into the analyses for other studies required by the Energy Act in 2008 and 2009, and into a subsequent rule to set the RFS program standard for 2013 and later.

3. Renewable Fuel Production and Distribution

Areas experiencing increased renewable production will experience the corresponding emission increases associated with their production. 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 and biodiesel production, including corn and soy farming, on emissions based on DOE's GREET model, version 1.7. In addition, we develop a second estimate of emissions from ethanol production facilities using estimates of emissions from current ethanol plants obtained from the States. We also include emissions effects resulting from the transport of increased volumes of renewable fuels and decreased volumes of gasoline and diesel fuel. These emissions are summarized in Table VIII.A.3–1.

TABLE VIII.A.3–1.—WELL-TO-PUMP EMISSIONS FOR PRODUCING AND DISTRIBUTING RENEWABLE FUELS

[Grams per gallon ethanol or biodiesel] [a]

| Pollutant | GREET1.7 | | GREET1.7 + state data | | Biodiesel—GREET1.7 |
|---|---|---|---|---|---|
| | Current ethanol plants | Future ethanol plants | Current ethanol plants | Future ethanol plants | |
| VOC | 1.8 | 1.8 | 3.6 | 3.2 | 37.6 |
| CO | 4.0 | 4.1 | 4.4 | 4.3 | 12.7 |
| NO$_X$ | 11.4 | 11.4 | 10.8 | 13.0 | 25.1 |
| PM10 | 4.9 | 4.9 | 6.1 | 2.8 | 4.8 |

[106] 71, **Federal Register**, 15804, March 29, 2006.

[107] ''A Comprehensive Analysis of Biodiesel Impacts on Exhaust Emissions,'' Draft Technical Report, U.S. EPA, EPA420–P–02–001, October 2002. http://www.epa.gov/otaq/models/biodsl.htm.

TABLE VIII.A.3–1.—WELL-TO-PUMP EMISSIONS FOR PRODUCING AND DISTRIBUTING RENEWABLE FUELS—Continued

[Grams per gallon ethanol or biodiesel] [a]

| Pollutant | GREET1.7 | | GREET1.7 + state data | | Biodiesel— GREET1.7 |
| --- | --- | --- | --- | --- | --- |
| | Current ethanol plants | Future ethanol plants | Current ethanol plants | Future ethanol plants | |
| SO$_X$ ....................................................... | 6.4 | 6.4 | 7.2 | 9.7 | 21.8 |

[a] Includes credit for reduced distribution of gasoline and diesel fuel.

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 renewable fuel use not risen. However, to the degree that increased renewable fuel use reduces imports of gasoline and diesel fuel, as opposed to the domestic production of these fuels, 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, many of these plants may be converted to produce other gasoline blendstocks, such as iso-octane or alkylate. In this case, their emissions are not likely to change substantially.

*B. Impact on Emission Inventories*

We use the NMIM to estimate emissions under the various ethanol scenarios on a county by county basis. NMIM basically runs MOBILE6.2 and NONROAD2005 with county-specific inputs pertaining to fuel quality, ambient conditions, levels of onroad vehicle VMT and nonroad equipment usage, etc. We ran NMIM for two months, July and January. We estimate annual emission inventories by summing the two monthly inventories and multiplying by six.

As described above, we removed the effect of gasoline fuel quality on exhaust VOC and NO$_X$ emissions from the onroad motor vehicle inventories which are embedded in MOBILE6.2. We then applied the exhaust emission effects from the EPA Predictive Models. In our primary analysis, we only applied these EPA Predictive Model effects to exhaust

VOC and NO$_X$ emissions from Tier 0 vehicles. In a sensitivity case, we applied them to exhaust VOC and NO$_X$ emissions from all vehicles. Regarding the effect of fuel quality on emissions of four air toxics from nonroad equipment (in terms of their fraction of VOC emissions), in all cases we replaced the fuel effects contained in NMIM with those for motor vehicles contained in MOBILE6.2. The projected emission inventories for the primary analysis are presented first, followed by those for the sensitivity analysis.

1. Primary Analysis

The national emission inventories for VOC, CO and NO$_X$ in 2012 with current fuels (i.e., ''reference fuel'') are summarized in Table VIII.B.1–1. Also shown are the changes in emissions projected for the two levels of ethanol use (i.e., ''control cases'') described in Section VI.

TABLE VIII.B.1–1.—2012 EMISSIONS NATIONWIDE FROM GASOLINE VEHICLES AND EQUIPMENT UNDER SEVERAL ETHANOL USE SCENARIOS—PRIMARY ANALYSIS

[Tons per year] [108]

| Pollutant | Inventory | Change in inventory in control cases | |
| --- | --- | --- | --- |
| | Reference case | RFS case | EIA case |
| VOC ....................................................................................................... | 5,882,000 | 18,000 | 43,000 |
| NO$_X$ ..................................................................................................... | 2,487,000 | 23,000 | 40,000 |
| CO ......................................................................................................... | 55,022,000 | −483,000 | −1,366,000 |
| Benzene ................................................................................................ | 178,000 | −3,200 | −7,200 |
| Formaldehyde ....................................................................................... | 40,400 | −600 | −200 |
| Acetaldehyde ........................................................................................ | 19,900 | 3,400 | 7,100 |
| 1,3-Butadiene ....................................................................................... | 18,900 | −200 | −300 |

Both VOC and NO$_X$ emissions are projected to increase with increased use of ethanol. However, the increases are small, generally less than 2 percent. CO emissions are projected to decrease by about 0.9 to 2.5 percent. Benzene emissions are projected to decrease by 1.8 to 4.0 percent. Formaldehyde emissions are projected to decrease slightly, on the order of 0.5 to 1.5 percent. 1,3-butadiene emissions are

projected to decrease by about 1.1 to 1.6 percent. The largest change is in acetaldehyde emissions, an increase of 17.1 to 35.7 percent, as acetaldehyde is a partial combustion product of ethanol.

CO also participates in forming ozone, much like VOCs. Generally, CO is 15–50 times less reactive than typical VOC. Still, the reduction in CO emissions is roughly 27–32 times the increase in VOC emissions in the two scenarios. Thus, the projected reduction in CO emissions is important from an ozone perspective. However, as described above, the methodology for projecting

the effect of ethanol use on CO emissions is inconsistent with that for exhaust VOC and NO$_X$ emissions. Thus, comparisons between changes in VOC and CO emissions are particularly uncertain.

There will also be some increases in emissions due to ethanol and biodiesel production. Table VIII.B.1–2 shows estimates of annual emissions expected to occur nationwide due to increased production of ethanol. These estimates include a reduction in emissions related to the distribution of the displaced gasoline. The table reflects the use of

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[108] These emission estimates do not include the impact of the recent mobile source air toxic standards (72 FR 8428, February 26, 2007).

emissions factors from DOE's GREET model, version 1.7, as well as estimates of ethanol plant emissions obtained from the States. It should be noted that emissions in the base case assume an 80/20 mix of dry mill and wet mill facilities. New plants (and thus, the emission increases) assume 100% dry mill facilities.

### TABLE VIII.B.1–2.—ANNUAL EMISSIONS NATIONWIDE FROM ETHANOL PRODUCTION AND TRANSPORTATION: 2012

[Tons per year]

| | GREET1.7 | | | GREET1.7 + State data | | |
|---|---|---|---|---|---|---|
| | Base case | RFS case | EIA case | Base case | RFS case | EIA case |
| | Emissions | Increase in emissions | | Emissions | Increase in emissions | |
| VOC | 8,000 | 5,000 | 11,000 | 14,000 | 10,000 | 20,000 |
| $NO_X$ | 17,000 | 13,000 | 26,000 | 18,000 | 14,000 | 27,000 |
| CO | 49,000 | 35,000 | 72,000 | 56,000 | 40,000 | 81,000 |
| $PM_{10}$ | 21,000 | 15,000 | 30,000 | 12,000 | 9,000 | 18,000 |
| $SO_X$ | 27,000 | 20,000 | 41,000 | 42,000 | 30,000 | 61,000 |

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. The vast majority of these emissions are related to farming and ethanol production. Both farms and ethanol plants are generally located in ozone attainment areas.

Where counties are constructing new ethanol plants, expanding existing plants, or planning construction for future plants, the average increase in VOC and $NO_X$ emissions from plants alone are about 26 tons/month VOC and 35 tons/month $NO_X$ using state data (about 17 tons/month VOC and 25 tons/month $NO_X$ using GREET 1.7 emission factors). Average VOC and $NO_X$ emissions increase to about 61 tons/month and 83 tons/month, respectively, in the 10% of counties expecting largest increases in ethanol production. For both VOC and $NO_X$, emissions estimates are about 35% less when using the GREET 1.7 emission factors.

Table VIII.B.1–3 shows estimates of annual emissions expected to occur nationwide due to increased production of biodiesel. These estimates include a reduction in emissions related to the distribution of the displaced diesel fuel. Again, these emissions are generally expected to be in ozone attainment areas.

### TABLE VIII.B.1–3.—ANNUAL EMISSIONS NATIONWIDE FROM BIODIESEL PRODUCTION AND TRANSPORTATION

[Tons per year]

| Pollutant | Reference inventory: 30 mill gal biodiesel per year | 2012 Emissions inventory: 300 mill gal biodiesel per year |
|---|---|---|
| VOC | 1,400 | 14,000 |
| $NO_X$ | 1,500 | 15,000 |
| CO | 800 | 8,000 |

### TABLE VIII.B.1–3.—ANNUAL EMISSIONS NATIONWIDE FROM BIODIESEL PRODUCTION AND TRANSPORTATION—Continued

[Tons per year]

| Pollutant | Reference inventory: 30 mill gal biodiesel per year | 2012 Emissions inventory: 300 mill gal biodiesel per year |
|---|---|---|
| $PM_{10}$ | 50 | 500 |
| $SO_X$ | 250 | 2,500 |

### 2. Sensitivity Analysis

The national emission inventories for VOC and $NO_X$ in 2012 with current fuels are summarized in Table VIII.B.2–1. Here, the emission effects contained in the EPA Predictive Models are assumed to apply to all vehicles, not just Tier 0 vehicles. Also shown are the changes in emissions projected for the two cases for future ethanol volume.

### TABLE VIII.B.2–1.—2012 EMISSIONS NATIONWIDE FROM GASOLINE VEHICLES AND EQUIPMENT UNDER TWO FUTURE ETHANOL USE SCENARIOS—SENSITIVITY ANALYSIS

[Tons per year]

| Pollutant | Inventory | Change in inventory in control cases | |
|---|---|---|---|
| | Reference case | RFS case | EIA case |
| VOC | 5,834,000 | −20,000 | −4,000 |
| $NO_X$ | 2,519,000 | 68,000 | 106,000 |
| CO | 54,315,000 | −692,000 | −1,975,000 |
| Benzene | 175,700 | −5,000 | −9,400 |
| Formaldehyde | 39,600 | −1,100 | −700 |
| Acetaldehyde | 19,500 | 3,000 | 6,600 |
| 1,3-Butadiene | 18,600 | −400 | −600 |

The overall VOC and $NO_X$ emission impacts of the various ethanol use scenarios change to some degree when all motor vehicles are assumed to be sensitive to fuel ethanol content. The increase in VOC emissions turns into a net decrease due to a greater reduction in exhaust VOC emissions from onroad vehicles. However, the increase in $NO_X$ emissions gets larger, as more vehicles are assumed to be affected by ethanol. Emissions of the four air toxics generally decrease slightly, due to the greater reduction in exhaust VOC emissions.

3. Local and Regional VOC and $NO_X$ Emission Impacts in July

We also estimate the percentage change in VOC, $NO_X$, and CO emissions from gasoline fueled motor vehicles and equipment in those areas which actually experienced a significant change in ethanol use. Specifically, we focused on areas where the market share of ethanol blends was projected to change by 50 percent or more. We also focused on summertime emissions, as these are most relevant to ozone formation. Finally, we developed separately estimates for: (1) RFG areas, including the state of California and the portions of Arizona where their CBG fuel programs apply, (2) low RVP areas (*i.e.*, RVP standards less than 9.0 RVP, and (3) areas with a 9.0 RVP standard. This set of groupings helps to highlight the emissions impact of increased ethanol use in those areas where emission control is most important.

Table VIII.B.3–1 presents our primary estimates of the percentage change in VOC, $NO_X$, and CO emission inventories for these three types of areas. Note that the analyses here are very similar to those described in Section 5.1 of the RIA, with the exception that Table VIII.B.3–1 below reflects 50 states (instead of 37 eastern states) and excludes diesel emissions.

TABLE VIII.B.3–1.—JULY 2015 CHANGE IN EMISSIONS FROM GASOLINE VEHICLES AND EQUIPMENT IN COUNTIES WHERE ETHANOL USE CHANGED SIGNIFICANTLY—PRIMARY ANALYSIS

| Ethanol use | RFS case | EIA case |
|---|---|---|
| **RFG Areas** | | |
| Ethanol Use | Down | Up. |
| VOC | 0.8% | 2.3%. |
| $NO_X$ | −3.4% | 1.6%. |
| CO | 6.1% | −2.6%. |
| **Low RVP Areas** | | |
| Ethanol Use | Up | Up. |
| VOC | 4.2% | 4.6%. |
| $NO_X$ | 6.2% | 5.7%. |
| CO | −12.5% | −13.7%. |
| **Other Areas (9.0 RVP)** | | |
| Ethanol Use | Up | Up. |
| VOC | 3.6% | 4.6%. |
| $NO_X$ | 7.3% | 7.0%. |
| CO | −6.4% | −6.0%. |

As expected, increased ethanol use tends to increase $NO_X$ 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. We would expect very similar results for 2012. The reader is referred to Chapter 2 of the RIA for discussion of how ethanol levels will change at the state-level.

Table VIII.B.3–2 presents the percentage change in VOC, $NO_X$, and CO emission inventories under our sensitivity case (*i.e.*, when we apply the emission effects of the EPA Predictive Models to all motor vehicles).

TABLE VIII.B.3–2.—JULY 2015 CHANGE IN EMISSIONS FROM GASOLINE VEHICLES AND EQUIPMENT IN COUNTIES WHERE ETHANOL USE CHANGED SIGNIFICANTLY—SENSITIVITY ANALYSIS

| Ethanol use | RFS case | EIA case |
|---|---|---|
| **RFG Areas** | | |
| Ethanol Use | Down | Up. |
| VOC | −1.0% | 1.0%. |
| $NO_X$ | −0.9% | 5.6%. |
| CO | 7.3% | −3.0%. |
| **Low RVP Areas** | | |
| Ethanol Use | Up | Up. |
| VOC | 3.4% | 3.7%. |
| $NO_X$ | 10.4% | 10.8%. |
| CO | −15.0% | −16.4%. |
| **Other Areas (9.0 RVP)** | | |
| Ethanol Use | Up | Up. |
| VOC | 3.0% | 3.9%. |
| $NO_X$ | 10.8% | 11.0%. |

TABLE VIII.B.3–2.—JULY 2015 CHANGE IN EMISSIONS FROM GASOLINE VEHICLES AND EQUIPMENT IN COUNTIES WHERE ETHANOL USE CHANGED SIGNIFICANTLY—SENSITIVITY ANALYSIS—Continued

| Ethanol use | RFS case | EIA case |
|---|---|---|
| CO ................................................................. | −9.0% ............................................................. | −8.9%. |

Directionally, the changes in VOC and $NO_X$ 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 $NO_X$ emissions are larger.

*C. Impact on Air Quality*

We estimate the impact of increased ethanol use on the ambient concentrations of two pollutants: Ozone and PM. Quantitative estimates are made for ozone, while only qualitative estimates can be made currently for ambient PM. These impacts are described below.

1. Impact of Increased Ethanol Use on Ozone

We use a metamodeling tool developed at EPA, the ozone response surface metamodel (Ozone RSM), to estimate the effects of the projected changes in emissions from gasoline vehicles and equipment for the RFS and EIA cases. We included the estimated changes in emissions from renewable fuel production and distribution. Because of limitations in the Ozone RSM, we could not easily assign these emissions to the specific counties where the plants are or are expected to be located. Instead, we assigned all of the emissions related to renewable fuel production and distribution to the set of states expected to contain most of the production facilities.

The Ozone RSM was created using multiple runs of the Comprehensive Air Quality Model with Extensions ($CAM_X$). Base and proposed control $CAM_X$ metamodeling was completed for the year 2015 over a modeling domain that includes all or part of 37 Eastern U.S. states, plus the District of Columbia. For more information on the Ozone RSM, please see Chapter 5 of the RIA for this final rule.

The Ozone RSM limits the number of geographically distinct changes in VOC and $NO_X$ emissions which can be simulated. As a result, we could not apply distinct changes in emissions for each county. Therefore, two separate runs were made with different VOC and $NO_X$ emissions reductions. We then selected the ozone impacts from the various runs which best matched the VOC and $NO_X$ emission reductions for that county. This models the impact of local emissions reasonably well, but loses some accuracy with respect to ozone transport. No ozone impact was assumed for areas which did not experience a significant change in ethanol use. The predicted ozone impacts of increased ethanol use for those areas where ethanol use is projected to change by more than a 50% market share are summarized in Table VIII.C.1–1. As shown in the Table 5.1–2 of the RIA, national average impacts (based on the 37-state area modeled) which include those areas where no change in ethanol use is occurring are considerably smaller.

TABLE VIII.C.1–1.—IMPACT ON 8-HOUR DESIGN VALUE EQUIVALENT OZONE LEVELS (PPB) [a]

| | Primary analysis | | Sensitivity analysis | |
|---|---|---|---|---|
| | RFS case | EIA case | RFS case | EIA case |
| Minimum Change ....................................................................................... | −0.015 | 0.000 | −0.115 | 0.028 |
| Maximum Change ...................................................................................... | 0.329 | 0.337 | 0.624 | 0.549 |
| Average Change [b] .................................................................................... | 0.153 | 0.181 | 0.300 | 0.325 |
| Population-Weighted Change [b] ................................................................. | 0.154 | 0.183 | 0.272 | 0.315 |

[a] In comparison to the 80 ppb 8-hour ozone standards.
[b] Only for those areas experiencing a change in ethanol blend market share of at least 50 percent.

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 $NO_X$ 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 in those areas where ethanol use changed significantly is 0.154–0.183 ppb. Since the 8-hour ambient ozone standard is 85 ppb, this increase represents about 0.2 percent of the standard, 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 is slightly less than twice as high, or 0.272–0.315 ppb. This increase represents about 0.35 percent of the standard.

There are a number of important caveats concerning these estimates. First, the emission effects of adding ethanol to gasoline are based on extremely limited data for recent vehicles and equipment. Second, the Ozone RSM does not account for changes in CO emissions. As shown above, ethanol use should reduce CO emissions significantly, directionally reducing ambient ozone levels in those areas where ozone formation is VOC-limited. (Ozone levels in areas which are $NO_X$-limited are less likely to be affected by a change in CO emissions.) 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 those areas where ozone formation is predominantly VOC-limited. Because of these limitations, anyone interested in the impact of increased ethanol use on ozone in any particular area should utilize more comprehensive dispersion modeling which accounts for these and other important factors.

We received several requests in comments on the proposal to quantify the impact of the reduced CO emissions

and VOC reactivity on ozone. As discussed in the S&A document, this is not possible without running more sophisticated ambient dispersion models. The impact of CO emissions and VOC reactivity on ozone vary significantly depending on ambient conditions and the relative amount of VOC and $NO_X$ in the atmosphere. Therefore, general rules of thumb cannot be applied.

Moving to health effects, exposure to ozone has been linked to lung function decrements, respiratory symptoms, aggravation of asthma, increased hospital and emergency room visits, increased asthma medication usage, inflammation of the lungs, and a variety of other respiratory effects and cardiovascular effects including premature mortality. Ozone can also adversely affect the agricultural and forestry sectors by decreasing yields of crops and forests. Although the health and welfare impacts of changes in ambient ozone levels are typically quantified in regulatory impact analyses, we do not evaluate them for this analysis. On average, the changes in ambient ozone levels shown above are small and would be even smaller if changes in CO emissions and VOC reactivity were taken into account. The increase in ozone would likely lead to negligible monetized impacts. We therefore do not estimate and monetize ozone health impacts for the changes in renewable use due to the small magnitude of this change, and the uncertainty present in the air quality modeling conducted here, as well as the uncertainty in the underlying emission effects themselves discussed earlier.

2. Particulate Matter

Ambient PM can come from two distinct sources. First, PM can be directly emitted into the atmosphere. Second, PM can be formed in the atmosphere from gaseous pollutants. Gasoline-fueled vehicles and equipment contribute to ambient PM concentrations in both ways.

As described above, we are not currently able to predict the impact of fuel quality on direct PM emissions from gasoline-fueled vehicles or equipment. Therefore, we are unable at this time to project the effect that increased ethanol use will have on levels of directly emitted PM in the atmosphere.

PM can also be formed in the atmosphere (termed secondary PM here) from several gaseous pollutants emitted by gasoline-fueled vehicles and equipment. Sulfur dioxide emissions contribute to ambient sulfate PM. $NO_X$ emissions contribute to ambient nitrate

PM. VOC emissions contribute to ambient organic PM. Increased ethanol use is not expected to change gasoline sulfur levels, so emissions of sulfur dioxide and any resultant ambient concentrations of sulfate PM are not expected to change. Increased ethanol use is expected to increase $NO_X$ emissions, so the possibility exists that ambient nitrate PM levels could increase. Increased ethanol is generally expected to increase total VOC emissions, which could also impact the formation of secondary organic PM. However, while non-exhaust VOC emissions are expected to increase, exhaust VOC emissions are expected to decrease. Generally, the higher the molecular weight of the specific VOC emitted, the greater the likelihood it will form PM in the atmosphere. Non-exhaust VOC is predominantly low in molecular weight, as much of it is due to fuel evaporating. Thus, emissions of VOCs likely to form PM in the atmosphere are likely decreasing with ethanol use.

The formation of secondary organic PM is very complex, due in part to the wide variety of VOCs emitted into the atmosphere. The degree to which a specific gaseous VOC reacts to form PM in the atmosphere depends on the types of reactions that specific VOC undergoes and the products of those reactions. Both of these factors depend on other pollutants present, such as the hydroxyl radical, ozone, $NO_X$ and other reactive compounds. The relative mass of secondary PM formed per mass of gaseous VOC emitted can also depend on the total concentration of gaseous VOC and organic PM in the atmosphere. Most of the secondary organic PM exists in a continually changing equilibrium between the gaseous and PM phases. Both the rates of these reactions and the gaseous-PM equilibria depend on temperature, so seasonal differences can be expected.

Recent smog chamber studies have indicated that gaseous aromatic VOCs can form secondary PM under certain conditions. These compounds comprise a greater fraction of exhaust VOC emissions than non-exhaust VOC emissions, as non-exhaust VOC emissions are dominated by VOCs with relatively high vapor pressures. Aromatic VOCs tend to have lower vapor pressures. As increased ethanol use is expected to reduce exhaust VOC emissions, emissions of aromatic VOCs should also decrease. In addition, refiners are expected to reduce the aromatic content of gasoline by 5 volume percentage points as ethanol is blended into gasoline. Emissions of aromatic VOCs should decrease with

lower concentrations of aromatics in gasoline. Thus, emissions of gaseous aromatic VOCs could decrease for both reasons.

Overall, we expect that the decrease in secondary organic PM is likely to exceed the increase in secondary nitrate PM. In 1999, $NO_X$ emissions from gasoline-fueled vehicles and equipment comprised about 20% of national $NO_X$ emissions from all sources. In contrast, gasoline-fueled vehicles and equipment comprised over 60% of all national gaseous aromatic VOC emissions. The percentage increase in national $NO_X$ emissions due to increased ethanol use should be smaller than the percentage decrease in national emissions of gaseous aromatics. Finally, in most urban areas, ambient levels of secondary organic PM exceed those of secondary nitrate PM. Thus, directionally, we expect a net reduction in ambient PM levels due to increased ethanol use. However, we are unable to quantify this reduction at this time.

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 $NO_X$ 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. We plan to incorporate this mechanism into the CMAQ model in 2007. 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 $NO_X$ emissions due to increased ethanol use as part of future analyses of U.S. fuel requirements required by the Act.

## IX. Impacts on Fossil Fuel Consumption and Related Implications

Renewable fuels have been of significant interest for many years due to their potential to displace fossil fuels, which have often been targeted as primary contributors to emissions of greenhouse gases such as carbon dioxide, and national energy concerns primarily due to an increasing dependence on foreign sources of petroleum. In the Notice of Proposed Rulemaking, we provided a preliminary assessment of the greenhouse gas emission and energy impacts of renewable fuel and an initial assessment of the economic value of renewable fuel displacing petroleum-based fuels. We

also indicated that we would be updating an analysis of energy security impacts that had been prepared by analysts at the Oak Ridge National Laboratory (ORNL) of the Department of Energy. We present some discussion of that analysis here.

We also performed a full lifecycle or well-to-wheel analysis for this final rule to estimate the GHG and fossil energy reductions from replacing petroleum based fuels with renewable fuels. Argonne National Laboratory's (ANL) GREET [109] model was utilized for this lifecycle analysis. Table IX–1 summarizes this model's estimated impact that increases in the use of renewable fuels are projected to have on

GHG emissions and fossil fuel consumption for the two renewable fuel volume scenarios considered in this final rulemaking relative to the reference case. As described later in this section, the results in Table IX–1 are based on a number of input assumptions including coal being used as process fuel in 14% of ethanol facilities.

As noted in Section III, although we have chosen to base our lifecycle analyses on Argonne National Laboratory's GREET model there are a variety of other lifecycle models and analyses available. The choice of model inputs and assumptions all have a bearing on the results of lifecycle analyses, and many of these

assumptions remain the subject of debate among researchers. Lifecycle analyses must also contend with the fact that the inputs and assumptions generally represent industry-wide averages even though energy consumed and emissions generated can vary widely from one facility or process to another.

There currently exists no organized, comprehensive dialogue among stakeholders about the appropriate tools and assumptions behind any lifecycle analyses. We will be initiating more comprehensive discussions about lifecycle analyses with stakeholders in the near future.

TABLE IX–1.—GREET MODEL LIFECYCLE REDUCTIONS FROM INCREASED RENEWABLE FUEL USE RELATIVE TO THE 2012 REFERENCE CASE

| | RFS case | | EIA case | |
| --- | --- | --- | --- | --- |
| | Reduction | % of trans. sector | Reduction | % of trans. sector |
| Fossil Energy (QBtu) ................................................................................ | 0.15 | 0.48 | 0.27 | 0.85 |
| Petroleum Energy (Bgal) ......................................................................... | 2.0 | 0.82 | 3.9 | 1.60 |
| GHG Emissions (MMT $CO_2$-eq.) ............................................................ | 8.0 | 0.36 | 13.1 | 0.59 |
| CO2 Emissions (MMT $CO_2$) .................................................................... | 11.0 | 0.52 | 19.5 | 0.93 |

We used the petroleum energy reductions shown in Table IX–1 to determine implications on imports of petroleum products. Our analysis found that calculated petroleum energy reductions come almost entirely from imports of finished products in this 2012 case and amount to the equivalent of 123,000 barrels of transportation fuel under the RFS case and 240,000 barrels of transportation fuel for the EIA case.

Another effect of increased use of renewable fuels in the U.S. is that it diversifies the energy sources in making transportation fuel. Diverse sources of fuel energy reduce both financial and strategic risks associated with a potential disruption in supply or a spike in cost of a particular energy source. This reduction in risks is a measure of improved energy security. The ORNL report used an "oil premium" approach to identify those energy-security related impacts which are not reflected in the market price of oil, and which are expected to change in response to an incremental change in the level of U.S. oil imports.

The following sections provide a more complete description of our analyses of the GHG emissions, fossil fuel, oil imports, and energy security impacts of this final rule.

## A. Impacts on Lifecycle GHG Emissions and Fossil Energy Use

Although the use of renewable fuels in the transportation sector directly displaces some petroleum consumed as motor vehicle fuel, this displacement of petroleum is in fact only one aspect of the overall impact of renewable fuels on fossil fuel use. Fossil fuels are also used in producing and transporting renewable feedstocks such as plants or animal byproducts, in converting the renewable feedstocks into renewable fuel, and in transporting and blending the renewable fuels for consumption as motor vehicle fuel. To estimate the true impacts of increases in renewable fuels on fossil fuel use, modelers attempt to take many or all these steps into account.

Similarly, energy is used and GHGs emitted in the pumping of oil, transporting the oil to the refinery, refining the crude oil into finished transportation fuel, transporting the refined gasoline or diesel fuel to the consumer and then burning the fuel in the vehicle. Such analyses are termed lifecycle or well-to-wheels analyses. We performed a full lifecycle analysis as part of this final rulemaking to determine the GHG and fossil energy

reductions from the increased use of renewable fuels.

This lifecycle assessment approach and rationale were highlighted in the proposal. Comments received focused mainly on improving the process, for example the choice of lifecycle model used and initiating a stakeholder dialogue to build consensus around the assumptions and approach. In general comments were supportive of using a full lifecycle assessment approach, but differed on the appropriate model and associated assumptions EPA should use in its analysis.

1. Time Frame and Volumes Considered

The results presented in this analysis represent a snapshot in time. They represent annual GHG and fossil fuel savings in the year considered, in this case 2012. Consistent with the emissions modeling described in Section VII, our analysis of the GHG and fossil fuel consumption impacts of renewable fuel use was conducted using three volume scenarios. The first scenario was the same reference case used elsewhere in this final rulemaking. The reference case scenario provided the point of comparison for the other two scenarios. The other two renewable fuel scenarios for 2012 represented the

[109] Greenhouse gases, Regulated Emissions, and Energy use in Transportation.

RFS program requirements and the volume projected by EIA.

In both the RFS and EIA scenarios, we assumed that the biodiesel production volume would be 0.303 billion gallons based on EIA AEO2006 projections. Furthermore, for both scenarios we assume that 250 million gallons of ethanol that qualify for cellulosic biomass ethanol credit will be produced in 2012 from corn using biomass as the process energy source. The remaining renewable fuel volumes in each scenario would be ethanol made from corn and imports. The import volume is based on EIA's projections for the percent of total ethanol volume supplied by imports in 2012. The total volumes for all three scenarios are shown in Table II.A.1–1.

For the purposes of calculating this difference or the amount of conventional fuel no longer consumed— that is, displaced—as a result of the use of the replacement renewable fuel, we assumed the ethanol volumes shown in Table II.A.1–1 are 5% denatured. The ethanol volumes were adjusted down to represent pure (100%) ethanol, biodiesel volumes were not adjusted. The adjusted volumes were then converted to total Btu using the appropriate volumetric energy content values (76,000 Btu/gal for ethanol, 115,000 Btu/gal for gasoline, 118,000 Btu/gal for biodiesel, and 130,000 Btu/gal for diesel fuel). 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).

This lifecycle analysis is conducted without any regard to the geographic attributes of where emissions or energy use occurs; the model represents global reductions in GHG emissions and energy use, not just those occurring in the U.S. For example, under a full lifecycle assessment approach, the savings associated with reducing overseas crude oil extraction and refining are included, as are the international emissions associated with producing imported ethanol. There were two exceptions to this, both dealing with secondary impacts that may result internationally due to the expanded use of renewable fuels within the United States.

The first exception is the emissions associated with international land use change. Due to decreasing corn exports some changes to international land use may occur, for example, as more crops are planted in other regions to compensate for the decrease in crop exports from the U.S. While the emissions associated with domestic

land use change are well understood and are included in our lifecycle analysis, we did not include the potential impact on international land use and any emissions that might directly result. Our currently modeling capability does not allow us to assess what international land use changes would occur or how these changes would affect greenhouse gas emissions. For example, we would need to know how international cropping patterns would change as well as farming inputs and practices that might affect emissions assessment.

The second case where we have not quantified the international impacts results from any reduction in world oil prices would tend to result from decreased demand in the U.S. as renewable fuels replace oil. It is commonly presumed in economic analyses that all else being equal quantity demanded of a valuable good (i.e., oil) will increase as price decreases. A world wide reduction of oil price would tend to reduce the cost of producing transportation fuel which in turn would tend to reduce the price consumers internationally would have to pay for this fuel.

To the extent fuel prices are decreased, demand and consumption would tend to increase; this impact of reduced cost of driving is sometimes referred to as a "rebound effect." Such a greater consumption internationally would presumably result in an increase in greenhouse gas emissions as consumers in the rest of the world drive more. These increased emissions would in part offset the emission impacts otherwise described in this preamble. While such international impacts of U.S. actions are important to understand, we have not have fully considered and quantified the international rebound effects of this renewable fuel standard. Nevertheless, such impacts remain an important consideration for future analysis.

2. GREET Model

As in the analyses for the proposal, for this final rulemaking we used the GREET fuel-cycle model. GREET has been under development for several years and has undergone extensive peer review through multiple updates. Of the available sources of information on lifecycle analyses of energy consumed and emissions generated, we believe that GREET offers the most comprehensive treatment of the transportation sector. For this final rule, we used an updated version of the

GREET model [110], with a few modifications to its input assumptions. These changes since the NPRM are described below.

The two main comments we received on our lifecycle modeling were that we should initiate a public dialogue on lifecycle analyses, models and assumptions, and that our sole reliance on the GREET model should be avoided, given other models are available. We have begun a public dialogue in that we identify the assumptions in the GREET model that were examined and modified for this final rulemaking. Furthermore, we will be initiating more comprehensive discussions about lifecycle analysis with stakeholders which could lead to an increased use of lifecycle analysis in future actions.

In terms of our sole reliance on the GREET model, several other models have been developed for conducting renewable fuels lifecycle analysis. For example, researchers at the Energy and Resources Group (ERG) of the University of California Berkeley have developed the ERG Biofuel Analysis Meta-Model (EBAMM) and Mark Delucchi at the Institute of Transportation Studies of the University of California Davis has developed the Lifecycle Emissions Model (LEM). Other non-fuel specific lifecycle modeling tools could also be used to perform renewable fuel lifecycle analysis.

Several studies have been released recently making use of these other models and showing different results than we find in the analysis done for this rule. For example, whereas GREET estimates a net GHG reduction of about 22% for corn ethanol compared to gasoline, the previously cited works by Farrell et al. utilizing the EBAMM show around a 13% reduction. The main difference in results is not due to the model used but assumptions on scope and input data.

For example, most studies focus on average or current ethanol production which uses a current mix of wet and dry mill ethanol production and use of coal and natural gas as process energy. In contrast, for this rulemaking we consider future increases in renewable fuel production so we focus on new production capacity which will rely more heavily on more efficient dry mill production than the current mix of wet and dry mill capacities. Other studies also typically base ethanol and farm energy use on historic data while we are assuming future capacity increases will use a state of the art dry milling plant and most current farming energy use

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[110] GREET version 1.7, released November 10, 2006.

data. Varying assumptions concerning how land use change impact $CO_2$ emissions and agriculture related GHG emissions could also have an impact on overall results. Other studies also differ in the environmental flows considered. For example, GREET uses the internationally accepted set of greenhouse gases while Delucchi uses additional types of greenhouse gases.

We have not had an opportunity to develop comparable analyses of the GHG and energy impacts of this rule using these other models. However, as discussed in chapters 6.1.1 and 6.2.3 of the RIA, we believe the scope of the GREET model and the assumptions we have used in running the model tend toward the middle of the range. Therefore we believe these results provide a reasonable assessment of the energy and GHG impacts of the expanded use of renewable fuels.

a. Renewable Fuel Pathways Considered

The feedstocks and processes used to model renewable fuel production were those which our analysis in Chapter 1 of the RIA shows will primarily be used through 2012. However, other pathways for producing renewable fuels may become popular such as producing cellulosic biomass ethanol from municipal solid waste as well as different process for the feedstocks considered, like gasification of switchgrass and production of ''renewable'' diesel fuel through hydrotreating vegetable oils.

Furthermore, the lifecycle analysis used for this rulemaking is based on averages of the different renewable fuels modeled. For example, the GHG emission and fossil energy savings associated with increased use of corn ethanol are calculated based on a mix of corn wet and dry milling, assuming a certain projected mix of each process. While this method may not exactly represent the reductions associated with a given gallon of renewable fuel, it is accurate for the purpose of this analysis which is to determine the impact of the total increased volume of renewable fuels used.

We recognize that different feedstocks and processes will each have unique characteristics when it comes to lifecycle GHG emissions and energy use. However, we understand that other feedstocks and processes as well as differences in other parts of the renewable fuel lifecycle will impact the savings associated with their use and this is the focus of ongoing work at the agency.

b. Modifications to GREET

Since the analysis done for the NPRM, we have updated the GREET model with the following changes:
—Included $CO_2$ emissions from corn farming lime use.
—Updated the corn farming fertilizer use inputs.
—Added cellulosic biomass ethanol production from corn stover and forest waste.
—Modeled biomass as a process fuel source in corn ethanol dry milling.

In addition to the changes listed above we also examined and updated other GREET input assumptions for corn ethanol and biodiesel production.

We also examined several other GREET input values, but determined that the default GREET values should not be changed for a variety of reasons. These included, corn and ethanol transport distances and modes and byproduct allocation methods. Our investigation of these other GREET input values are discussed more fully in Chapter 6 of the RIA. The current GREET default factors for these other inputs were included in the analysis for this final rule.

We did not investigate the input values associated with the production of petroleum-based gasoline or diesel fuel in the GREET model for this final rule. However, the refinery modeling discussed in Section VII provides some additional information on the process energy requirements associated with the production of gasoline and diesel under a renewable fuels mandate. We will use information from this refinery modeling in future analysis to determine if any GREET input values should be changed.

A summary of the GREET input values we investigated and modified for the final rule analysis is given below.

*Corn Farming Energy Use:* Corn farming energy use was updated based on the most recent USDA Agricultural Resource Management Survey (ARMS) data.

*$CO_2$ from Land Use Change:* The GREET model has a default factor for $CO_2$ from land use change that was included in the NPRM analysis. This factor was updated based on the results of the agricultural sector modeling outlined in Section X. The $CO_2$ emissions from land use change used in the final rulemaking represents approximately 1% of total corn ethanol lifecycle GHG emissions. However, this value could be more significant if increased amounts of renewable fuels are used in the transportation sector. The issue of $CO_2$ emissions from land use change associated with converting forest or Conservation Reserve Program

(CRP) land into crop production for use in producing renewable fuels is an important factor to consider when determining the overall sustainability of renewable fuel use. While the analysis described above is indicating that the volumes of renewable fuel analyzed in this rulemaking will not cause a significant change in land use, this is an area we will continue to research for any future analysis.

*Corn Ethanol Wet-Mill Versus Dry Mill Plants:* For this analysis, we expect most new ethanol plants will be dry mill operations. That has been the trend in the last few years as the demand for ethanol has grown, and our analysis of ethanol plants under construction and planned for the near future has verified this. Our analysis of production plans, as outlined in Section VI, indicates that essentially all new ethanol production will be from dry mill plants (99%).

*Corn Ethanol Dry Mill Plant Energy Use and Fuel Mix:* Our review of plants under construction and those planned for the near future as outlined in Section VI, indicates that coal will be used as process fuel for approximately 14% of the new under construction and planned ethanol production volume capacity. The energy use at a dry mill plant using natural gas was based on the model developed by USDA and modified by EPA for use in the cost analysis of this rulemaking described in Section VII. For this analysis, we assumed that a coal plant would require 15% [111] more electricity demand due to coal handling and have a 13% increase in thermal demand for steam dryers as compared to the natural gas fueled plant. We also considered a case where a corn ethanol plant utilized biomass as a fuel source. For this case we assumed the same amount of fuel and purchased electricity energy per gallon as a coal powered plant. This assumption is based on the biomass plant having more fuel handling than a natural gas plant and producing steam for DDGS drying.

*Corn Ethanol Dry Mill Plant Production Yield:* Modern ethanol plants are now able to produce more than 2.7 gallons of ethanol per bushel of corn compared with less than 2.4 gallons of ethanol per bushel of corn in 1980. The development of new enzymes continues to increase the potential ethanol yield. We used a value of

[111] Baseline Energy Consumption Estimates for Natural Gas and Coal-based Ethanol Plants—The Potential Impact of Combined Heat and Power (CHP), Prepared for: U.S. Environmental Protection Agency Combined Heat & Power Partnership, Prepared by: Energy and Environmental Analysis, Inc., July 2006.

2.71 [112] gal/bu in our analysis, which may underestimate actual future yields. For additional information on our yield analysis, see the cost modeling of corn ethanol discussed in Section VII.

*Corn Ethanol Co-Products:* We based the amount of DDGS produced by an ethanol dry mill plant on the USDA model used in the cost analysis work of this rulemaking, described in Section VII. Based on the agricultural sector modeling outlined in Section X, we assumed that one ton of DDGS displaces 0.5 tons of corn and 0.5 tons of soybean meal. We also assume for corn ethanol wet milling that one ton of corn gluten meal substitutes for one ton of soybean meal, one ton of corn gluten feed substitutes for 0.5 tons of corn, and one ton of corn oil substitutes for one ton of soybean oil.

*Biodiesel Production:* Two scenarios for biodiesel production were considered, one utilizing soybean oil as a feedstock and one using yellow grease. For the soybean oil scenario, the energy use and inputs for the biodiesel production process were based on a model developed by NREL and used by EPA in the cost modeling of soybean oil biodiesel, as discussed in Section VII. The GREET model does not have a specific case of biodiesel production from yellow grease. Therefore, as a surrogate we used the soybean oil based model with several adjustments. For the yellow grease case, we did not include soybean agriculture emissions or energy use. Soybean crushing was still included as a surrogate for yellow grease processing (purification, water removal, etc.). Also, due to additional processing requirements, the energy use associated with producing biodiesel from yellow grease is higher than for soybean oil biodiesel production. As per the cost modeling of yellow grease biodiesel discussed in Section VII, the energy use for yellow grease biodiesel production

was assumed to be 1.72 times the energy used for soybean oil biodiesel.

*Biodiesel Transportation:* Biodiesel transportation was based on the distribution infrastructure modeling for this rulemaking which indicates pipelines are not currently used to transport biodiesel and are not projected to play a role in biodiesel transport in the future time frame considered. Therefore, GREET default factors for biodiesel transportation from plant to terminal were modified to remove pipeline transport.

c. Sensitivity Analysis

As mentioned above, the results of lifecycle analysis are highly dependent on the input data assumptions used. Section IX.A.1.b outlined changes made to the GREET model inputs to better represent the scope and purpose of our analysis for this rulemaking. However, we also performed several sensitivity analyses on some key assumptions to see how varying them would impact overall results.

We performed a sensitivity analysis on expanding the lifecycle fuel production system boundaries to include farm equipment production (e.g., emissions and energy use associated with producing steel, rubber, etc. used to make farming equipment). It was found that including farm equipment production energy use and emissions increases ethanol lifecycle energy use and GHG emissions by approximately 1 percent. Therefore, the lifecycle results are not changed significantly due to this expansion of system boundaries.

We also performed a sensitivity analysis on the allocation method used in ethanol production. A number of by-products are 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. The displacement method for by-product allocation, described in Section 6.1.2.10 of the RIA, is the default for the GREET model and is the method used by EPA. However, we evaluated another method, the process energy approach, to determine the impact this assumption has on the overall results of the analysis.

Use of the process energy based allocation method reduces ethanol lifecycle energy use and GHG emissions by approximately 30 percent compared to the displacement allocation approach. This indicates that ethanol lifecycle analysis results are extremely sensitive to the choice of allocation method used. (See the RIA, Chapter 6 for more information on these two by-product allocation methods) The displacement allocation method is the method supported by international lifecycle assessment standards [113] and therefore EPA feels that it is the most accurate and preferred method to use. This does however highlight the sensitivity of lifecycle analysis results to choice of input parameters and assumptions.

3. Displacement Indexes (DI)

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:

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

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. Thus ethanol's carbon can be thought of as cycling from the environment into the plant material

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[112] All yield values presented represent pure ethanol production (*i.e.* no denaturant).

[113] ISO 14044:2006(E), ''Environmental Management—Life Cycle Assessment— Requirements and Guidelines'', International

Organization for Standardization (ISO), First edition, 2006–07–01, Switzerland.

used to make ethanol and, upon combustion of the ethanol, back into the environment from which it came. 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.

Using GREET, we calculated the lifecycle values for energy consumed and GHGs produced for corn-ethanol, cellulosic ethanol, and soybean-based biodiesel. These values were in turn used to calculate the displacement indexes. The results are shown in Table IX.A.3–1. Details of these calculations can be found in Chapter 6 of the RIA.

### TABLE IX.A.3–1.—DISPLACEMENT INDEXES DERIVED FROM GREET

[In percent]

| | Corn ethanol | Corn ethanol (biomass fuel) | Cellulosic ethanol | Imported ethanol | Biodiesel |
|---|---|---|---|---|---|
| $DI_{Fossil\ Fuel}$ ................................... | 39.4 | 76.3 | 92.7 | 69.0 | 61.5 |
| $DI_{Petroleum}$ .................................. | 91.8 | 92.0 | 91.7 | 92.0 | 91.2 |
| $DI_{GHG}$ ....................................... | 21.8 | 54.1 | 90.9 | 56.0 | 67.7 |
| $DI_{CO2}$ ...................................... | 40.3 | 72.3 | 100.1 | 71.0 | 69.8 |

The displacement indexes in this table represent the impact of replacing a Btu of gasoline or diesel with a Btu of renewable fuel. Thus, for instance, for every Btu of gasoline which is replaced by corn ethanol, the total lifecycle GHG emissions that would have been produced from that Btu of gasoline would be reduced by 21.8 percent. For every Btu of diesel which is replaced by biodiesel, the total lifecycle petroleum energy that would have been consumed as a result of burning that Btu of diesel fuel would be reduced by 91.2 percent.

Consistent with the cost modeling done for this rule, for the 2012 cases we assume the ''cellulosic'' ethanol volume is actually produced from corn utilizing a biomass fuel source at the ethanol production plant. The displacement index for that fuel as shown in Table IX.A.3–1 is used in the calculation of reductions. We have included the column for cellulosic ethanol for comparison, indicating that a move toward cellulosic ethanol will not displace petroleum much differently than other renewable fuels but will have a positive impact on GHG emissions reductions.

For imported ethanol, it is more difficult to estimate the lifecycle energy and GHG displacement indexes since we know much less about how the crops used to make the ethanol are grown and what energy is used in the ethanol production facility. While not exclusively, we anticipate much imported ethanol to be primarily sugarcane based ethanol.

The GHG emissions when producing sugarcane ethanol differs from corn ethanol in that the GHG emissions from growing sugarcane is likely different than for growing a equivalent amount of corn to make a gallon of ethanol. Also, the process of turning sugar into ethanol is easier than when starting with starch and therefore less energy intensive (which typically translates into lower GHG). Importantly, we understand that at least some of the ethanol produced in Brazil uses the bagasse from the sugarcane itself as a process fuel source. We know from our analysis that using a biomass source for process energy greatly improves the GHG benefit of the renewable fuel. These factors would result in sugarcane ethanol having a greater GHG benefit per gallon than corn ethanol, certainly where natural gas or coal is the typical process fuel source used.

Conversely, sugarcane ethanol production does not result in a co-product such as distillers grain as in the case of corn ethanol. In our analyses, accounting for co-products significantly improved the GHG displacement index for corn ethanol. Furthermore, there would be additional transportation emissions associated with transporting the imported ethanol to the U.S. as compared to domestically produced ethanol. Developing a technically rigorous lifecycle estimate for energy needs and GHG impacts for imported ethanol is not a simple task and was not available in the timeframe of this rulemaking.

Considering all of the differences between imported and domestic ethanol, for this rulemaking, we assumed imported ethanol would be predominately from sugarcane and have estimated DI's approximately mid-way between the DI's for corn ethanol and DI's for cellulosic ethanol. We are continuing to develop a better understanding of the lifecycle energy and GHG impacts of producing ethanol from sugarcane and other likely feedstock sources of imported ethanol for any future analysis.

4. Impacts of Increased Renewable Fuel Use

We used the methodology described above to evaluate impacts of increased use of renewable fuels on consumption of petroleum and fossil fuels and also on emissions of $CO_2$ and GHGs. This section describes our results.

a. Greenhouse Gases and Carbon Dioxide

We estimated the reduction associated with the increased use of renewable fuels on lifecycle emissions of $CO_2$ and total GHG. Since total GHG emission reductions are lower than $CO_2$ reductions, this indicates that lifecycle emissions of $CH_4$ and $N_2O$ are higher for renewable fuels than for the conventional fuels replaced. These values are then compared to the U.S. transportation sector emissions to get a percent reduction. The estimates for the 2012 cases are presented in Table IX.A.4.a–1.

TABLE IX.A.4.A–1.—ESTIMATED $CO_2$ AND GHG EMISSION IMPACTS OF INCREASED USE OF RENEWABLE FUELS IN THE TRANSPORTATION SECTOR IN 2012, RELATIVE TO THE 2012 REFERENCE CASE

| | RFS case | EIA case |
|---|---|---|
| $CO_2$ Reduction (million metric tons $CO_2$) ............................................................................................ | 11.0 | 19.5 |
| Percent reduction in Transportation Sector CO Emissions ................................................................. | 0.52 | 0.93 |
| GHG Reduction (million metric tons $CO_2$-eq.) ................................................................................. | 8.0 | 13.1 |
| Percent reduction in Transportation Sector GHG Emissions ............................................................... | 0.36 | 0.59 |

b. Fossil Fuel and Petroleum

We estimated the reduction associated with the increased use of renewable fuels on lifecycle fossil fuels and petroleum. These values are then compared to the U.S. transportation sector emissions to get a percent reduction. The estimates for the 2012 cases are presented in Table IX.A.4.b–1.

TABLE IX.A.4.B–1.—ESTIMATED FOSSIL FUEL AND PETROLEUM IMPACTS OF INCREASED USE OF RENEWABLE FUELS IN THE TRANSPORTATION SECTOR IN 2012, RELATIVE TO THE 2012 REFERENCE CASE

| | RFS case | EIA case |
|---|---|---|
| Fossil Fuel Reduction (quadrillion Btu) ............................................................................................ | 0.15 | 0.27 |
| Percent reduction in Transportation Sector Fossil Fuel Use .............................................................. | 0.48 | 0.85 |
| Petroleum Energy Reduction (billion gal.) ......................................................................................... | 2.0 | 3.9 |
| Percent reduction in Transportation Sector Petroleum Use ............................................................... | 0.82 | 1.60 |

## B. Implications of Reduced Imports of Petroleum Products

In the proposal, we estimated the impact of expanded renewable fuel use on the importation of oil and finished transportation fuel. No comments were received suggesting alternative methodologies should be used. Therefore, we have incorporated that calculation in this final rule without change.

In 2005, the United States imported almost 60 percent of the oil it consumed. This compares to just over 35 percent of oil from imports in 1975.[114] Transportation accounts for 70 percent of the U.S. oil consumption. It is clear that oil imports have a significant impact on the U.S. economy. Expanded production of renewable fuel is expected to contribute to energy diversification and the development of domestic sources of energy. We consider whether the RFS will reduce U.S. dependence on imported oil by calculating avoided expenditures on petroleum imports. Note that we do not calculate whether this reduction is on the net, socially beneficial, which would depend on the scarcity value of domestically produced ethanol versus

[114] Davis, Stacy C.; Diegel, Susan W., Transportation Energy Data Book: 25th Edition, Oak Ridge National Laboratory, U.S. Department of Energy, ORNL–6974, 2006.

that of imported petroleum products. However, the next section does discuss some of the energy security implications unique to petroleum imports.

To assess the impact of the RFS program on petroleum imports, we estimate the fraction of domestic consumption derived from foreign sources using results from the AEO 2006. We compared the levels and mix of imports in the AEO reference case with those in the low macroeconomic growth case and high oil price case. In Section 6.4.1 of the RIA we describe in greater detail how fuel producers may change their levels and mix of imports in response to a decrease in fuel demand. For the purposes of this rulemaking, we show values for the low macroeconomic growth comparison, where import reductions come almost entirely from imports of finished products as shown below in Table IX.B–1. The reductions in imports are compared to the AEO projected levels of net petroleum imports. The range of reductions in net petroleum imports are estimated to be between 0.9 to 1.7 percent, as shown in Table IX.B–1.

TABLE IX.B–1.—NET REDUCTIONS IN IMPORTS IN 2012

| | RFS case | EIA case |
|---|---|---|
| Reduction in finished products* (barrels per day) ................. | 123,000 | 240,000 |
| Percent reduction** ... | 0.89% | 1.73% |

*Net reductions relative to 2012 reference case.

**Compared to AEO 2006 projections for 2012 reference case.

We also calculate the change in expenditures in both petroleum and ethanol imports and compare these with the U.S. trade position measured as U.S. net exports of all goods and services economy-wide. The decreased expenditures were calculated by multiplying the changes in gasoline, diesel, and ethanol imports by the respective AEO 2006 wholesale gasoline, distillate, and ethanol price forecasts for the specific analysis years. In Table IX.B–2, the net expenditures in reduced petroleum imports, increased ethanol imports, and decreased corn exports are compared to 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 expenditures due to the RFS would represent 0.4 to 0.7% of economy-wide net exports.

TABLE IX.B–2.—AVOIDED IMPORT EXPENDITURES ($2004 BILLION)

| Cases | AEO total net exports | Expenditures on petroleum imports | Expenditures on ethanol imports | Decreased corn exports | Net expenditures on imports | Percent of total net exports |
|---|---|---|---|---|---|---|
| RFS Case ..................................... | −$383 (year 2012) ...................... | −$2.6 | +$0.7 | +$0.6 | −$1.4 | 0.4% |
| EIA Case ..................................... | ................................................... | −$5.1 | +$1.0 | +$1.3 | −$2.8 | 0.7% |

*C. Energy Security Implications of Increases in Renewable Fuels*

One of the effects of increased use of renewable fuels in the U.S. from the RFS is that it diversifies the energy sources in making transportation fuel. A potential disruption in supply reflected in the price volatility of a particular energy source carries with it both financial as well as strategic risks. These risks can be reduced to the extent that diverse sources of fuel energy reduce the dependence on any one source. This reduction in risks is a measure of improved energy security.

At the time of the proposal, EPA stated that an analysis would be completed and estimates provided in support of this rule. In order to understand the energy security implications of the RFS, EPA has worked with Oak Ridge National Laboratory (ORNL), which has developed approaches for evaluating the social costs and energy security implications of oil use. In a new study produced for the RFS, entitled *"The Energy Security Benefits of Reduced Oil Use,* 2006–2015,'' ORNL has updated and applied the method used in the 1997 report *"Oil Imports: An Assessment of Benefits and Costs'',* by Leiby, Jones, Curlee and Lee.[115][116] While the 1997 report including a description of methodology and results at that time has been used or cited on a number of occasions, this updated analysis and results have not been available for full public consideration. Since energy security will be a key consideration in future actions aimed at reducing our dependence on oil, it is important to assure estimates of energy security impacts have been thoroughly examined in a full and open public forum. Since the updated analysis was only recently available, such a thorough analysis has not been possible. Therefore, EPA has decided to consider

this update as a draft report, include it as part of the record of this rulemaking and invite further public analysis and consideration of both this particular draft report but also other perspectives on how to best quantify energy security benefits. To facilitate that additional consideration, we highlight below some of the key aspects of this particular draft analysis.

The approach developed by ORNL estimates the incremental benefits to society, in dollars per barrel, of reducing U.S. oil imports, called "oil premium." Since the 1997 publication of this report, changes in oil market conditions, both current and projected, suggest that the magnitude of the oil premium has changed. Significant driving factors that have been revised include: Oil prices, current and anticipated levels of OPEC production, U.S. import levels, the estimated responsiveness of regional oil supplies and demands to price, and the likelihood of oil supply disruptions. For this analysis, oil prices from the EIA's AEO 2006 were used. Using the "oil premium" approach, estimates of benefits of improved energy security from reduced U.S. oil imports from increased use of renewable fuels are calculated.

In conducting this analysis, ORNL considered the full economic cost of importing petroleum into the U.S. The full economic cost of importing petroleum into the U.S. is defined for this analysis to include two components in addition to the purchase price of petroleum itself. These are: (1) The higher costs for oil imports resulting from the effect of U.S. import demand on the world oil price and OPEC market power (i.e., the so called "demand" or "monoposony" costs); and (2) the risk of reductions in U.S. economic output and disruption of the U.S. economy caused by sudden disruptions in the supply of imported oil to the U.S. (i.e., macroeconomic disruption/adjustment costs).

1. Effect of Oil Use on Long-Run Oil Price, U.S. Import Costs, and Economic Output

The first component of the full economic costs of importing petroleum into the U.S. follows from the effect of

U.S. import demand on the world oil price over the long-run. Because the U.S. is a sufficiently large purchaser of foreign oil supplies, its purchases can affect the world oil price. This monopsony power means that increases in U.S. petroleum demand can cause the world price of crude oil to rise, and conversely, that reduced U.S. petroleum demand can reduce the world price of crude oil. Thus, one consequence of decreasing U.S. oil purchases due to increased use of renewable fuel is the potential decrease in the crude oil price paid for all crude oil purchased.

2. Short-Run Disruption Premium From Expected Costs of Sudden Supply Disruptions

The second component of the external economic costs resulting from U.S. oil imports arises from the vulnerability of the U.S. economy to oil shocks. The cost of shocks depends on their likelihood, size, and length, the capabilities of the market and U.S. Strategic Petroleum Reserve (SPR), the largest stockpile of government-owned emergency crude oil in the world, to respond, and the sensitivity of the U.S. economy to sudden price increases. While the total vulnerability of the U.S. economy to oil price shocks depends on the levels of both U.S. petroleum consumption and imports, variation in import levels or demand flexibility can affect the magnitude of potential increases in oil price due to supply disruptions. Disruptions are uncertain events, so the costs of alternative possible disruptions are weighted by disruption probabilities. The probabilities used by the ORNL study are based on a 2005 Energy Modeling Forum[117] synthesis of expert judgment and are used to determine an expected value of disruption costs, and the change in those expected costs given reduced U.S. oil imports.

3. Costs of Existing U.S. Energy Security Policies

The last often-identified component of the full economic costs of U.S. oil

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[115] Leiby, Paul N., Donald W. Jones, T. Randall Curlee, and Russell Lee, Oil Imports: An Assessment of Benefits and Costs, ORNL–6851, Oak Ridge National Laboratory, November, 1997.

[116] The 1997 ORNL paper was cited and its results used in DOT/NHTSA's rules establishing CAFE standards for 2008 through 2011 model year light trucks. See DOT/NHTSA, Final Regulatory Impacts Analysis: Corporate Average Fuel Economy and CAFE Reform MY 2008–2011, March 2006.

[117] Stanford Energy Modeling Forum, Phillip C. Beccue and Hillard G. Huntington, "An Assessment of Oil Market Disruption Risks," Final Report, EMF SR 8, October, 2005.

imports is the costs to the U.S. taxpayers of existing U.S. energy security policies. The two primary examples are maintaining a military presence to help secure stable oil supply from potentially vulnerable regions of the world and maintaining the SPR to provide buffer supplies and help protect the U.S. economy from the consequences of global oil supply disruptions.

U.S. military costs are excluded from the analysis performed by ORNL because their attribution to particular missions or activities is difficult. Most military forces serve a broad range of security and foreign policy objectives. Attempts to attribute some share of U.S. military costs to oil imports are further challenged by the need to estimate how those costs might vary with incremental variations in U.S. oil imports. Similarly, while the costs for building and maintaining the SPR are more clearly related to U.S. oil use and imports, historically these costs have not varied in response to changes in U.S. oil import levels. Thus, while SPR is factored into the ORNL analysis, the cost of maintaining the SPR is excluded.

As stated earlier, we have placed the draft report in the docket of this rulemaking for the purposes of inviting further consideration. However, the draft results of that report have not been used in quantifying the impacts of this rule.

## X. Agricultural Sector Economic Impacts

As described in the Notice of Proposed Rulemaking (NPRM), we used the Forest and Agricultural Sector Optimization Model (FASOM) developed by Professor Bruce McCarl of Texas A&M University and others, to estimate the agricultural sector impacts of increasing renewable fuel volumes required by the RFS and for those volumes anticipated by EIA for 2012. Although current renewable fuel volume predictions are higher than the scenarios described in this rulemaking, we based our analysis on assumptions developed during the NPRM process. Our agricultural sector analysis considered the impacts of the domestic production of renewable fuels. Therefore, when we refer to either the RFS Case or the EIA Case, we include only renewable fuels produced from feedstocks grown in the U.S.[118]

At the time the NPRM was published, we had not yet finished our analysis of the agricultural impacts associated with the RFS. In the NPRM, we stated our

intent to have the analysis completed in time for the Final Rulemaking (FRM). In the proposal we described our plan to evaluate the effect of increasing renewable fuels volumes on U.S. commodity prices, renewable fuel byproduct prices, livestock feed sources, land use, exports, and farm income. The results of this analysis are summarized in this section. Additional details are included in the Regulatory Impact Analysis (RIA).

FASOM is a long-term economic model of the U.S. agriculture sector that attempts to maximize total revenues for producers while meeting the demands of consumers. Using a number of inputs, FASOM estimates which crops, livestock, and processed agricultural products will be produced in the U.S. The cost of these and other inputs are used to determine the price and level of production of commodities (e.g., field crops, livestock, and biofuel products). FASOM does not capture short-term fluctuations (i.e., month-to-month, annual) in prices and production, however, as it is designed to identify long-term trends (i.e., five to ten years).

FASOM predicts that as renewable fuel volumes increase, corn prices will rise by about 18 cents (RFS Case) and 39 cents (EIA Case) above the Reference Case price of $2.32 per bushel. For consistency, all of the dollar estimates are presented in 2004 dollars. Soybean prices will rise by about 18 cents (RFS Case) and 21 cents (EIA Case) above the Reference Case price of $5.26 per bushel by 2012. Since biodiesel volumes will not increase significantly in either the RFS or EIA scenarios, FASOM does not predict significant changes in the soybean related markets with respect to usage changes, or most other variables of interest for this rulemaking. The one exception is U.S. soybean exports, which are affected modestly.

Changes in corn use can be seen by the changing percentage of corn used for ethanol. In 2005, approximately 12 percent of the corn supply was used for ethanol production, however we estimate the amount of corn used for ethanol in 2012 will increase to 20 percent (RFS Case) and 26 percent (EIA Case).

The rising price of corn and soybeans has a direct impact on how corn is used. Higher domestic corn prices lead to lower U.S. exports as the world markets shift to other sources of these products or expand the use of substitute grains. FASOM estimates that U.S. corn exports will drop from about 2 billion bushels in our Reference Case, to 1.6 billion bushels (RFS Case) and 1.3 billion bushels (EIA Case) by 2012. U.S. exports of corn are estimated to drop by about

19 percent by 2012 for the RFS Case and by roughly 38 percent in the EIA Case. In value terms, U.S. exports of corn fall by $573 million in the RFS Case and by $1.29 billion in the EIA Case in 2012.

The impact on domestic livestock feed due to higher corn prices and higher U.S. demand for corn in ethanol is also partially offset by decreasing the use of corn for U.S. livestock feed. Substitutes are available for corn as a feedstock, and this market is price sensitive. One alternate feedstock is distillers dried grains with solubles (DDGS), a byproduct associated with the dry milling of ethanol production. Since FASOM predicts relatively flat prices for DDGS across all ethanol volume scenarios, the result is a significant increase in the use of DDGS as a feed source. We estimate DDGS in feed for the RFS case will almost double by 2012, increasing from 8.5 million tons to 15.2 million tons. Under the EIA Case, we expect DDGS to increase to 22.2 million tons by 2012.

The increase in soybean prices is estimated to cause a decline in U.S. soybean exports. In terms of export earnings, U.S. exports of soybeans fall by $220 million in the RFS Case and by $194 million in the EIA Case in 2012.

The increase in renewable fuel production provides a significant increase in net farm income to the U.S. agricultural sector. FASOM predicts that in 2012, net U.S. farm income will increase by $2.6 billion dollars in the RFS renewable fuel volumes case (RFS Case) and $5.4 billion in the EIA renewable fuel volumes case (EIA Case). The RFS and EIA farm revenue increases represent roughly a 5 and 10 percent increase, respectively, in U.S. net farm income from the sale of farm commodities over the Reference Case of roughly $53 billion.

Higher corn prices will have a direct impact on the value of U.S. agricultural land. As demand for corn and farm products increases, the price of U.S. farm land will also increase. Our analysis shows that in 2012, higher renewable fuel volumes increase land prices by about 8 percent (RFS Case) and 17 percent (EIA Case). Much of the high quality, suitable land in the U.S. is already being used to produce corn. FASOM estimates an increase of 1.6 million acres (RFS Case) and 2.6 million acres (EIA Case) above the 78.5 million corn acres harvested in the Reference Case in 2012. Due to this higher value of land, we are predicting that farms will withdraw a portion of the land currently in the Conservation Reserve Program (CRP), about 2.3 million acres (RFS Case) and 2.5 million acres (EIA

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[118] The RIA contains additional information on the renewable fuels volumes analyzed for this rulemaking.

Case) out of the approximately 40 million acres in CRP.[119]

FASOM estimates U.S. annual wholesale food costs will increase by approximately $2.2 billion with the RFS renewable volumes and $3.7 billion with the EIA renewable volumes by 2012. These costs translate to approximately $7 per person per year (RFS case) and $12 per person per year (EIA case).

In the proposal, we noted that expansion in the use of renewable fuels also raises the issue of whether water quality and rural ecosystems in general could be affected due to increased production of agricultural feedstocks used to produce greater volumes of renewable fuels. We received one comment from Marathon asserting that our environmental assessment was incomplete and did not address water quality issues. In the time frame to complete this rulemaking, we were not able to conduct a comprehensive assessment of the environmental impacts in the agricultural sector of the wider use of renewable fuels. However, we have considered two indicators— fertilizer use on agricultural crops and Conservation Resource Program (CRP) lands—that may relate to environmental quality and water quality from the production of renewable fuels. The CRP is a voluntary program administered by the U.S. Department of Agriculture that helps defray the costs to farmers of taking agricultural lands out of production and placing them in CRP to provide environmental protection.

As discussed in Section X, FASOM predicts the total amount of nitrogen applied on all farms will increase by 1.2 percent in the RFS Case and by 2 percent in the EIA Case, relative to the Reference Case in 2012. The total amount of phosphorous applied on all farms increases by 0.7 percent in the RFS Case and 1.2 percent in the EIA Case, relative to the Reference Case in 2012. Currently, there are approximately 40 million acres in the CRP. FASOM predicts 2.3 million acres (RFS Case) and 2.5 million acres (EIA Case) of land would be withdrawn from the CRP due to higher land values.

## XI. Public Participation

Many interested parties participated in the rulemaking process that culminates with this final rule. This process provided opportunity for submitting written public comments

following the proposal that we published on September 22, 2006 (71 FR 55552). We considered these comments in developing the final rule. In addition, we held a public hearing on the proposed rulemaking on October 13, 2006, and we have considered comments presented at the hearing.

Throughout the rulemaking process, EPA met with stakeholders including representatives from the refining industry, renewable fuels production, and marketers and distributors, and others. The program we are finalizing today was developed as a collaborative effort with these stakeholders.

We have prepared a detailed Summary and Analysis of Comments document, which describes comments we received on the proposal and our response to each of these comments. The Summary and Analysis of Comments is available in the docket for this rule at the Internet address listed under **ADDRESSES**, as well as on the Office of Transportation and Air Quality Web site (*http://www.epa.gov/otaq/ renewablefuels/index.htm*). In addition, comments and responses for key issues are included throughout this preamble.

## XII. Administrative Requirements

### A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order (EO) 12866, (58 FR 51735, October 4, 1993) this action is a ''significant regulatory action'' because of the policy implications of the final rule. Even though EPA has estimated that renewable fuel use through 2012 will be sufficient through the operation of market forces to meet the levels required in the standard, the final rule reflects the first renewable fuel mandate at the federal level. Accordingly, EPA submitted this action to the Office of Management and Budget (OMB) for review under EO 12866 and any changes made in response to OMB recommendations have been documented in the docket for this action.

### B. Paperwork Reduction Act

The information collection requirements in this final rule have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* The Information Collection Request (ICR) prepared by EPA has been assigned EPA ICR number 2242.02. The information collection requirements are not enforceable until OMB approves them.

The information is planned to be collected to ensure that the required

amount of renewable fuel is used each year. The credit trading program required by the Energy Policy Act will be satisfied through a program utilizing Renewable Identification Numbers (RINs), which are assigned when renewable fuel is produced in or imported to geographic areas covered by the rule. Production and importation of renewable fuel will serve as a surrogate measure of renewable fuel consumption. Our final RIN-based program will fulfill all the functions of a credit trading program, and thus will meet the Energy Policy Act's requirements. For each calendar year, each obligated party will be required to submit a report to the Agency documenting the RINs it acquired, and showing that the sum of all RINs acquired is equal to or greater than its renewable volume obligation. The Agency could then verify that the RINs used for compliance purposes were valid by simply comparing RINs reported by producers to RINs claimed by obligated parties.

For fuel standards, Section 208(a) of the Clean Air Act requires that manufacturers provide information the Administrator may reasonably require to determine compliance with the regulations; submission of the information is therefore mandatory. We will consider confidential all information meeting the requirements of Section 208(c) of the Clean Air Act.

The annual public reporting and recordkeeping burden for this collection of information is estimated to be 3.3 hours per response. A document entitled ''Information Collection Request (ICR); OMB–83 Supporting Statement, Environmental Protection Agency, Office of Air and Radiation,'' has been placed in the public docket. The supporting statement provides a detailed explanation of the Agency's estimates by collection activity and explains how comments may be submitted by interested parties. The estimates contained in the docket are briefly summarized here:

Estimated total number of potential respondents: 6,425.

Estimated total number of responses: 13,380.

Estimated total annual burden hours: 43,030.

Estimated total respondent cost (estimated at $71 per hour): $3,055,130.

Estimated total non-postage purchased services (estimated at $142 per hour): $5,219,920.

EPA received various comments on the rulemaking provisions covered by the proposed ICR. All comments that were submitted to EPA are considered in the Summary and Analysis of Comments, which can be found in the

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[119] Since much of the CRP land is ill suited for corn or soybean production, it is unlikely this land will go directly into corn or soybean production but instead will more likely be used to replace other agricultural land uses displaced by expanded corn and soybean production.

docket. In response to comments, we have increased the frequency of reporting for transaction and summary reports from annually to quarterly. We have also removed a burden for small refiners that was associated with applying for small-refiner flexibilities. The burdens and costs shown above account for these changes.

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9. When this ICR is approved by OMB, the Agency will publish a technical amendment to 40 CFR part 9 in the **Federal Register** to display the OMB control number for the approved information collection requirements contained in this final rule.

*C. Regulatory Flexibility Act*

1. Overview

The Regulatory Flexibility Act (RFA) 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. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201 (see table below); (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. The following table provides an overview of the primary SBA small business categories potentially affected by this regulation:

| Industry | Defined as small entity by SBA if | NAICS codes[a] |
|---|---|---|
| Gasoline refiners. | ≤1,500 employees.[120]. | 324110 |

[a] North American Industrial Classification System.

EPA has determined that it is not necessary to prepare a regulatory flexibility analysis in connection with this final rule.

2. Background

Since the vast majority of crude oil produced in or imported into the U.S. is consumed as gasoline or diesel fuel, concerns about our dependence on foreign sources of crude oil has renewed interest in renewable transportation fuels. The passage of the Energy Policy Act of 2005 demonstrated a strong commitment on the part of U.S. policymakers to consider additional means of supporting renewable fuels as a supplement to petroleum-based fuels in the transportation sector. Section 1501 of the Energy Policy Act, which was added to the CAA as Section 211(o), requires EPA to establish the RFS program to ensure that the pool of gasoline sold in the contiguous 48 states contains specific volumes of renewable fuel for each calendar year starting with 2006. The Agency is required to set a standard for each year representing the amount of renewable fuel that obligated parties (e.g., refiners, blenders, and importers) must use as a percentage of gasoline sold or introduced into commerce, and the Agency is required to promulgate a credit trading program for the RFS program.

3. Small Refineries Versus Small Refiners

Title XV (Ethanol and Motor Fuels) of the Energy Policy Act provides, at Section 1501(a)(2) [42 U.S.C. 7545(o)(9)(A)–(D)], special provisions for ''small refineries'', such as a temporary exemption from the standards until calendar year 2011. The

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[120] In the NPRM, we also referred to a 125,000 barrels of crude per day (bpcd) crude capacity limit. This criterion was inadvertently used and is not applicable for this program (as it only applies in cases of government procurement). We note that the number of small entities remains the same whether this criterion is used or not.

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.'' As shown in the table above, this term is different than SBA's small business category for gasoline *refiners*, which is what the Regulatory Flexibility Act is concerned with. EPA is required under the RFA to consider impacts on small entities meeting SBA's small business definition; these entities are referred to as ''small refiners'' for our regulatory flexibility analysis under SBREFA.

A small refinery, per the Energy Policy Act, is a refinery where the annual crude throughput is less than or equal to 75,000 barrels (i.e., a small-capacity refinery), and could be owned by a larger refiner that exceeds SBA's small entity size standards. The small business employee criteria were established for SBA's small business definition to set apart those companies which are most likely to be at an inherent economic disadvantage relative to larger businesses.

4. Summary of Potentially Affected Small Entities

The refiners that are potentially affected by this rule are those that produce gasoline. For our recent final rule ''Control of Hazardous Air Pollutants From Mobile Sources'' (72 FR 8428, February 26, 2007), we performed an industry characterization of potentially affected gasoline refiners. We used that industry characterization to determine which refiners would also meet the SBA definition of a small entity. From that industry characterization, and further analysis following the Notice of Proposed Rulemaking (71 FR 55552, September 22, 2006), we have determined that there are 15 gasoline refiners who own 16 refiners (14 refiners own one refinery each, the remaining refiner owns two refineries) that meet the definition of a small refiner. Of the 16 refineries, 13 also meet the Energy Policy Act's definition of a small refinery.

5. Impact of the Regulations on Small Entities

As previously stated, many aspects of the RFS program, such as the required amount of annual renewable fuel volumes, are specified in the Energy Policy Act. As discussed above in Section II.A.1, the annual projections of ethanol production to satisfy market demand exceed the required annual renewable fuel volumes. When the small refinery exemption ends, it is anticipated that there will be over one

billion gallons in excess RINs available. We believe that this large volume of excess RINs will also lower the costs of this program. Thus, with the short-term relief provided under the Energy Policy Act for small refineries, and the anticipated low cost of RINs when the exemption expires, we believe that this program will not impose a significant economic burden on small refineries, small refiners, or any other obligated party. Therefore, we have determined that this rule will not have a significant economic impact on a substantial number of small entities.

When the Agency certifies that a rule will not have a significant economic impact on a substantial number of small entities, EPA's policy is to make an assessment of the rule's impact on any small entities and to engage the potentially regulated entities in a dialog regarding the rule, and minimize the impact to the extent feasible. The following sections discuss our outreach with the potentially affected small entities and regulatory flexibilities to decrease the burden on these entities in compliance with the requirements of the RFS program.

### 6. Small Refiner Outreach

We do not believe that the RFS program would have a significant economic impact on a substantial number of small entities, however we have still tried to reduce the impact of this rule on small entities. Prior to issuing the proposed rule, we held meetings with small refiners to discuss the requirements of the RFS program and the special provisions offered by the Energy Policy Act for small refineries.

The Energy Policy Act set out the following provisions for small refineries:

• A temporary exemption from the Renewable Fuels Standard requirement until 2011;

• An extension of the temporary exemption period for at least two years for any small refinery where it is determined that the refinery would be subject to a disproportionate economic hardship if required to comply;

• Any small refinery may petition, at any time, for an exemption based on disproportionate economic hardship; and,

• A small refinery may waive its temporary exemption to participate in the credit generation program, or it may also ''opt-in'', by waiving its temporary exemption, to be subject to the RFS requirement.

During these meetings with the small refiners we also discussed the impacts of these provisions being offered to small refineries only. Three refiners met

the definition of a small refiner, but their refineries did not meet the Act's definition of a small refinery; which naturally concerned the small refiners. Another concern that the small refiners had was that if this rule were to have a significant economic impact on a substantial number of small entities a lengthy SBREFA process would ensue (which would delay the promulgation of the RFS rulemaking) and thus provide less lead time for these small entities prior to the RFS program start date.

Following our discussions with the small refiners, they provided three suggested regulatory flexibility options that they believed could further assist affected small entities in complying with the RFS program standard: (1) That all small *refiners* be afforded the Act's small *refinery* temporary exemption, (2) that small refiners be allowed to generate credits if they elect to comply with the RFS program standard prior to the 2011 small refinery compliance date, and (3) relieve small refiners who generate blending credits of the RFS program compliance requirements.

We agreed with the small refiners' suggestion that small refiners be afforded the same temporary exemption that the Act specifies for small refineries. This relief would apply to refiners who meet the 1,500 employee count criteria, as well as the crude capacity criteria that we have used in previous fuels programs when providing relief for small refiners. Regarding the small refiners' second and third suggestions regarding credits, we note that the RIN-based program will automatically provide them with credit for any renewables that they blend into their motor fuels. Until 2011, small refiners will essentially be treated as oxygenate blenders and may separate RINs from batches and trade or sell these RINs, unless they choose to opt-in to the program.

### 7. Reporting, Recordkeeping, and Compliance Requirements

Registration, recordkeeping and reporting are necessary to track compliance with the renewable fuels standard and transactions involving RINs, and these compliance requirements will be similar to those required under our previous and current 40 CFR part 80 fuel compliance programs. We will use the same basic forms for RFS program registration that we use under the reformulated gasoline (RFG) and anti-dumping program, as these forms are well known in the regulated community and are simple to fill out. We will use a simplified method of reporting via the Agency's Central Data Exchange (CDX), which will

reduce the reporting burden on regulated parties. Records related to RIN transactions may be kept in any format and the period of record retention by reporting parties is five years, similar to other fuel programs. Records to be retained include copies of all compliance reports submitted to EPA and copies of product transfer documents (PTDs). Sections IV and V, above, contain more detailed discussions on the registration, recordkeeping, reporting, and compliance requirements of this final rule.

### 8. Related Federal Rules

We are aware of a few other current or proposed Federal rules that are related to this rule. The primary related federal rules are the Mobile Source Air Toxics (MSAT2) rule (72 FR 8428, February 26, 2007), the Tier 2 Vehicle/ Gasoline Sulfur rulemaking (65 FR 6698, February 10, 2000), and the fuel sulfur rules for highway diesel (66 FR 5002, January 18, 2001) and nonroad diesel (69 FR 38958, June 29, 2004).

### 9. Conclusions

As stated above, based on the statutory relief provided by the Energy Policy Act for small refineries, we are certifying that this rule will not have a significant economic impact on a substantial number of small entities. Additionally, we believe that extending the small refinery exemption to small refiners would further reduce the economic impacts on small entities. We believe that small refiners generally lack the resources available to larger companies, and therefore find it appropriate to extend this exemption to all small refiners. Thus, we are extending the small refinery temporary exemption to all qualified small refiners. Small refiners will also be permitted to separate RINs from batches and trade or sell these RINs prior to 2011 if the small refiner operates as an ethanol blender.

Past fuels rulemakings have included a provision that, for the purposes of the regulatory flexibility provisions for small entities, a refiner must also have an average crude capacity of no more than 155,000 barrels of crude per day (bpcd). To be consistent with these previous rules, we are finalizing in this rule that refiners that meet this criterion (in addition to having no more than 1,500 total corporate employees) will be considered small refiners for the purposes of the regulatory flexibility provisions for this rulemaking.

Since the RFS program would have no significant economic impact on a substantial number of small entities

with only the relief required in the Energy Policy Act for small refineries, it also follows that the rule will have no significant economic impact on a substantial number of small entities with the additional relief this final rule provides for small refiners.

### D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandates'' that may result in expenditures to State, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any one year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted.

Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under Section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory programs with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

EPA has determined that this rule does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any one year. EPA has estimated that renewable fuel use through 2012 will be sufficient to meet the required levels. Therefore, individual refiners, blenders, and importers are already on track to meet

rule obligations through normal market-driven incentives. Thus, today's rule is not subject to the requirements of Sections 202 and 205 of the UMRA.

EPA has determined that this rule contains no regulatory requirements that might significantly or uniquely affect small governments. Compliance with the mandates of the RFS rule, including the reporting and recordkeeping requirements, are the responsibility of exporters, producers, and importers of renewable fuel and gasoline, and not small governments.

### E. Executive Order 13132: Federalism

Executive Order 13132, entitled ''Federalism'' (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.'' ''Policies that have federalism implications'' is defined in the Executive Order to include regulations that have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

This final rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. Thus, Executive Order 13132 does not apply to this rule.

In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicited comment on the proposed rule from State and local officials. A number of states commented on the proposed rule. These comments are available in the rulemaking docket, and are summarized and addressed in the Summary and Analysis document.

### F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

Executive Order 13175, entitled ''Consultation and Coordination with Indian Tribal Governments'' (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure ''meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications.'' This final rule does not have tribal implications, as specified in Executive Order 13175. This rule will be implemented at the Federal level and

will apply to refiners, blenders, and importers. Tribal governments will be affected only to the extent they purchase and use regulated fuels. Thus, Executive Order 13175 does not apply to this rule.

### G. Executive Order 13045: Protection of Children From Environmental Health and Safety Risks

Executive Order 13045: ''Protection of Children from Environmental Health Risks and Safety Risks'' (62 FR 19885, April 23, 1997) applies to any rule that: (1) Is determined to be ''economically significant'' as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

EPA interprets EO 13045 as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the EO has the potential to influence the regulation. This final rule is not subject to EO 13045 because it does not establish an environmental standard intended to mitigate health or safety risks and because it implements specific standards established by Congress in statutes.

### H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This rule is not a ''significant energy action'' as defined in Executive Order 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'' (66 FR 28355 (May 22, 2001)) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy.

EPA expects the provisions to have very little effect on the national fuel supply since normal market forces alone are promoting greater renewable fuel use than required by the RFS mandate. We discuss our analysis of the energy and supply effects of the increased use of renewable fuels in Sections VI and X of this preamble.

### I. National Technology Transfer Advancement Act

As noted in the proposed rule, Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (''NTTAA''), Public Law No. 104–113, 12(d) (15 U.S.C. 272 note)

directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. The NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This rulemaking involves technical standards. EPA has decided to use ASTM D6751–06a ''Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels''. This standard was developed by ASTM International (originally known as the American Society for Testing and Materials), Subcommittee D02.E0, and was approved in August 2006. The standard may be obtained through the ASTM Web site (*www.astm.org*) or by calling ASTM at (610) 832–9585. ASTM D6751–06a meets the objectives of this final rule because it establishes one of the criteria by which biodiesel is defined.

*J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations*

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

EPA lacks the discretionary authority to address environmental justice in this final rulemaking since the Agency is implementing specific standards established by Congress in statutes. Although EPA lacks authority to modify today's regulatory decision on the basis of environmental justice considerations, EPA nevertheless determined that this final rule does not have a disproportionately high and adverse human health or environmental impact on minority or low-income populations.

*K. Congressional Review Act*

The Congressional Review Act, 5 U.S.C. 801 et seq., as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A Major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2). The effective date of the rule is September 1, 2007.

*L. Clean Air Act Section 307(d)*

This rule is subject to Section 307(d) of the CAA. Section 307(d)(7)(B) provides that ''[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review.'' This section also provides a mechanism for the EPA to convene a proceeding for reconsideration, ''[i]f the person raising an objection can demonstrate to the EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule.'' Any person seeking to make such a demonstration to the EPA should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave., NW., Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Director of the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave., NW., Washington, DC 20460.

**XIII. Statutory Authority**

Statutory authority for the rules finalized today can be found in section 211 of the Clean Air Act, 42 U.S.C. 7545. Additional support for the procedural and compliance related aspects of today's rule, including the recordkeeping requirements, come from Sections 114, 208, and 301(a) of the CAA, 42 U.S.C. 7414, 7542, and 7601(a).

**List of Subjects in 40 CFR Part 80**

Environmental protection, Air pollution control, Fuel additives, Gasoline, Imports, Incorporation by reference, Labeling, Motor vehicle pollution, Penalties, Reporting and recordkeeping requirements.

Dated: April 10, 2007.

**Stephen L. Johnson,**

*Administrator.*

■ 40 CFR part 80 is amended as follows:

**PART 80—REGULATION OF FUEL AND FUEL ADDITIVES**

■ 1. The authority citation for part 80 continues to read as follows:

**Authority:** 42 U.S.C. 7414, 7542, 7545, and 7601(a).

■ 2. Section 80.1100 is revised to read as follows:

**§ 80.1100   How is the statutory default requirement for 2006 implemented?**

(a) *Definitions.* For calendar year 2006, the definitions of section 80.2 and the following additional definitions apply to this section.

(1) *Renewable fuel.* (i) *Renewable fuel* means motor vehicle fuel that is used to replace or reduce the quantity of fossil fuel present in a fuel mixture used to operate a motor vehicle, and which:

(A) Is produced from grain, starch, oil seeds, vegetable, animal, or fish materials including fats, greases, and oils, sugarcane, sugar beets, sugar components, tobacco, potatoes, or other biomass; or

(B) Is natural gas produced from a biogas source, including a landfill, sewage waste treatment plant, feedlot, or other place where decaying organic material is found.

(ii) The term ''renewable fuel'' includes cellulosic biomass ethanol, waste derived ethanol, biodiesel, and any blending components derived from renewable fuel.

(2) *Cellulosic biomass ethanol* means 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 wastes 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.

(3) *Waste derived ethanol* means ethanol derived from animal wastes, including poultry fats and poultry wastes, and other waste materials, or municipal solid waste.

(4) *Small refinery* means a refinery for which the average aggregate daily crude

oil throughput for a calendar year (as determined by dividing the aggregate throughput for the calendar year by the number of days in the calendar year) does not exceed 75,000 barrels.

(5) *Biodiesel* means a diesel fuel substitute produced from nonpetroleum renewable resources that meets the registration requirements for fuels and fuel additives established by the Environmental Protection Agency under section 211 of the Clean Air Act. It includes biodiesel derived from animal wastes (including poultry fats and poultry wastes) and other waste materials, or biodiesel derived from municipal solid waste and sludges and oils derived from wastewater and the treatment of wastewater.

(b) *Renewable Fuel Standard for 2006.* The percentage of renewable fuel in the total volume of gasoline sold or dispensed to consumers in 2006 in the United States shall be a minimum of 2.78 percent on an annual average volume basis.

(c) *Responsible parties.* Parties collectively responsible for attainment of the standard in paragraph (b) of this section are refiners (including blenders) and importers of gasoline. However, a party that is a refiner only because he owns or operates a small refinery is exempt from this responsibility.

(d) *EPA determination of attainment.* EPA will determine after the close of 2006 whether or not the requirement in paragraph (b) of this section has been met. EPA will base this determination on information routinely published by the Energy Information Administration on the annual domestic volume of gasoline sold or dispensed to U.S. consumers and of ethanol produced for use in such gasoline, supplemented by readily available information concerning the use in motor fuel of other renewable fuels such as cellulosic biomass ethanol, waste derived ethanol, biodiesel, and other non-ethanol renewable fuels.

(1) The renewable fuel volume will equal the sum of all renewable fuel volumes used in motor fuel, provided that:

(i) One gallon of cellulosic biomass ethanol or waste derived ethanol shall be considered to be the equivalent of 2.5 gallons of renewable fuel; and

(ii) Only the renewable fuel portion of blending components derived from renewable fuel shall be counted towards the renewable fuel volume.

(2) If the nationwide average volume percent of renewable fuel in gasoline in 2006 is equal to or greater than the standard in paragraph (b) of this section, the standard has been met.

(e) *Consequence of nonattainment in 2006.* In the event that EPA determines that the requirement in paragraph (b) of this section has not been attained in 2006, a deficit carryover volume shall be added to the renewable fuel volume obligation for 2007 for use in calculating the standard applicable to gasoline in 2007.

(1) The deficit carryover volume shall be calculated as follows:

$$DC = Vgas * (Rs - Ra)$$

Where:

DC = Deficit carryover, in gallons, of renewable fuel.
Vgas = Volume of gasoline sold or dispensed to U.S. consumers in 2006, in gallons.
Rs = 0.0278.
Ra = Ratio of renewable fuel volume divided by total gasoline volume determined in accordance with paragraph (d)(2) of this section.

(2) There shall be no other consequence of failure to attain the standard in paragraph (b) of this section in 2006 for any of the parties in paragraph (c) of this section.

■ 3. Section 80.1101 is added to read as follows:

### § 80.1101 Definitions.

The definitions of § 80.2 and the following additional definitions apply for the purposes of this subpart. For calendar year 2007 and beyond, the definitions in this section § 80.1101 supplant those in § 80.1100.

(a) *Cellulosic biomass ethanol* means either of the following:

(1) Ethanol derived from any lignocellulosic or hemicellulosic matter that is available on a renewable or recurring basis and includes any of the following:

(i) Dedicated energy crops and trees.
(ii) Wood and wood residues.
(iii) Plants.
(iv) Grasses.
(v) Agricultural residues.
(vi) Animal wastes and other waste materials, the latter of which may include waste materials that are residues (e.g., residual tops, branches, and limbs from a tree farm).
(vii) Municipal solid waste.

(2) Ethanol made at facilities at which animal wastes or other waste materials are digested or otherwise used onsite to displace 90 percent or more of the fossil fuel that is combusted to produce thermal energy integral to the process of making ethanol, by:

(i) The direct combustion of the waste materials or a byproduct resulting from digestion of such waste materials (e.g., methane from animal wastes) to make thermal energy; and/or

(ii) The use of waste heat captured from an off-site combustion process as a source of thermal energy.

(b) *Waste derived ethanol* means ethanol derived from either of the following:

(1) Animal wastes, including poultry fats and poultry wastes, and other waste materials.

(2) Municipal solid waste.

(c) *Biogas* means methane or other hydrocarbon gas produced from decaying organic material, including landfills, sewage waste treatment plants, and animal feedlots.

(d) *Renewable fuel.* (1) *Renewable fuel* is any motor vehicle fuel that is used to replace or reduce the quantity of fossil fuel present in a fuel mixture used to fuel a motor vehicle, and is produced from any of the following:

(i) Grain.
(ii) Starch.
(iii) Oilseeds.
(iv) Vegetable, animal, or fish materials including fats, greases, and oils.
(v) Sugarcane.
(vi) Sugar beets.
(vii) Sugar components.
(viii) Tobacco.
(ix) Potatoes.
(x) Other biomass.
(xi) Natural gas produced from a biogas source, including a landfill, sewage waste treatment plant, feedlot, or other place where there is decaying organic material.

(2) The term ''Renewable fuel'' includes cellulosic biomass ethanol, waste derived ethanol, biodiesel (mono-alky ester), non-ester renewable diesel, and blending components derived from renewable fuel.

(3) Ethanol covered by this definition shall be denatured as required and defined in 27 CFR parts 20 and 21.

(4) Small volume additives (excluding denaturants) less than 1.0 percent of the total volume of a renewable fuel shall be counted as part of the total renewable fuel volume.

(5) A fuel produced by a renewable fuel producer that is used in boilers or heaters is not a motor vehicle fuel and therefore is not a renewable fuel.

(e) *Blending component* has the same meaning as ''Gasoline blending stock, blendstock, or component'' as defined at § 80.2(s), for which the portion that can be counted as renewable fuel is calculated as set forth in § 80.1115(a).

(f) *Motor vehicle* has the meaning given in Section 216(2) of the Clean Air Act (42 U.S.C. 7550).

(g) *Small refinery* means a refinery for which the average aggregate daily crude oil throughput for the calendar year 2004 (as determined by dividing the

aggregate throughput for the calendar year by the number of days in the calendar year) does not exceed 75,000 barrels.

(h) *Biodiesel (mono-alkyl ester)* means a motor vehicle fuel or fuel additive which is all the following:

(1) Registered as a motor vehicle fuel or fuel additive under 40 CFR part 79.

(2) A mono-alkyl ester.

(3) Meets ASTM D–6751–07, entitled ''Standard Specification for Biodiesel Fuel Blendstock (B100) for Middle Distillate Fuels.'' ASTM D–6751–07 is incorporated by reference. This incorporation by reference was approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. A copy may be obtained from the American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, Pennsylvania. A copy may be inspected at the EPA Docket Center, Docket No. EPA–HQ–OAR–2005–0161, EPA/DC, EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC, or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal-register/cfr/ibr-locations.html.*

(4) Intended for use in engines that are designed to run on conventional diesel fuel.

(5) Derived from nonpetroleum renewable resources (as defined in paragraph (m) of this section).

(i) *Non-ester renewable diesel* means a motor vehicle fuel or fuel additive which is all the following:

(1) Registered as a motor vehicle fuel or fuel additive under 40 CFR part 79.

(2) Not a mono-alkyl ester.

(3) Intended for use in engines that are designed to run on conventional diesel fuel.

(4) Derived from nonpetroleum renewable resources (as defined in paragraph (m) of this section).

(j) *Renewable crude* means biologically derived liquid feedstocks including but not limited to poultry fats, poultry wastes, vegetable oil, and greases that are used as feedstocks to

make gasoline or diesel fuels at production units as specified in paragraph (k) of this section.

(k) *Renewable crude-based fuels* are renewable fuels that are gasoline or diesel products resulting from the processing of renewable crudes in production units within refineries or at dedicated facilities within refineries, that process petroleum based feedstocks and which make gasoline and diesel fuel.

(l) *Importers.* For the purposes of this subpart only, an importer of gasoline or renewable fuel is:

(1) Any person who brings gasoline or renewable fuel into the 48 contiguous states of the United States from a foreign country or from an area that has not opted in to the program requirements of this subpart pursuant to § 80.1143; and

(2) Any person who brings gasoline or renewable fuel into an area that has opted in to the program requirements of this subpart pursuant to § 80.1143.

(m) *Nonpetroleum renewable resources* include, but are not limited to the following:

(1) Plant oils.

(2) Animal fats and animal wastes, including poultry fats and poultry wastes, and other waste materials.

(3) Municipal solid waste and sludges and oils derived from wastewater and the treatment of wastewater.

(n) *Export of renewable fuel* means:

(1) Transfer of a batch of renewable fuel to a location outside the United States; and

(2) Transfer of a batch of renewable fuel from a location in the contiguous 48 states to Alaska, Hawaii, or a United States territory, unless that state or territory has received an approval from the Administrator to opt-in to the renewable fuel program pursuant to § 80.1143.

(o) *Renewable Identification Number (RIN),* is a unique number generated to represent a volume of renewable fuel pursuant to §§ 80.1125 and 80.1126.

(1) *Gallon-RIN* is a RIN that represents an individual gallon of renewable fuel; and

(2) *Batch-RIN* is a RIN that represents multiple gallon-RINs.

(p) *Neat renewable fuel* is a renewable fuel to which only de minimus amounts of conventional gasoline or diesel have been added.

### §§ 80.1102 through 80.1103 [Reserved]

■ 4. Sections 80.1102 and 80.1103 are reserved.

■ 5. Sections 80.1104 through 80.1107 are added to read as follows:

### Subpart K—Renewable Fuel Standard

\* \* \* \* \*

Sec.
80.1104　What are the implementation dates for the Renewable Fuel Standard Program?
80.1105　What is the Renewable Fuel Standard?
80.1106　To whom does the Renewable Volume Obligation apply?
80.1107　How is the Renewable Volume Obligation calculated?

\* \* \* \* \*

### § 80.1104　What are the implementation dates for the Renewable Fuel Standard Program?

The RFS standards and other requirements of § 80.1101 and all sections following are effective beginning on September 1, 2007.

### § 80.1105　What is the Renewable Fuel Standard?

(a) The annual value of the renewable fuel standard for 2007 shall be 4.02 percent.

(b) Beginning with the 2008 compliance period, EPA will calculate the value of the annual standard and publish this value in the **Federal Register** by November 30 of the year preceding the compliance period.

(c) EPA will base the calculation of the standard on information provided by the Energy Information Administration regarding projected gasoline volumes and projected volumes of renewable fuel expected to be used in gasoline blending for the upcoming year.

(d) EPA will calculate the annual renewable fuel standard using the following equation:

$$RFStd_i = 100 * \frac{RFV_i - Cell_i}{(G_i - R_i) + (GS_i - RS_i) - GE_i}$$

Where:

RFStd$_i$ = Renewable Fuel Standard, in year i, in percent.

RFV$_i$ = Nationwide annual volume of renewable fuels required by section

211(o)(2)(B) of the Act (42 U.S.C. 7545), for year i, in gallons.

G$_i$ = Amount of gasoline projected to be used in the 48 contiguous states, in year i, in gallons.

R$_i$ = Amount of renewable fuel blended into gasoline that is projected to be used in

the 48 contiguous states, in year i, in gallons.

GS$_i$ = Amount of gasoline projected to be used in noncontiguous states or territories (if the state or territory opts-in), in year i, in gallons.

$RS_i$ = Amount of renewable fuel blended into gasoline that is projected to be used in noncontiguous states or territories (if the state or territory opts-in), in year i, in gallons.

$GE_i$ = Amount of gasoline projected to be produced by exempt small refineries and small refiners, in year i, in gallons (through 2010 only, except to the extent that a small refinery exemption is extended pursuant to § 80.1141(e)).

$Cell_i$ = Beginning in 2013, the amount of renewable fuel that is required to come from cellulosic sources, in year i, in gallons.

(e) Beginning with the 2013 compliance period, EPA will calculate the value of the annual cellulosic standard and publish this value in the **Federal Register** by November 30 of the year preceding the compliance period.

(f) EPA will calculate the annual cellulosic standard using the following equation:

$$RFCell_i = 100 * \frac{Cell_i}{(G_i - R_i) + (GS_i - RS_i)}$$

Where:

$RFCell_i$ = Renewable Fuel Cellulosic Standard in year i, in percent.

$G_i$ = Amount of gasoline projected to be used in the 48 contiguous states, in year i, in gallons.

$R_i$ = Amount of renewable fuel blended into gasoline that is projected to be used in the 48 contiguous states, in year i, in gallons.

$GS_i$ = Amount of gasoline projected to be used in noncontiguous states or territories (if the state or territory opts-in), in year i, in gallons.

$RS_i$ = Amount of renewable fuel blended into gasoline that is projected to be used in noncontiguous states or territories (if the state or territory opts-in), in year i, in gallons.

$Cell_i$ = Amount of renewable fuel that is required to come from cellulosic sources, in year i, in gallons.

### § 80.1106 To whom does the Renewable Volume Obligation apply?

(a) (1) An obligated party is a refiner that produces gasoline within the 48 contiguous states, or an importer that imports gasoline into the 48 contiguous states. A party that simply adds renewable fuel to gasoline, as defined in § 80.1107(c), is not an obligated party.

(2) If the Administrator approves a petition of Alaska, Hawaii, or a United States territory to opt-in to the renewable fuel program under the provisions in § 80.1143, then ''obligated party'' shall also include any refiner that produces gasoline within that state or territory, or any importer that imports gasoline into that state or territory.

(3) For the purposes of this section, ''gasoline'' refers to any and all of the products specified at § 80.1107(c).

(b) For each compliance period starting with 2007, any obligated party is required to demonstrate, pursuant to § 80.1127, that it has satisfied the Renewable Volume Obligation for that compliance period, as specified in § 80.1107(a).

(c) An obligated party may comply with the requirements of paragraph (b) of this section for all of its refineries in the aggregate, or for each refinery individually.

(d) An obligated party must comply with the requirements of paragraph (b) of this section for all of its imported gasoline in the aggregate.

(e) An obligated party that is both a refiner and importer must comply with the requirements of paragraph (b) of this section for its imported gasoline separately from gasoline produced by its refinery or refineries.

(f) Where a refinery or importer is jointly owned by two or more parties, the requirements of paragraph (b) of this section may be met by one of the joint owners for all of the gasoline produced at the refinery, or all of the imported gasoline, in the aggregate, or each party may meet the requirements of paragraph (b) of this section for the portion of the gasoline that it owns, as long as all of the gasoline produced at the refinery, or all of the imported gasoline, is accounted for in determining the renewable fuels obligation under § 80.1107.

(g) The requirements in paragraph (b) of this section apply to the following compliance periods:

(1) For 2007, the compliance period is September 1 through December 31.

(2) Beginning in 2008, and every year thereafter, the compliance period is January 1 through December 31.

### § 80.1107 How is the Renewable Volume Obligation calculated?

(a) The Renewable Volume Obligation for an obligated party is determined according to the following formula:

$RVO_i = (RFStd_i * GV_i) + D_{i-1}$

Where:

$RVO_i$ = The Renewable Volume Obligation for an obligated party for calendar year i, in gallons of renewable fuel.

$RFStd_i$ = The renewable fuel standard for calendar year i, determined by EPA pursuant to § 80.1105, in percent.

$GV_i$ = The non-renewable gasoline volume, determined in accordance with paragraphs (b), (c), and (d) of this section, which is produced or imported by the obligated party in calendar year i, in gallons.

$D_{i-1}$ = Renewable fuel deficit carryover from the previous year, per § 80.1127(b), in gallons.

(b) The non-renewable gasoline volume for a refiner, blender, or importer for a given year, $GV_i$, specified in paragraph (a) of this section is calculated as follows:

$$GV_i = \sum_{x=1}^{n} G_x - \sum_{y=1}^{m} RB_y$$

Where:

x = Individual batch of gasoline produced or imported in calendar year i.

n = Total number of batches of gasoline produced or imported in calendar year i.

$G_x$ = Volume of batch x of gasoline produced or imported, in gallons.

y = Individual batch of renewable fuel blended into gasoline in calendar year i.

m = Total number of batches of renewable fuel blended into gasoline in calendar year i.

$RB_y$ = Volume of batch y of renewable fuel blended into gasoline, in gallons.

(c) All of the following products that are produced or imported during a compliance period, collectively called ''gasoline'' for the purposes of this section (unless otherwise specified), are to be included in the volume used to calculate a party's renewable volume obligation under paragraph (a) of this section, except as provided in paragraph (d) of this section:

(1) Reformulated gasoline, whether or not renewable fuel is later added to it.

(2) Conventional gasoline, whether or not renewable fuel is later added to it.

(3) Reformulated gasoline blendstock that becomes finished reformulated gasoline upon the addition of oxygenate (''RBOB'').

(4) Conventional gasoline blendstock that becomes finished conventional gasoline upon the addition of oxygenate (''CBOB'').

(5) Blendstock (including butane and gasoline treated as blendstock (''GTAB'')) that has been combined with other blendstock and/or finished gasoline to produce gasoline.

(6) Any gasoline, or any unfinished gasoline that becomes finished gasoline upon the addition of oxygenate, that is produced or imported to comply with a state or local fuels program.

(d) The following products are not included in the volume of gasoline produced or imported used to calculate a party's renewable volume obligation under paragraph (a) of this section:

(1) Any renewable fuel as defined in § 80.1101(d).

(2) Blendstock that has not been combined with other blendstock or finished gasoline to produce gasoline.

(3) Gasoline produced or imported for use in Alaska, Hawaii, the Commonwealth of Puerto Rico, the U.S. Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Marianas, unless the area has opted into the RFS program under § 80.1143.

(4) Gasoline produced by a small refinery that has an exemption under § 80.1141 or an approved small refiner that has an exemption under § 80.1142 until January 1, 2011 (or later, for small refineries, if their exemption is extended pursuant to § 80.1141(e)).

(5) Gasoline exported for use outside the 48 United States, and gasoline exported for use outside Alaska, Hawaii, the Commonwealth of Puerto Rico, the U.S. Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Marianas, if the area has opted into the RFS program under § 80.1143.

(6) For blenders, the volume of finished gasoline, RBOB, or CBOB to which a blender adds blendstocks.

(7) The gasoline portion of transmix produced by a transmix processor, or the transmix blended into gasoline by a transmix blender, under 40 CFR 80.84.

## §§ 80.1108 through 80.1114 [Reserved]

■ 6. Sections 80.1108 through 80.1114 are reserved.

■ 7. Section 80.1115 is added to read as follows:

### § 80.1115 How are equivalence values assigned to renewable fuel?

(a)(1) Each gallon of a renewable fuel shall be assigned an equivalence value by the producer or importer pursuant to paragraph (b) or (c) of this section.

(2) The equivalence value is a number that is used to determine how many gallon-RINs can be generated for a batch of renewable fuel according to § 80.1126.

(b) Equivalence values shall be assigned for certain renewable fuels as follows:

(1) Cellulosic biomass ethanol and waste derived ethanol produced on or before December 31, 2012 which is denatured shall have an equivalence value of 2.5.

(2) Ethanol other than cellulosic biomass ethanol or waste-derived ethanol which is denatured shall have an equivalence value of 1.0.

(3) Biodiesel (mono-alkyl ester) shall have an equivalence value of 1.5.

(4) Butanol shall have an equivalence value of 1.3.

(5) Non-ester renewable diesel, including that produced from coprocessing a renewable crude with fossil fuels in a hydrotreater, shall have an equivalence value of 1.7.

(6) All other renewable crude-based renewable fuels shall have an equivalence value of 1.0.

(c)(1) For renewable fuels not listed in paragraph (b) of this section, a producer or importer shall submit an application to the Agency for an equivalence value

following the provisions of paragraph (d) of this section.

(2) A producer or importer may also submit an application for an alternative equivalence value pursuant to paragraph (d) of this section if the renewable fuel is listed in paragraph (b) of this section, but the producer or importer has reason to believe that a different equivalence value than that listed in paragraph (b) of this section is warranted.

(d) *Determination of equivalence values.* (1) Except as provided in paragraph (d)(4) of this section, the equivalence value for renewable fuels described in paragraph (c) of this section shall be calculated using the following formula:

EV = (R / 0.931) * (EC / 77,550)

Where:

EV = Equivalence Value for the renewable fuel, rounded to the nearest tenth.

R = Renewable content of the renewable fuel. This is a measure of the portion of a renewable fuel that came from a renewable source, expressed as a percent, on an energy basis.

EC = Energy content of the renewable fuel, in Btu per gallon (lower heating value).

(2) The application for an equivalence value shall include a technical justification that includes a description of the renewable fuel, feedstock(s) used to make it, and the production process.

(3) The Agency will review the technical justification and assign an appropriate Equivalence Value to the renewable fuel based on the procedure in this paragraph (d).

(4) For biogas, the Equivalence Value is 1.0, and 77,550 Btu of biogas is equivalent to 1 gallon of renewable fuel.

## §§ 80.1116 through 80.1124 [Reserved]

■ 8. Sections 80.1116 through 80.1124 are reserved.

■ 9. Sections 80.1125 through 80.1132 are added to read as follows:

## Subpart K—Renewable Fuel Standard

\* \* \* \* \*

\* \* \* \* \*

### § 80.1125 Renewable Identification Numbers (RINs).

Each RIN is a 38 character numeric code of the following form: KYYYYCCCCFFFFFBBBBBRRD SSSSSSSSEEEEEEEE

(a) K is a number identifying the type of RIN as follows:

(1) K has the value of 1 when the RIN is assigned to a volume of renewable fuel pursuant to §§ 80.1126(e) and 80.1128(a).

(2) K has the value of 2 when the RIN has been separated from a volume of renewable fuel pursuant to § 80.1126(e)(4) or § 80.1129.

(b) YYYY is the calendar year in which the batch of renewable fuel was produced or imported. YYYY also represents the year in which the RIN was originally generated.

(c) CCCC is the registration number assigned according to § 80.1150 to the producer or importer of the batch of renewable fuel.

(d) FFFFF is the registration number assigned according to § 80.1150 to the facility at which the batch of renewable fuel was produced or imported.

(e) BBBBB is a serial number assigned to the batch which is chosen by the producer or importer of the batch such that no two batches have the same value in a given calendar year.

(f) RR is a number representing the equivalence value of the renewable fuel as specified in § 80.1115 and multiplied by 10 to produce the value for RR.

(g) D is a number identifying the type of renewable fuel, as follows:

(1) D has the value of 1 if the renewable fuel can be categorized as cellulosic biomass ethanol as defined in § 80.1101(a).

(2) D has the value of 2 if the renewable fuel cannot be categorized as cellulosic biomass ethanol as defined in § 80.1101(a).

(h) SSSSSSSS is a number representing the first gallon-RIN associated with a batch of renewable fuel.

(i) EEEEEEEE is a number representing the last gallon-RIN associated with a batch of renewable fuel. EEEEEEEE will be identical to SSSSSSSS if the batch-RIN represents a single gallon-RIN. Assign the value of EEEEEEEE as described in § 80.1126.

### § 80.1126 How are RINs generated and assigned to batches of renewable fuel by renewable fuel producers or importers?

(a) *Regional applicability.* (1) Except as provided in paragraph (b) of this section, a RIN must be assigned by a renewable fuel producer or importer to every batch of renewable fuel produced by a facility located in the contiguous 48

states of the United States, or imported into the contiguous 48 states.

(2) If the Administrator approves a petition of Alaska, Hawaii, or a United States territory to opt-in to the renewable fuel program under the provisions in § 80.1143, then the requirements of paragraph (a)(1) of this section shall also apply to renewable fuel produced or imported into that state or territory beginning in the next calendar year.

(b) *Volume threshold.* Renewable fuel producers located within the United States that produce less than 10,000 gallons of renewable fuel each year, and importers that import less than 10,000 gallons of renewable fuel each year, are not required to generate and assign RINs to batches of renewable fuel. Such producers and importers are also exempt from the registration, reporting, and recordkeeping requirements of §§ 80.1150–80.1152. However, for such producers and importers that voluntarily generate and assign RINs, all the requirements of this subpart apply.

(c) *Definition of batch.* For the purposes of this section and § 80.1125, a "batch of renewable fuel" is a volume of renewable fuel that has been assigned a unique RIN code BBBBB within a calendar year by the producer or importer of the renewable fuel in accordance with the provisions of this section and § 80.1125.

(1) The number of gallon-RINs generated for a batch of renewable fuel may not exceed 99,999,999.

(2) A batch of renewable fuel cannot represent renewable fuel produced or imported in excess of one calendar month.

(d) *Generation of RINs.* (1) Except as provided in paragraph (b) of this section, the producer or importer of a batch of renewable fuel must generate RINs for that batch, including any renewable fuel contained in imported gasoline.

(2) A producer or importer of renewable fuel may generate RINs for volumes of renewable fuel that it owns on September 1, 2007.

(3) A party generating a RIN shall specify the appropriate numerical values for each component of the RIN in accordance with the provisions of § 80.1125 and this paragraph (d).

(4) Except as provided in paragraph (d)(6) of this section, the number of gallon-RINs that shall be generated for a given batch of renewable fuel shall be equal to a volume calculated according to the following formula:

$$V_{RIN} = EV * V_s$$

Where:

$V_{RIN}$ = RIN volume, in gallons, for use determining the number of gallon-RINs that shall be generated.
EV = Equivalence value for the renewable fuel per § 80.1115.
$V_s$ = Standardized volume of the batch of renewable fuel at 60 °F, in gallons, calculated in accordance with paragraph (d)(7) of this section.

(5) Multiple gallon-RINs generated to represent a given volume of renewable fuel can be represented by a single batch-RIN through the appropriate designation of the RIN volume codes SSSSSSSS and EEEEEEEE.

(i) The value of SSSSSSSS in the batch-RIN shall be 00000001 to represent the first gallon-RIN associated with the volume of renewable fuel.

(ii) The value of EEEEEEEE in the batch-RIN shall represent the last gallon-RIN associated with the volume of renewable fuel, based on the RIN volume determined pursuant to paragraph (d)(4) of this section.

(6) (i) For renewable crude-based renewable fuels produced in a facility or unit that coprocesses renewable crudes and fossil fuels, the number of gallon-RINs that shall be generated for a given batch of renewable fuel shall be equal to the gallons of renewable crude used rather than the gallons of renewable fuel produced.

(ii) Parties that produce renewable crude-based renewable fuels in a facility or unit that coprocesses renewable crudes and fossil fuels may submit a petition to the Agency requesting the use of volumes of renewable fuel produced as the basis for the number of gallon-RINs, pursuant to paragraph (d)(4) of this section.

(7) *Standardization of volumes.* In determining the standardized volume of a batch of renewable fuel for purposes of generating RINs under this paragraph (d), the batch volumes shall be adjusted to a standard temperature of 60 °F.

(i) For ethanol, the following formula shall be used:

$$V_{s,e} = V_{a,e} * (-0.0006301 * T + 1.0378)$$

Where:

$V_{s,e}$ = Standardized volume of ethanol at 60 °F, in gallons.
$V_{a,e}$ = Actual volume of ethanol, in gallons.
T = Actual temperature of the batch, in °F.

(ii) For biodiesel (mono alkyl esters), the following formula shall be used:

$$V_{s,b} = V_{a,b} * (-0.0008008 * T + 1.0480)$$

Where:

$V_{s,b}$ = Standardized volume of biodiesel at 60 °F, in gallons.
$V_{a,b}$ = Actual volume of biodiesel, in gallons.
T = Actual temperature of the batch, in °F.

(iii) For other renewable fuels, an appropriate formula commonly accepted by the industry shall be used

to standardize the actual volume to 60 °F. Formulas used must be reported to the Agency, and may be reviewed for appropriateness.

(8) (i) A party is prohibited from generating RINs for a volume of renewable fuel that it produces if:

(A) The renewable fuel has been produced from a chemical conversion process that uses another renewable fuel as a feedstock; and

(B) The renewable fuel used as a feedstock was produced by another party.

(ii) Any RINs that the party acquired with renewable fuel used as a feedstock shall be assigned to the new renewable fuel that was made with that feedstock.

(e) *Assignment of RINs to batches.* (1) Except as provided in paragraph (e)(4) of this section, the producer or importer of renewable fuel must assign all RINs generated to volumes of renewable fuel.

(2) A RIN is assigned to a volume of renewable fuel when ownership of the RIN is transferred along with the transfer of ownership of the volume of renewable fuel, pursuant to § 80.1128(a).

(3) All assigned RINs shall have a K code value of 1.

(4) *RINs not assigned to batches.* (i) If a party produces or imports a batch of cellulosic biomass ethanol or waste-derived ethanol having an equivalence value of 2.5, that party must assign at least one gallon-RIN to each gallon of cellulosic biomass ethanol or waste-derived ethanol, representing the first 1.0 portion of the Equivalence Value.

(ii) Any remaining gallon-RINs generated for the cellulosic biomass ethanol or waste-derived ethanol which represent the remaining 1.5 portion of the Equivalence Value may remain unassigned.

(iii) The producer or importer of cellulosic biomass ethanol or waste-derived ethanol shall designate the K code as 2 for all unassigned RINs.

### § 80.1127 How are RINs used to demonstrate compliance?

(a) *Renewable volume obligations.* (1) Except as specified in paragraph (b) of this section, each party that is obligated to meet the Renewable Volume Obligation under § 80.1107, or each party that is an exporter of renewable fuels that is obligated to meet a Renewable Volume Obligation under § 80.1130, must demonstrate pursuant to § 80.1152(a)(1) that it has taken ownership of sufficient RINs to satisfy the following equation:

$$(\Sigma RINNUM)_i + (\Sigma RINNUM)_{i-1} = RVO_i$$

Where:

$(\Sigma RINNUM)_i$ = Sum of all owned gallon-RINs that were generated in year i and are

being applied towards the $RVO_i$, in gallons.

$(\Sigma RINNUM)_{i-1}$ = Sum of all owned gallon-RINs that were generated in year $i-1$ and are being applied towards the $RVO_i$, in gallons.

$RVO_i$ = The Renewable Volume Obligation for the obligated party or renewable fuel exporter for calendar year i, in gallons, pursuant to § 80.1107 or § 80.1130.

(2) For compliance for calendar years 2008 and later, the value of $(\Sigma RINNUM)_{i-1}$ may not exceed a value determined by the following inequality: $(\Sigma RINNUM)_{i-1} \leq 0.20 \times RVO_i$

(3) RINs may only be used to demonstrate compliance with the RVO for the calendar year in which they were generated or the following calendar year. RINs used to demonstrate compliance in one year cannot be used to demonstrate compliance in any other year.

(4) A party may only use a RIN for purposes of meeting the requirements of paragraphs (a)(1) and (a)(2) of this section if that RIN is an unassigned RIN with a K code of 2 obtained in accordance with §§ 80.1126(e)(4), 80.1128, and 80.1129.

(5) The number of gallon-RINs associated with a given batch-RIN that can be used for compliance with the RVO shall be calculated from the following formula:

$RINNUM = EEEEEEEE - SSSSSSSS + 1$

Where:

$RINNUM$ = Number of gallon-RINs associated with a batch-RIN, where each gallon-RIN represents one gallon of renewable fuel for compliance purposes.

$EEEEEEEE$ = Batch-RIN component identifying the last gallon-RIN associated with the batch-RIN.

$SSSSSSSS$ = Batch-RIN component identifying the first gallon-RIN associated with the batch-RIN.

(b) *Deficit carryovers.* (1) An obligated party or an exporter of renewable fuel that fails to meet the requirements of paragraphs (a)(1) or (a)(2) of this section for calendar year i is permitted to carry a deficit into year i+1 under the following conditions:

(i) The party did not carry a deficit into calendar year i from calendar year $i-1$.

(ii) The party subsequently meets the requirements of paragraph (a)(1) of this section for calendar year i+1 and carries no deficit into year i+2.

(2) A deficit is calculated according to the following formula:

$D_i$ $RVO_{i-1}$ $(\Sigma RINNUM)_{i+1}$ $(\Sigma RINNUM)_{i-1}$

Where:

$D_i$ = The deficit, in gallons, generated in calendar year i that must be carried over to year i+1 if allowed to do so pursuant to paragraph (b)(1)(i) of this section.

$RVO_i$ = The Renewable Volume Obligation for the obligated party or renewable fuel exporter for calendar year i, in gallons.

$(\Sigma RINNUM)_{i-1}$ = Sum of all acquired gallon-RINs that were generated in year i and are being applied towards the $RVO_i$, in gallons.

$(\Sigma RINNUM)_{i-1}$ = Sum of all acquired gallon-RINs that were generated in year $i-1$ and are being applied towards the $RVO_i$, in gallons.

### § 80.1128 General requirements for RIN distribution.

(a) *RINs assigned to volumes of renewable fuel.* (1) *Assigned RIN,* for the purposes of this subpart, means a RIN assigned to a volume of renewable fuel pursuant to § 80.1126(e) with a K code of 1.

(2) Except as provided in § 80.1126(e)(4) and § 80.1129, no party can separate a RIN that has been assigned to a batch pursuant to § 80.1126(e).

(3) An assigned RIN cannot be transferred to another party without simultaneously transferring a volume of renewable fuel to that same party.

(4) No more than 2.5 assigned gallon-RINs with a K code of 1 can be transferred to another party with every gallon of renewable fuel transferred to that same party.

(5) (i) On each of the dates listed in paragraph (a)(5)(v) of this section in any calendar year, the following equation must be satisfied for assigned RINs and volumes of renewable fuel owned by a party:

$\Sigma(RIN)_D \leq \Sigma(V_{si} \times EV_i)_D$

Where:

D = Applicable date.

$\Sigma(RIN)_D$ = Sum of all assigned gallon-RINs with a K code of 1 that are owned on date D.

$(V_{si})_D$ = Volume i of renewable fuel owned on date D, standardized to 60 °F, in gallons.

$EV_i$ = Equivalence value representing volume i.

$\Sigma(V_{si} \times EV_i)_D$ = Sum of all volumes of renewable fuel owned on date D, multiplied by their respective equivalence values.

(ii) The equivalence value $EV_i$ for use in the equation in paragraph (a)(5)(i) of this section for any volume of ethanol shall be 2.5.

(iii) If the equivalence value for a volume of renewable fuel i can be determined pursuant to § 80.1115 based on its composition, then the appropriate equivalence value shall be used for $EV_i$.

(iv) If the equivalence value for a volume of renewable fuel cannot be determined based on its composition, the value of $EV_i$ shall be 1.0.

(v) The applicable dates are March 31, June 30, September 30, and December 31. For 2007 only, the applicable dates are September 30, and December 31.

(6) *Producers and importers of renewable fuel.* (i) Except as provided in paragraph (a)(6)(ii) of this section, a producer or importer of renewable fuel must transfer ownership of a number of gallon-RINs with a K code of 1 whenever it transfers ownership of a volume of renewable fuel such that the ratio of gallon-RINs to gallons is equal to the equivalence value for the renewable fuel.

$\Sigma(RIN) / V_s = EV$

Where:

$\Sigma(RIN)$ = Sum of all gallon-RINs with a K code of 1 which are transferred along with volume $V_s$.

$V_s$ = A volume of renewable fuel transferred, standardized to 60 °F, in gallons.

EV = Equivalence value assigned to the renewable fuel being transferred.

(ii) A producer or importer of renewable fuel can transfer ownership of a volume of renewable fuel without simultaneously transferring ownership of gallon-RINs having a K code of 1 if it can demonstrate one of the following:

(A) It is a small volume producer exempt from the requirement to generate RINs pursuant to § 80.1126(b); or

(B) The producer or importer received an equivalent volume of renewable fuel from another party without accompanying RINs.

(C) The producer or importer has generated RINs for cellulosic biomass ethanol or waste-derived ethanol having an equivalence value of 2.5, and has chosen to specify as unassigned a number of gallon-RINs pursuant to § 80.1126(e)(4).

(7) Any transfer of ownership of assigned RINs must be documented on product transfer documents generated pursuant to § 80.1153.

(i) The RIN must be recorded on the product transfer document used to transfer ownership of the RIN and the volume to another party; or

(ii) The RIN must be recorded on a separate product transfer document transferred to the same party on the same day as the product transfer document used to transfer ownership of the volume of renewable fuel.

(b) *RINs not assigned to volumes of renewable fuel.* (1) *Unassigned RIN,* for the purposes of this subpart, means a RIN with a K code of 2 that has been separated from a volume of renewable fuel pursuant to § 80.1126(e)(4) or § 80.1129.

(2) Any party that has registered pursuant to § 80.1150 can hold title to an unassigned RIN.

(3) Unassigned RINs can be transferred from one party to another any number of times.

(4) An unassigned batch-RIN can be divided by its holder into multiple batch-RINs, each representing a smaller number of gallon-RINs, if all of the following conditions are met:

(i) All RIN components other than SSSSSSS and EEEEEEEE are identical for the original parent and newly formed daughter RINs.

(ii) The sum of the gallon-RINs associated with the multiple daughter batch-RINs is equal to the gallon-RINs associated with the parent batch-RIN.

## § 80.1129 Requirements for separating RINs from volumes of renewable fuel.

(a)(1) Separation of a RIN from a volume of renewable fuel means termination of the assignment of the RIN to a volume of renewable fuel.

(2) RINs that have been separated from volumes of renewable fuel become unassigned RINs subject to the provisions of § 80.1128(b).

(b) A RIN that is assigned to a volume of renewable fuel is separated from that volume only under one of the following conditions:

(1) Except as provided in paragraph (b)(6) of this section, a party that is an obligated party according to § 80.1106 must separate any RINs that have been assigned to a volume of renewable fuel if they own that volume.

(2) Except as provided in paragraph (b)(5) of this section, any party that owns a volume of renewable fuel must separate any RINs that have been assigned to that volume once the volume is blended with gasoline or diesel to produce a motor vehicle fuel.

(3) Any party that exports a volume of renewable fuel must separate any RINs that have been assigned to the exported volume.

(4) Any renewable fuel producer or importer that produces or imports a volume of renewable fuel shall have the right to separate any RINs that have been assigned to that volume if the producer or importer designates the renewable fuel as motor vehicle fuel and the renewable fuel is used as motor vehicle fuel.

(5) RINs assigned to a volume of biodiesel (mono-alkyl ester) can only be separated from that volume pursuant to paragraph (b)(2) of this section if such biodiesel is blended into diesel fuel at a concentration of 80 volume percent biodiesel (mono-alkyl ester) or less.

(i) This paragraph (b)(5) shall not apply to obligated parties or exporters of renewable fuel.

(ii) This paragraph (b)(5) shall not apply to renewable fuel producers meeting the requirements of paragraph (b)(4) of this section.

(6) For RINs that an obligated party generates, the obligated party can only

separate such RINs from volumes of renewable fuel if the number of gallon-RINs separated is less than or equal to its annual RVO.

(7) A producer or importer of cellulosic biomass ethanol or waste-derived ethanol can separate a portion of the RINs that it generates pursuant to § 80.1126(e)(4).

(c) The party responsible for separating a RIN from a volume of renewable fuel shall change the K code in the RIN from a value of 1 to a value of 2 prior to transferring the RIN to any other party.

(d) (1) Upon and after separation from a renewable fuel volume, a RIN shall not appear on documentation that is either:

(i) Used to identify title to the volume of renewable fuel; or

(ii) Transferred with the volume of renewable fuel.

(2) Upon and after separation of a RIN from its associated volume, product transfer documents used to transfer ownership of the volume must continue to meet the requirements of § 80.1153(a)(5)(iii).

(e) Any obligated party that uses a renewable fuel in a boiler or heater must retire any RINs associated with that volume of renewable fuel and report the retired RINs in the applicable reports under § 80.1152.

## § 80.1130 Requirements for exporters of renewable fuels.

(a) Any party that owns any amount of renewable fuel (in its neat form or blended with gasoline or diesel) that is exported from the region described in § 80.1126(a) shall acquire sufficient RINs to offset a Renewable Volume Obligation representing the exported renewable fuel.

(b) *Renewable Volume Obligations.* An exporter of renewable fuel shall determine its Renewable Volume Obligation from the volumes of the renewable fuel exported.

(1) A renewable fuel exporter's total Renewable Volume Obligation shall be calculated according to the following formula:

$$RVO_i = \Sigma(VOL_k * EV_k)_i + D_{i-1}$$

Where:

$RVO_i$ = The Renewable Volume Obligation for the exporter for calendar year i, in gallons of renewable fuel.

k = A discrete volume of renewable fuel.

$VOL_k$ = The standardized volume of discrete volume k of exported renewable fuel, in gallons, calculated in accordance with § 80.1126(d)(7).

$EV_k$ = The equivalence value associated with discrete volume k.

$\Sigma$ = Sum involving all volumes of renewable fuel exported.

$D_{i-1}$ = Renewable fuel deficit carryover from the previous year, in gallons.

(2)(i) If the equivalence value for a volume of renewable fuel can be determined pursuant to § 80.1115 based on its composition, then the appropriate equivalence value shall be used in the calculation of the exporter's Renewable Volume Obligation.

(ii) If the equivalence value for a volume of renewable fuel cannot be determined, the value of $EV_k$ shall be 1.0.

(c) Each exporter of renewable fuel must demonstrate compliance with its RVO using RINs it has acquired pursuant to § 80.1127.

## § 80.1131 Treatment of invalid RINs.

(a) *Invalid RINs.* An invalid RIN is a RIN that is any of the following:

(1) Is a duplicate of a valid RIN.

(2) Was based on volumes that have not been standardized to 60 °F.

(3) Has expired.

(4) Was based on an incorrect equivalence value.

(5) Is deemed invalid under § 80.1167(g).

(6) Does not represent renewable fuel as it is defined in § 80.1101.

(7) Was otherwise improperly generated.

(b) In the case of RINs that are invalid, the following provisions apply:

(1) Invalid RINs cannot be used to achieve compliance with the Renewable Volume Obligation of an obligated party or exporter, regardless of the party's good faith belief that the RINs were valid at the time they were acquired.

(2) Upon determination by any party that RINs owned are invalid, the party must adjust their records, reports, and compliance calculations as necessary to reflect the deletion of the invalid RINs.

(3) Any valid RINs remaining after deleting invalid RINs must first be applied to correct the transfer of invalid RINs to another party before applying the valid RINs to meet the party's Renewable Volume Obligation at the end of the compliance year.

(4) In the event that the same RIN is transferred to two or more parties, all such RINs will be deemed to be invalid, unless EPA in its sole discretion determines that some portion of these RINs is valid.

## § 80.1132 Reported spillage of renewable fuel.

(a) A reported spillage under paragraph (d) of this section means a spillage of renewable fuel associated with a requirement by a federal, state or local authority to report the spillage.

(b) Except as provided in paragraph (c) of this section, in the event of a reported spillage of any volume of renewable fuel, the owner of the

renewable fuel must retire a number of gallon-RINs corresponding to the volume of spilled renewable fuel multiplied by its equivalence value.

(1) If the equivalence value for the spilled volume may be determined pursuant to § 80.1115 based on its composition, then the appropriate equivalence value shall be used.

(2) If the equivalence value for a spilled volume of renewable fuel cannot be determined, the equivalence value shall be 1.0.

(c) If the owner of a volume of renewable fuel that is spilled and reported establishes that no RINs were generated to represent the volume, then no gallon-RINs shall be retired.

(d) A RIN that is retired under paragraph (b) of this section:

(1) Must be reported as a retired RIN in the applicable reports under § 80.1152.

(2) May not be transferred to another party or used by any obligated party to demonstrate compliance with the party's Renewable Volume Obligation.

## §§ 80.1133 through 80.1140 [Reserved]

■ 10. Sections 80.1133 through 80.1140 are reserved.

■ 11. Sections 80.1141 through 80.1143 are added to read as follows:

## § 80.1141 Small refinery exemption.

(a)(1) Gasoline produced at a refinery by a refiner, or foreign refiner (as defined at § 80.1165(a)), is exempt from the renewable fuel standards of § 80.1105 if that refinery meets the definition of a small refinery under § 80.1101(g) for calendar year 20460.

(2) This exemption shall apply through December 31, 2010, unless a refiner chooses to waive this exemption (as described in paragraph (f) of this section), or the exemption is extended (as described in paragraph (e) of this section).

(3) For the purposes of this section, the term "refiner" shall include foreign refiners.

(b)(1) The small refinery exemption is effective immediately, except as specified in paragraph (b)(4) of this section.

(2) A refiner owning a small refinery must submit a verification letter to EPA containing all of the following information:

(i) The annual average aggregate daily crude oil throughput for the period January 1, 2004, through December 31, 2004 (as determined by dividing the aggregate throughput for the calendar year by the number 365).

(ii) A letter signed by the president, chief operating or chief executive officer of the company, or his/her designee, stating that the information contained in the letter is true to the best of his/her knowledge, and that the company owned the refinery as of January 1, 2004.

(iii) Name, address, phone number, facsimile number, and e-mail address of a corporate contact person.

(3) Verification letters must be submitted by August 31, 2007, to one of the addresses listed in paragraph (h) of this section.

(4) For foreign refiners the small refinery exemption shall be effective upon approval, by EPA, of a small refinery application. The application must contain all of the elements required for small refinery verification letters (as specified in paragraph (b)(2) of this section), must satisfy the provisions of § 80.1165(f) through (h) and (o), and must be submitted by August 31, 2007 to one of the addresses listed in paragraph (h) of this section.

(c) If EPA finds that a refiner provided false or inaccurate information regarding a refinery's crude throughput (pursuant to paragraph (b)(2)(i) of this section) in its small refinery verification letter, the exemption will be void as of the effective date of these regulations.

(d) If a refiner is complying on an aggregate basis for multiple refineries, any such refiner may exclude from the calculation of its Renewable Volume Obligation (under § 80.1107(a)) gasoline from any refinery receiving the small refinery exemption under paragraph (a) of this section.

(e)(1) The exemption period in paragraph (a) of this section shall be extended by the Administrator for a period of not less than two additional years if a study by the Secretary of Energy determines that compliance with the requirements of this subpart would impose a disproportionate economic hardship on the small refinery.

(i) A refiner may at any time petition the Administrator for an extension of its small refinery exemption under paragraph (a) of this section for the reason of disproportionate economic hardship.

(ii) A petition for an extension of the small refinery exemption must specify the factors that demonstrate a disproportionate economic hardship and must provide a detailed discussion regarding the inability of the refinery to produce gasoline meeting the requirements of § 80.1105 and the date the refiner anticipates that compliance with the requirements can be achieved at the small refinery.

(2) The Administrator shall act on such a petition not later than 90 days after the date of receipt of the petition.

(f) At any time, a refiner with an approved small refinery exemption under paragraph (a) of this section may waive that exemption upon notification to EPA.

(1) A refiner's notice to EPA that it intends to waive its small refinery exemption must be received by November 1 to be effective in the next compliance year.

(2) The waiver will be effective beginning on January 1 of the following calendar year, at which point the gasoline produced at that refinery will be subject to the renewable fuels standard of § 80.1105.

(3) The waiver must be sent to EPA at one of the addresses listed in paragraph (h) of this section.

(g) A refiner that acquires a refinery from either an approved small refiner (as defined under § 80.1142(a)) or another refiner with an approved small refinery exemption under paragraph (a) of this section shall notify EPA in writing no later than 20 days following the acquisition.

(h) Verification letters under paragraph (b) of this section, petitions for small refinery hardship extensions under paragraph (e) of this section, and small refinery exemption waivers under paragraph (f) of this section shall be sent to one of the following addresses:

(1) *For U.S. mail:* U.S. EPA—Attn: RFS Program, 6406J, 1200 Pennsylvania Avenue, NW., Washington, DC 20460.

(2) *For overnight or courier services:* U.S. EPA, Attn: RFS Program, 6406J, 1310 L Street, NW., 6th floor, Washington, DC 20005.

## § 80.1142 What are the provisions for small refiners under the RFS program?

(a) (1) Gasoline produced by a refiner, or foreign refiner (as defined at § 80.1165(a)), is exempt from the renewable fuel standards of § 80.1105 if the refiner or foreign refiner does not meet the definition of a small refinery under § 80.1101(g) but meets all of the following criteria:

(i) The refiner produced gasoline at its refineries by processing crude oil through refinery processing units from January 1, 2004 through December 31, 2004.

(ii) The refiner employed an average of no more than 1,500 people, based on the average number of employees for all pay periods for calendar year 2004 for all subsidiary companies, all parent companies, all subsidiaries of the parent companies, and all joint venture partners.

(iii) The refiner had a corporate-average crude oil capacity less than or equal to 155,000 barrels per calendar day (bpcd) for 2004.

(2) The small refiner exemption shall apply through December 31, 2010, unless a refiner chooses to waive the exemption (pursuant to paragraph (h) of this section) prior to that date.

(3) For the purposes of this section, the term ''refiner'' shall include foreign refiners.

(b) The small refiner exemption is effective immediately, except as provided in paragraph (d) of this section. Refiners who qualify for the small refiner exemption under paragraph (a) of this section must submit a verification letter (and any other relevant information) to EPA containing all of the following information for the refiner and for all subsidiary companies, all parent companies, all subsidiaries of the parent companies, and all joint venture partners:

(1)(i) A listing of the name and address of each company location where any employee worked for the period January 1, 2004 through December 31, 2004.

(ii) The average number of employees at each location based on the number of employees for each pay period for the period January 1, 2004 through December 31, 2004.

(iii) The type of business activities carried out at each location.

(iv) For joint ventures, the total number of employees includes the combined employee count of all corporate entities in the venture.

(v) For government-owned refiners, the total employee count includes all government employees.

(2) The total corporate crude oil capacity of each refinery as reported to the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE), for the period January 1, 2004 through December 31, 2004. The information submitted to EIA is presumed to be correct. In cases where a company disagrees with this information, the company may petition EPA with appropriate data to correct the record when the company submits its verification letter.

(3) The verification letter must be signed by the president, chief operating or chief executive officer of the company, or his/her designee, stating that the information is true to the best of his/her knowledge, and that the company owned the refinery as of December 31, 2004.

(4) Name, address, phone number, facsimile number, and e-mail address of a corporate contact person.

(c) Verification letters under paragraph (b) of this section must be submitted by September 1, 2007.

(d) For foreign refiners the small refiner exemption shall be effective upon approval, by EPA, of a small refiner application. The application must contain all of the elements required for small refiner verification letters (as specified in paragraphs (b)(1), (b)(3), and (b)(4) of this section), must demonstrate compliance with the crude oil capacity criterion of paragraph (a)(1)(iii) of this section, must satisfy the provisions of § 80.1165(f) through (h) and (o), and must be submitted by September 1, 2007 to one of the addresses listed in paragraph (j) of this section.

(e) A refiner who qualifies as a small refiner under this section and subsequently fails to meet all of the qualifying criteria as set out in paragraph (a) of this section will have its small refiner exemption terminated effective January 1 of the next calendar year; however, disqualification shall not apply in the case of a merger between two approved small refiners.

(f) If EPA finds that a refiner provided false or inaccurate information in its small refiner status verification letter under this subpart, the small refiner's exemption will be void as of the effective date of these regulations.

(g) If a small refiner is complying on an aggregate basis for multiple refineries, the refiner may exempt the refineries from the calculation of its Renewable Volume Obligation under § 80.1107.

(h) (1) A refiner may, at any time, waive the small refiner exemption under paragraph (a) of this section upon notification to EPA.

(2) A refiner's notice to EPA that it intends to waive the small refiner exemption must be received by November 1 in order for the waiver to be effective for the following calendar year. The waiver will be effective beginning on January 1 of the following calendar year, at which point the refiner will be subject to the renewable fuel standard of § 80.1105.

(3) The waiver must be sent to EPA at one of the addresses listed in paragraph (j) of this section.

(i) Any refiner that acquires a refinery from another refiner with approved small refiner status under paragraph (a) of this section shall notify EPA in writing no later than 20 days following the acquisition.

(j) Verification letters under paragraph (b) of this section and small refiner exemption waivers under paragraph (h) of this section shall be sent to one of the following addresses:

(1) *For U.S. Mail:* U.S. EPA—Attn: RFS Program, 6406J, 1200 Pennsylvania Avenue, NW., Washington, DC 20460.

(2) *For overnight or courier services:* U.S. EPA, Attn: RFS Program, 6406J, 1310 L Street, NW., 6th floor, Washington, DC 20005.

**§ 80.1143   What are the opt-in provisions for noncontiguous states and territories?**

(a) A noncontiguous state or United States territory may petition the Administrator to opt-in to the program requirements of this subpart.

(b) The Administrator will approve the petition if it meets the provisions of paragraphs (c) and (d) of this section.

(c) The petition must be signed by the Governor of the state or his authorized representative (or the equivalent official of the territory).

(d)(1) A petition submitted under this section must be received by the Agency by November 1 for the state or territory to be included in the RFS program in the next calendar year.

(2) A petition submitted under this section should be sent to either of the following addresses:

(i) *For U.S. Mail:* U.S. EPA—Attn: RFS Program, 6406J, 1200 Pennsylvania Avenue, NW., Washington, DC 20460.

(ii) *For overnight or courier services:* U.S. EPA, Attn: RFS Program, 6406J, 1310 L Street, NW., 6th floor, Washington, DC 20005.

(e) Upon approval of the petition by the Administrator:

(1) EPA shall calculate the standard for the following year, including the total gasoline volume for the State or territory in question.

(2) Beginning on January 1 of the next calendar year, all gasoline refiners and importers in the state or territory for which a petition has been approved shall be obligated parties as defined in § 80.1106.

(3) Beginning on January 1 of the next calendar year, all renewable fuel producers in the State or territory for which a petition has been approved shall, pursuant to § 80.1126(a)(2), be required to generate RINs and assign them to batches of renewable fuel.

**§§ 80.1144 through 80.1149   [Reserved]**

■ 12. Sections 80.1144 through 80.1149 are reserved.

■ 13. Sections 80.1150 through 80.1155 are added to read as follows:

**Subpart K—Renewable Fuel Standard**

\*    \*    \*    \*    \*

Sec.

80.1153 What are the product transfer document (PTD) requirements for the RFS program?
80.1154 What are the provisions for renewable fuel producers and importers who produce or import less than 10,000 gallons of renewable fuel per year?
80.1155 What are the additional requirements for a producer of cellulosic biomass ethanol or waste derived ethanol?

\*   \*   \*   \*   \*

### § 80.1150 What are the registration requirements under the RFS program?

(a) Any obligated party described in § 80.1106 and any exporter of renewable fuel described in § 80.1130 must provide EPA with the information specified for registration under § 80.76, if such information has not already been provided under the provisions of this part. An obligated party or an exporter of renewable fuel must receive EPA-issued identification numbers prior to engaging in any transaction involving RINs. Registration information may be submitted to EPA at any time after promulgation of this rule in the **Federal Register**.

(b) Any importer or producer of a renewable fuel must provide EPA the information specified under § 80.76, if such information has not already been provided under the provisions of this part, and must receive EPA-issued company and facility identification numbers prior to generating or assigning any RINs. Registration information may be submitted to EPA at any time after promulgation of this rule in the **Federal Register**.

(c) Any party who owns or intends to own RINs, but who is not covered by paragraphs (a) and (b) of this section, must provide EPA the information specified under § 80.76, if such information has not already been provided under the provisions of this part and must receive an EPA-issued company identification number prior to owning any RINs. Registration information may be submitted to EPA at any time after promulgation of this rule in the **Federal Register**.

(d) Registration shall be on forms, and following policies, established by the Administrator.

### § 80.1151 What are the recordkeeping requirements under the RFS program?

(a) Beginning September 1, 2007, any obligated party (as described at § 80.1106) or exporter of renewable fuel (as described at § 80.1130) must keep all of the following records:

(1) Product transfer documents consistent with § 80.1153 and associated with the obligated party's activity, if

any, as transferor or transferee of renewable fuel.

(2) Copies of all reports submitted to EPA under § 80.1152(a).

(3) Records related to each RIN transaction, which includes all the following:

(i) A list of the RINs owned, purchased, sold, retired or expired.

(ii) The parties involved in each RIN transaction including the transferor, transferee, and any broker or agent.

(iii) The date of the transfer of the RIN(s).

(iv) Additional information related to details of the transaction and its terms.

(4) Records related to the use of RINs (by facility, if applicable) for compliance, which includes all the following:

(i) Methods and variables used to calculate the Renewable Volume Obligation pursuant to § 80.1107 or § 80.1130.

(ii) List of RINs used to demonstrate compliance.

(iii) Additional information related to details of RIN use for compliance.

(b) Beginning September 1, 2007, any producer or importer of a renewable fuel as defined at § 80.1101(d) must keep all of the following records:

(1) Product transfer documents consistent with § 80.1153 and associated with the renewable fuel producer's or importer's activity, if any, as transferor or transferee of renewable fuel.

(2) Copies of all reports submitted to EPA under § 80.1152(b).

(3) Records related to the generation and assignment of RINs for each facility, including all of the following:

(i) Batch volume in gallons.

(ii) Batch number.

(iii) RIN number as assigned under § 80.1126.

(iv) Identification of batches meeting the definition of cellulosic biomass ethanol.

(v) Date of production or import.

(vi) Results of any laboratory analysis of batch chemical composition or physical properties.

(vii) Additional information related to details of RIN generation.

(4) Records related to each RIN transaction, including all of the following:

(i) A list of the RINs owned, purchased, sold, retired or expired.

(ii) The parties involved in each transaction including the transferor, transferee, and any broker or agent.

(iii) The date of the transfer of the RIN(s).

(iv) Additional information related to details of the transaction and its terms.

(5) Records related to the production or importation of any volume of

renewable fuel that the renewable fuel producer or importer designates as motor vehicle fuel and the use of the fuel as motor vehicle fuel.

(c) Beginning September 1, 2007, any producer of a renewable fuel defined at § 80.1101(d) must keep verifiable records of the following:

(1) The amount and type of fossil fuel and waste material-derived fuel used in producing on-site thermal energy dedicated to the production of ethanol at plants producing cellulosic biomass ethanol through the displacement of 90 percent or more of the fossil fuel normally used in the production of ethanol, as described at § 80.1101(a)(2).

(2) The amount and type of feedstocks used in producing cellulosic biomass ethanol as defined in § 80.1101(a)(1).

(3) The equivalent amount of fossil fuel (based on reasonable estimates) associated with the use of off-site generated waste heat that is used in the production of ethanol at plants producing cellulosic biomass ethanol through the displacement of 90 percent or more of the fossil fuel normally used in the production of ethanol, as described at § 80.1101(a)(2).

(4) The plot plan and process flow diagram for plants producing cellulosic biomass and waste derived ethanol as defined in § 80.1101(a) and (b), respectively.

(5) The independent third party verification required under § 80.1155 for producers of cellulosic biomass ethanol and waste derived ethanol.

(d) Beginning September 1, 2007, any party, other than those parties covered in paragraphs (a) and (b) of this section, that owns RINs must keep all of the following records:

(1) Product transfer documents consistent with § 80.1153 and associated with the party's activity, if any, as transferor or transferee of renewable fuel.

(2) Copies of all reports submitted to EPA under § 80.1152(c).

(3) Records related to each RIN transaction, including all of the following:

(i) A list of the RINs owned, purchased, sold, retired or expired.

(ii) The parties involved in each RIN transaction including the transferor, transferee, and any broker or agent.

(iii) The date of the transfer of the RIN(s).

(iv) Additional information related to details of the transaction and its terms.

(e) The records required under this section and under § 80.1153 shall be kept for five years from the date they were created, except that records related to transactions involving RINs shall be

kept for five years from the date of transfer.

(f) On request by EPA, the records required under this section and under § 80.1153 must be made available to the Administrator or the Administrator's authorized representative. For records that are electronically generated or maintained, the equipment or software necessary to read the records shall be made available; or, if requested by EPA, electronic records shall be converted to paper documents.

### § 80.1152  What are the reporting requirements under the RFS program?

(a) Any obligated party described in § 80.1106 or exporter of renewable fuel described in § 80.1130 must submit to EPA reports according to the schedule, and containing the information, that is set forth in this paragraph (a).

(1) An annual compliance demonstration report for the previous compliance period shall be submitted every February 28, except as noted in paragraph (a)(1)(x) of this section, and shall include all of the following information:

(i) The obligated party's name.

(ii) The EPA company registration number.

(iii) Whether the party is complying on a corporate (aggregate) or facility-by-facility basis.

(iv) The EPA facility registration number, if complying on a facility-by-facility basis.

(v) The production volume of all of the products listed in § 80.1107(c) for the reporting year.

(vi) The renewable volume obligation (RVO), as defined in § 80.1127(a) for obligated parties and § 80.1130(b) for exporters of renewable fuel, for the reporting year.

(vii) Any deficit RVO carried over from the previous year.

(viii) The total current-year gallon-RINs used for compliance.

(ix) The total prior-years gallon-RINs used for compliance.

(x) A list of all RINs used for compliance in the reporting year. For compliance demonstrations covering calendar year 2007 only, this list shall be reported by May 31, 2008. In all subsequent years, this list shall be submitted by February 28.

(xi) Any deficit RVO carried into the subsequent year.

(xii) Any additional information that the Administrator may require.

(2) The quarterly RIN transaction reports required under paragraph (c)(1) of this section.

(3) The quarterly gallon-RIN activity reports required under paragraph (c)(2) of this section.

(4) Reports required under this paragraph (a) must be signed and certified as meeting all the applicable requirements of this subpart by the owner or a responsible corporate officer of the obligated party.

(b) Any producer or importer of a renewable fuel must, beginning November 30, 2007, submit to EPA reports according to the schedule, and containing the information, that is set forth in this paragraph (b).

(1) A quarterly RIN-generation report for each facility owned by the renewable fuel producer, and each importer, shall be submitted according to the schedule specified in paragraph (d) of this section, and shall include for the reporting period all of the following information for each batch of renewable fuel produced or imported, where "batch" means a discreet quantity of renewable fuel produced or imported and assigned a unique RIN:

(i) The renewable fuel producer's or importer's name.

(ii) The EPA company registration number.

(iii) The EPA facility registration number.

(iv) The applicable quarterly reporting period.

(v) The RINs generated for each batch according to § 80.1126.

(vi) The production date of each batch.

(vii) The type of renewable fuel of each batch, as defined in § 80.1101(d).

(viii) Information related to the volume of denaturant and applicable equivalence value of each batch.

(ix) The volume of each batch produced or imported.

(x) Any additional information the Administrator may require.

(2) The RIN transaction reports required under paragraph (c)(1) of this section.

(3) The quarterly gallon-RIN activity report required under paragraph (c)(2) of this section.

(4) Reports required under this paragraph (b) must be signed and certified as meeting all the applicable requirements of this subpart by the owner or a responsible corporate officer of the renewable fuel producer.

(c) Any party, including any party specified in paragraphs (a) and (b) of this section, that owns RINs during a reporting period must, beginning November 30, 2007, submit reports to EPA according to the schedule, and containing the information, that is set forth in this paragraph (c).

(1) A RIN transaction report for each RIN transaction shall be submitted by the end of the quarter in which the transaction occurred, according to the schedule specified in paragraph (d) of this section. Each report shall include all of the following:

(i) The submitting party's name.

(ii) The party's EPA company registration number.

(iii) The party's facility registration number, if the report required under paragraph (c)(2) of this section is submitted on a facility-by-facility basis.

(iv) The applicable quarterly reporting period.

(v) Transaction type (RIN purchase, RIN sale, expired RIN, retired RIN).

(vi) Transaction date.

(vii) For a RIN purchase or sale, the trading partner's name.

(viii) For a RIN purchase or sale, the trading partner's EPA company registration number. For all other transactions, the submitting party's EPA company registration number.

(ix) RIN subject to the transaction.

(x) For a retired RIN, the reason for retiring the RIN (*e.g.*, reportable spill under § 80.1132, import volume correction under § 80.1166(k), renewable fuel used in boiler or heater under § 80.1129(e), enforcement obligation).

(xi) Any additional information that the Administrator may require.

(2) A quarterly gallon-RIN activity report shall be submitted to EPA according to the schedule specified in paragraph (d) of this section. Each report shall summarize gallon-RIN activities for the reporting period, separately for RINs separated from a renewable fuel volume and RINs assigned to a renewable fuel volume. A RIN owner with more than one facility may submit the report required under this paragraph for each of its facilities individually, or for all of its facilities in the aggregate. The quarterly gallon-RIN activity report shall include all of the following information:

(i) The submitting party's name.

(ii) The party's EPA company registration number.

(iii) Whether the party is submitting the report required under this paragraph on a corporate (aggregate) or facility-by-facility basis.

(iv) The party's EPA facility registration number, if the report required under this paragraph is submitted on a facility-by-facility basis.

(v) Number of current-year gallon-RINs owned at the start of the quarter.

(vi) Number of prior-years gallon-RINs owned at the start of the quarter.

(vii) The total current-year gallon-RINs purchased.

(viii) The total prior-years gallon-RINs purchased.

(ix) The total current-year gallon-RINs sold.

(x) The total prior-years gallon-RINs sold.

(xi) The total current-year gallon-RINs retired.

(xii) The total prior-years gallon-RINs retired.

(xiii) The total current-year gallon-RINs expired (fourth quarter only).

(xiv) The total prior-years gallon-RINs expired (fourth quarter only).

(xv) Number of current-year gallon-RINs owned at the end of the quarter.

(xvi) Number of prior-years gallon-RINs owned at the end of the quarter.

(xvii) For parties reporting gallon-RIN activity under this paragraph for RINs assigned to a volume of renewable fuel, the volume of renewable fuel (in gallons) owned at the end of the quarter.

(xviii) Any additional information that the Administrator may require.

(3) All reports required under this paragraph (c) must be signed and certified as meeting all the applicable requirements of this subpart by the RIN owner or a responsible corporate officer of the RIN owner.

(d) Quarterly reports shall be submitted to EPA by: May 31st for the first calendar quarter of January through March; August 31st for the second calendar quarter of April through June; November 30th for the third calendar quarter of July through September; and February 28th for the fourth calendar quarter of October through December. For 2007, quarterly reports shall commence on November 30, 2007.

(e) Reports required under this section shall be submitted on forms and following procedures as prescribed by EPA.

### § 80.1153 What are the product transfer document (PTD) requirements for the RFS program?

(a) Any time that a person transfers ownership of renewable fuels subject to this subpart, the transferor must provide to the transferee documents identifying the renewable fuel and any assigned RINs which include all of the following information as applicable:

(1) The name and address of the transferor and transferee.

(2) The transferor's and transferee's EPA company registration number.

(3) The volume of renewable fuel that is being transferred.

(4) The date of the transfer.

(5) Whether any RINs are assigned to the volume, as follows:

(i) If the assigned RINs are being transferred on the same PTD used to transfer ownership of the renewable fuel, then the assigned RINs shall be listed on the PTD.

(ii) If the assigned RINs are being transferred on a separate PTD from that which is used to transfer ownership of the renewable fuel, then the PTD which is used to transfer ownership of the renewable fuel shall state the number of gallon-RINs being transferred as well as a unique reference to the PTD which is transferring the assigned RINs.

(iii) If no assigned RINs are being transferred with the renewable fuel, the PTD which is used to transfer ownership of the renewable fuel shall state ''No RINs transferred''.

(b) Except for transfers to truck carriers, retailers, or wholesale purchaser-consumers, product codes may be used to convey the information required under paragraphs (a)(1) through (a)(4) of this section if such codes are clearly understood by each transferee. The RIN number required under paragraph (a)(5) of this section must always appear in its entirety.

### § 80.1154 What are the provisions for renewable fuel producers and importers who produce or import less than 10,000 gallons of renewable fuel per year?

(a) Renewable fuel producers located within the United States that produce less than 10,000 gallons of renewable fuel each year, and importers who import less than 10,000 gallons of renewable fuel each year, are not required to generate RINs or to assign RINs to batches of renewable fuel. Such producers and importers that do not generate and/or assign RINs to batches of renewable fuel are also exempt from all the following requirements of this subpart K, except as stated in paragraph (b) of this section:

(1) The registration requirements of § 80.1150.

(2) The recordkeeping requirements of § 80.1151.

(3) The reporting requirements of § 80.1152.

(b) Renewable fuel producers and importers who produce or import less than 10,000 gallons of renewable fuel each year and that generate and/or assign RINs to batches of renewable fuel are subject to the provisions of §§ 80.1150 through 80.1152.

### § 80.1155 What are the additional requirements for a producer of cellulosic biomass ethanol or waste derived ethanol?

(a) A producer of cellulosic biomass ethanol or waste derived ethanol (hereinafter referred to as ''ethanol producer'' under this section) is required to arrange for an independent third party to review the records required in § 80.1151(c) and provide the ethanol producer with a written verification that the records support a claim that:

(1) The ethanol producer's facility is a facility that has the capability of producing cellulosic biomass ethanol as defined in § 80.1101(a) or waste derived ethanol as defined in § 80.1101(b); and

(2) The ethanol producer produces cellulosic biomass ethanol as defined in § 80.1101(a) or waste derived ethanol as defined in § 80.1101(b).

(b) The verifications required under paragraph (a) of this section must be conducted by a Professional Chemical Engineer who is based in the United States and is licensed by the appropriate state agency, unless the ethanol producer is a foreign producer subject to § 80.1166.

(c) To be considered an independent third party under paragraph (a) of this section:

(1) The third party shall not be operated by the ethanol producer or any subsidiary of employee of the ethanol producer.

(2) The third party shall be free from any interest in the ethanol producer's business.

(3) The ethanol producer shall be free from any interest in the third party's business.

(4) Use of a third party that is debarred, suspended, or proposed for debarment pursuant to the Government-wide Debarment and Suspension regulations, 40 CFR part 32, or the Debarment, Suspension and Ineligibility provisions of the Federal Acquisition Regulations, 48 CFR, part 9, subpart 9.4, shall be deemed noncompliance with the requirements of this section.

(d) The ethanol producer must obtain the written verification required under paragraph (a)(1) of this section by February 28 of the year following the first year in which the ethanol producer claims to be producing cellulosic biomass ethanol or waste derived ethanol.

(e) The verification in paragraph (a)(2) of this section is required for each calendar year that the ethanol producer claims to be producing cellulosic biomass ethanol or waste derived ethanol. The ethanol producer must obtain the written verification required under paragraph (a)(2) of this section by February 28 for the previous calendar year.

(f) The ethanol producer must retain records of the verifications required under paragraph (a) of this section, as required in § 80.1151(c)(5).

(g) The independent third party shall retain all records pertaining to the verification required under this section for a period of five years from the date of creation and shall deliver such records to the Administrator upon request.

## §§ 80.1156 through 80.1159 [Reserved]

■ 14. Sections 80.1156 through 80.1159 are reserved.

■ 15. Sections 80.1160 and 80.1161 are added to read as follows:

## § 80.1160 What acts are prohibited under the RFS program?

(a) *Renewable fuels producer or importer violation.* Except as provided in § 80.1154, no person shall produce or import a renewable fuel without assigning the proper RIN value or identifying it by a RIN number as required under § 80.1126.

(b) *RIN generation and transfer violations.* No person shall do any of the following:

(1) Improperly generate a RIN (i.e., generate a RIN for which the applicable renewable fuel volume was not produced).

(2) Create or transfer to any person a RIN that is invalid under § 80.1131.

(3) Transfer to any person a RIN that is not properly identified as required under § 80.1125.

(4) Transfer to any person a RIN with a K code of 1 without transferring an appropriate volume of renewable fuel to the same person on the same day.

(c) *RIN use violations.* No person shall do any of the following:

(1) Fail to acquire sufficient RINs, or use invalid RINs, to meet the party's renewable fuel volume obligation under § 80.1127.

(2) Fail to acquire sufficient RINs to meet the party's renewable fuel volume obligation under § 80.1130.

(3) Use a validly generated RIN to meet the party's renewable fuel volume obligation under § 80.1127, or separate and transfer a validly generated RIN, where the party ultimately uses the renewable fuel volume associated with the RIN in a heater or boiler.

(d) *RIN retention violation.* No person shall retain RINs in violation of the requirements in § 80.1128(a)(5).

(e) *Causing a violation.* No person shall cause another person to commit an act in violation of any prohibited act under this section.

## § 80.1161 Who is liable for violations under the RFS program?

(a) *Persons liable for violations of prohibited acts.* (1) Any person who violates a prohibition under § 80.1160(a) through (d) is liable for the violation of that prohibition.

(2) Any person who causes another person to violate a prohibition under § 80.1160(a) through (d) is liable for a violation of § 80.1160(e).

(b) *Persons liable for failure to meet other provisions of this subpart.* (1) Any

person who fails to meet a requirement of any provision of this subpart is liable for a violation of that provision.

(2) Any person who causes another person to fail to meet a requirement of any provision of this subpart is liable for causing a violation of that provision.

(c) *Parent corporation liability.* Any parent corporation is liable for any violation of this subpart that is committed by any of its subsidiaries.

(d) *Joint venture liability.* Each partner to a joint venture is jointly and severally liable for any violation of this subpart that is committed by the joint venture operation.

## § 80.1162 [Reserved]

■ 16. Section 80.1162 is reserved.

■ 17. Sections 80.1163 through 80.1167 are added to read as follows:

## Subpart K—Renewable Fuel Standard

\* \* \* \* \*
Sec.
80.1163 What penalties apply under the RFS program?
80.1164 What are the attest engagement requirements under the RFS program?
80.1165 What are the additional requirements under this Subpart for a foreign small refiner?
80.1166 What are the additional requirements under this subpart for a foreign producer of cellulosic biomass ethanol or waste derived ethanol?
80.1167 What are the additional requirements under this subpart for a foreign RIN owner?

\* \* \* \* \*

## § 80.1163 What penalties apply under the RFS program?

(a) Any person who is liable for a violation under § 80.1161 is subject to a civil penalty of up to $32,500, as specified in sections 205 and 211(d) of the Clean Air Act, for every day of each such violation and the amount of economic benefit or savings resulting from each violation.

(b) Any person liable under § 80.1161(a) for a violation of § 80.1160(c) for failure to meet a renewable volume obligation, or § 80.1160(e) for causing another party to fail to meet a renewable volume obligation, during any averaging period, is subject to a separate day of violation for each day in the averaging period.

(c) Any person liable under § 80.1161(b) for failure to meet, or causing a failure to meet, a requirement of any provision of this subpart is liable for a separate day of violation for each day such a requirement remains unfulfilled.

## § 80.1164 What are the attest engagement requirements under the RFS program?

The requirements regarding annual attest engagements in §§ 80.125 through 80.127, and 80.130, also apply to any attest engagement procedures required under this subpart. In addition to any other applicable attest engagement procedures, the following annual attest engagement procedures are required under this subpart.

(a) The following attest procedures shall be completed for any obligated party as stated in § 80.1106(a) or exporter of renewable fuel that is subject to the renewable fuel standard under § 80.1105:

(1) *Annual compliance demonstration report.* (i) Obtain and read a copy of the annual compliance demonstration report required under § 80.1152(a)(1) which contains information regarding all the following:

(A) The obligated party's volume of finished gasoline, reformulated gasoline blendstock for oxygenate blending (RBOB), and conventional gasoline blendstock that becomes finished conventional gasoline upon the addition of oxygenate (CBOB) produced or imported during the reporting year.

(B) Renewable volume obligation (RVO).

(C) RINs used for compliance.

(ii) Obtain documentation of any volumes of renewable fuel used in gasoline during the reporting year; compute and report as a finding the volumes of renewable fuel represented in these documents.

(iii) Compare the volumes of gasoline reported to EPA in the report required under § 80.1152(a)(1) with the volumes, excluding any renewable fuel volumes, contained in the inventory reconciliation analysis under § 80.133.

(iii) Verify that the production volume information in the obligated party's annual summary report required under § 80.1152(a)(1) agrees with the volume information, excluding any renewable fuel volumes, contained in the inventory reconciliation analysis under § 80.133.

(iv) Compute and report as a finding the obligated party's RVO, and any deficit RVO carried over from the previous year or carried into the subsequent year, and verify that the values agree with the values reported to EPA.

(v) Obtain documentation for all RINs used for compliance during the year being reviewed; compute and report as a finding the RIN numbers and year of generation of RINs represented in these documents; and state whether this information agrees with the report to EPA.

(2) *RIN transaction reports.* (i) Obtain and read copies of a representative sample of all RIN transaction reports required under § 80.1152(a)(2) for the compliance year.

(ii) Obtain contracts or other documents for the representative sample of RIN transactions; compute and report as a finding the transaction types, transaction dates, and RINs traded; and state whether the information agrees with the party's reports to EPA.

(3) *Gallon-RIN activity reports.* (i) Obtain and read copies of all quarterly gallon-RIN activity reports required under § 80.1152(a)(3) for the compliance year.

(ii) Obtain documentation of total RINs (including current-year RINs and previous-year RINs) owned at the start of the quarter, purchased, used for compliance, sold, expired and retired during the quarter being reviewed, and owned at the end of the quarter; compute and report as a finding the total RINs owned at the start and end of the quarter, purchased, used for compliance, sold, expired and retired as represented in these documents; and state whether this information agrees with the party's reports to EPA.

(b) The following attest procedures shall be completed for any renewable fuel producer or importer:

(1) *RIN-generation reports.* (i) Obtain and read copies of the quarterly RIN generation reports required under § 80.1152(b)(1) for the compliance year.

(ii) Obtain production data for each renewable fuel batch produced during the year being reviewed; compute and report as a finding the RIN numbers, production dates, types, volumes of denaturant and applicable equivalence values, and production volumes for each batch; and state whether this information agrees with the party's reports to EPA.

(iii) Verify that the proper number of RINs were generated and assigned for each batch of renewable fuel produced, as required under § 80.1126.

(iv) Obtain product transfer documents for each renewable fuel batch produced during the year being reviewed; report as a finding any product transfer document that did not include the RIN for the batch.

(2) *RIN transaction reports.* (i) Obtain and read copies of a representative sample of the RIN transaction reports required under § 80.1152(b)(2) for the compliance year.

(ii) Obtain contracts or other documents for the representative sample of RIN transactions; compute and report as a finding the transaction types, transaction dates, and the RINs traded;

and state whether this information agrees with the party's reports to EPA.

(3) *Gallon-RIN activity reports.* (i) Obtain and read copies of the quarterly gallon-RIN activity reports required under § 80.1152(b)(3) for the compliance year.

(ii) Obtain documentation of total RINs (including current-year RINs and previous-year RINs) owned at the start of the quarter, purchased, sold, expired and retired during the quarter being reviewed, and owned at the end of the quarter; compute and report as a finding the total RINs owned at the start and end of the quarter, purchased, used for compliance, sold, expired and retired as represented in these documents; and state whether this information agrees with the party's reports to EPA.

(c) The following attest procedures shall be completed for any party other than an obligated party or renewable fuel producer or importer that owns any RINs during a calendar year.

(1) *RIN transaction reports.* (i) Obtain and read copies of a representative sample of the RIN transaction reports required under § 80.1152(c)(1) for the compliance year.

(ii) Obtain contracts or other documents for the representative sample of RIN transactions; compute and report as a finding the transaction types, transaction dates, and the RINs traded; and state whether this information agrees with the party's reports to EPA.

(2) *Gallon-RIN activity reports.* (i) Obtain and read copies of the gallon-RIN activity reports required under § 80.1152(c)(2) for the compliance year.

(ii) Obtain documentation of total RINs (including current-year RINs and previous-year RINs) owned at the start of the quarter, purchased, sold, expired and retired during the quarter being reviewed, and owned at the end of the quarter; compute and report as a finding the total RINs owned at the start and end of the quarter, purchased, used for compliance, sold, expired and retired as represented in these documents; and state whether this information agrees with the party's reports to EPA.

(d) The following submission dates apply to the attest engagements required under this section.

(1) For each compliance year, each party subject to the attest engagement requirements under this section shall cause the reports required under this section to be submitted to EPA by May 31 of the year following the compliance year.

(2) For the 2007 compliance year only, the attest engagement required under paragraph (a) of this section may be submitted to EPA with the attest

engagement for the 2008 compliance year.

**§ 80.1165  What are the additional requirements under this subpart for a foreign small refiner?**

(a) *Definitions.* The following definitions apply for this subpart:

(1) *Foreign refinery* is a refinery that is located outside the United States, the Commonwealth of Puerto Rico, the U.S. Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Mariana Islands (collectively referred to in this section as "the United States").

(2) *Foreign refiner* is a person that meets the definition of refiner under § 80.2(i) for a foreign refinery.

(3) *RFS–FRGAS* is gasoline produced at a foreign refinery that has received a small refinery exemption under § 80.1141 or a small refiner exemption under § 80.1142 that is imported into the United States.

(4) *Non-RFS–FRGAS* is one of the following:

(i) Gasoline produced at a foreign refinery that has received a small refinery exemption under § 80.1141 or a small refiner exemption under § 80.1142 that is not imported into the United States.

(ii) Gasoline produced at a foreign refinery that has not received a small refinery exemption under § 80.1141 or small refiner exemption under § 80.1142.

(5) A foreign small refiner is a foreign refiner that has received a small refinery exemption under § 80.1141 for one or more of its refineries or a small refiner exemption under § 80.1142.

(b) *General requirements for RFS– FRGAS foreign small refineries and small refiners.*

(1) A foreign small refiner must designate, at the time of production, each batch of gasoline produced at the foreign refinery that is exported for use in the United States as RFS–FRGAS; and

(2) Meet all requirements that apply to refiners who have received a small refinery or small refiner exemption under this subpart.

(c) *Designation, foreign refiner certification, and product transfer documents.* (1) Any foreign small refiner must designate each batch of RFS– FRGAS as such at the time the gasoline is produced.

(2) On each occasion when RFS– FRGAS is loaded onto a vessel or other transportation mode for transport to the United States, the foreign refiner shall prepare a certification for each batch of RFS–FRGAS that meets all the following requirements:

(i) The certification shall include the report of the independent third party

under paragraph (d) of this section, and all the following additional information:

(A) The name and EPA registration number of the refinery that produced the RFS–FRGAS.

(B) [Reserved]

(ii) The identification of the gasoline as RFS–FRGAS.

(iii) The volume of RFS–FRGAS being transported, in gallons.

(3) On each occasion when any person transfers custody or title to any RFS–FRGAS prior to its being imported into the United States, it must include all the following information as part of the product transfer document information:

(i) Designation of the gasoline as RFS–FRGAS.

(ii) The certification required under paragraph (c)(2) of this section.

(d) *Load port independent testing and refinery identification.* (1) On each occasion that RFS–FRGAS is loaded onto a vessel for transport to the United States the foreign small refiner shall have an independent third party do all the following:

(i) Inspect the vessel prior to loading and determine the volume of any tank bottoms.

(ii) Determine the volume of RFS–FRGAS loaded onto the vessel (exclusive of any tank bottoms before loading).

(iii) Obtain the EPA-assigned registration number of the foreign refinery.

(iv) Determine the name and country of registration of the vessel used to transport the RFS–FRGAS to the United States.

(v) Determine the date and time the vessel departs the port serving the foreign refinery.

(vi) Review original documents that reflect movement and storage of the RFS–FRGAS from the foreign refinery to the load port, and from this review determine:

(A) The refinery at which the RFS–FRGAS was produced; and

(B) That the RFS–FRGAS remained segregated from Non-RFS–FRGAS and other RFS–FRGAS produced at a different refinery.

(2) The independent third party shall submit a report to:

(i) The foreign small refiner containing the information required under paragraph (d)(1) of this section, to accompany the product transfer documents for the vessel; and

(ii) The Administrator containing the information required under paragraph (d)(1) of this section, within thirty days following the date of the independent third party's inspection. This report shall include a description of the

method used to determine the identity of the refinery at which the gasoline was produced, assurance that the gasoline remained segregated as specified in paragraph (j)(1) of this section, and a description of the gasoline's movement and storage between production at the source refinery and vessel loading.

(3) The independent third party must:

(i) Be approved in advance by EPA, based on a demonstration of ability to perform the procedures required in this paragraph (d);

(ii) Be independent under the criteria specified in § 80.65(f)(2)(iii); and

(iii) Sign a commitment that contains the provisions specified in paragraph (f) of this section with regard to activities, facilities, and documents relevant to compliance with the requirements of this paragraph (d).

(e) *Comparison of load port and port of entry testing.* (1)(i) Any small foreign small refiner and any United States importer of RFS–FRGAS shall compare the results from the load port testing under paragraph (d) of this section, with the port of entry testing as reported under paragraph (k) of this section, for the volume of gasoline, except as specified in paragraph (e)(1)(ii) of this section.

(ii) Where a vessel transporting RFS–FRGAS off loads this gasoline at more than one United States port of entry, the requirements of paragraph (e)(1)(i) of this section do not apply at subsequent ports of entry if the United States importer obtains a certification from the vessel owner that the requirements of paragraph (e)(1)(i) of this section were met and that the vessel has not loaded any gasoline or blendstock between the first United States port of entry and the subsequent port of entry.

(2) If the temperature-corrected volumes determined at the port of entry and at the load port differ by more than one percent, the United States importer and the foreign small refiner shall not treat the gasoline as RFS–FRGAS and the importer shall include the volume of gasoline in the importer's RFS compliance calculations.

(f) *Foreign refiner commitments.* Any small foreign small refiner shall commit to and comply with the provisions contained in this paragraph (f) as a condition to being approved for a small refinery or small refiner exemption under this subpart.

(1) Any United States Environmental Protection Agency inspector or auditor must be given full, complete and immediate access to conduct inspections and audits of the foreign refinery.

(i) Inspections and audits may be either announced in advance by EPA, or unannounced.

(ii) Access will be provided to any location where:

(A) Gasoline is produced;

(B) Documents related to refinery operations are kept; and

(C) RFS–FRGAS is stored or transported between the foreign refinery and the United States, including storage tanks, vessels and pipelines.

(iii) Inspections and audits may be by EPA employees or contractors to EPA.

(iv) Any documents requested that are related to matters covered by inspections and audits must be provided to an EPA inspector or auditor on request.

(v) Inspections and audits by EPA may include review and copying of any documents related to all the following:

(A) The volume of RFS–FRGAS.

(B) The proper classification of gasoline as being RFS–FRGAS or as not being RFS–FRGAS.

(C) Transfers of title or custody to RFS–FRGAS.

(D) Testing of RFS–FRGAS.

(E) Work performed and reports prepared by independent third parties and by independent auditors under the requirements of this section, including work papers.

(vi) Inspections and audits by EPA may include taking interviewing employees.

(vii) Any employee of the foreign refiner must be made available for interview by the EPA inspector or auditor, on request, within a reasonable time period.

(viii) English language translations of any documents must be provided to an EPA inspector or auditor, on request, within 10 working days.

(ix) English language interpreters must be provided to accompany EPA inspectors and auditors, on request.

(2) An agent for service of process located in the District of Columbia shall be named, and service on this agent constitutes service on the foreign refiner or any employee of the foreign refiner for any action by EPA or otherwise by the United States related to the requirements of this subpart.

(3) The forum for any civil or criminal enforcement action related to the provisions of this section for violations of the Clean Air Act or regulations promulgated thereunder shall be governed by the Clean Air Act, including the EPA administrative forum where allowed under the Clean Air Act.

(4) United States substantive and procedural laws shall apply to any civil or criminal enforcement action against the foreign refiner or any employee of

the foreign refiner related to the provisions of this section.

(5) Submitting an application for a small refinery or small refiner exemption, or producing and exporting gasoline under such exemption, and all other actions to comply with the requirements of this subpart relating to such exemption constitute actions or activities covered by and within the meaning of the provisions of 28 U.S.C. 1605(a)(2), but solely with respect to actions instituted against the foreign refiner, its agents and employees in any court or other tribunal in the United States for conduct that violates the requirements applicable to the foreign refiner under this subpart, including conduct that violates the False Statements Accountability Act of 1996 (18 U.S.C. 1001) and section 113(c)(2) of the Clean Air Act (42 U.S.C. 7413).

(6) The foreign refiner, or its agents or employees, will not seek to detain or to impose civil or criminal remedies against EPA inspectors or auditors, whether EPA employees or EPA contractors, for actions performed within the scope of EPA employment related to the provisions of this section.

(7) The commitment required by this paragraph (f) shall be signed by the owner or president of the foreign refiner business.

(8) In any case where RFS–FRGAS produced at a foreign refinery is stored or transported by another company between the refinery and the vessel that transports the RFS–FRGAS to the United States, the foreign refiner shall obtain from each such other company a commitment that meets the requirements specified in paragraphs (f)(1) through (f)(7) of this section, and these commitments shall be included in the foreign refiner's application for a small refinery or small refiner exemption under this subpart.

(g) *Sovereign immunity.* By submitting an application for a small refinery or small refiner exemption under this subpart, or by producing and exporting gasoline to the United States under such exemption, the foreign refiner, and its agents and employees, without exception, become subject to the full operation of the administrative and judicial enforcement powers and provisions of the United States without limitation based on sovereign immunity, with respect to actions instituted against the foreign refiner, its agents and employees in any court or other tribunal in the United States for conduct that violates the requirements applicable to the foreign refiner under this subpart, including conduct that violates the False Statements Accountability Act of 1996 (18 U.S.C. 1001) and section

113(c)(2) of the Clean Air Act (42 U.S.C. 7413).

(h) *Bond posting.* Any foreign refiner shall meet the requirements of this paragraph (h) as a condition to approval of a small foreign refinery or small foreign refiner exemption under this subpart.

(1) The foreign refiner shall post a bond of the amount calculated using the following equation:

Bond = G * $0.01

Where:

Bond = amount of the bond in United States dollars.
G = the largest volume of gasoline produced at the foreign refinery and exported to the United States, in gallons, during a single calendar year among the most recent of the following calendar years, up to a maximum of five calendar years: The calendar year immediately preceding the date the refinery's application is submitted, the calendar year the application is submitted, and each succeeding calendar year.

(2) Bonds shall be posted by:
(i) Paying the amount of the bond to the Treasurer of the United States;
(ii) Obtaining a bond in the proper amount from a third party surety agent that is payable to satisfy United States administrative or judicial judgments against the foreign refiner, provided EPA agrees in advance as to the third party and the nature of the surety agreement; or
(iii) An alternative commitment that results in assets of an appropriate liquidity and value being readily available to the United States, provided EPA agrees in advance as to the alternative commitment.

(3) Bonds posted under this paragraph (h) shall:
(i) Be used to satisfy any judicial judgment that results from an administrative or judicial enforcement action for conduct in violation of this subpart, including where such conduct violates the False Statements Accountability Act of 1996 (18 U.S.C. 1001) and section 113(c)(2) of the Clean Air Act (42 U.S.C. 7413);
(ii) Be provided by a corporate surety that is listed in the United States Department of Treasury Circular 570 "Companies Holding Certificates of Authority as Acceptable Sureties on Federal Bonds"; and
(iii) Include a commitment that the bond will remain in effect for at least five years following the end of latest annual reporting period that the foreign refiner produces gasoline pursuant to the requirements of this subpart.

(4) On any occasion a foreign refiner bond is used to satisfy any judgment, the foreign refiner shall increase the

bond to cover the amount used within 90 days of the date the bond is used.

(5) If the bond amount for a foreign refiner increases, the foreign refiner shall increase the bond to cover the shortfall within 90 days of the date the bond amount changes. If the bond amount decreases, the foreign refiner may reduce the amount of the bond beginning 90 days after the date the bond amount changes.

(i) *English language reports.* Any document submitted to EPA by a foreign refiner shall be in English language, or shall include an English language translation.

(j) *Prohibitions.* (1) No person may combine RFS–FRGAS with any Non-RFS–FRGAS, and no person may combine RFS–FRGAS with any RFS–FRGAS produced at a different refinery, until the importer has met all the requirements of paragraph (k) of this section.

(2) No foreign refiner or other person may cause another person to commit an action prohibited in paragraph (j)(1) of this section, or that otherwise violates the requirements of this section.

(k) *United States importer requirements.* Any United States importer of RFS–FRGAS shall meet the following requirements:

(1) Each batch of imported RFS–FRGAS shall be classified by the importer as being RFS–FRGAS.

(2) Gasoline shall be classified as RFS–FRGAS according to the designation by the foreign refiner if this designation is supported by product transfer documents prepared by the foreign refiner as required in paragraph (c) of this section. Additionally, the importer shall comply with all requirements of this subpart applicable to importers.

(3) For each gasoline batch classified as RFS–FRGAS, any United States importer shall have an independent third party do all the following:

(i) Determine the volume of gasoline in the vessel.

(ii) Use the foreign refiner's RFS–FRGAS certification to determine the name and EPA-assigned registration number of the foreign refinery that produced the RFS–FRGAS.

(iii) Determine the name and country of registration of the vessel used to transport the RFS–FRGAS to the United States.

(iv) Determine the date and time the vessel arrives at the United States port of entry.

(4) Any importer shall submit reports within 30 days following the date any vessel transporting RFS–FRGAS arrives at the United States port of entry to:

(i) The Administrator containing the information determined under paragraph (k)(3) of this section; and

(ii) The foreign refiner containing the information determined under paragraph (k)(3)(i) of this section, and including identification of the port at which the product was off loaded.

(5) Any United States importer shall meet all other requirements of this subpart for any imported gasoline that is not classified as RFS–FRGAS under paragraph (k)(2) of this section.

(l) *Truck imports of RFS–FRGAS produced at a foreign refinery.* (1) Any refiner whose RFS–FRGAS is transported into the United States by truck may petition EPA to use alternative procedures to meet all the following requirements:

(i) Certification under paragraph (c)(2) of this section.

(ii) Load port and port of entry testing requirements under paragraphs (d) and (e) of this section.

(iii) Importer testing requirements under paragraph (k)(3) of this section.

(2) These alternative procedures must ensure RFS–FRGAS remains segregated from Non-RFS–FRGAS until it is imported into the United States. The petition will be evaluated based on whether it adequately addresses the following:

(i) Provisions for monitoring pipeline shipments, if applicable, from the refinery, that ensure segregation of RFS–FRGAS from that refinery from all other gasoline.

(ii) Contracts with any terminals and/or pipelines that receive and/or transport RFS–FRGAS that prohibit the commingling of RFS–FRGAS with Non-RFS–FRGAS or RFS–FRGAS from other foreign refineries.

(iii) Attest procedures to be conducted annually by an independent third party that review loading records and import documents based on volume reconciliation, or other criteria, to confirm that all RFS–FRGAS remains segregated throughout the distribution system.

(3) The petition described in this section must be submitted to EPA along with the application for a small refinery or small refiner exemption under this subpart.

(m) *Additional attest requirements for importers of RFS–FRGAS.* The following additional procedures shall be carried out by any importer of RFS–FRGAS as part of the attest engagement required for importers under this subpart K.

(1) Obtain listings of all tenders of RFS–FRGAS. Agree the total volume of tenders from the listings to the gasoline inventory reconciliation analysis required in § 80.133(b), and to the

volumes determined by the third party under paragraph (d) of this section.

(2) For each tender under paragraph (m)(1) of this section, where the gasoline is loaded onto a marine vessel, report as a finding the name and country of registration of each vessel, and the volumes of RFS–FRGAS loaded onto each vessel.

(3) Select a sample from the list of vessels identified in paragraph (m)(2) of this section used to transport RFS–FRGAS, in accordance with the guidelines in § 80.127, and for each vessel selected perform the following:

(i) Obtain the report of the independent third party, under paragraph (d) of this section.

(A) Agree the information in these reports with regard to vessel identification and gasoline volume.

(B) Identify, and report as a finding, each occasion the load port and port of entry volume results differ by more than the amount allowed in paragraph (e)(2) of this section, and determine whether all of the requirements of paragraph (e)(2) of this section have been met.

(ii) Obtain the documents used by the independent third party to determine transportation and storage of the RFS–FRGAS from the refinery to the load port, under paragraph (d) of this section. Obtain tank activity records for any storage tank where the RFS–FRGAS is stored, and pipeline activity records for any pipeline used to transport the RFS–FRGAS prior to being loaded onto the vessel. Use these records to determine whether the RFS–FRGAS was produced at the refinery that is the subject of the attest engagement, and whether the RFS–FRGAS was mixed with any Non-RFS–FRGAS or any RFS–FRGAS produced at a different refinery.

(4) Select a sample from the list of vessels identified in paragraph (m)(2) of this section used to transport RFS–FRGAS, in accordance with the guidelines in § 80.127, and for each vessel selected perform the following:

(i) Obtain a commercial document of general circulation that lists vessel arrivals and departures, and that includes the port and date of departure of the vessel, and the port of entry and date of arrival of the vessel.

(ii) Agree the vessel's departure and arrival locations and dates from the independent third party and United States importer reports to the information contained in the commercial document.

(5) Obtain separate listings of all tenders of RFS–FRGAS, and perform the following:

(i) Agree the volume of tenders from the listings to the gasoline inventory reconciliation analysis in § 80.133(b).

(ii) Obtain a separate listing of the tenders under this paragraph (m)(5) where the gasoline is loaded onto a marine vessel. Select a sample from this listing in accordance with the guidelines in § 80.127, and obtain a commercial document of general circulation that lists vessel arrivals and departures, and that includes the port and date of departure and the ports and dates where the gasoline was off loaded for the selected vessels. Determine and report as a finding the country where the gasoline was off loaded for each vessel selected.

(6) In order to complete the requirements of this paragraph (m), an auditor shall:

(i) Be independent of the foreign refiner or importer;

(ii) Be licensed as a Certified Public Accountant in the United States and a citizen of the United States, or be approved in advance by EPA based on a demonstration of ability to perform the procedures required in §§ 80.125 through 80.127, 80.130, 80.1164, and this paragraph (m); and

(iii) Sign a commitment that contains the provisions specified in paragraph (f) of this section with regard to activities and documents relevant to compliance with the requirements of §§ 80.125 through 80.127, 80.130, 80.1164, and this paragraph (m).

(n) *Withdrawal or suspension of foreign refiner status.* EPA may withdraw or suspend a foreign refiner's small refinery or small refiner exemption where:

(1) A foreign refiner fails to meet any requirement of this section;

(2) A foreign government fails to allow EPA inspections as provided in paragraph (f)(1) of this section;

(3) A foreign refiner asserts a claim of, or a right to claim, sovereign immunity in an action to enforce the requirements in this subpart; or

(4) A foreign refiner fails to pay a civil or criminal penalty that is not satisfied using the foreign refiner bond specified in paragraph (h) of this section.

(o) *Additional requirements for applications, reports and certificates.* Any application for a small refinery or small refiner exemption, alternative procedures under paragraph (l) of this section, any report, certification, or other submission required under this section shall be:

(1) Submitted in accordance with procedures specified by the Administrator, including use of any forms that may be specified by the Administrator.

(2) Be signed by the president or owner of the foreign refiner company, or by that person's immediate designee,

and shall contain the following declaration:

I hereby certify: (1) That I have actual authority to sign on behalf of and to bind [NAME OF FOREIGN REFINER] with regard to all statements contained herein; (2) that I am aware that the information contained herein is being Certified, or submitted to the United States Environmental Protection Agency, under the requirements of 40 CFR part 80, subpart K, and that the information is material for determining compliance under these regulations; and (3) that I have read and understand the information being Certified or submitted, and this information is true, complete and correct to the best of my knowledge and belief after I have taken reasonable and appropriate steps to verify the accuracy thereof. I affirm that I have read and understand the provisions of 40 CFR part 80, subpart K, including 40 CFR 80.1165 apply to [NAME OF FOREIGN REFINER]. Pursuant to Clean Air Act section 113(c) and 18 U.S.C. 1001, the penalty for furnishing false, incomplete or misleading information in this certification or submission is a fine of up to $10,000 U.S., and/or imprisonment for up to five years.''

### § 80.1166 What are the additional requirements under this subpart for a foreign producer of cellulosic biomass ethanol or waste derived ethanol?

(a) *Foreign producer of cellulosic biomass ethanol or waste derived ethanol.* For purposes of this subpart, a foreign producer of cellulosic biomass ethanol or waste derived ethanol is a person located outside the United States, the Commonwealth of Puerto Rico, the Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Mariana Islands (collectively referred to in this section as ''the United States'') that has been approved by EPA to assign RINs to cellulosic biomass ethanol or waste derived ethanol that the foreign producer produces and exports to the United States, hereinafter referred to as a ''foreign producer'' under this section.

(b) *General requirements.* (1) An approved foreign producer under this section must meet all requirements that apply to cellulosic biomass ethanol or waste derived ethanol producers under this subpart, except to the extent otherwise specified in paragraph (b)(2) of this section.

(2)(i) The independent third party that conducts the facility verification required under § 80.1155(a) must inspect the foreign producer's facility and submit a report to EPA which describes in detail the physical plant and its operation.

(ii) The independent third party that conducts the facility verification required under § 80.1155(a) must be a licensed Professional Engineer in chemical engineering field, but need not

be based in the United States. The independent third party must include documentation of its qualifications as a licensed Professional Engineer in the report required in paragraph (b)(2)(i) of this section.

(iii) The requirements of paragraphs (b)(2)(i) and (ii) of this section must be met before a foreign entity may be approved as a foreign producer under this subpart.

(c) *Designation, foreign producer certification, and product transfer documents.*

(1) Any approved foreign producer under this section must designate each batch of cellulosic biomass ethanol or waste derived ethanol as ''RFS–FRETH'' at the time the ethanol is produced.

(2) On each occasion when RFS–FRETH is loaded onto a vessel or other transportation mode for transport to the United States, the foreign producer shall prepare a certification for each batch of RFS–FRETH; the certification shall include the report of the independent third party under paragraph (d) of this section, and all the following additional information:

(i) The name and EPA registration number of the company that produced the RFS–FRETH.

(ii) The identification of the ethanol as RFS–FRETH.

(iii) The volume of RFS–FRETH being transported, in gallons.

(3) On each occasion when any person transfers custody or title to any RFS–FRETH prior to its being imported into the United States, it must include all the following information as part of the product transfer document information:

(i) Designation of the ethanol as RFS–FRETH.

(ii) The certification required under paragraph (c)(2) of this section.

(d) *Load port independent testing and refinery identification.* (1) On each occasion that RFS–FRETH is loaded onto a vessel for transport to the United States the foreign producer shall have an independent third party do all the following:

(i) Inspect the vessel prior to loading and determine the volume of any tank bottoms.

(ii) Determine the volume of RFS–FRETH loaded onto the vessel (exclusive of any tank bottoms before loading).

(iii) Obtain the EPA-assigned registration number of the foreign producer.

(iv) Determine the name and country of registration of the vessel used to transport the RFS–FRETH to the United States.

(v) Determine the date and time the vessel departs the port serving the foreign producer.

(vi) Review original documents that reflect movement and storage of the RFS–FRETH from the foreign producer to the load port, and from this review determine the following:

(A) The facility at which the RFS–FRETH was produced.

(B) That the RFS–FRETH remained segregated from Non-RFS–FRETH and other RFS–FRETH produced by a different foreign producer.

(2) The independent third party shall submit a report to the following:

(i) The foreign producer containing the information required under paragraph (d)(1) of this section, to accompany the product transfer documents for the vessel.

(ii) The Administrator containing the information required under paragraph (d)(1) of this section, within thirty days following the date of the independent third party's inspection. This report shall include a description of the method used to determine the identity of the foreign producer facility at which the ethanol was produced, assurance that the ethanol remained segregated as specified in paragraph (j)(1) of this section, and a description of the ethanol's movement and storage between production at the source facility and vessel loading.

(3) The independent third party must:

(i) Be approved in advance by EPA, based on a demonstration of ability to perform the procedures required in this paragraph (d);

(ii) Be independent under the criteria specified in § 80.65(e)(2)(iii); and

(iii) Sign a commitment that contains the provisions specified in paragraph (f) of this section with regard to activities, facilities and documents relevant to compliance with the requirements of this paragraph (d).

(e) *Comparison of load port and port of entry testing.* (1)(i) Any foreign producer and any United States importer of RFS–FRETH shall compare the results from the load port testing under paragraph (d) of this section, with the port of entry testing as reported under paragraph (k) of this section, for the volume of ethanol, except as specified in paragraph (e)(1)(ii) of this section.

(ii) Where a vessel transporting RFS–FRETH off loads the ethanol at more than one United States port of entry, the requirements of paragraph (e)(1)(i) of this section do not apply at subsequent ports of entry if the United States importer obtains a certification from the vessel owner that the requirements of paragraph (e)(1)(i) of this section were

met and that the vessel has not loaded any ethanol between the first United States port of entry and the subsequent port of entry.

(2)(i) If the temperature-corrected volumes determined at the port of entry and at the load port differ by more than one percent, the number of RINs associated with the ethanol shall be calculated based on the lesser of the two volumes in paragraph (e)(1)(i) of this section.

(ii) Where the port of entry volume is the lesser of the two volumes in paragraph (e)(1)(i) of this section, the importer shall calculate the difference between the number of RINs originally assigned by the foreign producer and the number of RINs calculated under § 80.1126 for the volume of ethanol as measured at the port of entry, and retire that amount of RINs in accordance with paragraph (k)(4) of this section.

(f) *Foreign producer commitments.* Any foreign producer shall commit to and comply with the provisions contained in this paragraph (f) as a condition to being approved as a foreign producer under this subpart.

(1) Any United States Environmental Protection Agency inspector or auditor must be given full, complete and immediate access to conduct inspections and audits of the foreign producer facility.

(i) Inspections and audits may be either announced in advance by EPA, or unannounced.

(ii) Access will be provided to any location where:

(A) Ethanol is produced;

(B) Documents related to ethanol producer operations are kept; and

(C) RFS–FRETH is stored or transported between the foreign producer and the United States, including storage tanks, vessels and pipelines.

(iii) Inspections and audits may be by EPA employees or contractors to EPA.

(iv) Any documents requested that are related to matters covered by inspections and audits must be provided to an EPA inspector or auditor on request.

(v) Inspections and audits by EPA may include review and copying of any documents related to the following:

(A) The volume of RFS–FRETH.

(B) The proper classification of gasoline as being RFS–FRETH;

(C) Transfers of title or custody to RFS–FRETH.

(D) Work performed and reports prepared by independent third parties and by independent auditors under the requirements of this section, including work papers.

(vi) Inspections and audits by EPA may include interviewing employees.

(vii) Any employee of the foreign producer must be made available for interview by the EPA inspector or auditor, on request, within a reasonable time period.

(viii) English language translations of any documents must be provided to an EPA inspector or auditor, on request, within 10 working days.

(ix) English language interpreters must be provided to accompany EPA inspectors and auditors, on request.

(2) An agent for service of process located in the District of Columbia shall be named, and service on this agent constitutes service on the foreign producer or any employee of the foreign producer for any action by EPA or otherwise by the United States related to the requirements of this subpart.

(3) The forum for any civil or criminal enforcement action related to the provisions of this section for violations of the Clean Air Act or regulations promulgated thereunder shall be governed by the Clean Air Act, including the EPA administrative forum where allowed under the Clean Air Act.

(4) United States substantive and procedural laws shall apply to any civil or criminal enforcement action against the foreign producer or any employee of the foreign producer related to the provisions of this section.

(5) Applying to be an approved foreign producer under this section, or producing or exporting ethanol under such approval, and all other actions to comply with the requirements of this subpart relating to such approval constitute actions or activities covered by and within the meaning of the provisions of 28 U.S.C. 1605(a)(2), but solely with respect to actions instituted against the foreign producer, its agents and employees in any court or other tribunal in the United States for conduct that violates the requirements applicable to the foreign producer under this subpart, including conduct that violates the False Statements Accountability Act of 1996 (18 U.S.C. 1001) and section 113(c)(2) of the Clean Air Act (42 U.S.C. 7413).

(6) The foreign producer, or its agents or employees, will not seek to detain or to impose civil or criminal remedies against EPA inspectors or auditors, whether EPA employees or EPA contractors, for actions performed within the scope of EPA employment related to the provisions of this section.

(7) The commitment required by this paragraph (f) shall be signed by the owner or president of the foreign producer company.

(8) In any case where RFS–FRETH produced at a foreign producer facility is stored or transported by another

company between the refinery and the vessel that transports the RFS–FRETH to the United States, the foreign producer shall obtain from each such other company a commitment that meets the requirements specified in paragraphs (f)(1) through (7) of this section, and these commitments shall be included in the foreign producer's application to be an approved foreign producer under this subpart.

(g) *Sovereign immunity.* By submitting an application to be an approved foreign producer under this subpart, or by producing and exporting ethanol to the United States under such approval, the foreign producer, and its agents and employees, without exception, become subject to the full operation of the administrative and judicial enforcement powers and provisions of the United States without limitation based on sovereign immunity, with respect to actions instituted against the foreign producer, its agents and employees in any court or other tribunal in the United States for conduct that violates the requirements applicable to the foreign producer under this subpart, including conduct that violates the False Statements Accountability Act of 1996 (18 U.S.C. 1001) and section 113(c)(2) of the Clean Air Act (42 U.S.C. 7413).

(h) *Bond posting.* Any foreign producer shall meet the requirements of this paragraph (h) as a condition to approval as a foreign producer under this subpart.

(1) The foreign producer shall post a bond of the amount calculated using the following equation:

Bond = G * $ 0.01

Where:

Bond = amount of the bond in U.S. dollars.
G = The largest volume of ethanol produced at the foreign producer's facility and exported to the United States, in gallons, during a single calendar year among the most recent of the following calendar years, up to a maximum of five calendar years: The calendar year immediately preceding the date the refinery's application is submitted, the calendar year the application is submitted, and each succeeding calendar year.

(2) Bonds shall be posted by any of the following methods:

(i) Paying the amount of the bond to the Treasurer of the United States.

(ii) Obtaining a bond in the proper amount from a third party surety agent that is payable to satisfy United States administrative or judicial judgments against the foreign producer, provided EPA agrees in advance as to the third party and the nature of the surety agreement.

(iii) An alternative commitment that results in assets of an appropriate liquidity and value being readily available to the United States provided EPA agrees in advance as to the alternative commitment.

(3) Bonds posted under this paragraph (h) shall:

(i) Be used to satisfy any judicial judgment that results from an administrative or judicial enforcement action for conduct in violation of this subpart, including where such conduct violates the False Statements Accountability Act of 1996 (18 U.S.C. 1001) and section 113(c)(2) of the Clean Air Act (42 U.S.C. 7413);

(ii) Be provided by a corporate surety that is listed in the United States Department of Treasury Circular 570 ''Companies Holding Certificates of Authority as Acceptable Sureties on Federal Bonds''; and

(iii) Include a commitment that the bond will remain in effect for at least five years following the end of the latest annual reporting period that the foreign producer produces ethanol pursuant to the requirements of this subpart.

(4) On any occasion a foreign producer bond is used to satisfy any judgment, the foreign producer shall increase the bond to cover the amount used within 90 days of the date the bond is used.

(5) If the bond amount for a foreign producer increases, the foreign producer shall increase the bond to cover the shortfall within 90 days of the date the bond amount changes. If the bond amount decreases, the foreign refiner may reduce the amount of the bond beginning 90 days after the date the bond amount changes.

(i) *English language reports.* Any document submitted to EPA by a foreign producer shall be in English language, or shall include an English language translation.

(j) *Prohibitions.* (1) No person may combine RFS–FRETH with any Non-RFS–FRETH, and no person may combine RFS–FRETH with any RFS–FRETH produced at a different refinery, until the importer has met all the requirements of paragraph (k) of this section.

(2) No foreign producer or other person may cause another person to commit an action prohibited in paragraph (j)(1) of this section, or that otherwise violates the requirements of this section.

(k) *Requirements for United States importers of RFS–FRETH.* Any United States importer shall meet the following requirements:

(1) Each batch of imported RFS–FRETH shall be classified by the importer as being RFS–FRETH.

(2) Ethanol shall be classified as RFS–FRETH according to the designation by the foreign producer if this designation is supported by product transfer documents prepared by the foreign producer as required in paragraph (c) of this section.

(3) For each ethanol batch classified as RFS–FRETH, any United States importer shall have an independent third party do all the following:

(i) Determine the volume of gasoline in the vessel.

(ii) Use the foreign producer's RFS–FRETH certification to determine the name and EPA-assigned registration number of the foreign producer that produced the RFS–FRETH.

(iii) Determine the name and country of registration of the vessel used to transport the RFS–FRETH to the United States.

(iv) Determine the date and time the vessel arrives at the United States port of entry.

(4) Where the importer is required to retire RINs under paragraph (e)(2) of this section, the importer must report the retired RINs in the applicable reports under § 80.1152.

(5) Any importer shall submit reports within 30 days following the date any vessel transporting RFS–FRETH arrives at the United States port of entry to the following:

(i) The Administrator containing the information determined under paragraph (k)(3) of this section.

(ii) The foreign producer containing the information determined under paragraph (k)(3)(i) of this section, and including identification of the port at which the product was off loaded, and any RINs retired under paragraph (e)(2) of this section.

(6) Any United States importer shall meet all other requirements of this subpart for any imported ethanol or other renewable fuel that is not classified as RFS–FRETH under paragraph (k)(2) of this section.

(l) *Truck imports of RFS–FRETH produced by a foreign producer.* (1) Any foreign producer whose RFS–FRETH is transported into the United States by truck may petition EPA to use alternative procedures to meet all the following requirements:

(i) Certification under paragraph (c)(2) of this section.

(ii) Load port and port of entry testing under paragraphs (d) and (e) of this section.

(iii) Importer testing under paragraph (k)(3) of this section.

(2) These alternative procedures must ensure RFS–FRETH remains segregated

from Non-RFS–FRETH until it is imported into the United States. The petition will be evaluated based on whether it adequately addresses the following:

(i) Contracts with any facilities that receive and/or transport RFS–FRETH that prohibit the commingling of RFS–FRETH with Non-RFS–FRETH or RFS–FRETH from other foreign producers.

(ii) Attest procedures to be conducted annually by an independent third party that review loading records and import documents based on volume reconciliation to confirm that all RFS–FRETH remains segregated.

(3) The petition described in this section must be submitted to EPA along with the application for approval as a foreign producer under this subpart.

(m) *Additional attest requirements for producers of RFS–FRETH.* The following additional procedures shall be carried out by any producer of RFS–FRETH as part of the attest engagement required for renewable fuel producers under this subpart K.

(1) Obtain listings of all tenders of RFS–FRETH. Agree the total volume of tenders from the listings to the volumes determined by the third party under paragraph (d) of this section.

(2) For each tender under paragraph (m)(1) of this section, where the ethanol is loaded onto a marine vessel, report as a finding the name and country of registration of each vessel, and the volumes of RFS–FRETH loaded onto each vessel.

(3) Select a sample from the list of vessels identified in paragraph (m)(2) of this section used to transport RFS–FRETH, in accordance with the guidelines in § 80.127, and for each vessel selected perform the following:

(i) Obtain the report of the independent third party, under paragraph (d) of this section, and of the United States importer under paragraph (k) of this section.

(A) Agree the information in these reports with regard to vessel identification and ethanol volume.

(B) Identify, and report as a finding, each occasion the load port and port of entry volume results differ by more than the amount allowed in paragraph (e) of this section, and determine whether the importer retired the appropriate amount of RINs as required under paragraph (e)(2) of this section, and submitted the applicable reports under § 80.1152 in accordance with paragraph (k)(4) of this section.

(ii) Obtain the documents used by the independent third party to determine transportation and storage of the RFS–FRETH from the foreign producer's facility to the load port, under

paragraph (d) of this section. Obtain tank activity records for any storage tank where the RFS–FRETH is stored, and activity records for any mode of transportation used to transport the RFS–FRGAS prior to being loaded onto the vessel. Use these records to determine whether the RFS–FRETH was produced at the foreign producer's facility that is the subject of the attest engagement, and whether the RFS–FRETH was mixed with any Non-RFS–FRETH or any RFS–FRETH produced at a different facility.

(4) Select a sample from the list of vessels identified in paragraph (m)(2) of this section used to transport RFS–FRETH, in accordance with the guidelines in § 80.127, and for each vessel selected perform the following:

(i) Obtain a commercial document of general circulation that lists vessel arrivals and departures, and that includes the port and date of departure of the vessel, and the port of entry and date of arrival of the vessel.

(ii) Agree the vessel's departure and arrival locations and dates from the independent third party and United States importer reports to the information contained in the commercial document.

(5) Obtain a separate listing of the tenders under this paragraph (m)(5) where the gasoline is loaded onto a marine vessel. Select a sample from this listing in accordance with the guidelines in § 80.127, and obtain a commercial document of general circulation that lists vessel arrivals and departures, and that includes the port and date of departure and the ports and dates where the ethanol was off loaded for the selected vessels. Determine and report as a finding the country where the ethanol was off loaded for each vessel selected.

(6) In order to complete the requirements of this paragraph (m) an auditor shall:

(i) Be independent of the foreign producer;

(ii) Be licensed as a Certified Public Accountant in the United States and a citizen of the United States, or be approved in advance by EPA based on a demonstration of ability to perform the procedures required in §§ 80.125 through 80.127, 80.130, 80.1164, and this paragraph (m); and

(iii) Sign a commitment that contains the provisions specified in paragraph (f) of this section with regard to activities and documents relevant to compliance with the requirements of §§ 80.125 through 80.127, 80.130, 80.1164, and this paragraph (m).

(n) *Withdrawal or suspension of foreign producer approval.* EPA may

withdraw or suspend a foreign producer's approval where any of the following occur:

(1) A foreign producer fails to meet any requirement of this section.

(2) A foreign government fails to allow EPA inspections as provided in paragraph (f)(1) of this section.

(3) A foreign producer asserts a claim of, or a right to claim, sovereign immunity in an action to enforce the requirements in this subpart.

(4) A foreign producer fails to pay a civil or criminal penalty that is not satisfied using the foreign producer bond specified in paragraph (g) of this section.

(o) *Additional requirements for applications, reports and certificates.* Any application for approval as a foreign producer, alternative procedures under paragraph (l) of this section, any report, certification, or other submission required under this section shall be:

(1) Submitted in accordance with procedures specified by the Administrator, including use of any forms that may be specified by the Administrator.

(2) Signed by the president or owner of the foreign producer company, or by that person's immediate designee, and shall contain the following declaration:

I hereby certify: (1) That I have actual authority to sign on behalf of and to bind [insert name of foreign producer] with regard to all statements contained herein; (2) that I am aware that the information contained herein is being Certified, or submitted to the United States Environmental Protection Agency, under the requirements of 40 CFR part 80, subpart K, and that the information is material for determining compliance under these regulations; and (3) that I have read and understand the information being Certified or submitted, and this information is true, complete and correct to the best of my knowledge and belief after I have taken reasonable and appropriate steps to verify the accuracy thereof. I affirm that I have read and understand the provisions of 40 CFR part 80, subpart K, including 40 CFR 80.1165 apply to [insert name of foreign producer]. Pursuant to Clean Air Act section 113(c) and 18 U.S.C. 1001, the penalty for furnishing false, incomplete or misleading information in this certification or submission is a fine of up to $10,000 U.S., and/or imprisonment for up to five years.

### § 80.1167 What are the additional requirements under this subpart for a foreign RIN owner?

(a) *Foreign RIN owner.* For purposes of this subpart, a foreign RIN owner is a person located outside the United States, the Commonwealth of Puerto Rico, the Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Mariana Islands (collectively referred to in this

section as ''the United States'') that has been approved by EPA to own RINs.

(b) *General Requirement.* An approved foreign RIN owner must meet all requirements that apply to persons who own RINs under this subpart.

(c) *Foreign RIN owner commitments.* Any person shall commit to and comply with the provisions contained in this paragraph (c) as a condition to being approved as a foreign RIN owner under this subpart.

(1) Any United States Environmental Protection Agency inspector or auditor must be given full, complete and immediate access to conduct inspections and audits of the foreign RIN owner's place of business.

(i) Inspections and audits may be either announced in advance by EPA, or unannounced; and

(ii) Access will be provided to any location where documents related to RINs the foreign RIN owner has obtained, sold, transferred or held are kept.

(iii) Inspections and audits may be by EPA employees or contractors to EPA.

(iv) Any documents requested that are related to matters covered by inspections and audits must be provided to an EPA inspector or auditor on request.

(v) Inspections and audits by EPA may include review and copying of any documents related to the following:

(A) Transfers of title to RINs.

(B) Work performed and reports prepared by independent auditors under the requirements of this section, including work papers.

(vi) Inspections and audits by EPA may include interviewing employees.

(vii) Any employee of the foreign RIN owner must be made available for interview by the EPA inspector or auditor, on request, within a reasonable time period.

(viii) English language translations of any documents must be provided to an EPA inspector or auditor, on request, within 10 working days.

(ix) English language interpreters must be provided to accompany EPA inspectors and auditors, on request.

(2) An agent for service of process located in the District of Columbia shall be named, and service on this agent constitutes service on the foreign RIN owner or any employee of the foreign RIN owner for any action by EPA or otherwise by the United States related to the requirements of this subpart.

(3) The forum for any civil or criminal enforcement action related to the provisions of this section for violations of the Clean Air Act or regulations promulgated thereunder shall be governed by the Clean Air Act,

including the EPA administrative forum where allowed under the Clean Air Act.

(4) United States substantive and procedural laws shall apply to any civil or criminal enforcement action against the foreign RIN owner or any employee of the foreign RIN owner related to the provisions of this section.

(5) Submitting an application to be a foreign RIN owner, and all other actions to comply with the requirements of this subpart constitute actions or activities covered by and within the meaning of the provisions of 28 U.S.C. 1605(a)(2), but solely with respect to actions instituted against the foreign RIN owner, its agents and employees in any court or other tribunal in the United States for conduct that violates the requirements applicable to the foreign RIN owner under this subpart, including conduct that violates the False Statements Accountability Act of 1996 (18 U.S.C. 1001) and section 113(c)(2) of the Clean Air Act (42 U.S.C. 7413).

(6) The foreign RIN owner, or its agents or employees, will not seek to detain or to impose civil or criminal remedies against EPA inspectors or auditors, whether EPA employees or EPA contractors, for actions performed within the scope of EPA employment related to the provisions of this section.

(7) The commitment required by this paragraph (c) shall be signed by the owner or president of the foreign RIN owner business.

(d) *Sovereign immunity.* By submitting an application to be a foreign RIN owner under this subpart, the foreign entity, and its agents and employees, without exception, become subject to the full operation of the administrative and judicial enforcement powers and provisions of the United States without limitation based on sovereign immunity, with respect to actions instituted against the foreign RIN owner, its agents and employees in any court or other tribunal in the United States for conduct that violates the requirements applicable to the foreign RIN owner under this subpart, including conduct that violates the False Statements Accountability Act of 1996 (18 U.S.C. 1001) and section 113(c)(2) of the Clean Air Act (42 U.S.C. 7413).

(e) *Bond posting.* Any foreign entity shall meet the requirements of this paragraph (d) as a condition to approval as a foreign RIN owner under this subpart.

(1) The foreign entity shall post a bond of the amount calculated using the following equation:

Bond = G * $0.01

Where:

Bond = amount of the bond in U.S. dollars.

G = The total of the number of gallon-RINs the foreign entity expects to sell or transfer during the first calendar year that the foreign entity is a RIN owner, plus the number of gallon-RINs the foreign entity expects to sell or transfer during the next four calendar years. After the first calendar year, the bond amount shall be based on the actual number of gallon-RINs sold or transferred during the current calendar year and the number held at the conclusion of the current averaging year, plus the number of gallon-RINs sold or transferred during the four most recent calendar years preceding the current calendar year. For any year for which there were fewer than four preceding years in which the foreign entity sold or transferred RINs, the bond shall be based on the total of the number of gallon-RINs sold or transferred during the current calendar year and the number held at the end of the current calendar year, plus the number of gallon-RINs sold or transferred during any calendar year preceding the current calendar year, plus the number of gallon-RINs expected to be sold or transferred during subsequent calendar years, the total number of years not to exceed four calendar years in addition to the current calendar year.

(2) Bonds shall be posted by doing any of the following:

(i) Paying the amount of the bond to the Treasurer of the United States.

(ii) Obtaining a bond in the proper amount from a third party surety agent that is payable to satisfy United States administrative or judicial judgments against the foreign RIN owner, provided EPA agrees in advance as to the third party and the nature of the surety agreement.

(iii) An alternative commitment that results in assets of an appropriate liquidity and value being readily available to the United States, provided EPA agrees in advance as to the alternative commitment.

(3) Bonds posted under this paragraph (e) shall:

(i) Be used to satisfy any judicial judgment that results from an administrative or judicial enforcement action for conduct in violation of this subpart, including where such conduct violates the False Statements Accountability Act of 1996 (18 U.S.C. 1001) and section 113(c)(2) of the Clean Air Act (42 U.S.C. 7413);

(ii) Be provided by a corporate surety that is listed in the United States Department of Treasury Circular 570 "Companies Holding Certificates of Authority as Acceptable Sureties on Federal Bonds"; and

(iii) Include a commitment that the bond will remain in effect for at least five years following the end of latest reporting period in which the foreign

RIN owner obtains, sells, transfers or holds RINs.

(4) On any occasion a foreign RIN owner bond is used to satisfy any judgment, the foreign RIN owner shall increase the bond to cover the amount used within 90 days of the date the bond is used.

(f) *English language reports.* Any document submitted to EPA by a foreign RIN owner shall be in English language, or shall include an English language translation.

(g) *Prohibitions.* (1) A foreign RIN owner is prohibited from obtaining, selling, transferring or holding any RIN that is in excess of the number for which the bond requirements of this section have been satisfied.

(2) Any RIN that is sold, transferred or held that is in excess of the number for which the bond requirements of this section have been satisfied is an invalid RIN under § 80.1131.

(3) Any RIN that is obtained from a person located outside the United States that is not an approved foreign RIN owner under this section is an invalid RIN under § 80.1131.

(4) No foreign RIN owner or other person may cause another person to commit an action prohibited in this paragraph (g), or that otherwise violates the requirements of this section.

(h) *Additional attest requirements for foreign RIN owners.* The following additional requirements apply to any foreign RIN owner as part of the attest engagement required for RIN owners under this subpart K.

(1) The attest auditor must be independent of the foreign RIN owner.

(2) The attest auditor must be licensed as a Certified Public Accountant in the United States and a citizen of the United States, or be approved in advance by EPA based on a demonstration of ability to perform the procedures required in §§ 80.125 through 80.127, 80.130, and 80.1164.

(3) The attest auditor must sign a commitment that contains the provisions specified in paragraph (c) of this section with regard to activities and documents relevant to compliance with the requirements of §§ 80.125 through 80.127, 80.130, and 80.1164.

(i) *Withdrawal or suspension of foreign RIN owner status.* EPA may withdraw or suspend its approval of a foreign RIN owner where any of the following occur:

(1) A foreign RIN owner fails to meet any requirement of this section, including, but not limited to, the bond requirements.

(2) A foreign government fails to allow EPA inspections as provided in paragraph (c)(1) of this section.

(3) A foreign RIN owner asserts a claim of, or a right to claim, sovereign immunity in an action to enforce the requirements in this subpart.

(4) A foreign RIN owner fails to pay a civil or criminal penalty that is not satisfied using the foreign RIN owner bond specified in paragraph (e) of this section.

(j) *Additional requirements for applications, reports and certificates.* Any application for approval as a foreign RIN owner, any report, certification, or other submission required under this section shall be:

(1) Submitted in accordance with procedures specified by the Administrator, including use of any forms that may be specified by the Administrator.

(2) Signed by the president or owner of the foreign RIN owner company, or that person's immediate designee, and shall contain the following declaration:

I hereby certify: (1) That I have actual authority to sign on behalf of and to bind [insert name of foreign RIN owner] with regard to all statements contained herein; (2) that I am aware that the information contained herein is being Certified, or submitted to the United States Environmental Protection Agency, under the requirements of 40 CFR part 80, subpart K, and that the information is material for determining compliance under these regulations; and (3) that I have read and understand the information being Certified or submitted, and this information is true, complete and correct to the best of my knowledge and belief after I have taken reasonable and appropriate steps to verify the accuracy thereof. I affirm that I have read and understand the provisions of 40 CFR part 80, subpart K, including 40 CFR 80.1167 apply to [insert name of foreign RIN owner]. Pursuant to Clean Air Act section 113(c) and 18 U.S.C. 1001, the penalty for furnishing false, incomplete or misleading information in this certification or submission is a fine of up to $10,000 U.S., and/or imprisonment for up to five years.

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