ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 80

[EPA–OAR–2005–0161; FRL–8218–8]

RIN 2060–AN76

Regulation of Fuels and Fuel Additives: Renewable Fuel Standard Program

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of proposed rulemaking.

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 needs to be used in each year, with the total volume increasing over time. In this context, it is expected to simultaneously reduce dependence on foreign sources of petroleum, increase domestic sources of energy, and help us make progress in moving beyond a petroleum-based economy. The increased use of renewable fuels such as ethanol and biodiesel is also expected to have the added benefit of providing an expanded market for agricultural products such as corn and soybeans, expanding economic benefits for our nation's agricultural sector. Based on our analysis, there is also reason to believe that the expanded use of renewable fuels will provide reductions in carbon dioxide emissions and some air toxics emissions, such as benzene, from the transportation sector, while other emissions may increase.

This action proposes regulations designed to ensure that refiners, blenders, and importers of gasoline will use enough renewable fuel each year so that this total volume requirement is met. Our proposal describes the standard that will apply to these parties and the renewable fuels that qualify for compliance. The regulations would also establish a trading program that would be a critical 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: *Comments:* Comments must be received on or before November 12, 2006. Under the Paperwork Reduction Act, comments on the information collection provisions must be received by OMB on or before October 30, 2006.

Hearing: A public hearing will be held at 10 a.m. (Central) on October 13, 2006 at the Sheraton Gateway Suites Chicago O'Hare in Rosemont, IL. To request to speak at a public hearing, send a request to the contact in **FOR FURTHER INFORMATION CONTACT** by October 4, 2006.

ADDRESSES: *Comments:* Submit your comments, identified by Docket ID No. EPA–OAR–2005–0161, by one of the following methods:

- *http://www.regulations.gov:* Follow the on-line instructions for submitting comments.
- E-mail: *ASDinfo@epa.gov.*
- Mail: U.S. Environmental Protection Agency, EPA West (Air Docket), 1200 Pennsylvania Ave., NW., Room B108, Mail Code 6102T, Washington, DC 20460, Attention Docket ID No. OAR–2005–0161. Please include a total of 2 copies. In addition, please mail a copy of your comments on the information collection provisions to the Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), Attn: Desk Officer for EPA, 725 17th St., NW., Washington, DC 20503.
- Hand Delivery: EPA Docket Center, EPA/DC, EPA West, Room B102, 1301 Constitution Ave., NW., Washington DC. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. EPA–OAR–2005–0161. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through www.regulations.gov or e-mail. The *www.regulations.gov* Web site is an ''anonymous access'' system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *www.regulations.gov* your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Docket: All documents in the docket are listed in the *www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.*, CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *www.regulations.gov* or in hard copy at the EPA Docket Center, EPA/DC, EPA West, Room B102, 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 Docket telephone number is (202) 566–1742. The telephone number for the Public Reading Room is (202) 566–1744.

Note: The EPA Docket Center suffered damage due to flooding during the last week of June 2006. The Docket Center is continuing to operate. However, during the cleanup, there will be temporary changes to Docket Center telephone numbers, addresses, and hours of operation for people who wish to make hand deliveries or visit the Public Reading Room to view documents. Consult EPA's **Federal Register** notice at 71 FR 38147 (July 5, 2006) or the EPA Web site at *http://www.epa.gov/epahome/dockets.htm* for current information on docket operations, locations and telephone numbers. The Docket Center's mailing address for U.S. mail and the procedure for submitting comments to www.regulations.gov are not affected by the flooding and will remain the same.

Hearing: The hearing will be held at 10 a.m. (Central) on October 13, 2006 at the Sheraton Gateway Suites Chicago O'Hare, 6501 North Mannheim Road, Rosemont, Illinois 60018. To request to speak at a public hearing, send a request to the contact in **FOR FURTHER INFORMATION CONTACT**.

FOR FURTHER INFORMATION CONTACT: Julia MacAllister, U.S. EPA, National Vehicle and Fuel Emissions Laboratory, 2000 Traverwood, Ann Arbor, MI 48105; Telephone (734) 214–4131, FAX (734) 214–4816, E-mail *macallister.julia@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does This Action Apply to Me?

Entities potentially affected by this proposed 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 proposed action. Other types of entities not listed in the table could also be affected. To decide whether your organization might be affected if this proposed action is finalized, 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.

B. What Should I Consider as I Prepare my Comments for EPA?

1. *Submitting CBI.* Do not submit this information to EPA through *www.regulations.gov* or e-mail. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD ROM that you mail to EPA, mark the outside of the disk or CD ROM as CBI and then identify electronically within the disk or CD ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

2. *Tips for Preparing Your Comments.* When submitting comments, remember to:

• Identify the rulemaking by docket number and other identifying information (subject heading, **Federal Register** date and page number).

• Follow directions—The agency may ask you to respond to specific questions or organize comments by referencing a Code of Federal Regulations (CFR) part or section number.

• Explain why you agree or disagree; suggest alternatives and substitute language for your requested changes.

• Describe any assumptions and provide any technical information and/or data that you used.

• If you estimate potential costs or burdens, explain how you arrived at your estimate in sufficient detail to allow for it to be reproduced.

• Provide specific examples to illustrate your concerns, and suggest alternatives.

• Explain your views as clearly as possible, avoiding the use of profanity or personal threats.

• Make sure to submit your comments by the comment period deadline identified.

3. *Docket Copying Costs.* A reasonable fee may be charged by EPA for copying docket materials, as provided in 40 CFR part 2.

Table of Contents

I. Background

This section describes the required elements of the renewable fuel program, also known as the Renewable Fuel Standard (RFS) program, as stipulated in Section 211(o) of the Clean Air Act (CAA) as amended by the Energy Policy Act of 2005 (the Energy Act or the Act).

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 renewables 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 also blended ethanol during the winter months to help meet this new standard, such as Denver and Phoenix. As a result of these programs, and other factors, currently all areas requiring RFG or winter oxygenated fuels are blending ethanol at some level to support meeting the clean fuel requirements.

Today, the role and importance of renewable fuels in the transportation sector continues 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 has 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 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. The RFS program is such a program.

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 fuels 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 in moving beyond a petroleum-based economy.

The increased use of renewable fuels such as ethanol and biodiesel is also expected to have the added benefit of providing an expanded market for agricultural products such as corn and soybeans. Based on our analysis, there is also an expectation that the expanded use of renewable fuels will provide reductions in carbon dioxide emissions and air toxics emissions such as benzene from the transportation sector, while other emissions such as hydrocarbons and oxides of nitrogen may increase.

The level of the renewable fuels standard set forth by Congress works in conjunction with other provisions that were enacted as part of the Energy Act. In particular, the level of the renewable fuel standard more than offset the possible loss in demand for renewable fuels occasioned by the Act's repeal of the oxygen content mandate in the reformulated gasoline program while allowing greater flexibility in how renewable fuels were blended into the nation's fuel supply. The renewable fuel standard additionally created 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 is an important first step in U.S. efforts to move toward energy independence. The RFS standard provides the certainty that at least a minimum amount of renewable fuel will be used in the U.S., which in turn provides investment certainty for the growth in production capacity of renewable fuels. However, the RFS program is not the only thing 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 were forced to switch to ethanol to satisfy the oxygen content mandate for their reformulated gasoline in the U.S., causing a large, quick 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 has been 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 dramatic 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 statutory goal of the RFS program is to provide an important foundation for ongoing investment in renewable fuel production. However, market demand for renewable fuels is expected to exceed the statutory minimums. We believe we are proposing a program structure that could continue to 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 provides the statutory basis for the RFS program. This provision was added to the CAA as 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	4.0
2007	4.7
2008	5.4
2009	6.1
2010	6.8
2011	7.4

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

Calendar year	Billion gallons
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 a 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.

Renewable fuels are defined in the Act primarily on the basis of the feedstock. In general, renewable fuels 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 ensuring is introduced 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 fact that small refineries are exempted from the program until 2011, but must take into account the use of renewable fuel by those small refineries.

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 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 also determine who can generate credits and under what conditions, how credits may be transferred from one party to another, and in certain cases 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. Default Standard Applicable to 2006

The Energy Act was enacted in August of 2005 and included provisions for a renewable fuel program that was to begin in January of 2006. We recognized that a rulemaking implementing the full RFS program, including both program design and the various analyses necessary, would require a substantial effort involving many stakeholders. This process was expected to take longer than one year, and as a result we knew it would not be completed in time to be implemented by January of 2006.

The Energy Act anticipated this possibility and specified a default standard applicable for just 2006. The default standard specified that the percentage of renewable fuel in gasoline sold or dispensed to consumers in the U.S. in calendar year 2006 must be 2.78 volume percent.[1] The default standard would be applicable if the Agency did not promulgate regulations to implement the full RFS program for 2006. Since the full program could not be promulgated during 2006, the default standard of 2.78 percent applies to calendar year 2006.

However, the provision for the default standard in the Act does not provide adequate specificity on how to implement the default standard. For instance, the Act's default standard provision does not specify the liable parties and the specific nature of their obligation. It also does not discuss compliance mechanisms, reporting requirements, or credit generation and use. The resulting uncertainty associated with the default standard would have created confusion and risked a problematic initial implementation of the RFS program.

As a result, the Agency published a rule on December 30, 2005 that interpreted and implemented the default provision, to provide certainty to parties involved in the production and distribution of gasoline and renewable fuels.[2] In that action, the Agency clarified the default standard for 2006 with regulations identifying the liable parties as refiners, importers, and blenders. The default standard was interpreted as establishing a collective obligation, rather than an individual obligation. Under this interpretation, refiners, blenders, and importers are responsible as a group for meeting the default 2.78 percent standard, and compliance with this standard is calculated over the pool of all gasoline sold to consumers. An individual refiner, blender, or importer is not responsible for meeting the 2.78 percent standard for the specific gasoline it produces. The regulations implementing the default standard for 2006 did not include any provisions for credit generation or trading, given the collective nature of the obligation. However, any shortfall in renewable fuel production in 2006 would be added as a deficit carryover to the standard for 2007. Based on information available to date, this does not appear to be necessary. Total ethanol production in the U.S. exceeded 4.0 billion gallons in 2005 by a small margin, and several hundred million gallons of additional ethanol production capacity has come online in 2006. Thus it is anticipated that the total ethanol production volume and ultimate use in 2006 will be more than sufficient to meet the default standard of 2.78 percent.

Today's proposal outlines the full RFS program, covering all of the provisions required in the Act. It applies in calendar year 2007 and beyond, since the direct final rule described above addresses RFS compliance for 2006 only.

D. Development of the Proposal

The RFS program was prescribed in section 1501 of the Act, including the

[1] The default standard of 2.78 percent represented approximately 4.0 billion gallons of renewable fuel.

[2] 70 FR 77325 (December 30, 2005).

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 program. As with many legislative actions, various aspects of the program require additional development by the Agency beyond the specifications in the Act. The credit trading program and related compliance mechanisms are a central aspect of the program, and the Agency is responsible for developing regulations to ensure the successful implementation of the RFS program, based on the framework spelled out in the statute.

Under the RFS program the credit trading provisions will comprise a critical element of compliance. Many obligated parties do not have easy access to renewable fuels or the ability to blend them, and so will rely on the use of credits to comply. The RFS credit 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.

Given these considerations, 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 in the end 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 finally that the Agency should have the ability to easily verify compliance to ensure that the volume obligations are in fact met. Over the course of several months, these guiding principles helped to move us toward today's proposal.

II. Overview of the Proposal

Today's action describes our proposed requirements for the RFS program, as well as a preliminary 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 proposal and renewable fuel impacts assessment. Sections III through V provide the details of the proposed structure of the program, while Sections VI through X describe our preliminary assessment of the impacts on emissions, air quality, fossil fuel use, and cost resulting from expanded renewable fuel use.

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 program. 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. This makes an assessment of the program of limited if any utility, given that it is not currently driving real world impacts and future projections by the Energy Information Administration indicate that this favorable condition will continue. Consequently, it is of greater relevance and interest 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 of the RFS program itself.

In summary, depending on the volume of renewable fuel assumed to be used in 2012 (7.5 to 9.9 billion gallons), we estimate that this transition to renewable fuels will reduce petroleum consumption by 2.3 to 3.9 billion gallons or approximately 1.0 to 1.6 percent of the petroleum that would otherwise be used by the transportation sector. Carbon monoxide emissions from gasoline powered vehicles and equipment will be reduced by 1.3 to 3.6 percent while emissions of benzene (a mobile source air toxic) will be reduced by 1.7 to 6.2 percent. At the same time, other emissions may increase. Nationwide, we estimate between a 28,000 and 97,000 ton increase in VOC + NO_X emissions. However, the effects will vary significantly by region with some major areas like New York City, Chicago and Los Angeles experiencing no increase while other areas may see an increase in VOC emissions from 3 to 5 percent and an increase in NO_X emissions from 4 to 6 percent from gasoline powered vehicles and equipment. Furthermore, the use of renewable fuel will reduce CO_2 equivalent greenhouse gas emissions by 9 to 14 million tons, about 0.4 to 0.6 percent of the anticipated greenhouse gas emissions from the transportation sector in the United States in 2012. On average, we estimate the cost of this increase in renewable fuel to range from 0.3 cents per gallon to 1 cent per gallon of gasoline for the nation as a whole. We anticipate additional impacts that we intend to evaluate as part of the final rulemaking, including changes in renewable fuel feedstock market prices, decreased imports of petroleum, and effects on energy security.

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 production data, and fuel quality data was 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 appropriate.

We evaluated the impacts of expanded renewable 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. We also evaluated the impacts on emissions, including greenhouse gas emissions, and the corresponding impacts on nationwide and regional air quality. Our preliminary analyses are summarized in this section. There are a number of uncertainties associated with this preliminary assessment. The analyses described here will be updated for the final rule including additional investigation into these uncertainties.

1. Renewable Fuel Volumes 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, EIA projects renewable demand in 2012 of 9.6 billion gallons for ethanol, and 300 million gallons for biodiesel using crude oil prices forecast at $47 per barrel. Therefore, in assessing the impacts of expanded use of renewable fuels, we evaluated two comparative scenarios, one representing the statutorily required minimum, and one 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.

The Act also stipulates that at least 250 million gallons out of the total volume required in 2013 and beyond must be cellulosic biomass ethanol. Because we anticipate a ramp-up in production of cellulosic biomass ethanol products in the coming years, we have assumed that 250 million gallons of ethanol in 2012 will come from a cellulosic biomass source. Also, EIA has projected in their economic modeling a biodiesel demand in 2012 of 300 million gallons. Thus for both the required and projected volume scenarios that we evaluated for 2012, we assumed these same production volumes for cellulosic biomass ethanol and biodiesel.

As discussed above, we chose 2004 as our baseline. However, a direct comparison of the fuel quality impacts on emissions and air quality required that changes in overall fuel volume, fleet characterization, and other factors be constant. Therefore, we developed a reference case which represents the fuel volume, fleet characterization, and other factors expected in 2012. Fuel quality was maintained by simply growing ethanol use in equal proportion to growth in gasoline demand through 2012.

A summary of the assumed renewable fuel volumes for the scenarios we compared is shown in Table II.A.1–1.

TABLE II.A.1.–1—RENEWABLE FUEL VOLUME SCENARIOS

[billion gallons]

	2004 Base case	2012		
		Reference case	RFS required volume	Projected volume
Corn-ethanol	3.5	3.9	6.95	9.35
Cellulosic ethanol	0	0	0.25	0.25
Biodiesel	0.025	0.028	0.3	0.3
Total volume	3.025	3.928	7.5	9.9

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 2012 reference case. For the nation as a whole, we estimated that summertime VOC and NO_X emissions from gasoline and diesel vehicles and equipment would each increase by about 0.5 percent for the 7.5 billion gallon scenario, and by about 1.0 percent for the 9.9 billion gallon scenario. This would be equivalent to between 28,000 and 97,000 tons of VOC + NO_X nationwide. However, the effects will vary by region. For instance, for areas in which 10 percent ethanol blends already predominated in 2004, such as New York City, Chicago, and Los Angeles, if they continue to use ethanol at the same levels there will be no impact. However, for conventional gasoline areas in which no ethanol was used in 2004 but which are projected to transition to full use of ethanol in 2012, we estimated that VOC and NO_X emissions from gasoline vehicles and equipment would increase by 3–5 percent and 4–6 percent, respectively.

Unlike VOC and NO_X, emissions of CO and benzene from gasoline and diesel vehicles and equipment were estimated to decrease when the use of renewable fuels increased. Reductions in emissions of CO varied from as low as 1.3 percent to as high as 3.6 percent for the nation as a whole, depending on both the renewable fuel volume scenario and assumptions regarding the amount of ethanol used in reformulated versus conventional gasoline. Benzene emissions from gasoline vehicles and equipment were estimated to be reduced from 1.7 to 6.2 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, but do expect a net reduction in ambient PM levels to result due to the secondary PM impacts as discussed in section VIII.C. However, data on direct PM emission impacts is available for biodiesel. We estimate that reductions in emissions of direct PM from the projected increase in the use of biodiesel to be about 100 tons nationwide, equivalent to less than 0.5 percent of the diesel PM inventory.

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.[3] 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 in 2008 and 2009, 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 increased use of ethanol on ozone levels for the 7.5 billion gallon use scenario representing the required volumes

[3] 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.

under the RFS program. We did not evaluate other renewable fuel volumes scenarios due to the limited amount of time available for completing this NPRM. 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, ozone levels increased by 0.06 ppb, which represents less than 0.1 percent of the standard. Even for areas expected to experience a significant increase in ethanol use, ozone levels increased by only 0.1–0.2 ppb, less than 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 effects may mitigate these already small ozone increases. The ozone impacts also do not consider the impact of increased emissions from ethanol and biodiesel production facilities or any corresponding decrease in emissions from refineries.

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 draft Regulatory Impact Analysis (DRIA). 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 suggests 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 slightly while NO_X would still 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 expected 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. However, ethanol use may have an affect on ambient PM levels. Emerging science indicates that aromatic VOC emissions react in the atmosphere to form PM. Increased ethanol use is expected to cause a corresponding reduction in the aromatic content of gasoline, which should reduce aromatic VOC emissions and therefore potentially also impact atmospheric PM levels. All of these issues will be the subject of further study and analysis in the future.

3. Economic Impacts

As discussed in more detail in Section X, for the final rule we also plan to assess a range of economic impacts that could result from the expanded use of renewable fuels. Due to the time required to complete these analyses, we only have preliminary data for some of these impacts available for this proposal.

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 $1.20 per gallon in 2012 (2004 dollars) in the case of the 7.2 billion gallons per year case and $1.26 per gallon in the case of the 9.6 billion gallon 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 $2.11 per gallon if produced using soy bean oil, and less if using yellow grease or other relatively low cost or no-cost feedstocks. All of these fuel production costs are without accounting for tax subsidies for these renewable fuels.[4] 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, in some cases even exceeding those prices.

These renewable feedstocks are then used as blend fuels in gasoline and diesel. While biodiesel is typically just blended with 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 of the increased use of renewable fuels and their replacement of MTBE, will range from an estimate of 0.3 cent to 1 cent per gallon of gasoline.

This fuel cost impact does not consider other societal benefits. For example, the petroleum-based fuel displaced 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 through reductions in net petroleum imports. In Section IX of this preamble we estimate the value of the decrease in imported petroleum at about $3.5 billion in 2012 for the 7.5 billion gallon case and $5.8 billion for the 9.6 billion gallon case, in comparison to our 2012 reference case. Total petroleum import expenditures in 2012 are projected to be about $698 billion.

The above numbers only assess those impacts of increased production and use of renewable fuel that we can quantify at this time. 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 analyze the impacts on the U.S. agricultural sector, EPA has selected the Forest and Agricultural Sector Optimization Model (FASOM) developed by Professor Bruce McCarl, Texas A&M University and others over the past thirty years. FASOM is a dynamic, nonlinear programming model of the agriculture and forestry sectors of the U.S. (For this analysis, we will be focusing upon the agriculture portion of the model.) The strength of this model is its consideration of the full direct and indirect impacts of a shift in production of an agricultural commodity. For example, increased ethanol use will increase the demand for corn. The model assesses not only the impacts of increased demand for corn on acres devoted to corn production but also where the incremental corn will be produced, what other crops will be displaced and how corn is allocated among competing uses. Shifts in corn production will likely impact the price of corn and other crop prices. The model can also estimate the impacts of increased renewable fuel use on animal feed costs, animal production, costs to consumers and U.S. agricultural exports. Similarly, FASOM can estimate effects on U.S. farm employment and income (broken down by region, and farm sector such as corn farmers versus soybean producers versus the livestock industry, for example).

[4] Tax subsidies were subtracted out of the cost estimates, but consumer behavior in the absence of these tax subsidies was not modeled.

One of the effects of increased use of renewable fuel is that it diversifies the energy sources used in making transportation fuel. To the extent that diverse sources of fuel energy reduce the dependence on any one source, the risks, both financial as well as strategic, of potential disruption in supply or spike in cost of a particular energy source is reduced. As part of the RFS rulemaking, EPA is estimating the energy security effects of reduced oil use due to the expanded use of renewable fuel. However, these analyses will not be available until the final rule.

4. Greenhouse Gases and Fossil Fuel Consumption

There has been considerable interest in the impacts of fuel programs on greenhouse gases and fossil fuel consumption. Therefore, in this proposed 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 major 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.

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. Based on a comparison to the 2004 base fuel, we estimated that the increased use of renewable fuels will reduce petroleum consumption by about 1.0 to 1.6 percent in the transportation sector in 2012. This is equivalent to 2.3–3.9 billion gallons of petroleum in 2012. We also estimated that greenhouse gases from the transportation sector will be reduced by about 0.4–0.6 percent, equivalent to about 9–14 million tons. These reductions are projected to continue to increase in the future as crude oil prices are expected to continue to provide the stimulus for greater use of renewable fuels beyond 2012. These greenhouse gas emission reductions are also dominated by the forecast that the majority of the future ethanol use will be produced from corn. If advances in cellulosic technology allow its use to exceed the levels assumed in our analysis, then even greater greenhouse gas reductions would result.[5]

5. Potential Water Quality Impacts

Expansion in the use of renewable fuels will also have other important impacts which should be the focus of further study and evaluation. In particular, renewable fuels such as ethanol and biodiesel produced from agricultural feedstocks raise important issues with respect to the water quality impacts resulting from the increased production of corn and soybeans. Due to competing demand, which includes livestock producers, sweetener manufacturers, and foreign buyers among others, it is extremely unlikely that the current corn crop would be devoted to ethanol production. USDA's Economic Research Service predicts that current demand for feed and exports are expected to stay constant or perhaps rise.[6] Additional corn-based ethanol production would have to come from increased corn yields, increased acreage, and switching acreage to corn production from other crops like soybeans and cotton.[7]

Changes in agriculture as a result of increased use of renewable fuels can have significant adverse effects upon water quality, either locally or on a more broad basis. This has the potential to lead to increased runoff and delivery to water bodies of nutrients, pesticides and sediments, as well as increased salinity of farmland resulting from increased irrigation. The increased runoff of nutrients in turn can cause eutrophication of small water bodies as a result of localized runoff or large water bodies as a result of increased regional runoff such as currently occurs in the creation of the hypoxic zone in the Gulf of Mexico, or eutrophication in the Chesapeake Bay. Some lands have been retired (*e.g.*, under the Farm Bill's Conservation Reserve Program, or simply at the land-owner's initiative) because those lands are highly erosive, steep, or adjacent to water bodies. Therefore, farming these lands without appropriate mitigation measures would pose a particularly great risk to water quality and threaten to erase some of the gains of the last 20 years of Farm Bill and Clean Water Act implementation. Note that there may be similar environmental implications in other countries depending on the extent that either imports of renewable fuels or exports of agricultural commodities such as corn are affected.

We have not conducted an analysis for this proposal of the impacts on water quality that might result from the increased use of renewable fuels. However, this impact could present important public policy issues as renewable use expands, with examination required of both the possible benefits and detriments.

B. Program Structure

The RFS program proposed today requires refiners, importers, and blenders (other than oxygenate blenders) to show that a required volume of renewable fuel is used. 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 to every batch of renewable fuel produced. The RIN shows that a certain volume of renewable fuel was produced. 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 in the same manner 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 would both meet the requirements of the Act and provide several other important advantages:

[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] ''USDA Agricultural Baseline Projections To 2015,'' February 2006, Economic Research Service.

[7] For more discussion of agricultural sector effects, see Section IX.

• 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 proposed RIN-based trading program will be 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. The renewable volume obligation that would apply to an obligated party would 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, since this rulemaking will not be finalized prior to November, 2006, we are proposing in this notice that the standard for 2007 be 3.71 percent. Section III.A describes the calculation of the standard.

2. Who Must Meet the Standard?

Under our proposal, any party that produces gasoline for consumption in the U.S., including refiners, importers, and blenders (other than oxygenate blenders), would be subject to a renewable volume obligation that is based on the renewable fuel standard. These obligated parties would determine the level of their obligation by multiplying the percentage standard by their annual gasoline production volume. The result would 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. EPA will publish the percentage standard for a year by November of the preceding year.

For 2007, we are proposing that the renewable fuel volume obligation be etermined by multiplying the percentage standard by the volume of gasoline produced or imported prospectively from the effective date of the final rule until December 31, 2007. As discussed in Section III.A.3, we considered and are seeking comment on several other approaches for compliance in 2007, but believe this approach is most appropriate given the circumstances. We are also confident that the total volume of renewable fuel used in 2007 will still exceed the volume specified in the Act.

In determining their annual gasoline production volume, obligated parties would include all of the finished gasoline which they produced or imported for use in the contiguous 48 states, and would also include renewable blendstock for oxygenate blending (RBOB), and conventional blendstock for oxygenate blending (CBOB). Blenders would count as their gasoline production only the volumes of blendstocks added to finished or unfinished gasoline. Renewable fuels blended into gasoline by any party would not be counted as gasoline for the purposes of calculating the annual gasoline production volume.

Small refiners and small refineries would be exempt from meeting the renewable fuel requirements through 2010. All gasoline producers located in Alaska, Hawaii, and noncontiguous U.S. territories would be exempt indefinitely. However, if Alaska, Hawaii or a noncontiguous territory opted into the RFS program, all of the refiners (except for small refiners and refineries), importers, and blenders located in the state would 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 proposal flexibly 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 proposed program will provide the greatest possible encouragement for the development, production, and use of renewable fuels to reduce our dependence on petroleum. In general, renewable fuels must be produced from plant or animal products or wastes, as opposed to fossil fuel sources. Valid renewable fuels would 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 would qualify. Section III.B provides more details on the renewable fuels that would be allowed to be used for compliance with the standard under our proposal.

4. Equivalence Values of Different Renewable Fuels

One question that EPA 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 ethanol be treated as if it were 2.5 gallons of renewable fuel, but does not specify the values for other renewable fuels. As discussed in Section III.B.4., we considered and are seeking comment on a range of options including straight volume, energy content, and life cycle energy or greenhouse gas emissions. However, we are proposing 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 of 2.5. The proposed methodology can be used to determine the appropriate Equivalence Value for any other potential renewable fuel as well.

5. How Will Compliance Be Determined?

Under our proposed program, every gallon of renewable fuel produced or imported into the U.S. would be assigned a unique renewable identification number (RIN). A block of RINs could be assigned to any batch of renewable fuel that is valid for compliance purposes under the RFS program. These RINs would be placed on product transfer documents (PTD) as a batch of renewable fuel is 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 could be separated from the batch of renewable fuel to which it had been assigned, and then either used for compliance purposes or traded. For excess RINs resulting from the production of renewable fuels with Equivalence Values greater than 1.0, the producer of the renewable fuel could retain them for marketing separately (they need not be assigned to a batch of renewable fuel and placed on PTDs).

RINs would represent proof of production which is then taken as proof of consumption as well, since all 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 potential uses. An obligated party would demonstrate compliance with the renewable fuel standard by accumulating sufficient RINs to cover their individual renewable fuel volume obligation. It would not matter whether the obligated party used the renewable fuel themselves. A party's obligation would be to ensure that a certain amount of renewable fuel was used, whether by themselves or by someone else, and the RIN would be evidence that this occurred for a certain volume of renewable fuel. Exporters of renewable fuel would also be required to retire RINs in sufficient quantities to cover the volume of renewable fuel exported. RINs claimed for compliance purposes would thus represent renewable fuel actually consumed as motor vehicle fuel in the U.S.

RINs would be valid for compliance purposes for the calendar year in which they were generated, or the following calendar year. This approach to RIN life would be consistent with the Act's prescription that credits be valid for compliance purposes for 12 months as of the date of generation. An obligated party could either use RINs to demonstrate compliance, or could transfer RINs to any other party. If an obligated party was not able to accumulate sufficient RINs for compliance in a given year, it could carry a deficit over to the next year so long as the full deficit and obligation were 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 proposing to place 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 would mean that no more than 20% of the current year obligation could 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 from excess compliance in prior years to significantly depress renewable fuel demand in any future year. In keeping with the Act, excess RINs not used would expire.

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

6. How Would the Trading Program Work?

Renewable fuel producers and importers would be required to generate RINs when they produce or import a batch of renewable fuel. They would then be required to transfer those RINs along with the renewable fuel batches that they represent whenever they transfer the batch to another person. Likewise any other party that takes ownership or custody of the batch would be required to transfer the RIN with the batch. The RIN could be separated from the batch 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 through blending with conventional gasoline or diesel).

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

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

7. How Would the Program be Enforced?

As in all EPA fuel regulations, there would be a system of registration, recordkeeping, and reporting requirements for obligated parties, renewable producers (RIN generators), as well as any parties that procure or trade RINs either as part of their renewable purchases or separately. In most cases, the recordkeeping requirements are not expected to be 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 would be reported and verified. Thus, EPA, as well as industry could have confidence that invalid RINs are not generated and that there is no double counting.

C. Voluntary Labeling Program

EPA is considering whether voluntary program options to encourage adoption and use of practices that minimize environmental concerns which may arise with the production of renewable fuels are appropriate. Renewable fuels present a number of environmental advantages as explained elsewhere in the rulemaking package. However, to assure maximum advantage we also need to acknowledge the potential adverse environmental impacts that could arise from the production of renewable fuel and invite consideration of ways of offsetting these potential adverse impacts.

While in other areas of this document we focus on general impacts on air emissions, we also recognize that individual farming and fuel production operations can contribute to air and water pollution if appropriate practices and/or controls are not adopted. Increased production of renewable fuel may result in more intensive use of crop lands and perhaps the addition of crop land acres to meet the expanding need for renewable feed stocks. Such trends could have an adverse impact on, for example, local water quality. Similarly in the case of fuel production facilities, a range of design and operation options could result in varying levels of energy use and air and water pollution.

EPA is considering what voluntary program(s) can be put into place that would encourage farming and fuel production practices to minimize concerns that expanded production of renewable fuel in the United States is likely to result in adverse environmental impacts such as those identified above.

One option could be a voluntary labeling program which would make use of the RIN program proposed in this rulemaking. Under this concept, fuel producers which use best practices would have the option of 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. The details of such a concept, including the points noted below, would need to be developed before it could be fully considered for adoption.

At this time, we are requesting comments on voluntary programs that would recognize the efforts of farmers and renewable fuel producers that undertake the most environmentally sound practices and encourage others to adopt similar practices. In particular we are interested in comments on options for designs of potential voluntary programs including what criteria should be used to establish environmentally sound practices, how to verify that these environmental practices are indeed used in the production of renewable fuel, how this information could be used to promote expanded use of good practices, how the program could be most efficiently and effectively administered whether by EPA, some other Federal agencies, or perhaps a third-party, and finally how to assess effectiveness of such a voluntary program.

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 actually 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 how much credit each type of renewable fuel will receive. This section discusses how the annual standard is determined and which parties and volumes of gasoline would be subject to the proposed 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, compliance with the RFS program requirements will depend heavily on a credit trading program. This section also describes all the elements of our proposed credit 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 would 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 renewable volume obligation based on this percentage then the total amount of renewable fuel used is expected to 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, several adjustments to what is otherwise a simple calculation must be made.

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, EPA is required 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 would be further reduced if Alaska, Hawaii, or a U.S. territory chose 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 choose to opt into the RFS program, the projected gasoline volume would increase above that consumed in the 48 contiguous states. EIA has 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. Since the October 2006 document is not currently available for the purpose of proposing the 2007 standard and projecting the 2008 and later standards, we have used the gasoline volume projections in EIA's 2006 Annual Energy Outlook (AEO), Table A2 ''Energy Consumption by Sector and Source.'' We intend to use the October 2006 Short-Term Energy Outlook values for the final rule.

However, these gasoline volumes include renewable fuel use, which in the coming years is expected to be mostly ethanol. As discussed below in Section III.C.1, the renewable fuel obligation will 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, the renewable fuel volume must be subtracted 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 monthly EIA publication Short-Term Energy Outlook. For the purpose of proposing the 2007 standard and projecting the 2008 and later standards, we have used the renewable (ethanol) volume projections in EIA's 2006 Annual Energy Outlook (AEO), Table 17 ''Renewable Energy Consumption by Sector and Source.'' As for the gasoline projections discussed above, we intend to use the October 2006 renewable fuel values for the final rule.

The Act exempts small refineries [8] from the RFS requirements until the 2011 compliance period. As discussed in Section III.C.3.a, EPA is proposing to also exempt small refiners [9] from the RFS requirements until 2011, and to treat small refiner gasoline volumes the same as small refinery gasoline volumes. Since small refineries and small refiners would be exempt from the program until 2011, EPA is proposing that their gasoline volumes be excluded from the overall non-renewable gasoline

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

[9] 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 previus EPA fuel regulations.

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. This would only occur though the 2010 compliance period when the exemption ends. Calculation of the standard for calendar year 2011 and beyond would include small refinery and small refiner volumes.

As discussed above, calculation of the standard requires projections of gasoline use for the upcoming compliance period. EIA does not project small refinery or small refiner gasoline volumes, so other methods of estimating these values are necessary. EPA receives gasoline production data as a part of its fuel programs' reporting requirements that could be used for this purpose. However, since we do not receive the data until late February, the most recent complete annual data set available would be from two years earlier. Given this, the fact that this adjustment is only needed for 4 years, and because the total small refinery and small refiner gasoline production volume is expected to be fairly constant compared to total U.S. gasoline production during this period, we are proposing to estimate small refinery and small refiner gasoline volumes using a constant percentage of national consumption. This percentage would be based on the most recent small refinery and small refiner gasoline data available in time for the final rule. Using information from gasoline batch reports submitted to EPA, EIA data and input from the California Air Resources Board regarding California small refiners, we have estimated this percentage to be 13.5%.[10] EPA requests comments on this method of estimating small refinery and small refiner gasoline volumes.

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, and thus directionally would reduce the percentage standard. However, there would be no available data on which to base such an adjustment. Furthermore, EPA believes that 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) would be very small. In light of the total volume of renewable fuel required and the precision in which the statute specifies this total volume, the very small volume at issue here would not change the resulting percentage. Under the proposal, small refineries and small refiners are merely treated as any other renewable blender until 2011. Consequently, whatever renewables they blend will be reflected as RINs available in the market, and thus should not be accounted for in the equation used to determine the standard. Therefore, EPA is proposing to assume this value to be zero.

We are proposing that the amount of renewable fuel used in Alaska, Hawaii, or U.S. territories would not affect the amount of renewable fuel required nationwide. We believe this approach is appropriate because the Act requires that the renewable fuel be consumed in the contiguous 48 states unless Alaska, Hawaii, or a U.S. territory opt-in. Additionally, renewable fuel produced in Alaska, Hawaii, and U.S. territories is unlikely to be transported to the contiguous 48 states, and vice versa. Thus, 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.

A final issue that could affect the calculated value of the standard is any deficit carryover from 2006. Any deficit carryover from 2006 would increase the standard only for 2007. Since renewable fuel use in 2006 is expected to exceed the 2.78 percent default standard, we are proposing that no deficit be carried 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, in order to get the total projected non-renewable gasoline volumes from which to calculate the standard, EPA is proposing to use EIA projections of nationwide and state gasoline consumption, and small refinery and small refiner volumes estimated as a constant percentage of national gasoline volumes.

Based on the discussion above, the formula which we are proposing to be used for calculating the percentage standard is shown below:

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

Where:

$RFStd_i$ = Renewable Fuel standard in year i, in percent

RFV_i = Nationwide 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)

$Cell_i$ = 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)

As described in III.B.4.b, we are not proposing 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 a result, the proposed 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.

EPA is proposing the following formula for calculating the cellulosic

[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.

standard that is required beginning in 2013:

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

Where, except for $\mathrm{RFCell_i}$, the variable descriptions are as discussed above. The definition of $\mathrm{RFCell_i}$ is proposed as:

$\mathrm{RFCell_i}$ = Renewable Fuel Cellulosic Standard in year i, in percent

EPA requests comments on the components of both of the proposed formulas, and on how the values for the components should be obtained.

2. What Are the Applicable Standards?

EPA will set the percentage standard for each upcoming year based on the most recent EIA 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. We are proposing the standard for 2007 and estimating the standard for later years based on current information using the formulas discussed above. The standards would be 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.

For illustrative purposes, we have estimated the standards for 2007 and later based on current information using the formulas discussed above.[11] These values are listed below in Table III.A.2–1. The values of the variable RFV are the required renewable fuel volumes specified in the Act (and shown in Table I.B–1). The projected gasoline and renewable fuels volumes were determined from EIA's energy projections. 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. Small refinery and small refiner gasoline volumes were calculated based on our proposed method of assuming a constant percentage relative to projected nationwide gasoline. 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. The deficit for 2006 (applicable to the 2007 standard) was assumed to be zero.

TABLE III.A.2–1.—PROJECTED STANDARDS

Year	Standard	Cellulosic standard
2007	3.71%	Not applicable.
2008	4.22%	Not applicable.
2009	4.72%	Not applicable.
2010	5.21%	Not applicable.
2011	4.82%	Not applicable.
2012	4.85%	Not applicable.
2013+	4.70% min. (non-cellulosic)	0.16% min.

For calendar year 2013 and thereafter, the applicable volumes are to 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. This rulemaking would present our conclusions regarding the appropriate applicable volume of renewable fuel for use in calculating the renewable fuel standard for 2013 and beyond. However, at a minimum we expect that the sum of the cellulosic and non-cellulosic standards for 2013 will be no lower than the 2012 standard. Until such time as we conduct that rulemaking, the program proposed by this rule would continue to apply after 2012.

Prior to 2013, the Act specifies that cellulosic biomass ethanol or waste derived ethanol will be considered equivalent to 2.5 gallons of renewable fuel when determining compliance with the renewable volume obligation. As discussed in Section III.D below, a batch's RIN would indicate whether it was cellulosic or non-cellulosic ethanol. Beginning in 2013, the 2.5 to 1 ratio no longer applies for cellulosic biomass ethanol. In its place, 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 above, we have estimated this value (250 million gallons) as a percent of an obligated party's production for 2013. Thus, an obligated party would be subject to two standards in 2013 and beyond, a non-cellulosic standard and a cellulosic 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. As described in Section I.C, 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. However, the Act provides no default standard for any other year. Instead, the regulations we promulgate are required to address renewable fuel usage, including calendar year 2007. The program we are proposing today will therefore apply in 2007. While we plan to promulgate the final rule as soon after today's proposal as possible, it will likely not be effective by January 1, 2007. Therefore, our proposal must address how, and for what time periods, the applicable standard and other program requirements will apply to regulated parties for gasoline produced during 2007.

We have identified several options for 2007 compliance. One option would be to extend the collective compliance approach used for 2006 to 2007. Although the Act contains no default

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

standard applicable to 2007, under this approach we would apply the renewable fuel standard that we calculate for 2007 to obligated parties on a collective basis rather than on an individual basis. Under this approach, no individual facility or company would be liable for meeting the applicable standard. At the end of 2007 we would determine if the industry as a whole had met the standard on average, and any deficit would be carried over into 2008. This approach would be essentially equivalent to deferring the start of the program to 2008, but with the addition of an industry-wide deficit carryover provision. Current projections from the Energy Information Administration (EIA) on the volume of renewable fuel expected to be produced in 2007 indicate that an industry-wide deficit carryover would most likely be unnecessary under this collective compliance approach.

However, given the requirements of the Act, we do not believe that a collective compliance approach is appropriate for 2007. The Energy Act requires us to promulgate regulations that provide for the generation of credits by any person who overcomplies 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.

A variation of the collective compliance approach would add a credit carryover provision in which any excess renewable fuel produced on an industry-wide basis in 2007 would be subtracted from the required volume in the calculation of the applicable 2008 standard. However, under a collective compliance approach, such a credit carryover provision would not meet the statutory requirement since no individual companies could generate, bank, or trade credits. Therefore we do not believe that a collective compliance approach is appropriate.

Another option for 2007 compliance would be for obligated parties to calculate their renewable fuel obligation based on all gasoline volumes produced at any time during the calendar year, regardless of when in 2007 the final rule is published or becomes effective (i.e., the calculation of the renewable volume obligation looks back retroactively to the beginning of the year for gasoline production). Compliance would be determined based on a whole calendar year's production of gasoline, and the compliance determination would not be required until calendar year 2007 was over, after the final rule was published. Obligated parties would know the proposed standard based on today's action, and all regulated parties would likewise know the proposed provisions for recordkeeping, RIN generation and assignment, etc. On this basis they could begin the process of generating RINs and tracking batches of renewable fuel prior to the publication of the final rule. However, it might not be appropriate to apply the standard to all gasoline produced in 2007 unless the regulatory provisions in today's proposal are very similar to those in the final rule. Otherwise, obligated parties and renewable fuel producers would not have adequate lead-time.

For this approach to be effective, renewable producers would have to begin placing RINs on their PTDs at the start of the year 2007 even though the regulations are not yet final. If they do not, then there could be a shortage of RINs available for obligated parties to use for compliance by the end of the year. Since there is no guarantee that renewable fuel producers would generate RINs appropriate prior to adoption of the regulations, another option would be for the Agency to finalize just those RIN-related provisions prior to the end of 2006 that are critical to measuring and tracking batches of renewable fuel and the assignment of RINs to those batches. However, in practice this approach would be little different than finalizing the full rulemaking. As a result we do not believe that this would be a viable option given the time available.

Finally, given the challenges and shortcomings inherent in the other options, we could simply apply the renewable fuel standard 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. As a result, such an approach would be relatively straightforward to implement, provide the industry with the certainty they need to comply, and give them time to put in place their compliance plans and actions. It also would be unlikely to have any negative impacts on renewable fuel use given the expectations that total volumes in 2007 will exceed the national volume required for 2007. This is the approach we are proposing today.

This ''prospective'' approach would not formally apply the standard to all of the gasoline produced in the 2007 calendar year. As a result, it would not formally ensure that the total volume of renewable fuel required to be used in 2007 would actually be used. However, given the present circumstances, we believe this is an appropriate way to implement the Act's provisions. We are confident that the combined effect of the proposed 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. 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.[12] Under this option we believe there would be reasonable lead-time for regulated parties to meet their 2007 compliance obligations.

While we are proposing to apply the renewable fuel standard for 2007 prospectively only from the effective date of the final rule, we nevertheless request comment on all these options for addressing compliance in calendar year 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:

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

[12] 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 promulgate regulations.

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.

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 would likewise be reduced proportionally and their ability to comply with the RFS requirements would 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.[13] It also includes all motor vehicle fuels that are produced from biomass material such as grain, starch, oilseeds, animal, or fish materials including fats, greases and oils, sugarcane, sugar beets, tobacco, potatoes or other biomass. 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 intends to consider 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 vehicles, without regard to whether it in fact is used in a highway or nonroad vehicle. 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 an RVO without the need to track it to determine its actual application in a highway vehicle. 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. Fuels that otherwise meet this definition but are designated by the producer for use in boilers, or heaters, or any use other than highway or nonroad use, would not meet the definition of renewable fuel.

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. 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 ''biocrude,'' 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, other fuels that meet the definition of renewable fuel include biodiesel and various alternative fuels that can be used in their neat form, such as ethanol, methanol or natural gas, without blending into gasoline and without being used to produce a gasoline blending component (such as ETBE). The definition of renewable fuel in the Act is not limited to fuels that can be blended with gasoline. 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, in the billions of gallons 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 bio-diesel, 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

[13] 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 aklyl ester) and renewable diesel (other diesels that meet the Energy Act's definition but are not mono akly esters.

renewable fuel obligation would still be ethanol blended with gasoline. Whether one counts or does not count these additional renewable fuels would not in practice change whether the total national goal for renewable fuel use was met, given the size of the goal specified in the Act and the form in which the total is expressed. 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 would avoid 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 EPA believes its proposal is consistent with the intent of Congress and is a reasonable interpretation of the Act.

We are therefore proposing that in addition to any renewable fuels that are actually blended into gasoline and are designated for use in a highway vehicle, we would also count any renewable fuels falling into the following categories as being valid for RFS compliance purposes:

1. Any renewable fuels used in nonroad applications;
2. Any renewable fuels used in their neat (unblended) form in onroad and nonroad applications; and
3. Any renewable fuel used in a motor vehicle that does not normally run on gasoline. For instance, biogas used in a CNG vehicle, or biogenic methanol used in a dedicated methanol vehicle.

The Agency solicits comment on this approach.

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, but can also be produced from carbohydrates in corn and other feedstocks. This process is accomplished by first converting the carbohydrates 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 carbohydrates to make ethanol. Cellulosic feedstocks (composed of cellulose and hemicellulose) are currently more difficult and costly to convert to sugar than are carbohydrates because of this intermediate conversion step. While the cost and difficulty are a disadvantage, the cellulosic process offers the advantage that more feedstocks can be used and 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 While these materials may or may not contain cellulosic material, their inclusion in the definition requires that ethanol made from such sources be treated as cellulosic biomass ethanol under the regulations. ''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.''

b. *Ethanol Made From Any Feedstock in Facilities Run Mostly With Biomass-Based Fuel.* 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 proposes to interpret 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 propose to interpret as meaning (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, 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, could be used as fuel for gasifier/boiler units at ethanol plants, since they are waste materials and would not be used as a feedstock to carbohydrate-based ethanol plants. Although such waste materials conceivably could be feedstocks to a cellulosic ethanol plant, its use as a fuel at a carbohydrate based ethanol plant does not subvert the intent of the definition.[14]

[14] 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.

Today's regulations will require owners of ethanol plants to keep records of fuel use to ensure compliance with and enforcement of this provision of the definition of cellulosic ethanol. Due to potential enforcement-related problems associated with application of this component of the definition of cellulosic ethanol to foreign facilities, we intend for the final rule to develop compliance and enforcement related safeguards similar to those set forth in proposed 80.1165(f), (g), (h) and (j), and with additional inspection, audit, recordkeeping and reporting safeguards to verify compliance with the requirements on fuel use at foreign facilities. We seek comment on the most effective means of doing this. Because of the difficulty of implementing these safeguards, however, we also solicit comment on a provision that would limit the application of this definition of cellulosic ethanol only to ethanol plants in the U.S.

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 are proposing to include waste heat in the definition of ''other waste materials'', and also that waste heat captured and used as a source of thermal energy in an ethanol plant would satisfy the requirement of other waste materials being ''otherwise used'' to make ethanol. Although the source of the waste heat is ultimately a fossil fuel in most cases, we recognize that without the capture of the heat and subsequent use in the ethanol plant, that energy would be unused, and the ethanol plant would consume the equivalent amount of fossil fuel. Thus, for the same amount of fossil fuel consumption at the off-site plant, heat energy capture would result in displacement of fossil fuel use at the ethanol plant. Because of potential confusion identifying thermal energy that is waste heat from fossil fuel combustion sources on site (i.e., at the ethanol plant itself), we are limiting this proposal to waste heat captured at off-site plants. The Agency solicits comment on our proposal to consider waste heat in the definition of ''other waste materials''.

We propose to interpret the term ''fossil fuel normally used in the production of ethanol'' to mean 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 criteria 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.[15] The Agency solicits comments on this aspect of our approach in accounting for fossil fuel displacement.

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 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. We are therefore proposing that the displacement of 90 percent of fossil fuels at the ethanol plant means those fuels consumed on-site and that are used to generate thermal energy used to produce ethanol. The term ''fossil fuel normally used in the production of ethanol'' in today's proposal means fossil fuel that is combusted at the facility itself to produce thermal energy. Owners are required 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 the waste heat captured and used in the ethanol 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 would 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. Holders of RINs associated with the sale or trade of such cellulosic ethanol would get the benefit of the 2.5 credit (through 2012 when such credit is valid).

In the event that the requirements of 90 percent displacement of fossil fuel are not met, the owner of a facility producing such ethanol would be required to obtain additional RINs to make up whatever deficit exists for those RINs sold or traded with a value of 2.5. Assuming this is made up, then holders of the RINs associated with the ethanol the plant produced in the previous year would not be affected. We solicit comment on this proposed approach.

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.'' The determination of the appropriate category of ethanol is based on whether the feedstocks on question contain cellulose or hemicellulose that is used to make the ethanol. Thus, if the ethanol is made from the non-cellulosic portions of animal, other waste, or municipal waste, it is labeled ''waste derived ethanol.''

2. What Is Biodiesel?

The definition of renewable fuel in the Act includes corn-based and cellulosic biomass ethanol, waste derived ethanol, and the renewable fuel portion of blending components derived from renewable fuel. Biodiesel is also specifically named as being included in the Act's definition of renewable fuel. 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 ASTM specification D–6751[16] (the most common meaning of the term

[15] 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 plant in our analysis, we are using average nationwide values, rather than data collected for individual plants.

[16] In the event that the ASTM specification D–6751 is succeeded with a different number in the future, EPA may revise the regulations accordingly at such time.

''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 propose to divide 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 would fulfill the Act's definition of biodiesel. The Agency solicits comment on this approach and specifically asks whether the ''non-ester renewable diesel'' definition be referenced explicitly to ASTM D–975.

a. *Biodiesel (Mono-Alkyl Esters).* Under this part, 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–6751–02a; (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 including, but not limited to, 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.

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 including, but not limited to, 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. Current examples of a non-ester renewable diesel include: ''renewable diesel'' produced by the Neste process, or diesel fuel produced by processing fats and oils through a refinery hydrotreating process.

3. Is Motor Fuel That Is Made From a Renewable Feedstock a Renewable Fuel?

We interpret the statutory definition of renewable fuels to include all gasoline or diesel that is made from a class of feedstocks called ''biocrudes'', which are defined as biologically derived feedstocks (such as fats and greases). We are providing a definition of ''biocrude-based renewable fuels'' to mean gasoline or diesel products resulting from the processing of biocrudes in production units within refineries that process crude oil and other petroleum based feedstocks and which make gasoline and diesel fuel.[17] A particular batch of biocrude 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 non-ester renewable diesel defined in Section III.B.2.b above could be one such type.

We are assuming that all of the biocrude used as a feedstock in a refinery unit will end up as a biocrude-based renewable 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 proposing to have the volume of the biocrude 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.

We are also proposing that the Equivalence Value assigned to biocrude-based renewable fuels be designated as 1.0, despite the fact that they might warrant a higher value based on their energy content as described in the next section.[18] This approach should balance out the likelihood that some of the biocrude-based renewable fuel is not a motor vehicle fuel.

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

One question that EPA must address is how to count volumes of renewable fuel in determining compliance with the renewable volume obligation. For instance, the Act stipulates that every gallon of cellulosic 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 proposing that the ''Equivalence Values'' for 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, and for cellulosic ethanol of 2.5. However, the methodology can be used to determine the appropriate equivalence value for any other potential renewable fuel as well.

This section describes why we believe that the use of relative energy content is appropriate under the Act, and our investigation of the alternative use of lifecycle analyses as the basis of Equivalence Values.

a. *Authority Under The Act To Establish Equivalence Values.* We are proposing 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 would mean that every physical gallon of renewable fuel would count as one gallon for RFS compliance purposes. An Equivalence Value greater than 1.0 would mean that every physical gallon of renewable fuel would count as more than one gallon for RFS compliance purposes, while a value less than 1.0 would count as less than one gallon.

We are interpreting the Act as allowing EPA to develop Equivalence Values according to the methodology discussed below. We believe that the use of Equivalence Values is consistent with the intent of Congress to treat different renewable fuels differently in different circumstances, and to provide

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

[18] With respect to biodiesel, however, since such fuel is typically not made in a traditional petroleum-based refinery, it would not be a biocrude-based renewable fuel and would thus not be limited to the 1.0 Equivalence Value.

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. All of 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 for certain specified circumstances.

The Act is unclear as to whether a straight gallon measurement is required in circumstances other than those specified by Congress. We believe the Act can and should be interpreted to allow the use of Equivalence Values in those circumstances. First, this is consistent with the way Congress treated the various specific circumstances noted above, and thus is basically a continuation of that process. Second, EPA does not believe that providing such an Equivalence Value for this small volume of renewable fuel will interfere in any way with meeting the total national volume goals for usage of renewable fuel. We are proposing to use an Equivalence Value of 1.0 for ethanol other than cellulosic biomass or waste derived ethanol, and we expect that there will only be very limited additional situations where an Equivalence Value other than 1.0 is used. As a result, this approach is a reasonable way for the RFS program to ensure that the total volume of renewable fuels will be used as required under the Act.

b. *Energy Content and Renewable Content as the Basis for Equivalence Values.* We believe it is appropriate to base the Equivalence Value assigned to a particular renewable fuel on the degree to which the renewable fuel supplants the petroleum content of fuel used in a motor vehicle. This is consistent with the Act's definition of renewable fuel, which refers to the degree to which it is directly used to replace or reduce the quantity of fossil fuel present in a fuel mixture used to operate a motor vehicle. The degree to which the fossil fuel is replaced is best represented by its relative energy content. 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 propose to calculate Equivalence Values using both the renewable content of a renewable fuel and its energy content. This section describes our proposal for calculating the 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 would be 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 could be 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 would allow actual volumes of renewable fuel to be consistent with the volumes required by the Act while still allowing some renewable fuels to be attributed a higher value in terms of RFS compliance to the extent that they have a higher energy content than ethanol.

Equivalence Values should 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. We have interpreted this to mean that every renewable fuel should be evaluated at the molecular level to distinguish between those components that were derived from a renewable feedstock, versus those components that were derived from a fossil fuel feedstock. Along with energy content in comparison to ethanol, the relative amount of renewable versus non-renewable content can then be used directly as the basis for the Equivalence Value.

We propose that the calculation of Equivalence Values should simultaneously take into account both the renewable content of a renewable fuel and its energy content in comparison to ethanol. To accomplish this, we propose 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.

R_{Eth} = Renewable content of ethanol, in percent.

EC_{RF} = Energy content of the renewable fuel, in Btu per gallon (LHV).

EC_{Eth} = Energy content of ethanol, in Btu per gallon (LHV).

R is a measure of that portion of a single renewable fuel molecule which can be considered to have come from a renewable source. Since R is being combined with relative energy content in the formula above, the value of R cannot be based on the weight fraction of the renewable atoms in the molecule, but rather must be based on the energy content of those atoms. As a result the calculation of R for any particular renewable fuel requires an analysis of the chemical process through which it was produced. A detailed explanation of calculations for R and several examples are given in a technical memorandum in the docket [19].

In the case of ethanol, denaturants are added to preclude its 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. In general this would mean that the Equivalence Value of ethanol would be 0.95. However, 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

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

allow them to include the denaturant in their reported volumes.

Since we are proposing 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 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}. We are therefore proposing three simplifications to streamline the application of Equivalence Values in the context of the RFS program. First, consistent with our approach to the R value for ethanol, we are proposing that all Equivalence Values calculated to be in the range of 0.9–1.2 be treated as if they were exactly 1.0. This approach would eliminate many of the complexities described in Section III.D.2 that are associated with using renewable fuels for RFS compliance purposes that have an Equivalence Value other than 1.0. Second, we propose that several bins be created for renewable fuels with Equivalence Values above 1.0. These bins would replace the calculated Equivalence Values with standardized ones to account for uncertainty in the calculations as well as to simplify their application. We propose that the bins be 1.0, 1.3, 1.5, and 1.7. Each renewable fuel would be assigned to the bin that is closest to its calculated Equivalence Value. Finally, we propose that all Equivalence Values, if any, which are calculated to be less than 0.9 be rounded to the first decimal place.

Using the methodology described above, we calculated the Equivalence Values for a number of different renewable fuels expected to be in use over the next few years, and modified them according to our proposed rounding protocols. These are shown in the table below.

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

	Equivalence Value (EV)
Cellulosic biomass ethanol or waste-derived ethanol	2.5
Ethanol from corn, starches, or sugar	1.0
Biodiesel (mono alkyl ester)	1.5
Non-ester renewable diesel	1.7
Butanol	1.3
ETBE from corn ethanol	0.4

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. In such cases we propose to allow the producer to submit a petition to the Agency describing the renewable fuel, its feedstock and production process, and the calculation of its Equivalence Value. The Agency would review the petition and assign an appropriate Equivalence Value to the renewable fuel based on the proposed rounding protocols described above. Regarding publication of the newly assigned Equivalence Value, we could publish it in the **Federal Register** at the same time as the annual standard is published each November. We request comment on whether publishing new Equivalence Values in this manner is appropriate.

Regarding biodiesel (mono alkyl esters), we also considered an additional approach in setting the Equivalence Value. 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, it might be appropriate to create a parallel provision for biodiesel made from wastes. Under this approach, biodiesel made from waste products would be assigned an Equivalence Value of 2.5 through 2012. Currently, waste products (for example, poultry fats and poultry wastes, municipal solid waste, or wastewater sludge) make up less than 10 percent of biodiesel feedstocks. This approach would have the effect of incentivizing the use of waste products and recycled biomass to make biodiesel. Beyond the RFS program, it could also set a precedent to promote recycling and waste conservation. While we are not proposing to set the Equivalence Value for waste-derived biodiesel at 2.5 in today's action, we nevertheless believe that this approach has merit and request comment on it.

c. *Lifecycle Analyses as The Basis for Equivalence Values.* Although we are proposing that Equivalence Values be based on energy content relative to ethanol and renewable content, some stakeholders have suggested that Equivalence Values should be based on lifecycle analyses. Such an approach may have merit, but it would also raise a number of challenges. Consequently, we are inviting comment here not only on the merit and basis for setting equivalence values on a lifecycle basis, but also the appropriate means of doing so.

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 they provide a more complete picture of the potential impacts of different fuels or different fuel sources.

Advocates for using lifecycle analyses for setting the Equivalence Values for different renewable fuels indicate that there could be several advantages to 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 fossil fuel use or emissions.

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

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 can vary widely from one facility or process to another. There currently exists no single body, governmental or otherwise, that has organized a comprehensive dialogue among stakeholders about the appropriate tools and assumptions behind any lifecycle analyses with the goal of coming to agreement.

Another issue 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, criteria 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 unless the RFS standard was simultaneously adjusted.

Finally, lifecycle analyses of different renewable fuels are likely to change over time as farming practices and process technologies evolve. Significant changes would necessitate corresponding changes in the RFS program to adjust the Equivalence Values on an ongoing basis which would add uncertainty into the long-term RIN market.

We request comment on all issues associated with the use of lifecycle analyses in establishing the Equivalence Values for different renewable fuels for the RFS program.

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.[20] To implement this provision, we are proposing that the volume of gasoline used to determined the renewable fuel obligation include all finished gasoline, RFG and conventional, produced or imported for use in the contiguous United States during the annual averaging period. We are also proposing to include in the volume of gasoline used to determine the renewable fuel obligation 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 (e.g. sub-octane conventional gasoline), called ''CBOB.''

Under the proposed rule, the volume of any other unfinished gasoline or blendstock, such as butane, would not be 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. Where a blendstock is blended with other blendstock to produce finished gasoline, RBOB, or CBOB, the total volume of the gasoline blend would be 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 would be included, since the finished gasoline would have been included in the compliance determinations of the refiner or importer of the gasoline.[21] Gasoline produced or imported for use in a noncontiguous state or U.S. territory[22] would not be included in the volume used to determine the renewable fuels obligation (unless the noncontiguous state or territory has opted-in to the RFS program), nor would gasoline, RBOB or CBOB exported for use outside the United States.

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

Generally, ethanol and other renewable fuels would typically be used in gasoline, increasing the volume of the entire gasoline blend. We are proposing to exclude 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 is 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.''[23] 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 would apply to any renewable fuels that are blended into gasoline at a refinery, contained in imported gasoline, or added at a downstream blending facility. 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

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

[21] ''Gasoline treated as blendstock,'' or ''GTAB,'' would be treated as any other blendstock with regard to the RFS rule; i.e., where the GTAB is blended with other blendstock to produce gasoline, the total volume of the gasoline blend, including the GTAB, would be included in the volume gasoline used to determine the renewable fuel obligation for the blender. Where the GTAB is blended with finished gasoline, only the GTAB volume would be included.

[22] 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.

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

volume of renewable fuels required, merely on the number of obligated parties. We invite comment on the proposal to exclude renewable fuels in the volume of gasoline subject to the renewable fuels obligation. As discussed earlier, in a similar manner this volume of renewable fuel would also be excluded from the calculation performed each year by EPA to determine the applicable percentage.

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

Under the proposed rule, persons who meet the definition of refiner, which includes blenders who produce gasoline by combining blendstocks or blending blendstocks into finished gasoline, and persons who meet the definition of importer under the fuels regulations would be subject to the renewable fuel obligation. As noted above, blenders who only blend renewable fuels downstream from the refinery or importer would not be 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, as the covered blenders are all refiners under the regulations.

A refiner or importer located in a noncontiguous state or U.S. territory would not be subject to the renewable fuel obligation and thus would not be an obligated party (unless the noncontiguous state or territory opts-in to the RFS program). A party located within the contiguous 48 states that ''imports'' into the 48 states gasoline produced or imported by a refiner or importer located in a noncontiguous state or territory would be an obligated party and must meet the renewable fuel obligation for such gasoline.

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.'' [24] Under the proposed rule, 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. Beginning in 2011, small refineries would be required to meet the same renewable fuel obligation as all other refineries. This exemption would apply 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.

In addition to small refineries as defined in the Act, we are proposing to extend this relief to refiners who meet the proposed criteria for small refiner status. Under the proposal, a small refiner is defined as any refiner who, during 2004: (1) Produces gasoline at a refinery by processing crude oil through refinery processing units; (2) employs 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) has a total crude oil processing capability for all of the small refiner's refineries of 155,000 barrels per calendar year (bpcd). These size requirements were established in prior rulemakings and were the result of our analysis of small refiner impacts. We do not believe that there are more than 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 request comment on whether a refiner who has a refinery which exceeds the 75,000 bpcd criteria should be eligible to apply for a small refiner exemption under the RFS program. EPA believes it has this 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 are also proposing to allow foreign refiners to apply for a small refinery or small refiner exemption under the RFS program. This would apply to foreign refiners that apply for refineries under the 75,000 bpcd criteria or foreign refiners that apply for small refiner status. Under the anti-dumping, MSAT and gasoline sulfur rules, foreign refiners are allowed to comply with certain regulations separately from any importer. Additional requirements applicable to such foreign refiners are included in these rules to ensure that enforcement of the regulations at the foreign refinery would not be compromised. We are proposing similar enforcement-related requirements that would apply to foreign refiners that apply for a small refinery or small refiner exemption. Under the existing fuels regulations, few foreign refiners have chosen to undertake these additional requirements, and almost all gasoline produced at foreign refineries is included in the importers' compliance determinations. We invite comment on the value of extending the small refinery and small refiner exemptions to foreign refiners under the RFS program.

Under the proposed rule, 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. The application must include documentation that the small refinery's average aggregate daily crude oil throughput for calendar year 2004 did not exceed 75,000 barrels. As long as the refinery met the criteria in 2004, it would have the exemption through 2010 regardless of changes in crude throughput or ownership. A 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 are proposing to base eligibility 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 Hurricane Katrina in 2005. We request comment on whether multiple-year average should be the basis for eligibility.

As discussed above, 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. The application must be received by EPA by September 1, 2007 for the exemption to be effective in 2007 and subsequent calendar years. Like the exemption for small refineries, 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. EPA will notify the refiner of approval or disapproval of small refiner status by letter. Unlike the case for small refineries, refiners that receive approved small refiner status and subsequently do not meet all of the criteria for small

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

refiner status (i.e., cease producing gasoline from 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. 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, the proposed rule includes a process by which refiners with small refineries may petition EPA for an extension of the small refinery exemption. As provided in the Act, the proposed rule would require EPA to act on the petition not later than 90 days after the date of receipt of the petition.

During the initial exemption period and any extended exemption periods, the gasoline produced by small refineries and refineries owned by approved small refiners would be subject to the renewable fuel standard.

Under the proposed rule, the automatic five year exemption for small refineries, and any extended exemptions, may be waived upon notification to EPA. In waiving its exemption, gasoline produced at a small refinery would be included in the RFS program and would be included in the gasoline used to determine a refiner's renewable fuel obligation. If a refiner waives the exemption for their small refinery or their exemption as a small refiner, the refiner would 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 refiner operates as an oxygenate blender).

b. *General Hardship Exemption.* In recent rulemakings, we have included a general hardship exemption for parties that could demonstrate severe economic hardship in complying with the standard. We are proposing not to include in the RFS program provisions for a general hardship exemption. 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 would 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 would 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, we believe that there likely would be no need for a general hardship exemption. We request comment on whether there is a need to include a general hardship exemption in the RFS program.

c. *Temporary Exemption Based On Unforeseen Circumstances.* In recent rulemakings, we have also included a temporary exemption based on unforeseen circumstances. We are proposing 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 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 believe, therefore, 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 request comment on whether there would be a need to include a temporary exemption based on unforeseen circumstances, and, in particular, circumstances that may affect ethanol producers.

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 effective date of the RFS program.[25] 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.

Today's proposed rule would implement this provision of the Act by providing a process wherein the governor of a noncontiguous state or territory may petition EPA to have the state or territory included in the RFS program. However, we believe that approval of the petition would not require a showing other than a request to be included in the program. The petition must be received by EPA on or before October 31 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 October 31 would not be included in the RFS program in the next calendar year, but would be included in the RFS program in the following 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 October 31 would be necessary to allow EPA time to make any adjustments in applicable standard. The method for recalculating 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.

Where a noncontiguous state or territory opts-in to the RFS program, producers and importers of gasoline for that state or territory would be obligated parties subject to the renewable fuel requirements. All refiners, blenders and importers who produce or import gasoline for use in a state or territory that has opted-in to the RFS program would be required to count this volume of gasoline in determining their renewable fuel obligation, and would be able to separate RINs from batches of renewable fuels used in gasoline that is sold or introduced into commerce in the

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

state or territory that has opted-in to the RFS program.

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 request comment on the opt-in provisions.

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.[26] 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 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 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. Renewable fuel use in the state in question would thus continue to be driven by natural market forces.

Given that state petitions for a waiver of the RFS program are unlikely to affect renewable fuel use in that state, we are not proposing 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. We request comment on this approach.

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. The Act envisions a regulatory program that would ensure the national volume is met as long as a refiner or importer ensured that someone used a certain volume of renewable fuel, whether it was themselves or another party. 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 proposed compliance program. It is based on the use of unique renewable identification numbers (RINs) assigned to batches of renewable fuel by renewable fuel producers. These numbers could then be sold or traded, and ultimately used by any obligated party to demonstrate compliance with the applicable standard. Excess RINs would be identical to the credits envisioned by the Act. 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 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 they 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 can be used only as motor vehicle fuel. In discussions with stakeholders, it has become clear that other renewable fuels, including biodiesel and renewable fuels used in their neat (unblended) form, likewise are not used for anything other than 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. It is therefore appropriate for EPA to establish the obligation for refiners and importers as an obligation to ensure that a certain volume of renewable fuel has been produced. This will ensure that the total required volume of renewable fuels will be used in the U.S., and as discussed below has many benefits as far as streamlining the program and minimizing disruptions to the current marketplace for production, distribution, and use of renewable fuels.

Implementing a program that is based on ensuring production of a certain volume of renewable fuels requires a system of volume accounting and tracking of renewable fuels. We propose that this system be based on the assignment of unique numbers to each batch of renewable fuel. These numbers would be called Renewable Identification Numbers or RINs, and would be assigned to each batch by the renewable fuel producer or importer.

The use of RINs would allow 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 as described in Section III.D.1.b below. For instance, ethanol producers are already required to report their production volumes to EIA through Monthly Oxygenate Reports. This data would provide an independent source for verifying volumes. The total number of batches and parties involved is 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 are approximately 100 ethanol plants and 40 biodiesel plants in the U.S., compared with approximately 1200 blenders.[27]

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

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

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

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 can also identify the Equivalence Value of the renewable fuel which will often only be known at the point of its production. Finally, the RIN can identify the year in which the batch was produced, a critical element of determining the applicable time period within which RINs are valid for compliance purposes.

Production volumes of renewable fuels intended for blending into gasoline are an accurate surrogate for volumes actually blended into gasoline. In addition, production volumes of renewable fuels capture those renewable fuels used as motor vehicle fuel in their neat (unblended) form. Thus we believe that this approach would allow us to account for all renewable fuels consumed in the U.S. because renewable fuels always end up being used as fuel in the U.S. or exported.

There are also changes that 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. However, these stock changes always have a net change of zero over the long term since there is no economic benefit to stockpiling renewable fuels.

Exports of renewable fuel represent the only 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, we believe that our proposed approach can account for exports through an explicit requirement placed upon exporters (discussed in Section III.D.4 below). As a result, we are confident that our proposed 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. A credit trading program would allow a refiner that overcomplied with its annual RVO to generate credits representing the excess renewable fuel. The Act stipulates that those credits could 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 would permit current blending practices to continue wherein 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 comply with the standard.

Our proposed RIN-based program would fulfill all the functions of a credit trading program, and thus would meet 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, banked, or traded in the next compliance period. RINs could be transferred to another party in an identical fashion to a credit. However, our proposed program provides additional flexibility in that it would permit all RINs to be transferred between parties before they were 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 proposing 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 would be required to verify that the number of RINs generated matched the volume renewables produced, that any extra value RINs were appropriately generated, and that RINs numbers were properly assigned and documented on the renewable fuel PTDs as required by the regulations.

b. *Alternative Approach To Tracking Batches.* If we did not implement 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. However, this alternative approach would create a number of significant problems.

First, the parties obligated to meet the standard (refiners, importers, and blenders of gasoline) are often not the parties who produce renewable fuel or blend renewable fuels such as ethanol into gasoline. This separation would require a mechanism for obligated parties to obtain credit for renewable fuels blended by non-obligated parties. Generally, this would be done through contract management. Unfortunately, there might be an incentive to exaggerate the volumes of renewable fuel blended and thus exaggerate the number of credits generated. This alternative approach might also create opportunities for double-counting batches of renewable fuel, either intentionally or unintentionally.

Second, as described in Section I, one of our guiding principles in designing the RFS compliance and trading program was to ensure that existing business practices could continue to the degree possible. With the alternative approach described above, some refiners might have to significantly change their business or production practices to take greater control of ethanol blending and, therefore, the mechanism for compliance with the RFS program. For instance, a refiner could establish a contract with an oxygenate blender, securing the rights to the credits that oxygenate blender creates. A refiner might also decide to take on more blending responsibilities itself. However, these approaches would run counter to the normal business practices that keep fuel costs to a minimum, and would thus have a tendency to increase fuel costs.

Third, tracking renewable fuel volumes to identify the date, place, and volume of blending into gasoline would maximize the number of parties involved, overly complicating the compliance system. There are approximately 1200 blenders in the U.S. who blend ethanol into gasoline, in addition to those that blend biodiesel into conventional diesel fuel. Many of these parties are small businesses that have not been regulated in an EPA fuel program before. Enforcement efforts would necessarily be placed on them, imposing upon them the primary burden of accurately documenting the volumes of renewable fuel that are blended into gasoline even though they are not obligated for meeting the standard. In contrast, under our proposed program blenders would only need to keep records of RINs acquired with batches. It is our expectation that in most cases obligated parties will separate the RINs from batches before those batches are transferred to blenders. Therefore, blenders will only have to keep records of RINs for a fraction of the renewable fuel produced.

Fourth, a focus on the point of blending would not address renewable fuels that need not be blended into gasoline or diesel. For example, although biodiesel [28] is generally blended into conventional diesel before being used as fuel, it can be used in its neat form (B100). If volumes of renewable fuel were counted only when blending into conventional fuel occurred, then B100 could never be claimed by an obligated party for RFS compliance purposes. The same would be true of other renewable fuels which, although not produced in significant quantities today, could play a more substantial role in the renewable fuels market in the future. Examples of these other unblended renewable fuels could include renewable diesel made by hydrotreating plant oils instead of transesterifying them, or a renewable gasoline made from a Fischer-Tropsch process applied to biogas.

Finally, a focus on the point of blending would not permit cellulose biomass ethanol to be distinguished from other forms of ethanol. Since the Act requires that 250 million gallons of cellulosic biomass ethanol be produced starting in 2013, this alternative approach would require tracking of batches of renewable fuel at the producer level.

In a blender-based approach, then, special exceptions would need to be developed in order for these neat fuels to be available for RFS program compliance purposes. For instance, a system of measuring and tracking neat renewable fuel volumes at the point of production would likely be necessary. This would be no different from a RIN-based program for such fuels.

Our proposed RIN-based program would address all these concerns automatically by shifting the focus of accounting to the point of production rather than blending. As a result we believe that a blender-based alternative approach described above is inferior to our proposed program. We request comment on a RIN-based system for uniquely identifying, measuring, and tracking batches of renewable fuel for compliance purposes.

2. Generating RINs and Assigning Them to Batches

a. *Form of Renewable Identification Numbers.* Each RIN would be generated by the producer or importer of the renewable fuel and would uniquely identify not only a specific batch, but also every gallon in that batch. The RIN would consist of a 34-character code having the following form:

RIN: YYYYCCCCFFFFFBBBBB RRDKSSSSSSEEEEEE

Where:
YYYY = Calendar year of production or import
CCCC = Company ID
FFFFF = Facility ID
BBBBB = Serial batch number
RR = Code identifying the Equivalence Value
D = Code identifying cellulosic biomass ethanol or waste-derived ethanol
K = Code identifying extra-value RINs
SSSSSS = Start of volume block.
EEEEEE = End of volume block.

Some examples of RINs are given in Section III.E.1.b.

The company and facility IDs would be assigned by the EPA as part of the registration process as described in Section IV.B. The serial batch number would be chosen by the producer and would generally be a sequential value starting with 000001 at the beginning of each year. We have chosen five digits for the serial batch number to allow for facilities that produce up to a hundred thousand batches per year. However, we request comment on whether four digits would be sufficient.

The RR, D, and K codes would together describe the nature of the renewable fuel and the RINs that were generated to represent it. The RR code would simply represent 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 would identify 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.

The K code would be used to specify whether the RIN represents actual gallons of renewable fuel, or instead represents extra-value RINs. Extra-value RINs arise only in cases where the Equivalence Value is greater than 1.0. Extra-value RINs are discussed in more detail in Section III.D.2.b below.

The RIN also contains two values that together identify the total number of gallons in a batch as well as uniquely identifying each gallon in that batch.[29] When RINs are first assigned to a batch of renewable fuel by its producer or importer, the volume start block for that batch will in general be 1 (i.e. SSSSSS will have a value of 000001). The volume block end is the total volume number of gallons in the batch (i.e. for a 10,000 gallon batch, EEEEEE would have a value of 010000). Thus the single RIN assigned to the batch is in effect shorthand for all the unique RINs assigned to every individual gallon in the batch. We propose that the number of gallons in a batch be standardized to 60 °F to avoid RIN assignment problems associated with volume swell due to temperature changes. We have assigned six digits to the volume block codes to allow batches up to a million gallons in size. We request comment on whether a fewer number of digits for the SSSSSS and EEEEEE codes would be sufficient.

Since ''RIN'' can refer to either the number assigned to the batch or the number representing each gallon in that batch, we propose distinguishing between a batch-RIN and a gallon-RIN. A batch-RIN would be the multi-character code written on a product transfer document associated with a batch of renewable fuel. The batch-RIN would include SSSSSS and EEEEEE values identifying every (volume-standardized) gallon in the batch, each of which would be assigned its own gallon-RIN. A gallon-RIN would have identical SSSSSS and EEEEEE values identifying one gallon in a batch.

Our approach to RINs permits the batch to be divided into smaller batches at any point in the distribution system while maintaining the assignment of unique RINs. For instance, if a 1000 gallon batch of renewable fuel is divided into two 500 gallon batches, the volume block start and block end values

[28] Mono-alkyl esters made from plant or animal oils or fats, and which have been registered with the EPA for use in highway motor vehicles.

[29] RINs represent actual gallons in a batch when the RIN is a standard-value RIN. Extra-value RINs represent additional gallons in cases where the Equivalence Value is greater than Equivalence Value is greater than 1.0. See further discussion in Section III.D.2.b.

in the original batch-RIN would change to reflect the batch split. The batch-RIN for the first 500 gallon batch would have an SSSSSS value of 000001 and an EEEEEE value of 000500, while the second 500 gallon batch would have an SSSSSS value of 000501 and an EEEEEE value of 001000. Additional batch splits would be handled similarly. More discussion of batch splits is provided in Section III.E.1.b.i.

b. *Generating Extra-Value RINs.* In general, there is a one-to-one correspondence between gallon-RINs and physical gallons of renewable fuel in a batch. For instance, a 10,000 gallon batch of renewable fuel would be assigned 10,000 gallon-RINs, and the batch-RIN would contain volume block start and volume block end values summarizing the 10,000 gallon-RINs. However, under certain circumstances RINs may be generated in addition to those that represent the volume of renewable fuel actually produced. This would occur in cases where the Equivalence Value of the renewable fuel in question is greater than 1.0. Renewable fuel Equivalence Values are discussed in Section III.B.4.

If a renewable fuel has an Equivalence Value greater than 1.0, the incremental value above 1.0 can be used to generate ''extra-value'' RINs. For instance, the Equivalence Value for biodiesel shown in Table III.B.4–1 is 1.5. If a biodiesel producer made a 1000 gallon batch of biodiesel, 1000 standard-value gallon-RINs would be assigned to the batch and an additional 500 extra-value gallon-RINs could also be generated.

All the RINs generated to represent a batch of renewable fuel would contain the same RR code representing the Equivalence Value of the renewable fuel. However, extra-value RINs would be treated differently from standard-value RINs in two ways. First, the extra-value RINs would include a K code that identifies them as extra-value RINs, distinguishing them from standard-value RINs that represent actual gallons of renewable fuel. Second, extra-value RINs would not be required to be transferred along with the batch of renewable fuel as it moves through the distribution system.[30] Rather, an extra-value RINs could be transferred as an independent commodity by the producer. This approach would provide an incentive for producers to make renewable fuels that have a comparatively greater value in terms of meeting the volume requirements of the RFS program. Also, by not requiring extra-value RINs to be assigned to the batches of renewable fuel that they represent, batches of renewable fuel can continue to have a one-to-one correspondence between gallon-RINs assigned to the batch and the number of physical gallons in that batch. This approach can greatly simplify the transfer of RINs with batches particularly when batch splits occur.

c. *Cases in Which RINs Are Not Generated.* Although in general every (temperature-standardized) gallon of renewable fuel produced or imported would be assigned a gallon-RIN, there are several cases in which a RIN may not be assigned. For instance, if a renewable fuel producer also operated as an exporter, any renewable fuel that it produced and exported would not need to be assigned a RIN. Since the gasoline that is blended with renewable fuels under the RFS program must be ''sold or introduced into commerce'' within the U.S., renewable fuels that are exported cannot be claimed by an obligated party for compliance purposes, and therefore would not need to be assigned a RIN. Exports of renewable fuel are discussed further in Section III.D.4.

Another case in which a RIN may not be assigned to a batch of renewable fuel would be if the renewable fuel was consumed within the confines of the production facility where it was made. RINs under today's proposal would be assigned to renewable fuel when it leaves the production facility. So long as renewable fuel remained at the production facility, it would not need to be assigned a RIN.

A third case in which some renewable fuel would not be assigned a RIN would occur for small volume producers. We are proposing that renewable fuel producers who produce less than 10,000 gallons in a year would not be required to generate RINs or assign them to batches. If they chose to register as a renewable fuel producer under the RFS program, however, they would be subject to all the regulatory provisions that apply to all producers, including the requirement to assign RINs to batches. We request comment on the 10,000 gallon threshold.

A fourth case in which some renewable fuel would not be assigned a RIN could occur when a gasoline or diesel blending component is only partially derived from a renewable source. In such cases the Equivalence Value associated with the renewable fuel would be less than 1.0, indicating that it is produced by combining a renewable fuel with a non-renewable fossil fuel. 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. Equivalence Values are discussed in Section III.B.4. In this situation only a fraction of the gallons of renewable fuel produced would be assigned a RIN in proportion to its Equivalence Value, with the remaining gallons not being assigned a RIN.

Finally, a renewable fuel whose energy content is less than that of ethanol might also be assigned an Equivalence Value less than 1.0, and as a result fewer gallon-RINs would be assigned to a batch than physical gallons in that batch. For example, methanol made from biogenic methane (biogas) for use in a methanol vehicle would have an energy content less than that for ethanol. Although methanol is currently used as a fuel in only very small quantities, if it was produced from renewable feedstocks it would have an Equivalence Value less than 1.0.

If a renewable fuel has a Equivalence Value less than 1.0, then gallon-RINs could only be assigned to a portion of the batch. The number of gallons within a batch that could be assigned a RIN would be calculated from the following formula:

$$V_a = EV \times V_s$$

Where:

V_a = Volume of the batch that is assigned a RIN, in gallons (rounded to the nearest whole gallon).

EV = Equivalence Value for the renewable fuel in question (<1.0).

V_s = Total volume of the batch standardized to 60 °F, in gallons.

In such cases, the volume block start and volume block end values in the batch-RIN (i.e. SSSSSS and EEEEEE codes described in Section III.D.2.b) would not exactly correspond to the volume of the batch. Instead, they would cover the first portion of the batch. The remaining portion of the batch would not be assigned a RIN. For clarity in regards to batch splits, a party could assign the gallon-RINs to the first-out gallons of the batch. Thus if a batch split occurred, every gallon drawn out of the original batch to form a new, smaller batch would be assigned a gallon-RIN, up to the point when all the available gallon-RINs were assigned to the new batch. Any additional gallons drawn out of the original batch, or left with the original batch, would have no associated RINs. However, we are not requiring this approach but only offer it as one possibility. We propose that parties that have ownership or custody of batches of renewable fuel have the discretion to split batches and their associated RINs in any way, subject to

[30] As described in Section III.E below, we are proposing that standard-value RINs would be assigned to the batch of renewable fuel they represent and would be required to be transferred with the batch.

certain restrictions. Batch splits are discussed in more detail in Section III.E.1.b.i.

3. Calculating and Reporting Compliance

Under our proposed program, RINs would form the basis of the volume accounting and tracking system that would allow each obligated party to demonstrate that they had discharged their renewable fuel obligation. This section describes how the compliance process using RINs would work. Our proposed 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 proposed program, each obligated party would 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 produced for use 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, the RVO for each obligated party is likewise an obligation that is calculated on an annual basis.

Since our proposed 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 would meet their RVO through the accumulation of RINs. In so doing, they would effectively be causing the renewable fuel represented by the RINs to be consumed as motor vehicle fuel. Obligated parties would not be required to physically blend the renewable fuel into gasoline or diesel fuel themselves. The accumulation of RINs would be the means through which each obligated party would show compliance with its RVO, and thus with the renewable fuel standard.

For each calendar year, each obligated party would be required to submit a report to the Agency documenting the RINs it acquired, and showing that the sum of all gallon-RINs acquired were 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 would have the same compliance value, i.e. there would be no distinction between standard-value RINs and extra-value RINs for compliance purposes. 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. We could 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 would be 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 could 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 would be allowed are determined by the valid life of a RIN, described in more detail in Sections III.D.3.b below. If alternatively an obligated party has not acquired sufficient RINs to meet its RVO, then under certain conditions it could carryover a deficit into the next year. Deficit carryovers are discussed in more detail in Section III.D.3.d.

The regulations would prohibit any party from creating or transferring invalid RINs. Invalid RIN could not be used in demonstrating compliance regardless of the good faith belief of a party that the RINs were 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 would address the consequences if an obligated party was found to have used invalid RINs to demonstrate compliance with its RVO. In this situation, the refiner or importer that used the invalid RINs would be required to deduct any invalid RINs from its compliance calculations. The refiner or importer would be liable for violating the standard if the remaining number of valid RINs was insufficient to meet its RVO, and the obligated party might be subject to monetary penalties if it used invalid RINs in its compliance demonstration. In determining what penalty was appropriate, if any, we would 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, and whether the purchaser was indeed a good faith purchaser based on an investigation of the RIN transfer. A penalty might include both the economic benefit of using invalid RINs and/or a punitive component.

Although an obligated party would be liable under our proposed program for a violation if it used invalid RINs for compliance purposes, we would normally look first to the generator/seller of the invalid RINs both for payment of penalty and to procure sufficient valid RINs to offset the invalid RINs. However, if that party was found to be out of business, then attention would turn to the obligated party who would have to obtain sufficient valid RINs to offset the invalid RINs.

As for RIN generators, we are proposing that obligated parties be required to 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 would verify the volume of renewable fuel exported and therefore the magnitude of their RVO. Attest engagement reports would be submitted to the party that commissioned the engagement, and to EPA.

b. *Valid Life of RINs.* The Act requires that renewable fuel credits be valid to show compliance for 12 months as of the date of generation. This section describes our proposed interpretation of this provision in the context of a RIN-based program. We also discuss some possible alternative interpretations that we have considered.

As described in Section III.D.1.a, credits 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, compliance would be determined shortly after the end of the year, and credits would be identified at that time. Compliance is typically demonstrated 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.

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 market. 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 and the use of ethanol in gasoline became 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 find themselves with a stranded investment. The 12 month valid life limit for credits minimizes the potential for this type of result.

For obligated parties, the 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 credit 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 thus 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 RINs, and thus ethanol blends, could spike 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 these potential price spikes. 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 proposed RIN-based program, we are 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 the following year. RINs not used for compliance purposes in the year in which they were generated would by definition be in excess of the RINs an obligated party needed in that year, making excess RINs equivalent to credits. Excess RINs would be valid for compliance purposes in the year following the one in which they initially came into existence.[31] RINs not used within their valid life would expire. This would satisfy the Act's 12 month duration for credits.

Thus we propose 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 could 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 would expire.

There are alternative approaches that could be taken to establishing the valid life of a RIN. For instance, excess RINs could be deemed to be generated not at the end of an annual compliance period, but rather on the date that an obligated party must submit its annual report to the Agency (February 28 as described in Section IV.A.2). In this case the 12-month valid life could extend into the following calendar year. As described above, the fact that compliance is determined on an annual basis means that RINs that are valid for any portion of a calendar year should be available for demonstrating compliance with that year's compliance obligation. Under this alternative approach, RINs would be valid for three full compliance periods: the calendar year in which the original RIN came into existence, the following year during which it was deemed to be in excess of an obligated party's RVO, and a third year within which the 12 month valid life expired. We do not believe that this interpretation is most consistent with the Act's purposes. This could allow a given year's exceptional overcompliance to effectively reduce required renewable fuel volumes for two years in the future. We do not believe that this would promote the best balance between allowing flexibility for obligated parties while also increasing the use of renewable fuels annually.

Another possible approach to RIN life would be to interpret the Energy Act's 12-month credit life provision as applying retrospectively, not prospectively. Under this approach, the 12-month timeframe in the Act would be interpreted to refer to the calendar year within which a credit was generated. If excess RINs were deemed to be such on December 31, then under this alternative approach no RINs could be used for compliance purposes beyond the year in which they originally came into existence.

However, 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 believe that it is appropriate for all RINs to be valid for the year in which they were generated and the following calendar year. In comparison to a single-year valid life for RINs, our proposed 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 to a minimum.

We recognize that the language of the Act regarding credit valid life is not unequivocal. However, 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. The record of the development of this legislation does not provide a clear indication to the contrary. In fact, while some stakeholders have argued that the Energy Act could have been written to explicitly allow a valid life of multiple years if that had been Congress' intent, we believe it could likewise have been written to explicitly limit the valid life to the year in which the renewable fuel was produced if that had been its clear intent. Therefore, the interpretation of the valid life language in the Act must be established in the context of the statutory requirements for the full RFS program and the practical implications of its implementation.

One possible objection to our proposed approach is 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. However, the language in the Act shows that Congress clearly intended a credit program that provided a degree of implementation flexibility. 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

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

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.

We request comment on the valid life of RINs, including our proposed approach in which RINs would be valid for the year generated or the following year, and the alternative approaches in which RINs would be valid for more or less time than under our proposal.

c. *Cap on RIN Use to Address Rollover.* As described in Section III.D.3.b above, we are proposing that RINs be valid for compliance purposes for the calendar year in which they were 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 proposed 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 example below illustrates the issue.

TABLE III.D.3.c–1.—Example of RIN Rollover Issue

[Billion RINs]

	Available RINs			Compliance Determination		
	Required under RFS [a]	RINs generated [b]	Excess	Previous year RINs	Additional RINs needed	New excess RINs generated
2007	4.7	5.2	0.5	0.0	4.7	0.5
2008	5.4	6.0	0.6	0.5	4.9	1.1
2009	6.1	6.9	0.8	1.1	5.0	1.9

[a] Equivalent to the required volumes shown in Table I.B–1.
[b] One possible production volume scenario based on EIA projections in their Annual Energy Outlook 2006.

In this example, there are 0.5 billion more RINs available for compliance year 2007 than are needed to comply with the RFS program requirements. Since these RINs are not used in the year in which they are generated (2007), they can be used for compliance purposes in the following year (2008). If they are not used in 2008, they will expire.

In 2008, 0.6 billion more RINs come into existence than are needed to meet the 2008 requirements. This should mean that there are 0.6 billion more RINs available than are needed to comply with the RFS program requirements for 2008, and thus 0.6 billion RINs should be carried into 2009. However, since there are also 0.5 billion RINs available from the previous year which can be used for compliance purposes in 2008, this permits the generation of 0.5 new excess RINs in 2008 if all the 2007 RINs are used to demonstrate compliance in 2008. Thus there are in fact 1.1 billion excess RINs generated in 2008 rather than only 0.6 billion, and they can all be used for compliance purposes in 2009. In summary, the excess RINs from 2007 were used to generate new excess RINs in 2008, and in effect (though not by record) the excess RINs from 2007 can be used for compliance purposes in 2009, a year after they should have expired. Thus excess RINs have ''rolled over'' multiple years.

The rollover issue essentially could make the applicable valid life for RINs virtually meaningless in practice. Even though individual RINs technically could only be used for compliance purposes for the year generated and the following year, in practice obligated parties could use previous-year RINs to generate new excess current-year RINs which could then be carried into the following year. This could continue for every year in which the volume of renewable fuel produced in a given year exceeds the RFS requirements for that year, up to limit of 100 percent of the standard for that year. The net result is that the RFS program could operate as if there was virtually no valid life limit for RINs at all.

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.

Some stakeholders do not perceive a problem with the RIN rollover issue. They point to the need for maximum flexibility in responding to fluctuations in the market, and they are 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 even returned to the 1995 levels. 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. Obligated parties have 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.

We believe that the rollover issue can and should 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 have a de facto 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. We considered a number of possible approaches for accomplishing this, some of which are discussed below. After consultation with stakeholders, we decided that the best approach would be to place a percentage cap on the amount of an obligated party's Renewable Volume Obligation (RVO) that can be met using previous-year RINs. We are proposing that this cap be set at 20 percent. Thus each obligated party would 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. The cap would not be effective until compliance year 2009, since no rollover is possible in years 2007 or 2008.

Any previous-year RINs that an obligated party may have that are in excess of the 20 percent cap could be traded to other obligated parties that need them. If the previous-year RINs in excess of the 20 percent cap were not used by any obligated party for compliance, they would expire. The net result would be that, for the market as a whole, no more than 20 percent of a given year's renewable fuel standard could be met with RINs from the previous year.

Furthermore, 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 would apply equally to all obligated parties, and the cap would 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 would be readily enforceable with minimal additional program complexity, as each obligated party's annual report would simply provide separate listings of previous-year and current-year RINs to establish that the cap had not been exceeded. A 20 percent cap would have no impact on who would own RINs, their valid life, or any other regulatory provision regarding compliance.

Rather than employing a fixed 20 percent cap, we also considered an approach whereby we would set the cap annually based on the actual excess renewable fuel production. Table III.D.3.c–2 provides an example of how the caps would be calculated if the EIA projections for ethanol production prove accurate.

TABLE III.D.3.C–2.—REQUIRED AND PROJECTED RENEWABLE FUEL VOLUMES

[Billion gallons]

	Required under RFS [a]	Ethanol produced [b]	Excess [d]	Previous Year excess ethanol as a fraction of current year compliance (percent)
2008	5.4	6.0	0.6	....
2009	6.1	6.9	0.8	9.8
2010	6.8	7.9	1.1	11.8
2011	7.4	8.8	1.4	14.9
2012	7.5	9.6	2.1	18.7
2013	[c] 7.6	10.1	2.5	27.6
2014	[c] 7.8	10.3	2.5	32.1
2015	[c] 7.9	10.5	2.6	31.6

[a] Equivalent to the required volumes shown in Table I.B–1

[b] Projected ethanol production volumes from EIA, Annual Energy Outlook 2006.

[c] Example of possible increases in the required volumes. The Energy Act requires at minimum a constant percentage of renewable fuel in gasoline after 2012.

[d] Does not include other renewable fuels such as biodiesel which would increase the excess even further.

In 2009, for instance, the cap would be 9.8 percent, and by 2012 it would be 18.7 percent. Under such an approach, the value of the cap might more precisely reflect the actual excess RINs and preclude their rollover. However, the annual calculation of the cap would require that the total renewable fuel volumes from the previous year be known. For compliance year 2009, information on 2008 renewable fuels production would not generally be known until spring of 2009. Therefore, obligated parties would not know until mid-year at the earliest what the exact cap would be for that year. The Agency could publish an estimate of the cap by the end of the previous year, but it would not provide obligated parties with the certainty they may need for establishing contracts and business relationships for RIN trading. In addition, such a variable cap may not ensure a smoothly functioning RIN market under all possible market conditions. Market flexibility is needed most when the RIN market is the tightest (i.e. when renewable fuel production volumes are closest to the volumes required under the RFS program). Yet under this alternative approach, the cap would be the smallest when supply was closest to demand for

RINs. The cap would approach zero as supply approached the volumes required under the RFS program, and thus an obligated party that had even a small number of excess RINs from the prior year could not use them, but rather would be forced to trade them to someone else. Conversely, when supply significantly exceeds demand and market flexibility is needed least, the cap would be the highest. 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.

The level of 20 percent is also consistent with both past ethanol market fluctuations and future projections of excess ethanol. 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. Furthermore, as illustrated in Table III.D.3.c–2, EIA projections indicate that previous year volumes will exceed current-year requirements by roughly 10 to 30 percent between 2009 and 2015. Our proposed 20 percent cap lies in the midrange of these values.

As a result, we believe that a cap of 20 percent appears to be 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 would also ensure that many previous-year RINs can still be used for current year compliance, providing some flexibility in the event of market disruptions.

Despite the flexibility it would provide, a cap of 20 percent would not be guaranteed to be sufficient to address every potential future supply shortfall or fluctuation in the renewable fuels market. Thus we request comment on whether a higher cap, such as 30 percent, would be more appropriate. On the other hand, since EIA is projecting that a cap of 20 percent will be more than what is necessary in the first few years of the program to address rollover, we also request comment on whether a smaller cap, such as 10 percent, would be appropriate.

We also request 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.

In addition to our proposed 20 percent cap, we also evaluated an alternative approach for addressing the RIN rollover issue. Under this alternative, we would not employ a uniform cap at all, but rather would require current-year RINs to be applied towards an obligated party's RVO before any previous-year RINs were considered. This ''last-in, first-out'' (LIFO) approach would eliminate the possibility that previous-year RINs could be used to generate new excess current-year RINs, forcing them to expire. Although it would focus the RIN rollover correction on obligated parties and would tailor it to the specific circumstances of each party, this alternative approach would also create the need for an additional regulatory prohibition. Under this approach, RINs held by non-obligated parties would not automatically expire. As a result, non-obligated parties could in essence serve as a bank of previous-year RINs, thus permitting the rollover to continue despite the imposition of a LIFO protocol. To prevent this, the LIFO approach would have to include a requirement that non-obligated parties be prohibited from owning previous-year RINs. If a non-obligated party were to own a current-year RIN on December 31 and hold it until January 1, that RIN would automatically expire. In order to enforce this provision, the Agency would also need to keep track of and receive reports on all RIN transactions for non-obligated parties by their transaction date.

Given the additional uncertainty and complexity caused by this alternative approach, we believe that our proposed 20 percent cap provides the greatest degree of simplicity and flexibility while still addressing the RIN rollover issue. However, we request comment on any alternative approaches to addressing the RIN rollover issue.

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 generate or purchase sufficient credits to meet 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 has not acquired 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 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 would 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 are not proposing that any particular demonstration of ''inability'' be a prerequisite to the ability of obligated parties to carry deficits forward. However, we request comment on this issue.

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 proposed 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 should not be 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.

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. Ideally the producer of the exported renewable fuel would simply not create RINs for those batches. However, in the fungible distribution system it is common for exportation of fuel to occur without the knowledge of the producer. As a result, we cannot rely on the producers to know which batches will be exported and to not generate RINs for those batches. Another approach would be to increase the obligation placed on refiners, importers, and blenders of gasoline based on the volume of renewable fuel exported. Obligated parties would thus acquire RINs to meet the standard described in Section III.A, and would also be required to acquire RINs to cover the volume of renewable fuel exported. However, this approach would not only require 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 exports.

Given these drawbacks, we believe that these two approaches would be unworkable. As a result, we believe that it should be the exporter's responsibility to account for exported renewable fuel. The most straightforward mechanism to accomplish this would be to assign an RVO to each exporter that is equal to the annual volume of renewable fuel it exported. Just as for obligated parties, then, the exporter would be required to acquire sufficient gallon-RINs to meet its RVO. If the exporter purchased renewable fuel directly from a producer, that renewable fuel would come with associated gallon-RINs which could then be applied to its RVO under our proposed program. In this circumstance, the exporter would not need to acquire RINs from any other source. If, however, the exporter received renewable fuel without the associated RINs, it would need to acquire RINs from some other source in order to meet its RVO.

As discussed in Section III.D.2.c, it may be possible to eliminate the need for RINs altogether in specific circumstances involving exports of renewable fuels. 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. Likewise if a renewable fuel producer specifically and explicitly earmarked a batch of renewable fuel for export, there would be no need for a RIN to be generated. However, in both of these cases the producer would need to report the volumes that were not assigned a RIN to the EPA in its annual RFS report, along with the connection to exports, in order to demonstrate that RINs were legitimately not assigned to these batches. We request comment on these special-case approaches to exported renewable fuels.

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 RINs generated for that batch. For instance, extra-value RINs can be generated in cases where the Equivalence Value is greater than 1.0. If the RVO assigned to the exporter were based strictly on the actual volume of the exported product, it would not capture the extra-value RINs which generally are not assigned to batches. Thus we propose 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 would 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 propose that for such cases the exporter simply 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 renewable fuel had in fact been assigned an Equivalence Value greater than 1.0. However, we believe that the potential impact of this error would be exceedingly small. We request comment on our proposed approach to exporters of renewable fuel and any alternative approaches that could ensure that production volumes of renewable fuel can be used as an accurate surrogate for consumed volumes.

5. How Would the Agency Verify Compliance?

The primary means through which the Agency would verify an obligated party's compliance with its RVO would be the annual reports. These reports would include a variety of information required for compliance and enforcement, including the demonstration of compliance with the previous calendar year's RVO, a list 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 would 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 would 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 would also indicate which RINs were used for compliance with the RVO including any potential deficit, which current-year RINs were not used for compliance and would therefore be valid for compliance the next year, and which previous-year RINs were not used for compliance and therefore expired. The report would also include a demonstration that the 20 percent cap to address RIN rollover had been met, as described in Section III.D.3.c.

In order to verify compliance for each obligated party, the primary Agency activity would involve the validation of RINs. There are four basic elements of RIN validation:

(1) RINs used by an obligated party to comply with its RVO would 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 would be cross-checked with annual 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 would 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 would be checked to ensure that they do not exceed 20 percent of the obligated party's RVO.

In cases where a RIN was highlighted under suspicion of being invalid, the Agency would then need to take additional steps to resolve the issue. In general this would involve a review of RIN transfer records submitted to the Agency by all parties in the distribution system that held the RINs. RIN transfers would be recorded through EPA's Central Data Exchange as described in Section IV. These RIN transfer records would permit the Agency to identify all transaction(s) involving the RINs in question. Liable parties could then be contacted and appropriate steps taken 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 proposed program structure, a Renewable Identification Number (RIN) would be generated for every gallon of renewable fuel produced or imported into the U.S., and would be acquired by obligated parties for use in demonstrating compliance with the RFS requirements. However, there are a variety of ways in which RINs could be transferred from the point of generation by renewable fuel producers to the obligated parties that need them.

EPA's proposal was developed in light of the somewhat unique aspects of the RFS program. As discussed earlier, under this program the refiners and importers 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 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, EPA believes the RIN transfer mechanism should focus first on facilitating compliance by refiners and importers, and doing that in a way that imposes minimum burden on other parties and minimum disruption of current mechanisms for distribution of renewable fuels.

Our proposal 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. EPA's proposal would basically have the RIN follow with the ethanol until the point the ethanol is purchased by the obligated party, or is blended into gasoline by a blender. This approach would allow the RIN to be incorporated into the current market structure for sale and distribution of ethanol, and would avoid 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 proposed program, it is also not required.

The Agency has also evaluated several other options for distributing RINs. We are not proposing 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. At the same time, we recognize that all of the alternatives described below, as well as our proposal, have differing positive and negative aspects, and we invite comment on them, especially comments comparing and contrasting them with our proposed program. Our proposal is described in subsections 1 through 3 below, and alternative approaches in subsection 4.

1. Distribution of RINs With Batches of Renewable Fuel

We are proposing that standard-value RINs be transferred with actual batches of renewable fuel as they move through the distribution system, until ownership of the batch is assumed by an obligated party or by a party that converts the renewable fuel into motor vehicle fuel. After such time, the RINs could be separated from the batch and freely traded. This approach would place 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 specific batches of renewable fuel would 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. They would construct each batch-RIN based on the particular circumstances associated with each batch, including the creation of a unique serial number for the batch and specifying its Equivalence Value. The batch-RIN would also identify the specific number of gallons in the batch, thereby summarizing the gallon-RINs assigned to every gallon in the batch. See Section III.D.2.a for details on our proposed format for RINs.

Only standard-value RINs would have to be assigned to batches. Extra-value RINs could be generated by the renewable fuel producer in cases where the renewable fuel in question has an Equivalence Value greater than 1.0 (see Section III.D.2.c for further discussion). However, the extra-value RINs would not need to be assigned to the batch. Instead, they could be transferred to another party independent of the batch. This requirement would in general result in a one-to-one correspondence between gallons in a batch and the volume block numbers in the batch-RIN assigned to that batch. As a result, the process of dividing and combining RINs during batch splits and mergers would be simplified, and the fungibility of RINs in the distribution system would be maintained. For example, a marketer who took custody of ethanol batches from several different producers, including a producer of cellulosic biomass ethanol, and combined them all in a single tank could then withdraw batches of any size from the tank, and assign a number of gallon-RINs to each batch that is equivalent to the number of actual gallons in that batch. This approach would also provide an incentive for producers to produce renewable fuels with higher Equivalence Values, since they could transfer the extra-value RINs to any party.

However, we are also proposing that producers have the option of assigning even extra-value RINs to batches if they chose to do so. Under these circumstances, the extra-value RINs would be treated just like standard-value RINs, and thus would be subject to the same limitations on who can separate the RIN from the batch. The assignment of extra-value RINs to batches would also mean that the number of gallon-RINs assigned to the batch would be greater than the number of gallons in the batch. As a result, care would have to be taken during batch splits and batch mergers to appropriately pass RINs assigned to a parent batch on to the daughter batches. We request comment on allowing extra-value RINs to be assigned to batches.

There are two other cases in which the gallon-RINs assigned to a batch would 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 RINs could only be assigned to a portion of the batch. Such potential circumstances are described in Section III.D.2.d. 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 proposing that all batch volumes be corrected to represent a standard condition of 60 °F prior to the assignment of a RIN. For ethanol,[32] we propose that the correction be done as follows:[33]

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

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 would be consistent with current practices and would maintain the one-to-one correspondence between the volume block in the batch-RIN and the standardized volume of the batch. We propose a similar approach to biodiesel, where the volume correction can be calculated using the following equation:[34]

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

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.

The RIN would have to be assigned to a batch no later than the point in time when the batch physically leaves the production or importing facility. Although ownership of the batch may be retained by the producer or importer, the RIN would nevertheless be required to be transferred along with the batch as it leaves the originating facility. This requirement would ensure that RINs could be verified against production or importing facility records and against mandated reports to the Energy Information Administration (EIA). It would also centralize the process of assigning RINs to batches.

The means through which RINs would be transferred with batches would in some respects be left to the discretion of the renewable fuel producer or importer. The primary requirement would be that the RIN be included 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 batch. The batch documentation must be of the sort that uniquely identifies the batch and is generally transferred from one party to another, in electronic or paper form, when ownership of the batch is transferred. In many cases a bill-of-lading could serve this purpose. The RIN must be displayed prominently on the document when the batch leaves the originating facility, so that parties taking ownership of the batch could make a record of this fact with specific reference to the RIN. The RIN must be included on a PTD whenever ownership or custody of the batch is transferred, until such time as the RIN may be separated from the batch as described in Section III.E.2. 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 would be transferable in the context of the RFS program, and except as discussed above, must be transferred along with ownership or custody of the batch. The approach that a producer or importer takes to the transfer or sale of RINs and batches would be at their discretion, under the condition that the two be transferred or sold simultaneously and to the same party.

b. *Responsibilities of Parties That Buy, Sell, or Handle Renewable Fuels.* Batches 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 batches, 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 batch of renewable fuel can be owned or held by any number of parties including marketers, distributors, terminal operators, and refiners. Under our proposed program, when any party takes ownership of a batch of renewable fuel prior to ownership of the batch of fuel by an obligated party or blender, the RINs associated with that batch must be transferred as well. The RINs would be included on PTDs that the party procures when taking ownership of a batch.

We propose that in general all parties that assume ownership of any batch of renewable fuel be required to transfer all RINs assigned to that batch to another party to whom ownership of the batch is being transferred. Batch splits and batch mergers represent special cases of RIN transfers, and are described in more detail below. As described in Section III.E.2, the only exception to the requirement that RINs be transferred with batches would be parties who are obligated to meet the renewable fuel standard, and parties who convert the renewable fuel into motor vehicle fuel. Since our proposed program is designed to allow RIN transfer and documentation to occur as part of normal business practices in the context of renewable fuel distribution, the incremental costs of transferring RINs with batches should be minimal. Marketers and distributors would simply be adding the batch-RIN to transfer documents such as bills-of-lading, and recording the batch-RINs in their records of batch purchases and sales.

Under most other credit trading programs, parties obligated to meet a standard are also the parties that generate credits for trade. Under these systems, non-obligated parties can participate only to the degree that obligated parties explicitly include them. In the case of the RFS program, however, the production of renewable fuels and their conversion into motor vehicle fuel through blending is largely done by persons other than obligated parties. To the degree that our proposed program allowed the disparity between RFS obligations and the means of compliance to continue, stakeholders have expressed concerns about a variety of problems that could arise, such as market power by RIN sellers in the market where RINs are exchanged. Market power on the part of non-obligated parties could result in higher prices for RINs than prices that would arise in a competitive, well-functioning market setting. For instance, if a renewable fuel producer or marketer could separate the batch-RIN from the batch, he could in theory withhold the RIN from the marketplace temporarily. By the end of an annual compliance period, a scarcity of RINs could increase their price, at which point the renewable fuel producers or marketers could begin to sell the RINs at an inflated price. In the extreme such parties could potentially withhold a large number of RINs from the market, creating a scarcity of RINs that could compel obligated parties to purchase additional volumes of renewable fuel with associated RINs. These scenarios are of particular concern given that we expect there will be a relatively small number of renewable fuel producers and marketers selling RINs in the

[32] An appropriate temperature correction for other renewable fuels should likewise be used.

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

[34] 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.

marketplace. For instance, although there currently exist about 100 ethanol production facilities in the U.S., nearly half of the production volumes come from only seven companies. Likewise, only five companies manage the majority of ethanol marketing.

We believe that the general prohibition against the separation of RINs from batches in the distribution system will place only a small additional burden on marketers and distributors of renewable fuel. According to several stakeholders, a large amount of ethanol is already purchased from renewable fuel producers directly by refiners. In these cases, the RIN would be transferred directly from the renewable fuel producer to an obligated party. For the remaining batches of ethanol that do experience multiple transfers before being blended into gasoline, the RIN itself would represent a small incremental item of information that must be recorded and transferred along with batches and could be included in normal business records.

In addition to the recordkeeping responsibilities described in more detail in Section IV, parties that would be required to transfer RINs with batches under our proposed program would also have the primary responsibility of maintaining the integrity of RIN-batch pairing when batches are split or merged. Our proposed approach to these situations is described below.

i. Batch splits

As described in Section III.D.2, batch-RINs assigned to batches of renewable fuel would be formatted such that the volume block codes (SSSSSS and EEEEEE) would identify every gallon in a batch, and thus every gallon-RIN. Thus in most cases there will be a one-to-one correspondence between gallons in a batch and the volume block codes for the batch-RIN assigned to that batch. If a batch of renewable fuel is split into two or more new batches, the gallon-RINs assigned to the original batch can be split coincidentally with batch volumes. The following example shows how this would be done (volume blocks separated for clarity):

Parent batch:

1000 gallons,
batch-RIN: 2007123412345000011021–000001–001000.

Daughter batch #1:

600 gallons,
batch-RIN: 2007123412345000011021–000001–000600.

Daughter batch #2:

100 gallons,
batch-RIN: 2007123412345000011021–000601–000700.

Daughter batch #3:

300 gallons,
batch-RIN: 2007123412345000011021–000701–001000.

In this example, the gallon-RINs remain both unique and paired on a one-to-one basis with actual gallons even after the parent batch is divided into smaller daughter batches.

However, there will be some cases in which there is not a one-to-one correspondence between a RIN assigned to a batch and the actual gallons in that batch, and such cases could complicate the process of splitting batches. For instance, changes in temperature could cause batch volumes to swell or shrink. Renewable fuels with Equivalence Values less than 1.0, although currently unlikely to arise in appreciable volumes, will have more actual gallons in the original batch than RINs assigned to that batch. And some producers may choose to assign extra-value RINs to batches in cases wherein the Equivalence Value is greater than 1.0.

To address such cases, we propose to allow parties in the distribution system the discretion to split batches and their assigned RINs following any protocol they choose, as long as that protocol preserves the requirement that gallon-RINs that have been assigned to a batch by the producer are subsequently assigned to a batch after splitting has occurred. Thus regardless of the splitting protocol used, no gallon-RINs assigned to a batch could be retained by a party after every gallon in that batch has been transferred to another party.

There are a variety of batch splitting protocols that a party could choose from for situations where there is not a one-to-one correspondence between the number of gallon-RINs assigned to a batch and the number of standardized gallons in that batch. However, we have identified two acceptable protocols that we expect most parties to use. These are described in Table III.E.1.b.i–1 below. Examples of batch splits using both types of splitting protocols are given in Tables III.E.1.b.i–2 and III.E.1.b.i–3. We propose that the Proportional Protocol be required for cases in which the Equivalence Value of a renewable fuel is less than 1.0. For cases in which the Equivalence Value is equal to or greater than 1.0, we propose to allow parties the flexibility to follow a batch splitting protocol of their own choosing so long as there is at least one gallon-RIN for every physical gallon in each of the daughter batches. We request comment on these batch splitting protocols, any alternative protocols, and the need to codify a protocol in the regulations for specific situations.

TABLE III.E.1.B.I–1.—TWO BATCH SPLITTING PROTOCOLS

	Proportional	One-to-one alignment
Description	The gallon-RINs assigned to a parent batch are split proportionally with the volumes in the daughter batches.	The gallon-RINs assigned to a parent batch are split to ensure that some daughter batches have a one-to-one correspondence between physical gallons and gallon-RINs. Remaining gallon-RINs are assigned to remaining gallons.
Impacts for EV[a] < 1.0	Ratio of actual gallons to gallon-RINs in the parent batch is preserved in all daughter batches.	Some daughter batches may have no assigned RIN.
Impacts for EV > 1.0	Ratio of actual gallons to gallon-RINs in the parent batch is preserved in all daughter batches.	Ratio of actual gallons to gallon-RINs in some daughter batches will be different than the ratio for the parent batch.

[a] Equivalence Value.

TABLE III.E.1.B.I–2.—EXAMPLE OF PROPORTIONAL BATCH SPLITTING

	EV < 1.0	EV > 1.0
Parent batch:		
Actual volume (gal)	[1] 1000	[1] 1000
Batch-RIN SSSSSS code	000001	000001
Batch-RIN EEEEEE code	000800	002500
Number of gallon-RINs	800	2500
Daughter batch #1:		
Actual volume (gal)	[1] 600	[1] 600
Batch-RIN SSSSSS code	000001	000001
Batch-RIN EEEEEE code	000480	001500
Number of gallon-RINs	480	1500
Daughter batch #2:		
Actual volume (gal)	[1] 400	[1] 400
RIN volume block start (SSSSSS)	000481	001501
RIN volume block end (EEEEEE)	000800	002500
Number of gallon-RINs	320	1000

[1] gal.

TABLE III.E.1.B.I–3—EXAMPLE OF BATCH SPLITTING WITH ONE-TO-ONE ALIGNMENT

	EV < 1.0	EV > 1.0
Parent batch:		
Actual volume (gal)	[1] 1000	[1] 1000
Batch-RIN SSSSSS code	000001	000001
Batch-RIN EEEEEE code	000800	002500
Number of gallon-RINs	800	2500
Daughter batch #1:		
Actual volume (gal)	[1] 600	[1] 600
Batch-RIN SSSSSS code	000001	000001
Batch-RIN EEEEEE code	000600	000600
Number of gallon-RINs	600	600
Daughter batch #2:		
Actual volume (gal)	[1] 400	[1] 400
Batch-RIN SSSSSS code	000601	000601
Batch-RIN EEEEEE code	000800	002500
Number of gallon-RINs	200	1900

[1] gal.

ii. *Batch mergers.*

In general batch mergers will begin with at least two parent batches having different RINs. After the merger of the two parent batches, the RINs from the two parents would simply need to be listed separately on any product transfer documents such as bills-of-lading, since they differ not just in the volume block codes but also in other aspects of the RIN. We are not proposing any mechanism for simplifying the RIN in the case of a batch merger, such as combining two different RINs into a single RIN or replacing a collection of different RINs with a new single RIN. We believe that such approaches would be likely to create significant difficulties in tracking RINs and verifying their validity.

Parties that have two or more batches of renewable fuel that have been merged into a single batch will be free to determine how the RINs will be subsequently split and assigned to new daughter batches during a batch split. We are not proposing a specific protocol for such cases, beyond the general requirement that RINs that have been assigned to parent batches remain assigned to a daughter batch after splitting has occurred. However, it may be helpful for RINs to be ordered on PTDs in the order in which the batches were combined, and then assigned to daughter batches on a first-in, first-out basis. Thus as individual parent batches are added to, for instance, a tank already containing renewable fuel, the RINs associated with the newly added batch could be added below the existing RINs on the documentation. As product was drawn back out of the tank, the RINs assigned to the removed product would be those at the top of the list of RINs on the tank documentation. This FIFO approach would ensure that RINs assigned to parent batches continue to move through the distribution system, and batch splits could occur straightforwardly even in cases that begin with merged batches. We request comment on whether this FIFO approach should remain guidance or whether instead it should be a regulatory requirement.

2. Separation of RINs From Batches

Separation of a RIN from a batch means that the RIN would no longer be included on the PTD, and could be traded independently from the batch to which it had originally been assigned.

We believe that the regulatory program should be structured around facilitating compliance by obligated parties with their renewable fuel obligation. This means that obligated parties should have the right to market the renewable fuel separately from the RIN originally assigned to it. We are therefore proposing that a refiner or importer would have the right to separate the RIN from the batch as soon as he assumes ownership of that batch. In the case of ethanol blended into gasoline at low concentrations (≤ 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 batches 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 believe that a blender should also have the right to separate the RIN from the batch if he actually blends the ethanol into gasoline. This would only apply to batches where the RIN had not already been separated by an obligated party. Since blenders would in general not be obligated parties under our proposed program, blenders who separate RINs from batches would have no need to hold onto those RINs and thus could transfer them to an obligated party for compliance purposes, or to any other party.

There may be occasions in which a downstream customer actually owns the batch of ethanol when it is blended into gasoline. In such cases the blender will have custody but not ownership of the batch. We propose that the RIN can be separated from the batch of ethanol when the batch is blended into gasoline, but the RIN could only be separated by the party that owns that batch of renewable fuel at the time of blending.

Once a RIN is separated from a batch of renewable fuel, the PTDs associated with that batch could no longer list the RIN. Parties who subsequently take ownership of the batch may not know if the RIN had been separated, or if a RIN had never been assigned to the batch in the first place, contrary to regulatory requirements. To avoid concerns about whether RINs assigned to batches have not been appropriately transferred with the batch, we request comment on whether PTDs should include some notation indicating that the assigned RIN has been removed.

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 may not be captured. This would include such renewable fuels as neat biodiesel (B100), methanol for use in a dedicated methanol vehicle, biogas for use in a CNG vehicle, or renewable diesel used in its neat form.

As for ethanol and biodiesel, neat renewable fuels would be assigned a RIN by the producer. However, in cases where the neat renewable fuel is never owned by an obligated party or blended into gasoline or diesel before being used as a motor vehicle fuel, no party would have the right to separate the RIN from the batch. The RIN would therefore never become available to an obligated party for RFS compliance purposes. Although the current use of these neat renewable fuels is minor in comparison to the volumes of ethanol and lower blend levels of biodiesel, we nevertheless believe that they should be allowed to help meet the volume requirements of the RFS program.

To address this issue, we propose to more broadly define the right to separate a RIN from a batch. In addition to obligated parties and blenders, we believe that any party holding a batch of renewable fuel for which the RIN has not been separated could separate the RIN from the batch 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. Given the lack of any significant use of ethanol in its neat (but denatured) form as a motor vehicle fuel, RINs for neat ethanol could only be separated by an obligated party or a party that blends it with gasoline. This would include a party that blended ethanol with a small amount of gasoline to form E85, since there are millions of vehicles in the fleet that can operate on E85. In this case, E85 would be treated like any other ethanol/gasoline blend.

Under our proposed approach, therefore, any party that holds a batch of renewable fuel that is typically used in its neat form and was designated by the producer for use in its neat form as a motor vehicle fuel would be given the right to separate the RIN from the batch. 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.

Biodiesel (mono alkyl esters) 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, including the following:

- To reduce impacts on fuel economy.
- To mitigate cold temperature operability issues.
- To market biodiesel as an additive rather than an alternative fuel.
- To address concerns of some engine owners or manufacturers regarding the impacts of biodiesel on engine durability or drivability.
- To reduce the cost of the resulting fuel.

Biodiesel 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 is occasionally used in its neat form. However, this approach is the exception rather than the rule. Consequently, we propose that the RIN assigned to a batch of biodiesel could only be separated from that batch if and when the biodiesel is blended with conventional diesel. To avoid claims that very high concentrations of biodiesel count as a blended product, we also propose that biodiesel must be blended into conventional diesel at a concentration of 80 volume percent or less before the RIN can be separated from the batch.

Our proposed approach to biodiesel would mean that biodiesel used in its neat form would not be valid for compliance purposes under the RFS program. To address this issue, we request comment on additionally allowing a biodiesel producer to separate the RIN from the batch if it could establish that it produced the batch of biodiesel specifically for use as motor vehicle fuel in its neat form, and that the biodiesel was in fact used in its neat form.

3. Distribution of Separated RINs

Once a RIN is separated from a batch of renewable fuel, it would become freely transferable. Each RIN could be held by any party, and transferred between parties any number of times. This approach would apply to extra-value RINs (RINs generated based on Equivalence Values greater than 1.0) as well as standard-value RINs.

We are not proposing to limit the number of times that a RIN could be transferred, nor the types of parties that could receive or transfer RINs. However, this approach would be unique among EPA's fuel regulations. For all previous motor vehicle fuel credit trading programs we have allowed only refiners and importers to transfer credits, and have limited the number of times credits could be transferred to one or two transfers. This includes, for example, the credit trading programs for reformulated gasoline and gasoline sulfur. These limitations were included to make the credit trading programs enforceable by making the transfer of credits, from the credit generator to the credit user, shorter, and populated only by the refiners and importers who were obligated to meet those standards. These approaches also helped to ensure the validity of credits by limiting the sources of credits to companies that the obligated parties know to be reliable business partners. A recent report provided to the Agency by the American Petroleum institute also provides support for limiting RIN trading to obligated parties.[35] Therefore, we are seeking comment on limiting the number of trades and limiting the trades to only occur between obligated parties even though we are not proposing to do so here.

For the RFS program, we believe that there is a need to provide for this more open trading, and that it can occur without unduly sacrificing the enforceability of the program or increasing its oversight burden. As described earlier, the RFS program is unique in that obligated parties are typically not the ones producing the renewable fuels and generating the RINs, so there is a need for trades to occur between obligated parties and non-obligated parties. By prohibiting anyone except obligated parties from holding RINs after they have been separated from a batch, we might be making it more difficult for those RINs to eventually be transferred to the obligated parties that need them. This is especially important in the case of the RFS program, because the program must work efficiently not only for a limited number of obligated parties, but a number of non-obligated parties as well. A potentially large number of oxygenate blenders, many of which will be small businesses, will be looking for ways to market their RINs. Furthermore, in some cases renewable fuel producers will also have RINs (in particular, extra-value RINs) that can be marketed. Allowing other parties, including brokers, to receive 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.

We believe we can ensure the enforceability of the program despite opening up trading to non-obligated parties and allowing multiple trades. The RIN number, along with the associated electronic reporting mechanism, should allow 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 would be straightforward. The number of RIN trades, and the parties between whom the RINs are being traded, would only have the effect of increasing the size of the database.

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. would be at the discretion of the parties involved. The Agency would be 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 would therefore be the subject of various recordkeeping and reporting requirements as described in Section IV, and these requirements would generally apply regardless of whether RIN has been separated from a batch.

The means through which RIN trades would occur would also be at the discretion of the parties involved. For instance, parties with RINs could 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 willing party. Brokers involved in RIN transfer could either operate in the role of arbitrator without holding the RINs, or alternatively could receive the RINs from one party and transfer them to another. If they are the transferee of any RINs, they would also be subject to the registration, recordkeeping, and reporting requirements. We do not believe that it would be appropriate or useful for the EPA to become directly involved in RIN transfers, other than in the role of providing a database within which transfers can be recorded. Thus EPA would not plan on establishing a clearinghouse or centralized brokerage for the management of RIN transfers, nor contract with a private firm through whom all RIN buyers and sellers would arrange transfers. Our experience with other credit trading programs suggests that, left to themselves, natural free-market mechanisms will arise to handle RIN transfers, and that these mechanisms will maximize the efficiency of the market while minimizing the transaction costs for transfers of RINs.

4. Alternative Approaches to RIN Distribution

During the development of our proposed RFS trading and compliance program, stakeholders offered a variety of alternative program design approaches. Most of these alternatives recognize the value of a RIN-based system of compliance, but they differ in terms of which parties would be allowed to separate a RIN from a batch and the means through which the RINs should be transferred to obligated parties. We invite comment on all of these options.

Our primary concern with the alternative approaches is that we believe they would be less effective than our proposed program at ensuring that RINs would get to the obligated parties who need them in a timely fashion. As described above, stakeholders have expressed serious concerns about any program structure that could allow non-obligated parties to exercise market power in the RIN market, and the program we are proposing today is designed to minimize these concerns. The alternative approaches described below, in contrast, could potentially allow some non-obligated parties who acquire RINs to either refuse to transfer them, make them difficult for obligated parties to obtain, or drive their price up by exercising market power. We believe that these stakeholder concerns about alternative program options are legitimate, given that nearly half of the production volumes of ethanol come from only seven companies and only five companies manage the majority of ethanol marketing. Our proposal also best addresses other related issues, such as limiting the number of obligated parties, providing for the most open RIN market, and providing an effective means at ensuring RIN certainty.

a. Producer With Direct Transfer of RINs. One alternative to our proposed program would allow producers and importers of renewable fuels to transfer RINs separately from the renewable fuel that they represent. The producer or importer would still generate the RIN, but would not necessarily need to assign it to a specific batch of renewable fuel. The producer or importer would be required to transfer the RIN, but only to an obligated party.

Under this approach non-obligated parties other than producers and importers would have no RIN ownership opportunities and would therefore not bear any burden associated with transferring RINs with batches.

[35] Montgomery, David W., ''Recommendations for a Trading Program Which Will Comply with the Renewable Fuel Standard,'' CRA International, Inc. May 25, 2006.

This would eliminate most of the recordkeeping and reporting requirements applicable to them under our proposed program. There would also be no need for any regulatory requirements to ensure proper accounting of RINs as they move through the distribution system, such as requirements necessary to address volume changes due to temperature, batch splits and mergers, use of renewable fuels in their neat form, and the recordkeeping and reporting associated with these requirements.

The challenges associated with this approach, however, pertain to the disconnect between RINs and batches of renewable fuel. For instance, the disconnect would produce the possibility for the creation of market power with the renewable fuel producer that generates the RINs. As discussed above, there is the possibility that renewable producers might not place all RINs on the market for procurement by the obligated parties, thereby driving up their price and/or increasing further the demand for renewables. It is very unlikely that they would withhold renewable fuel itself from the market in order to drive up the price for it. Not only is storage capacity limited, but there is no evidence that ethanol producers or marketers have ever exercised this type of market control. This is also true under our proposed program.

In addition, although a refiner could purchase renewable fuel directly from a producer and acquire RINs at the same time, there would be many other cases in which a refiner would purchase renewable fuel without RINs (such as from a marketer). Although the market would likely develop in such a way that renewable fuel without RINs would be priced differently than renewable fuels with RINs, the purchase of the renewable fuel would still have no bearing on the refiner's RFS compliance demonstration, contrary to the intent of the Act. The refiner would have to procure RINs separately. If the refiner purchased more renewable fuel than it needed for compliance purposes in this way, it would not have any excess RINs to transfer to another party. The Act stipulates that allowances must be made for credits to be generated for excess renewable fuel.

To address the concern regarding producers withholding RINs from the market, under this alternative the renewable producer would be required to make the RINs available for transfer to an obligated party. As under the proposed option, this RIN transfer could be done in one of several ways, such as through direct contract or a restricted clearinghouse. Any RINs not provided directly to an obligated party would then need to be made available through a regularly scheduled public auction to the highest bidder. This could be through an existing internet auction Web site, or through another auction mechanism implemented by a generator so long as the mechanism is equally open and available to all obligated parties. Only obligated parties would be permitted to bid on the RINs in such an auction.

To ensure the effectiveness of such an approach, however, there are a number of additional aspects of the program that would need to be specified. Since a renewable producer could essentially withhold RINs from the market by setting the selling price too high, such an approach would hinge upon any such auctions occurring without any minimum price for the RINs. Producers would be required to transfer RINs to the highest bidder regardless of the bid price, even if there was only a single bidder. The renewable producer would be required to send the successful bidder a written confirmation of the RIN transfer, including the RIN identification numbers. If there were no bids, the renewable producer would be required to roll them over to subsequent auction cycles until such time as the RINs were no longer valid for compliance purposes and they would simply be retired. Finally, in order to ensure that RINs were actually being made available, such sales, trades, or auctions would be required to occur at least quarterly, but we seek comment on whether a shorter cycle would be more appropriate.

Various other aspects of the RIN auctions or transactions would also have to be specified. For example, the location, time, and other details of any auction would have to be made widely known to obligated parties in sufficient time for them to participate. To this end, the rule could specify that there must be advance public notice of the intent to conduct an auction and the auction procedures, and that this notice must be advertised through nationwide media or a public Internet posting. The minimum amount of advance notice could be, for example, one week or four weeks. The regulations could require that the RINs be transferred in large enough blocks, such as 5,000 RINs, in order to prevent undue transaction costs. The regulations could also specify the time period during which any public auction must remain open; seven days could be specified, for example. Other criteria for how the auction is conducted could be included in order to ensure its legitimacy. Interested commenters should include details for RIN auctions or transactions that they believe should be addressed in implementing regulations.

Our proposed program is designed to ensure that the existing market mechanisms for the distribution of renewable fuel can be used for the distribution of RINs as well. The need for independent RIN markets is minimized, and likewise the regulatory oversight of such markets is minimized. Under the direct transfer alternative described above, however, not only does an independent RIN market become a central feature of the RFS program, but the regulations might need to specify the many various aspects of RIN transfers as described above, and doing so would represent an intervention into the market that the Agency has not exercised before. It may be necessary to design the regulatory provisions in this way in order to have an enforceable program under this alternative, but we would have to be convinced that such an approach could be properly structured and that it was superior to other alternatives.

Under this option, non-obligated parties such as marketers or brokers would not be allowed to own RINs. It could be possible to add in this flexibility, but in effect this option would then operate similarly to our proposed approach, but with additional complications and transaction costs due to the fact RINs would not follow batches through the distribution system. Therefore, we do not believe it is appropriate to provide this flexibility as part of the direct-transfer option.

b. Producer With Open RIN Market. Another approach would allow producers and importers of renewable fuels to transfer RINs separately from the renewable fuel to any party. If a renewable fuel producer did choose to transfer the RIN with the batch, any downstream party would have the right to separate that RIN from the batch.

Although we believe that the recordkeeping burden placed upon marketers and distributors under our proposed program would be minimal, this alternative approach would essentially eliminate that burden altogether. Marketers and distributors would not have to ensure that RINs were transferred with batches and keep a record of those transfers, and would not be responsible for ensuring that RINs remain assigned to batches during batch splits and mergers. Any marketer or distributor that did receive a batch with an assigned RIN could separate the RIN from the batch and transfer it, maximizing the choices available to them.

However, this alternative approach would increase the burdens for obligated parties to comply with their renewable fuel obligation since all RINs would be controlled by producers and marketers at the point of generation. The concerns described above regarding the exercising of market power in the RIN market by a small number of non-obligated parties would apply to this alternative. Although these concerns may be less significant under EIA's current projections that renewable fuel production volumes will exceed the RFS program requirements, we believe that we should design the RFS program to function smoothly under any future market scenario. Since it is possible that the market conditions leading to EIA's projections could change, we believe that the concern about producers and marketers exercising market power in the RIN market is important. As a result, we do not believe that this alternative approach is most appropriate.

c. First Purchaser. As under our proposed approach, in this alternative the renewable fuel producer would be required to assign a RIN to every batch of renewable fuel and to transfer that RIN with the batch. However, the first party in the distribution system to take ownership of the batch would have the right to separate the RIN from the batch. This means that any non-obligated party that purchased the renewable fuel from its producer would be able to separate the RIN and to transfer it independently from the batch.

The advantage of this alternative approach, as compared to our proposal, is that it would remove control of the sale of RINs from the producers. However, the concern raised by refiners about the exercise of market power in the RIN market remains because only five companies today manage the majority of ethanol marketing in the U.S. With such a small number of companies, any one could exert a controlling influence on the RIN market. In addition, many large producers operate as marketers for other smaller producers, allowing some producers to be the first purchaser. As discussed for the previous alternative, we believe that we should design the RFS program to function smoothly under any future market scenario, including ones different from those forming the basis of the current EIA projections. Thus we believe that the concern about marketers exercising market power in the RIN market is still important, and as a result we do not believe that the first purchaser approach offers significant advantages over our proposed program.

d. Owner at Time of Blending. An alternative approach to our proposed option of allowing obligated parties to separate RINs as soon as they gain ownership would prohibit all parties from separating a RIN from a batch of renewable fuel until the batch had actually been blended into gasoline or diesel. The obligated party could retain the RIN as soon as it gained ownership of the batch, but could not transfer the RIN or use it for compliance purposes until the renewable fuel that it represented was actually blended into gasoline or diesel. Thus, a RIN could be separated from the batch of renewable fuel to which it has been assigned only at the time of blending, and whomever owns the batch at the time of blending would also have the right to separate the RIN and use or transfer it.

Although we based our proposed program design on the expectation that all renewable fuels will eventually be consumed as fuel, primarily through blending with conventional gasoline or diesel, this alternative approach would provide direct verification of blending. However, we do not believe that this is necessary in order to provide an enforceable program, and in fact it would create an additional and unnecessary burden for blenders.

As discussed in Section III.D, it is not necessary to track renewable fuels all the way to the point of blending because we can confidently treat production volumes as an accurate surrogate for consumption. This fact provides the basis for our proposed program, and could also be used in support of the alternatives described previously. 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 proposed program.

By requiring refiners to wait until renewable fuel is blended before they can separate the RIN, this 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, we do not believe that this represents an advantage to this alternative since it could not occur under our proposed program either. There are no geographic limitations to RIN transfers within the 48 contiguous states, so obligated parties that need RINs can purchase them from any refiner who has an excess. 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, thereby demanding an unreasonably high price for them.

For these reasons, we do not believe that requiring renewable fuel to be blended into gasoline or diesel before a RIN could be separated from the batch would provide any significant advantages over our proposed program. However, we request comment on this alternative approach.

e. Blender at Time of Blending. Although we have concluded that production volumes are an accurate surrogate for consumption, thus eliminating the need to measure renewable fuel volumes at the point of blending into gasoline or diesel, an alternative approach would do just that.

In this alternative program approach, RINs would not be generated by the producer of the renewable fuel and assigned to batches. Instead, blenders would keep detailed records of the volumes of renewable fuel that they blended into gasoline or diesel, and would generate credits for those volumes. Blenders would be considered obligated parties, but their obligation would be considered as zero percent to avoid redundant obligations (i.e., to avoid the blender being responsible for blending renewable fuel into gasoline for which a refiner or importer also has an RFS program responsibility). Thus they would generate credits which could then be sold to a refiner or importer who needs it for compliance purposes.

The blender approach would differ from our proposed program and all the other alternative approaches in that it would be based on actual blending activity, as compared to ownership of the renewable fuel. Under this alternative approach, the blender would not use records of batch ownership to establish generation of credits, but rather would be required to demonstrate that it had actually blended the renewable fuel into gasoline or diesel. Since the blender was responsible for blending, the blender would generate the credits from that blending and would have the right to transfer them to another party.

Although blenders could use IRS fuel credit forms to verify the volumes of ethanol blended into gasoline under this alternative, the IRS forms would not provide useful information related to biodiesel or other renewable fuels that are blended into conventional gasoline or diesel.[36] Alternative approaches to verifying that these other renewable fuels were actually blended would therefore need to be designed under this alternative, and these verifications would necessarily involve additional recordkeeping and reporting requirements.

This approach would also tend to increase the burdens on refiners to gain access to credits and thus demonstrate compliance. A refiner who took ownership of a batch of renewable fuel could not use that batch to meet its RVO unless he blended it into gasoline or diesel himself. Such circumstances would create additional complexity for the obligated parties that are avoided by the more streamlined approach we are proposing.

A blender approach would also be difficult to implement. To begin with, many blenders are small businesses, and none have been substantially regulated in an EPA fuel program before. We would be imposing upon these parties the primary enforcement burden associated with the RFS program even though they are not obligated for meeting the renewable fuel standard. Also, this approach would not be able to distinguish between cellulosic biomass ethanol and ethanol made from other feedstocks, which creates significant difficulties in meeting program requirements.

Under a blender approach, even accurate records of blending would be difficult to verify. There are more than 1200 blenders in the U.S. who blend ethanol into gasoline, in addition to those that blend biodiesel into conventional diesel fuel. Thus the blender approach would maximize the number of parties involved, overly complicating the compliance system. The enforcement burden on the Agency would be significant, and ultimately it would be likely that many claims of blending would go unchecked.

Some of the concerns raised above could be addressed by re-introducing the RIN concept into a blender approach. For instance, the existence of RINs could help identify cellulosic biomass ethanol as such. However, if a RIN-based system were implemented, this alternative approach would become very similar to our proposed program, but with additional enforcement burdens placed upon blenders. As a result the advantages of this alternative approach over our proposed program would disappear.

Due to the additional and unnecessary recordkeeping and reporting burdens that would be placed upon blenders under this alternative, the dissociation of credits from renewable fuels acquired by obligated partiers, and the likelihood that many blending events may go unchecked, we do not believe that the alternative blender approach should be adopted.

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. We are proposing to utilize the same basic forms for registration that we use under the reformulated gasoline (RFG) and anti-dumping program.[37] These forms are well known in the regulated community and are simple to fill out. Information requested includes company and facility names and addresses and the identification of a contact person with phone number and e-mail address. Registrations do not expire and upon receipt of a completed registration form, EPA will issue unique company and facility identification numbers that will appear in compliance reports and, in the case of renewable fuels producers, will be incorporated in the unique RINs they generate for each batch of renewable fuel. We intend to use the same simplified registration method we use for existing fuels programs under 40 CFR part 80, and parties who have already registered with EPA under an existing fuels program will not be required to re-register and will be able to use their existing EPA-issued company and facility registration numbers.

We plan to use a simplified method of reporting via the Agency's Central Data Exchange (CDX). CDX will permit us to accept reports that are electronically signed and certified by the submitter in a secure and robustly encrypted fashion. Guidance for reporting will be issued prior to implementation and will contain specific instructions and formats consistent with provisions in the final rule. We intend to accept electronic reports generated in virtually all commercially available spreadsheet programs and to permit parties to submit reports in comma delimited text, which can be generated with a variety of basic software packages. 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 included in a compliance database managed by EPA's Office of Transportation and Air Quality and will be reviewed for completeness and for potential violations. Potential violations will be referred to enforcement personnel.

Records related to RIN transactions may be kept in any format and the period of record retention by reporting parties is five (5) years, which is the time frame for retention under similar 40 CFR part 80 fuels compliance reporting programs. Records retained would include copies of all compliance reports submitted to EPA and copies of product transfer documents (PTDs). Records would have to be provided to the Administrator or the Administrator's representative upon request and they may have to be converted to a readable, usable format.

B. Requirements for Obligated Parties and Exporters of Renewable Fuels

1. Registration

We are proposing that ''obligated parties'' including refiners, importers, and blenders of gasoline, as well as exporters of renewable fuel, must register with EPA by [90 DAYS AFTER FINAL PUBLICATION OF THE FINAL RULE]. Most refiners and importers are already registered with us under various regulations related to reformulated (RFG) and conventional gasoline or diesel fuel. We propose that these existing registrations be applicable under the renewable fuel standard as well. Exporters of renewable fuels may not have registered with EPA and we anticipate perhaps 25 new registrations and 25 updated registrations because of this program. If a party becomes subject to this proposed regulation after the effective date, then we propose that they must register with us and receive their EPA-issued company and facility registration numbers prior to engaging in any transaction involving RINs.

Any party who is not currently registered with us would have to submit a simple registration form. We will issue a 4-digit company identification number and, for each facility registered, a 5-digit facility identification number. Currently registered parties will only be

[36] There is some evidence that biodiesel producers are operating as blenders in order to claim the right to the Federal excise tax credit for biodiesel. However, in these cases they often blend only very small amounts of conventional diesel into biodiesel, such as 0.1 volume percent. The mixture, identified as B99.9, is then transported to another blender who often adds significant additional quantities of conventional diesel to make blends such as B2 or B20.

[37] Please refer to *http://www.epa.gov/otaq/regs/fuels/rfgforms.htm.* The relevant registration forms for our existing fuels programs are 3520–20A, 3520–20B, and 3520–20B1. Interested parties may wish to view these forms, as they may be useful in preparing comments on this proposed rule.

responsible for updating company and facility records as the need to update routine information arises, for example, if corporate points of contact or addresses change. Currently registered refiners and importers would continue to use their existing 4-digit company and 5-digit facility identification numbers.

2. Reporting

There are three types of reports that would be required of obligated parties and exporters of renewable fuel. Reports would be required to be submitted on an annual basis by the February 28 following a given January through December annual compliance period.

The first type of report would provide the compliance demonstration. It would require obligated parties to provide information about their annual volume of gasoline produced or imported, and would require exporters to provide information about their annual volume of renewable fuel exported. The report would also describe the calculation of their corresponding renewable volume obligation (RVO), a listing of the RINs applied towards the RVO, any deficit carried over from the previous year, and any deficit carried into the next year.

The second type of report would provide detailed transactional information regarding RINs. It would be akin to credit trading reports submitted by refiners and importers under other fuels programs in 40 CFR part 80, such as the gasoline sulfur program. The purpose of this report would be to document the ownership, transfer and use of RINs and to track expired RINs. As such, and noted below, these reports would be required of any party that owns RINs during the compliance period covered by the report. The transactional report is necessary because compliance with the RVO is primarily demonstrated through self-reporting of RIN trades and therefore it is necessary for Agency personnel to 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. Because the use of RINs permits great flexibility in meeting the RVO, we believe that obligated parties and others who create and handle RINs (including brokers) will benefit from self-reporting.

The third type of report will summarize RIN activities for the previous year and will include the total number of RINs owned, used for compliance, transferred and expired. This report would not include details of every RIN owned or used, since this information would be included in the compliance and transactional reports. Instead, this third report would simply summarize the total number of RINs falling into different categories.

All reports submitted to us would have to be signed and certified as true and correct by a responsible corporate officer. This can be done electronically. As discussed above, we plan to utilize a highly simplified electronic method of reporting via the Agency's Central Data Exchange that is secure, provides encryption and reliable electronic signatures, and that permits us to accept reports in the submitter's choice of simple comma delimited text or commercially available spreadsheet packages.

We are proposing annual reporting only. However, we encourage comments related to the frequency of reporting. We are particularly interested in comments related to the frequency of transactional reports related to RINs and whether these reports should be submitted quarterly rather than annually. We also request comment on our proposed requirement that three distinct types of reports be submitted for each calendar year, specifically whether these reports could be simplified or whether a smaller number of reports could provide the same information.

3. Recordkeeping

The proposed recordkeeping requirements for obligated parties and exporters of renewable fuel support the enforcement of the use of RINs for compliance purposes. Product transfer documents (PTDs) are central to tracking individual RINs through the fungible distribution system when those RINs are assigned to batches of renewable fuel. PTDs are customarily issued in the course of business (i.e., issuing them is a ''customary business practice'') and are familiar to parties who transfer or receive fuel. As with other fuels programs, PTDs may take many forms, including bills of lading, as long as they travel with the volume of renewable fuel being transferred. Specifically, we propose that on each occasion any person transfers ownership of renewable fuels subject to this proposed regulation that they provide the transferee documents identifying the renewable fuel and containing identifying information including the name and address of the transferor and transferee, the EPA-issued company and facility IDs of the transferor and transferee, the volume of renewable fuel that is being transferred, the location of the renewable fuel at the time of transfer, and the unique RIN associated with the volume of fuel being transferred, if any. PTDs are used by all parties in the distribution chain down to the retail outlet or wholesale purchaser-consumer facility that dispenses it into motor vehicles.

Except for transfers to truck carriers, retailers or wholesale purchaser-consumers, product codes describing various attributes of the fuel may be used to convey the information required for PTDs, as long as the codes are clearly understood by each transferee. Therefore, refiners and importers and exporters of renewable fuel may use codes. The RIN would always have to appear on each PTD in its entirety before it is separated from a batch, since it is a unique identification number and cannot be summarized by a shorter code.

Obligated parties and exporters of renewable fuel would have to keep copies of PTDs and of all compliance reports submitted to EPA for a period of not less than five (5) years. The five year period is common to all our 40 CFR part 80 programs and is a reasonable period to retain records in the event a potential violation is reported and must be investigated and pursued by enforcement personnel. They would also have to keep information related to the sale, purchase, brokering and trading of RINs that support the information they report to EPA. Refiners and importers would be responsible for providing records to the Administrator or the Administrator's authorized representative in a usable format upon request.

C. Requirements for Producers and Importers of Renewable Fuel

1. Registration

We propose that any producer or importer of renewable fuel must register by [90 DAYS AFTER THE DATE OF FINAL PUBLICATION OF THE FINAL RULE]. The registration requirements are the same as those for refiners and importers of gasoline, as described above. Renewable fuel producers were not previously required to register with EPA and we anticipate around 280 new registrants as a result of this proposed registration requirement. Although renewable fuels producers are not ''obligated parties,'' they are the parties who generate RINs. As mentioned above in IV.B.1, the EPA-issued registration numbers will be part of the unique RIN generated by the producer or importer of renewable fuel. In order to support effective recordkeeping and reporting for compliance purposes, we believe it is necessary for them and any party who generates or owns RINs to register with the Agency.

Registration is a simple process and there is no expiration date associated with a registration. However, registration information may be updated by the registrant as needed, for example, if a mailing address changes. The information collected includes company name and address; facility name(s) and address(es); and a contact person's name, phone number and e-mail address. Any party who is not currently registered with us would have to submit registration forms. We will issue a 4-digit company identification number and, for each facility registered, a 5-digit facility identification number. If a party becomes subject to this proposed regulation after the effective date, then we propose that they must register with us and receive their EPA-issued company and facility identification numbers prior to generating or holding any RINs.

We also propose that small volume domestic producers of renewable fuels, those who produce less than 10,000 gallons per year, be allowed to remain unregistered. This proposed provision would free them from recordkeeping and reporting requirements, but it would also preclude them from generating RINs.

2. Reporting

Renewable fuel producers and importers would be required to submit three different annual reports by February 28, reflecting activity during the previous calendar year. The first report would be an annual report that reflects the generation of RINs. This report would identify each batch of renewable fuel produced or imported during the previous year and the RINs generated for each batch. This annual report would provide information about the production date, renewable fuel type and volume of renewable fuel produced or imported. For specific information about how RINs are actually generated, please refer to the discussion in Section III.D.2 of this preamble.

Like any of the parties who can own RINs, a renewable fuel producer would also have to submit a second type of report detailing transactional information regarding RINs. This report would list the RINs which they own at the end of the reporting period as well as any RINs they have acquired from other parties or have transferred to other parties, identifying which parties took part in the transfer. This report would be similar to the transaction report described below required of RIN owners who are not obligated parties, exporters, or producers of renewable fuels.

Finally, each producer or importer of renewable fuel would be required to submit a third annual report summarizing RIN activities for the previous year. This report would include the total number of RINs generated, owned, transferred, and expired.

All reports would have to be signed and certified as true and correct by a responsible corporate officer. This can be done electronically. As discussed above, we plan to utilize a highly simplified electronic method of reporting via the Agency's Central Data Exchange that is secure, provides encryption and reliable electronic signatures, and that permits generation of reports in the submitter's choice of simple comma delimited text or commercially available spreadsheet packages.

We request comment on our proposed requirement that three distinct types of reports be submitted for each calendar year, specifically whether these reports could be simplified or whether a smaller number of reports could provide the same information.

3. Recordkeeping

The proposed recordkeeping requirements for renewable fuels producers support the enforcement of the use of RINs for compliance purposes. Product transfer documents (PTDs) are central to tracking individual RINs through the fungible distribution system when those RINs are assigned to batches of renewable fuel. PTDs are customarily generated and issued in the course of business (*i.e.* issuing them is a "customary business practice") and are familiar to parties who transfer or receive fuel. As with other fuels programs, PTDs may take many forms, including bills of lading, as long as they travel with the volume of renewable fuel being transferred. Specifically, we propose that on each occasion any person transfers ownership of renewable fuels subject to this proposed regulation that they provide the transferee documents identifying the renewable fuel and containing identifying information including the name and address of the transferor and transferee, the EPA-issued company and facility IDs of the transferor and transferee, the volume of renewable fuel that is being transferred, the location of the renewable fuel at the time of transfer, and the unique RIN associated with the volume of fuel being transferred, if any. PTDs are used by all parties in the distribution chain down to the retail outlet or wholesale purchaser-consumer facility that dispenses it into motor vehicles.

Except for transfers to truck carriers, retailers or wholesale purchaser-consumers, product codes may be used to convey the information required for PTDs, as long as the codes are clearly understood by each transferee. Therefore, renewable fuels producers may use codes. The RIN would always have to appear on each PTD in its entirety before it was separated from the batch, since it is a unique identification number and cannot be summarized by a shorter code.

Renewable fuels producers would have to keep copies of PTDs and of all compliance reports submitted to EPA for a period of not less than five (5) years. They would also have to keep information related to the sale, purchase, brokering and trading of RINs. Upon request, renewable fuels producers or importers would be responsible for providing documentation of PTDs to the Administrator or the Administrator's authorized representative in a usable format.

D. Requirements for Other Parties Who Own RINs

1. Registration

We propose that other parties who intend to own RINs, and who are not obligated parties, exporters of renewable fuels, or renewable fuels producers or importers, must also register before ownership of any RINs is assumed. The registration requirements are the same as those for other parties discussed previously in Sections IV.B.1 and IV.C.1 above, and require the registrant to provide very basic information about the company, its facility or facilities, and a contact person. The registration is on very simple forms provided by EPA. A variety of parties may own RINs including (but certainly not limited to) marketers, blenders, terminal operators, and jobbers. (As is mentioned in the previous two sections, obligated parties and renewable producers may also own RINs but have other reporting responsibilities, as well.)

It is possible to own RINs separately from batches of renewable fuel. For example, a broker might be expected to own RINs in this fashion. Any party who is not currently registered with us and who intends to own RINs would have to submit a simple registration form, as described above. We anticipate about 1,500 new registrants as a result of this proposed registration requirement, although an exact estimation of the number of parties that will constitute this group is difficult to make. As with the other parties described in this Section, we will issue a 4-digit company identification number and, for each facility registered, a 5-digit facility identification number. If a party becomes subject to this proposed regulation after the effective date, then we propose that they must register with us and receive their EPA-issued company and facility identification numbers prior to owning any RINs.

2. Reporting

Parties who own RINs would be required to submit two types of annual reports by February 28, representing activity in the previous calendar year. The first report would document RIN transactions. This report is akin to the credit trading reports submitted by refiners and importers under other fuels programs in 40 CFR part 80 and is the same as the second report described for obligated parties in some detail in Section IV.B.2 above.

The second type of report would summarize RIN activities for the previous year, including the total number of RINs owned, transferred, and expired. This report would not include details of every RIN owned or used, since this information would be included in the transactional report. Instead, this report would simply summarize the total number of RINs falling into different categories.

All reports would have to be signed and certified as true and correct by a responsible corporate officer. This can be done electronically. As discussed above, we plan to utilize a highly simplified electronic method of reporting via the Agency's Central Data.

As discussed above, we are seeking comments on the frequency of reporting, especially with regard to RIN transactions. We are proposing annual reporting, but are seeking comments on whether reporting should be quarterly.

We also request comment on our proposed requirement that two distinct types of reports be submitted for each calendar year, specifically whether these reports could be simplified or whether a smaller number of reports could provide the same information.

3. Recordkeeping

The proposed recordkeeping requirements for parties who own RINs support the enforcement of the use of RINs for compliance purposes. Product transfer documents (PTDs) are central to tracking individual RINs through the fungible distribution system when those RINs are assigned to batches of renewable fuel. PTDs are customarily generated and issued in the course of business (*i.e.*, issuing them is a ''customary business practice'') and are familiar to parties who transfer or receive fuel. As with other fuels programs, PTDs may take many forms, including bills of lading, as long as they travel with the volume of renewable fuel being transferred. Specifically, we propose that on each occasion any person transfers ownership of RINs (whether assigned to batches of renewable fuel or not) that they provide the transferee documents identifying the RIN and containing identifying information including the name and address of the transferor and transferee, the EPA-issued company and facility IDs of the transferor and transferee, and the unique RINs that are being transferred. Typically, parties who own RINs connected with batches of fuel would handle PTDs; however, parties who own RINs separate from batches may not. A party who owns RINs in connection with fuel and who received a PTD would be responsible for meeting requirements related to PTDs.

Parties who own RINs but who are not obligated parties, exporters of renewable fuel, or renewable fuel producers or importers would have to keep copies of PTDs associated with RIN transfers and of all compliance reports submitted to EPA for a period of not less than five (5) years. They would also have to keep information related to the sale, purchase, brokering and trading of RINs. Upon request, owners of RINs would be responsible for providing records to the Administrator or the Administrator's authorized representative in a usable format.

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

The prohibition and liability provisions applicable to this proposed RFS program would be similar to those of other gasoline programs. The proposed 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 that is not assigned a proper RIN, creating or transferring invalid RINs, or transferring RINs that are not identified by proper RIN numbers. Any person subject to a prohibition would be held liable for violating that prohibition. Thus, for example, an obligated party would be liable if the party failed to acquire sufficient RINs to meet its RVO. A party who produces or imports renewable fuels would be liable for a failure to assign proper RINs to batches of renewable fuel produced or imported. Any party, including an obligated party, would be liable for transferring a RIN that was not properly identified.

In addition, any person who is subject to an affirmative requirement under the RFS program would be liable for a failure to comply with the requirement. For example, an obligated party would be liable for a failure to comply with the annual compliance reporting requirements. A renewable fuel producer or importer would be liable for a failure to comply with the applicable 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 proposed 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).[38] Accordingly, under the proposed 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 proposed rule, a failure to acquire sufficient RINs to meet a party's renewable fuels obligation would constitute a separate day of violation for each day the violation occurred during the annual averaging period.

As discussed above and in Section III.D, the regulations would prohibit any party from creating or transferring invalid RINs. These invalid RIN provisions would apply regardless of the good faith belief of a party that the RINs were 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 would address the consequences if an obligated party was found to have used invalid RINs to demonstrate compliance with its RVO. In this situation, the refiner or importer that used the invalid RINs would be required to deduct any invalid RINs from its compliance calculations. The refiner or importer would be liable for violating the standard if the remaining number of valid RINs was insufficient to meet its RVO, and the obligated party might be subject to monetary penalties if it used invalid RINs in its compliance demonstration. In determining what penalty is appropriate, if any, we would consider a number of factors, including

[38] Sec. 1501(b) of the Energy Policy Act of 2005.

whether the obligated party did in fact procure sufficient valid RINs to cover the deficit created by the invalid RINs, and whether the purchaser was indeed a good faith purchaser based on an investigation of the RIN transfer. A penalty might include both the economic benefit of using invalid RINs and/or a gravity component.

Although an obligated party would be liable under our proposed program for a violation if it used invalid RINs for compliance purposes, we would normally 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, for example, that party was out of business, then attention would turn to the obligated party who would have to obtain sufficient valid RINs to offset the invalid RINs.

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. We request comment on whether a presumptive liability scheme may have application under the RFS rule. We also request comment on the need for additional prohibition and liability provisions specific to the proposed RFS program.

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 June 2006, there were 102 ethanol production facilities operating in the United States with a combined production capacity of approximately 4.9 billion gallons per year.[39] 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 93 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 MMGal/yr	Percent of capacity	Number of plants	Percent of plants
Corn [a]	4,516	92.7	85	83.3
Corn/Milo	162	3.3	5	4.9
Corn/Wheat	90	1.8	2	2.0
Corn/Barley	40	0.8	1	1.0
Milo/Wheat	40	0.8	1	1.0
Waste Beverage [b]	16	0.3	5	4.9
Cheese Whey	8	0.2	2	2.0
Sugars & Starches	2	0.0	1	1.0
Total	4,872	100.0	102	100.0

[a] Includes seed corn.
[b] Includes brewery waste.

There are a total of 94 plants processing corn and/or other similarly processed grains. Of these facilities, 84 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. Carbon dioxide is also produced in the process and may be recovered as a saleable product. 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, approximately 23 percent of the current 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 more simplistic enzymatic fermentation process.

In addition to grain and starch-to-ethanol production, another method exists for producing ethanol from a more diverse feedstock base. This process involves converting cellulosic feedstocks such as bagasse, wood, straw, switchgrass, and other biomass into ethanol. Cellulose consists of tightly-linked polymers of starch, and production of ethanol from it requires additional steps to convert these polymers into fermentable sugars. Scientists are actively pursuing acid and enzyme hydrolysis to achieve this goal, but the technologies are still not fully developed for large-scale commercial production. As of June 2006, there were no U.S ethanol plants processing cellulosic feedstocks. Currently, the only known cellulose-to-ethanol plant in North America is Iogen in Canada, which produces approximately one

[39] The June 2006 ethanol production baseline was generated from a variety of data sources including Renewable Fuels Association (RFA), Ethanol Biorefinery Locations (Updated June 19, 2006); Ethanol Producer Magazine (EPM), U.S. & Canada Fuel Ethanol Plant Map (Spring 2006); and International Fuel Quality Center (IFQC), Special Biofuels Report #75 (April 11, 2006) as well as ethanol producer websites. The production baseline includes small-scale ethanol production facilities as well as former food-grade ethanol plants that have since transitioned into the fuel-grade ethanol market. Where applicable, current ethanol plant production levels were used to represent plant capacity, as nameplate capacities are often underestimated.

million gallons of ethanol per year from wood chips. For a more detailed discussion on cellulosic ethanol production/technologies, refer to Section 7.1.2 of the Draft Regulatory Impact Analysis (DRIA).

The ethanol production process is relatively resource-intensive and requires the use of water, electricity and steam. Steam needed to heat the process is generally produced onsite or by other dedicated boilers. Of today's 102 ethanol production facilities, 98 burn natural gas, 2 burn coal, 1 burns coal and biomass, and 1 burns syrup from the process to produce steam. A summary of ethanol production by plant energy source is found below in Table VI.A.1–2.

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

Energy source	Capacity MMGal/yr	Percent of capacity	Number of plants	Percent of plants
Natural Gas [a]	4,671	95.9	98	96.1
Coal	102	2.1	2	2.0
Coal & Biomass	50	1.0	1	1.0
Syrup	49	1.0	1	1.0
Total	4,872	100.0	102	100.0

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

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

The majority of ethanol is produced in the Midwest within PADD 2—not surprisingly, where most of the corn is grown. Of the 102 U.S. ethanol production facilities, 93 are located in Midwest. The PADD 2 facilities account for about 97 percent (or 4.7 billion gallons per year) of the total 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 MMgal/yr	Percent of capacity	Number of plants	Percent of plants
PADD 1	0.4	0.0	1	1.0
PADD 2	4,710	96.7	93	91.2
PADD 3	30	0.6	1	1.0
PADD 4	98	2.0	4	3.0
PADD 5	34	0.7	3	2.9
Total	4,872	100.0	102	100.0

Leading the Midwest in ethanol production are Iowa, Illinois, Nebraska, Minnesota, and South Dakota with a combined capacity of 3.9 billion gallons per year. Together, these five states' 69 ethanol plants account for 80 percent of the total domestic product. Although the majority of ethanol production comes from the Midwest, there is a sprinkling of plants situated outside the corn belt ranging from California to Tennessee all the way down to Georgia.

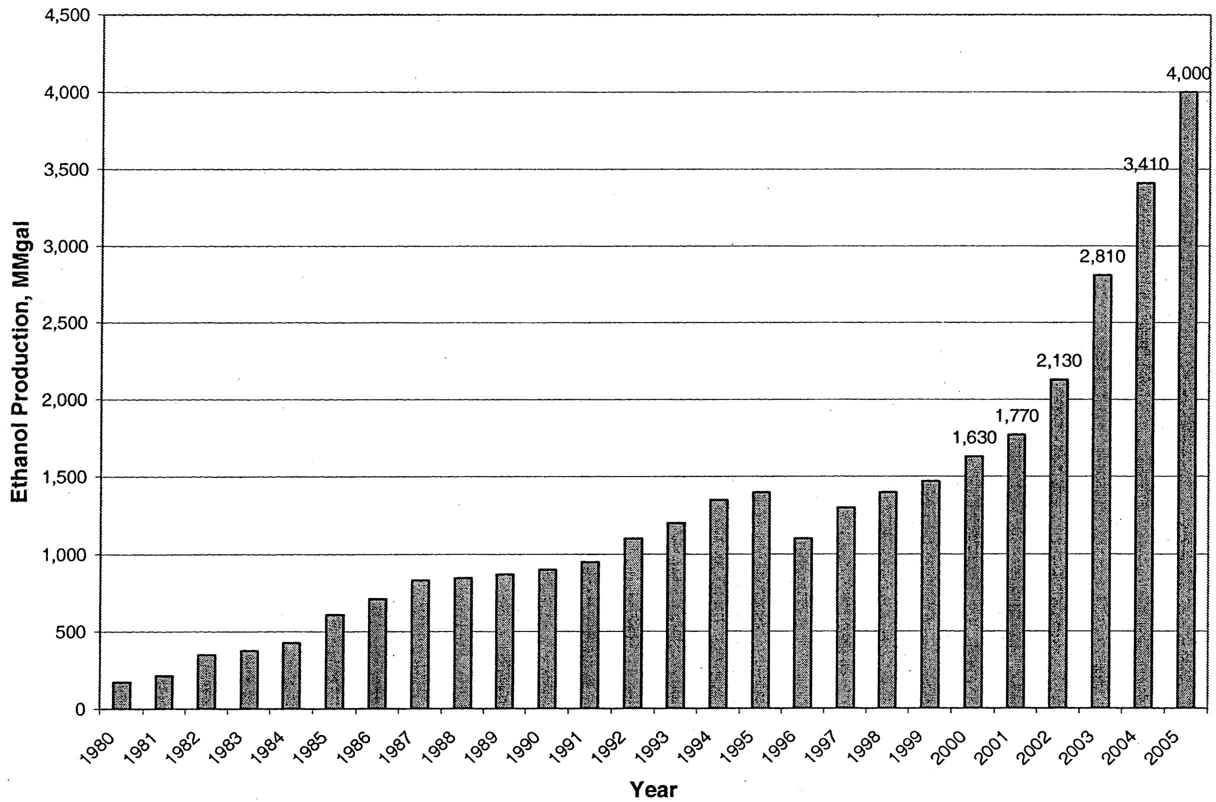
The U.S. ethanol industry is currently comprised of a mixture of corporations and farmer-owned cooperatives (co-ops). More than half (55) of today's plants are owned by corporations and, on average, these plants are larger in size than farmer-owned co-ops. Accordingly, company-owned plants account for nearly 65 percent of the total U.S. ethanol production capacity. Additionally, 45 percent of the total capacity comes from 22 plants owned by just 8 different companies.

2. Expected Growth in Ethanol Production

Over the past 25 years, domestic fuel ethanol production has steadily increased due to technological advances, environmental regulation (e.g., oxygenate requirements in ozone and carbon monoxide non-attainment areas), and the rising cost of crude oil. More recently, ethanol production has soared due to state MTBE bans, steep increases in crude oil prices, and producer tax incentives. As shown below 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.

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 ethanol production to 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, record-high crude oil prices are expected to continue to drive up demand for ethanol. As a result, the nation is on track to exceed the renewable fuel volume requirements contained in the Act. Today's ethanol production capacity (4.9 billion gallons) is already exceeding the 2006 renewable fuel requirement (4.0 billion gallons). In addition, there is another 2.5 billion gallons of ethanol production capacity currently under construction.[40] A summary of the new construction and expansion projects currently underway (as of June 2006) is found in Table VI.A.2–1.

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

	2006 ETOH baseline		New construction		Plant expansions		2006 baseline + UC [a]	
	MMGal/yr	Plants	MMGal/yr	Plants	MMGal/yr	Plants	MMGal/yr	Plants
PADD 1	0.4	1	0	0	0	0	0.4	1
PADD 2	4,710	93	2,048	35	252	8	7,010	128
PADD 3	30	1	30	1	0	0	60	2
PADD 4	98	4	50	1	7	1	155	5
PADD 5	34	3	90	2	0	0	124	5

[40] Under construction plant locations, capacities, feedstocks, and energy sources as well as planned/proposed plant locations and capacities were derived from a variety of data sources including Renewable Fuels Association (RFA), Ethanol Biorefinery Locations (Updated June 19, 2006); Ethanol Producer Magazine (EPM), U.S. & Canada Fuel Ethanol Plant Map (Spring 2006); and International Fuel Quality Center (IFQC), Special Biofuels Report #75 (April 11, 2006) as well as ethanol producer Web sites.

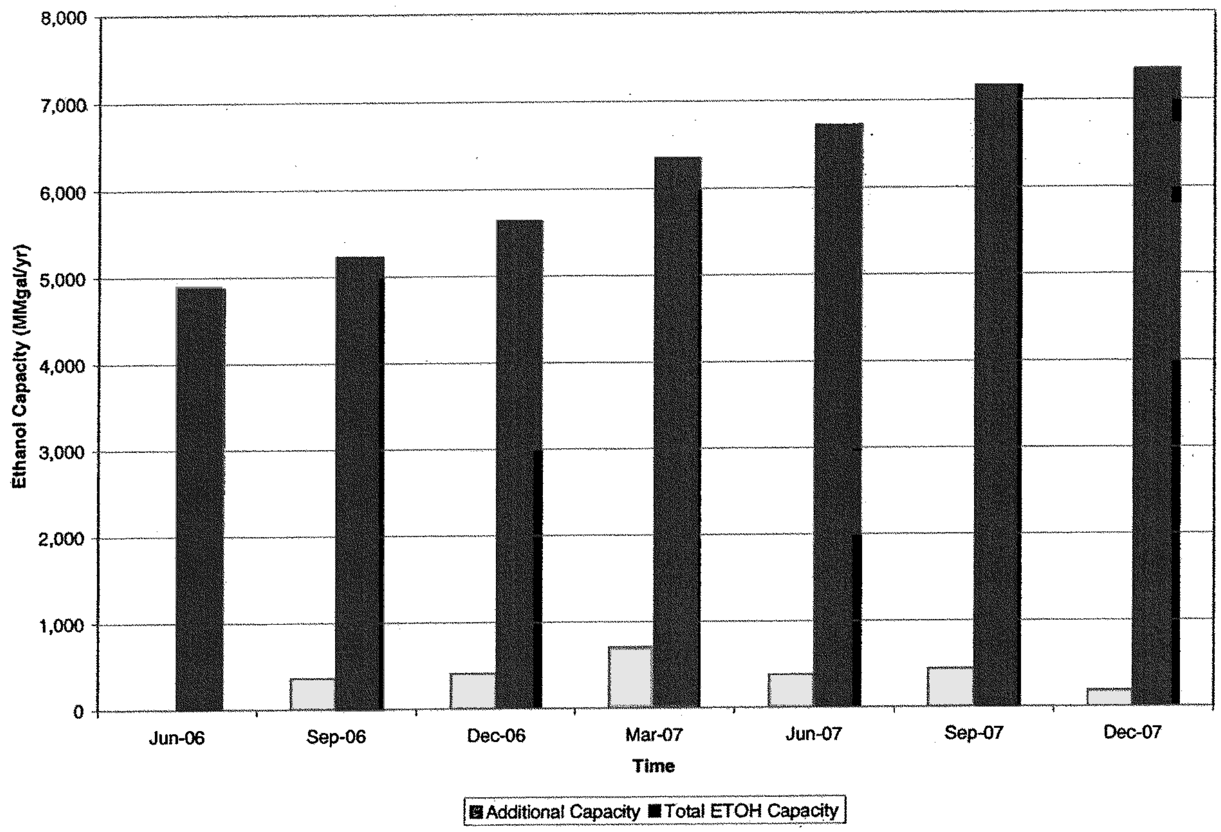
TABLE VI.A.2–1.—UNDER CONSTRUCTION U.S. ETHANOL PLANT CAPACITY—Continued

	2006 ETOH baseline		New construction		Plant expansions		2006 baseline + UC[a]	
	MMGal/yr	Plants	MMGal/yr	Plants	MMGal/yr	Plants	MMGal/yr	Plants
Total	4,872	102	2,218	39	259	9	7,349	141

[a] Under Construction.

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

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



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

As shown in Table VI.A.2–1 and Figure VI.A.2–2, once all the construction projects currently underway are complete (estimated by December 2007), the resulting U.S. ethanol production capacity would be over 7.3 billion gallons. Together with estimated biodiesel production (300 million gallons by 2012), this would be more than enough renewable fuel to satisfy the 2012 renewable fuel requirement (7.5 billion gallons) contained in the Act. However, ethanol production is not expected to stop here. There are more and more ethanol projects being announced each day. Many of these potential projects are at various stages of planning, such as conducting feasibility studies, gaining city/county approval, applying for permits, applying for financing/fundraising, or obtaining contractor agreements. Other projects have been proposed or announced, but have not entered the formal planning process. If all these plants were to come to fruition, the combined domestic ethanol production could exceed 20 billion gallons as shown in Table VI.A.2–2.

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

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

[a] Under Construction.

However, although there is clearly a great potential for growth in ethanol production, it is unlikely that all the announced projects would actually reach completion in a reasonable amount of time. There is no precise way to know exactly which plants would come to fruition in the future; however, we've chosen to focus our further discussions on only those plants which are under construction or in the final planning stages (denoted as ''planned'' above in Table VI.A.2–2). The distinction between ''planned'' versus ''proposed'' is that as of June 2006 planned projects had completed permitting, fundraising/financing, and had builders assigned with definitive construction timelines whereas proposed projects did not.

As shown in Table VI.A.2–2, once all the under construction and planned projects are complete (by 2012 or sooner), the resulting U.S. ethanol production capacity would be 9.8 billion gallons, exceeding the 2012 EIA demand estimate (9.6 billion gallons). This forecasted growth would double today's production capacity and greatly exceed the 2012 renewable fuel requirement (7.5 billion gallons). In addition, domestic ethanol production would be supplemented by imports, which are also expected to increase in the future (as discussed in DRIA Section 1.5).

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

Under the Energy Act, the RFS program requires that 250 million gallons of the renewable fuel consumed in 2013 and beyond meet the definition of cellulosic biomass ethanol. As discussed in Section III.B.1, 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.

Of the 60 forecasted plants, only one is expected to meet the definition of ''cellulosic biomass ethanol'' based on feedstocks. The planned 108 MMgal/yr facility would start off processing corn and then transition into processing bagasse, rice hulls, and wood (cellulosic feedstocks). It is unclear as to whether this facility would be processing cellulosic material by 2013, however there are several other facilities that could potentially meet the Act's definition of cellulosic ethanol based on plant energy sources. In total, there are seven ethanol plants that burn or plan to burn renewable feedstocks to generate steam for their processes. As shown in Table VI.A.1–2, two existing plants burn renewable feedstocks. One plant burns a combination of coal and biomass and the other burns syrup from the production process. Together these existing plants have a combined ethanol production capacity of 99 MMgal/yr. Additionally, there are four under construction ethanol plants which plan to burn renewable fuels. One plant plans to burn a combination of coal and biomass, two plants plan to rely on manure/syngas, and the other plans to start up burning natural gas and then transition to biomass. Together these under construction facilities have a combined ethanol production capacity of 87 MMgal/yr. Finally, a planned 275 MMgal/yr ethanol production facility plans to burn a combination of coal, tires, and biomass. Depending on how much fossil fuel is displaced by these renewable feedstocks (on a plant-by-plant basis), a portion or all of the aforementioned ethanol production (up to 461 MMgal/yr) could potentially qualify as ''cellulosic biomass ethanol'' under the Act. Combined with the 108 MMgal/yr plant planning to process renewable feedstocks, the total cellulosic potential could be as high as 569 MMgal/yr in 2013. Even if only half of this ethanol were to end up qualifying as cellulosic biomass ethanol, it would still be more than enough to satisfy the Act's cellulosic requirement (250 million gallons).[41]

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[42] and 1.9 billion gallons of MTBE[43] were blended into gasoline to supply the transportation sector with a total of 136 billion gallons of gasoline.[44] A breakdown of the 2004 gasoline and oxygenate consumption by PADD is found below in Table VI. A.3–1.

[41] We anticipate a ramp-up in cellulosic ethanol production in the years to come so that capacity exists to satisfy the 2013 Act's 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.

[42] EIA Monthly Energy Review, June 2006 (Table 10.1: Renewable Energy Consumption by Source, Appendix A: Thermal Conversion Factors).

[43] File containing historical RFG MTBE usage obtained from EIA representative on March 9, 2006.

[44] EIA 2004 Petroleum Marketing Annually (Table 48: Prime Supplier Sales Volumes of Motor

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

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

[a] MTBE blended into RFG.
[b] PADD 5 excluding California.

As shown above, nearly half (or about 45 percent) of the ethanol was consumed in PADD 2 gasoline, not surprisingly, where the majority of ethanol was produced. The next highest region of use was the State of California which accounted for about 25 percent of domestic ethanol consumption. This 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.[45] 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.[46]

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.[47]

In 2004, total ethanol use exceeded MTBE use. Ethanol's lead oxygenate role is relatively new, however the trend has been a work in progress over the past few years. From 2001 to 2004, ethanol consumption more than doubled (from 1.7 to 3.5 billion gallons), while MTBE use (in RFG) was virtually cut in half (from 3.7 to 1.9 billion gallons). A plot of oxygenate use over the past decade is provided below in Figure 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 DRIA Table 2.1–4.

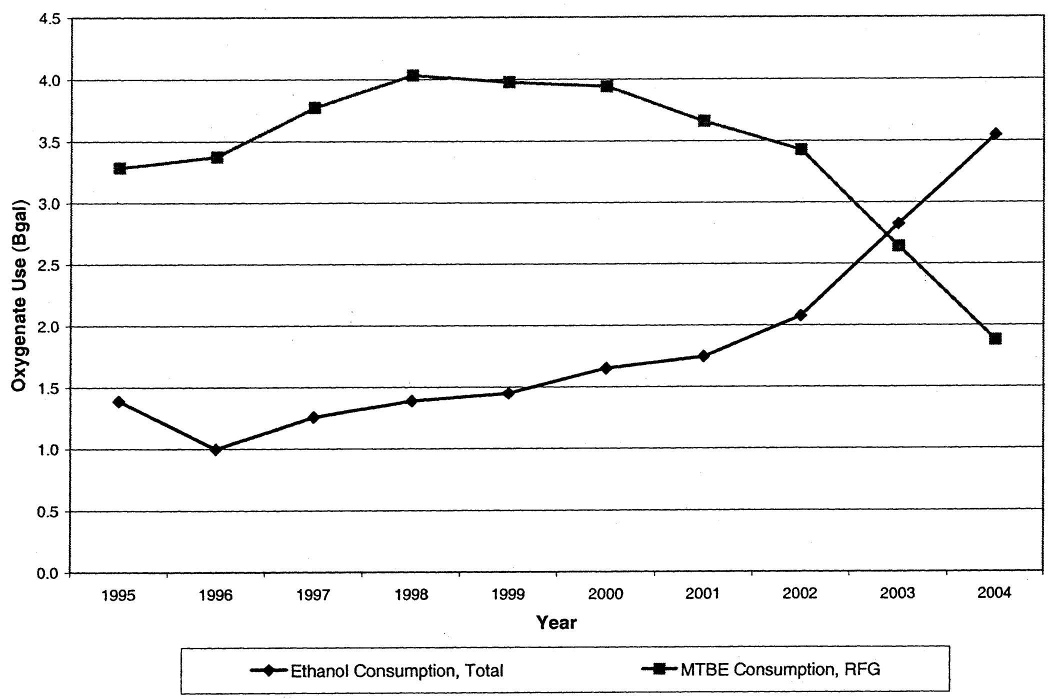
Gasoline by Grade, Formulation, PAD District, and State).

[45] Based on conversation with Dean Simeroth at California Air Resources Board (CARB).

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

[47] 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[48]

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 oxygenate mandate for reformulated gasoline (RFG),[49] all U.S. refiners are expected to eliminate the use of MTBE in gasoline as soon as possible. In order to accomplish this transition quickly (by 2006 or 2007 at the latest) while maintaining gasoline volume, octane, and mobile source air toxics emission performance standards, refiners are electing to blend ethanol into virtually all of their RFG.[50] This has caused a dramatic increase in demand for ethanol which, in 2006 is being 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 dramatic rise in the price of crude oil 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[51] and biodiesel use would be about 0.3 billion gallons at a crude oil price forecast of $47 per barrel. 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. Therefore, in assessing the impacts of expanded use of renewable fuels, 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 7.2 billion gallons of ethanol (0.25 of which was assumed to be cellulosic) and 0.3 billion gallons of biodiesel. For the higher projected renewable fuel consumption scenario, we assumed 9.6 billion gallons of ethanol (0.25 of which is once again 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 these two scenarios provide a reasonable range for analysis purposes.[52]

In addition to modeling two different future 2012 ethanol consumption levels, two scenarios were considered based on how refineries could potentially respond to the recent removal of the RFG oxygenate mandate. In both cases, the impacted RFG areas did not change

[48] Total ethanol use based on EIA Monthly Energy Review, June 2006 (Table 10.1: Renewable Energy Consumption by Source, Appendix A: Thermal Conversion Factors). MTBE use in RFG also provided by EIA (file received from EIA representative on March 9, 2006). Reported 2004 MTBE use has been adjusted from 2.0 to 1.9 Bgal based on assumption of timely implementation of CA, CT, and NY MTBE bans on 1/1/04 (EIA reported a slight delay and thus showed small amounts of MTBE use in these states in 2004).

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

[50] Based on discussions with the refining industry.

[51] AEO 2006 Table 17 Renewable Energy Consumption by Sector and Source shows 0.80 quadrillion BTUs of energy coming from ethanol in 2012. A parallel spreadsheet provided to EPA shows 2012 total ethanol use as 628.7 thousand bbls/day (which works out to be 9.64 billion gallons/yr).

[52] As a comparison point for cost and emissions analyses, a 2012 reference case of 3.9 billion gallons of ethanol was also considered. The reference case is described in Section II.A.1 (above) and a complete derivation is contained in DRIA Section 2.1.3.

from the 2004 base case.[53] In the maximum scenario (''max-RFG''), refineries would continue to add oxygenate (ethanol) into all batches of reformulated gasoline. In this case, refineries currently blending MTBE (at 11 volume percent) would be expected to replace it with ethanol (at 10 volume percent). In the minimum scenario (''min-RFG''), we predict some refineries would respond by using less (or even zero) ethanol in RFG based on the minimum amount needed to meet volume, octane, and/or total toxics performance requirements. Applying the max-RFG and min-RFG criteria resulted in a total of four different 2012 ethanol consumption control cases:

1. 7.2 billion gallons of ethanol, maximum amount used in RFG areas;
2. 7.2 billion gallons of ethanol, minimum amount used in RFG areas;
3. 9.6 billion gallons of ethanol, maximum amount used in RFG areas; and
4. 9.6 billion gallons of ethanol, minimum amount used in RFG areas.

The seasonal RFG assumptions applied in 2012 (in terms of percent ethanol marketshare) are summarized below in Table VI.A.4–1. The rationale behind these selected values are explained in DRIA Section 2.1.4.2.

TABLE VI.A.4–1.—2012 RFG AREA ASSUMPTIONS

RFG areas	ETOH-blended gasoline (% market share) [a]			
	Min-RFG scenario	Max-RFG scenario		
		Summer (percent)	Winter (percent)	Summer (percent)
PADD 1	0	100	100	100
PADD 2	50	100	100	100
PADD 3	0	25	100	100
California [b]	25	100	100	100
Arizona [c]	0	100	100	100

[a] Percent marketshare of E10, with the exception of California (E5.7 year-round) and Arizona (E5.7 summer only).
[b] Pertains to both Federal RFG and California Phase 3. RFG.
[c] Pertains to Arizona Clean Burning Gasoline (CBG).

Once we determined how much ethanol was likely to be used in RFG areas (by PADD), we systematically allocated the remaining ethanol into conventional gasoline. First it was apportioned to winter oxy-fuel areas. In the 2004 base case, there were 14 state-implemented winter oxy-fuel programs in 11 states. Of these programs, 9 were required in response to non-attainment with the CO National Ambient Air Quality Standards (NAAQS) and 4 were implemented to maintain CO attainment status.[54] By 2012, 4 areas are expected to be redesignated to CO attainment status and discontinue oxy-fuel use and 2 areas are predicted to discontinue using oxy-fuel as a maintenance strategy. Accordingly, a reduced amount of ethanol was allocated to oxy-fuel areas in 2012. The remaining ethanol was distributed to conventional gasoline (CG) in different states based on a computed ethanol margin (rack gasoline price minus ethanol delivered price adjusted by miscellaneous subsidies/ penalties). The methodology is described in DRIA Section 2.1.4.3.

The main difference in the four resulting ethanol consumption scenarios was how far the ethanol penetrated the conventional gasoline pool. A summary of the forecasted 2012 ethanol consumption (by control case, fuel type and season) is found in Table VI.A.4–2.

TABLE VI.A.4–2.—2012 FORECASTED U.S. ETHANOL CONSUMPTION BY SEASON

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

[a] Winter oxy-fuel programs.
[b] Federal RFG plus Ca Phase 3 RFG and Arizona CBG.

As expected, the least amount of ethanol was consumed in conventional gasoline in the 7.2 billion gallon control case when a maximum amount was allocated to RFG. Similarly, the most ethanol was consumed in CG in the 9.6 billion gallon control case when a minimum amount was allocated to RFG. For more information on the four resulting 2012 control cases, refer to DRIA Section 2.1.4.6.

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 consideration of the benefits of subsidies and credits provided by Federal and state programs. Much of the demand occurred as a result of mandates from states and local municipalities, which required the use

[53] For a list of the Federal RFG areas, refer to DRIA Table 2.2–1.

[54] Refer to DRIA Table 2.1–2.

of biodiesel. However, over the past couple 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 65 biodiesel plants in operation with an annual production capacity of 395 million gallons per year.[55] The majority of the current production capacity was built in 2005, and was first available to produce fuel in the last quarter of 2005. Though capacity has grown, historically the biodiesel production capacity has far exceeded actual production with only 10–30 percent of this being utilized to make biodiesel, see Table VI.B.1–2.[56]

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

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

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

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

In addition to the 53 biodiesel plants already in production, as of early 2006, there were an additional 50 plants and 8 plant expansions in the construction phase, which when completed would increase total biodiesel production capacity to over one billion gallons per year. Most of these plants should be completed by early 2007. There were also 36 more plants in various stages of the preconstruction phase (i.e. raising equity, permitting, conceptual design, buying equipment) with a capacity of 755 million gallons/year. As shown in Table VI.B.2–1, if all of this capacity came to fruition, U.S. biodiesel capacity would exceed 1.8 billion gallons.

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

	Existing plants	Construction phase	Pre-construction phase
Number of plants	53	58	36
Total Plant Capacity, MM Gallon/year	354	714	754.7

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 in a manner consistent with the growth of gasoline.[57] The resulting 2012 reference case consisted of approximately 28 million gallons of biodiesel. Finally, for the 2012 control case, forecasted biodiesel use was assumed to be 300 million gallons based on EIA's AEO 2006 report (rounded value from Table 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

[55] NBB Survey April 28, 2006 "Commercial Biodiesel Production Plants."

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

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

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. 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. Production Capacity of Cellulosic Ethanol

Beginning in 2013, a minimum of 250 million gallons per year of cellulosic ethanol must be used in gasoline. The Act's definition of cellulosic, however, includes corn based ethanol as long as greater than 90% of the process energy was derived from animal wastes or other waste materials. As discussed in section VI.A. above, we believe that of the ethanol plants currently in existence, under construction, or in the final stages of planning there is likely to be more than 250 million gallons per year of ethanol produced from plants which meet these alternative definitions for cellulosic ethanol.

However, this is not to say that ethanol produced from cellulose will not be part of the renewable supply by 2012. As far as we know there is currently only one demonstration-level cellulosic ethanol plant in operation in North America; it produces 1 million gallons of ethanol per year (Iogen a privately held company, based in Ottawa, Ontario, Canada). However, the technology used to produce ethanol from cellulosic feedstocks continues to improve. With the grants made available through the Energy Act, we expect several cellulosic process plants will be constructed and an ever increasing effort will naturally be made to find better, more efficient ways to produce cellulosic ethanol.

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

Some technologies that are being developed may solve some of the problems associated with production of ethanol from cellulosic sources. Specifically, one problem with cellulosic feedstocks is that the hydrolysis reactions produce both glucose, a six-carbon sugar, and xylose, a five-carbon sugar (pentose sugar, $C_5H_{10}O_5$; sometimes called ''wood sugar''). Early conversion technology required different microbes to ferment each sugar. Recent research has developed better cellulose hydrolysis enzymes and ethanol-fermenting organisms. Now, glucose and xylose can be co-fermented—hence, the present-day terminology: Weak-acid enzymatic hydrolysis and co-fermentation. In addition, several research 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 a process known as weak-acid, enzymatic-prehydrolysis.

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. In particular, there is only one cellulosic ethanol plant in North America (Iogen, Ottawa, Ontario, Canada). To the best of our knowledge, the technology that Iogen employs is not yet fully developed or optimized. Generally, the industry seems to be moving toward a process that uses dilute acid enzymatic prehydrolysis with simultaneous saccharification (enzymatic) and co-fermentation.

3. Renewable Fuel Distribution System Capability

Ethanol and biodiesel blended fuels are 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 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. In the past the refining industry has raised concerns regarding whether the distribution infrastructure can expand rapidly enough to accommodate the increased demand for ethanol. The most comprehensive study of the infrastructure requirements for an expanded fuel ethanol industry was conducted for the Department of Energy (DOE) in 2002.[58] 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

[58] ''Infrastructure Requirements for an Expanded Fuel Ethanol Industry,'' Downstream Alternatives Inc., January 15, 2002.

contained in section VII.B. of this 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 and independent 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. We also expect that by ending the use of MTBE that the former MTBE feedstock, isobutylene, will be reused to produce increased volumes of alkylate, a moderate to high octane gasoline blendstock. 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 production of alkylate.

As discussed in section II., we chose to analyze a range of renewable fuels 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, and the higher end is based on AEO 2006. 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 VII–1.

TABLE VII–1.—RENEWABLE FUELS VOLUMES USED IN COST ANALYSIS

	Renewable fuels consumption in 2012 (billion gallons)	
	Low	High
Corn Ethanol	6.95	9.35
Cellulosic Ethanol	0.25	0.25
Biodiesel	0.30	0.30
Total Biofuel Consumption	7.5	9.90

We have estimated an average corn ethanol production cost of $1.20 per gallon in 2012 (2004 dollars) in the case of 7.5 billion gallons per year (bill gal/yr) and $1.26 per gallon in the case of 9.9 bill gal/yr. 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 this 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 gal in 2012. For yellow grease derived biodiesel, we estimate an average production cost of $1.19 per gallon in 2004 and $1.10 in 2012.

The impacts on overall gasoline costs with and without fuel consumption subsidies resulting from the increased use of ethanol and the corresponding changes to the other aspects of gasoline were estimated for both of these cases. The 7.5 bill gal/yr case would result in increased total costs which range from 0.33 cents to 0.41 cents per gallon depending on assumptions with respect to ethanol use in RFG and butane control constraints. The 9.9 bill gal/yr case would result in increased total costs which range from 0.93 to 1.05 cents per gallon. The actual cost at the fuel pump, however, will be decreased due the effect of State and Federal tax subsidies for ethanol. Taking this into consideration results in ''at the pump'' decreased costs (cost savings) ranging from 0.82 to 0.89 cents per gallon for the 7.5 bill gal/yr case and ''at the pump'' decreased costs ranging from 0.98 to 1.08 cents per gallon for the 9.9 bill gal/yr case. We ask for comment on these derived costs as well as on the analysis methodology used to derive these costs, and refer the reader to Section 7 of the DRIA which contains much 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,[59] and it produces results that compare well with cost information found in surveys of existing plants.[60] 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 represents about 50% of the final per-gallon cost, while utilities, capital and labor comprise about 20%, 10%, and 5%, respectively. For this work, we used corn price projections from USDA of $2.23 per bushel in 2012 for the 7.2 bill gal/yr case, and an adjusted value of $2.31 per bushel for the 9.6 bill gal/yr

[59] Kwaitkowski, J.R., McAloon, A., Taylor, F., Johnston, D.B., Industrial Crops and Products 23 (2006) 288–296.

[60] Shapouri, H., Gallagher, P., USDA's 2002 Ethanol Cost-of-Production Survey (published July 2005).

case.[61] The adjustment at the higher volume case was taken from work done by FAPRIand EIA. [62][63] Prices used for DDGS were $65 per ton in the 7.2 bill gal/yr case and $55 per ton in the 9.6 case, based on work by FAPRI and EIA.[64] Energy prices were derived from historical data and projected to 2012 using EIA's AEO 2006.[65] While we believe the use of USDA and FAPRI estimates for corn and DDGS prices is reasonable, additional modeling work is being done for the final rulemaking using the Forestry and Agricultural Sector Optimization Model described further in Chapter 8 of the RIA.

The estimated average corn ethanol production cost of $1.20 per gallon in 2012 (2004 dollars) in the case of 7.2 bill gal/yr and $1.26 per gallon in the case of 9.6 bill gal/yr 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 does not account for any subsidies on production or sale of ethanol. This cost is independent of the market price of ethanol, which has been related closely to the wholesale price of gasoline for the past decade.[66][67]

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.[68] It is expected that the 250 million gallons per year of cellulosic ethanol production required by 2013 will be made using this provision. While we have been unable to develop a detailed production cost estimate for 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 these processes will simply be corn ethanol plants with additional fuel handling mechanisms that allow them to combust waste materials for process energy instead of natural gas. We expect them to be in locations where the very low or zero cost of the waste material or biogas itself will likely offset the costs of hauling it and/or the additional capital for processing and firing it, making them cost-competitive with conventional corn ethanol plants. Furthermore, because the quantity of ethanol produced using these processes is still expected to be a relatively small fraction of the total ethanol demand, the sensitivity of the overall analysis to this assumption is also very small. 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 hardwood chips.[69] 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 proposed 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 N_{th} 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.[70] 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).

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

We obtained gasoline blending costs on a PADD basis for octane from a consultant who conducted a cost analysis for a renewable fuels program using an LP refinery cost model. LP refinery models value the cost of octane based on the octane producing capacity for the refinery's existing units, by

[61] USDA Agricultural Baseline Projections to 2015, Report OCE–2006–1.

[62] EIA NEMS model for ethanol production, updated for AEO 2006.

[63] Food and Agricultural Policy Research Institute (FAPRI) study entitled ''Implications of Increased Ethanol Production for U.S. Agriculture'', FAPRI–UMC Report #10–05.

[64] Food and Agricultural Policy Research Institute (FAPRI) U.S. and World Agricultural Outlook, January 2006, FAPRI Staff Report 06–FSR 1.

[65] Historical data at *http://tonto.eia.doe.gov/dnav/pet/pet_pri_allmg_d_nus_PTA_cpgal_m.htm* (gasoline), *http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm* (natural gas), *http://www.eia.doe.gov/cneaf/electricity/page/sales_revenue.xls* (electricity), *http://www.eia.doe.gov/cneaf/coal/page/acr/table28.html* (coal); EIA Annual Energy Outlook 2006, Tables 8, 12, 13, 15; EIA Web site.

[66] Whims, J., Sparks Companies, Inc. and Kansas State University, ''Corn Based Ethanol Costs and Margins, Attachment 1'' (Published May 2002).

[67] Piel, W.J., Tier & Associates, Inc., March 9, 2006 report on costs of ethanol production and alternatives.

[68] Energy Policy Act of 2005, Section 1501 amending Clean Air Act Section 211(o)(1)(A).

[69] 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.

[70] 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.

added capital and operating costs for new octane producing capacity, and based on purchased gasoline blendstocks. The value of octane is expressed as a per-gallon cost per octane value, and ranges from 0.38 cents per octane-gallon in PADD 2 where lots of ethanol is expected to be used, to 1.43 cents per octane-gallon in California. Octane is more costly in California because the Phase 3 RFG standards restriction aromatics content which also reduces the use of a gasoline blendstock named reformate—a relatively cheap source of octane. Also, California's Phase 3 RFG distillation restrictions tend to limit the volume of eight carbon alkylate, another lower cost and moderately high octane blendstock.

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

2. Biodiesel Production Costs

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

Each model is based on a medium sized biodiesel plant that was designed to process raw degummed virgin soy oil as the feedstock, yielding 10 million gallons per year of biodiesel fuel. USDA estimated the equipment needs and operating requirements for their biodiesel plant through the use of process simulation software. This software determines the biodiesel process requirements based on the use of established engineering relationships, process operating conditions and reagent needs. To substantiate the validity and accuracy of their model, USDA solicited feedback from major biodiesel producers. Based on responses, they then made adjustments to their model. The NREL model is also based on process simulation software, though the results are adjusted to reflect NREL's modeling methods.

The production costs are based on an average biodiesel plant located in the Midwest using soy oil and methanol, which are catalyzed into esters and glycerol by use of sodium hydroxide. Because local feedstock costs, distribution costs, and biodiesel plant type introduce some variability into cost estimates, we believe that using an average plant to estimate production costs provides a reasonable approach. Therefore, we simplified our analysis and used costs based on an average plant and average feedstock prices since the total biodiesel volumes forecasted are not large and represent a small fraction of the total projected renewable volumes. The production costs are based on a plant that makes 10 million gallons per year of biodiesel fuel.

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

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 111 cents per gallon for soy derived biodiesel and 60 to 78 cents per gallon for yellow grease biodiesel 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 expires in 2008 if not extended. Congress may later elect to extend the blender credit program, though, following the precedence used for extending the ethanol blending subsidies. Additionally, the Small Biodiesel Blenders Tax credit program and state tax and credit programs offer some additional subsidies and credits, though the benefits are modest in comparison to the Blender's Tax credit.

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 under two scenarios, with refinery diesel prices as forecasted by EIA's AEO 2006 with crude at $47 a barrel and with refinery diesel prices based on $70 per barrel crude oil.

We estimate the net effect that biodiesel production has on overall cost for diesel fuel in year 2012 using total production costs for biodiesel and diesel fuel. The costs are evaluated based on how much refinery-based diesel fuel is displaced by the biodiesel volumes as forecasted by EIA, accounting for energy density differences between the fuels. The cost impact is estimated from a 2004 year basis, by multiplying the production costs of each fuel by the respective changes in volumes for biodiesel and estimated displaced diesel fuel. We further assume that all of the forecasted biodiesel volume is used as transport fuel, neglecting minor uses in the heating oil market.

For the AEO scenario, the net effect of biodiesel production on diesel fuel costs, including the biodiesel blenders' subsidy, is a reduction in the cost of transport diesel fuel costs by $90 million per year, which equates to a reduction in fuel cost of about 0.15 c/gal.[71] Without the subsidy, the transport diesel fuel costs are increased by $118 million per year, or an increase of 0.20 c/gal for transport diesel fuel. With crude at $70 per barrel, including the biodiesel blenders subsidy, results in a cost reduction of $184 million per

[71] Based on EIA's AEO 2006, the total volume of highway and off-road diesel fuel consumed in 2012 was estimated at 58.9 billion gallons.

year, or a reduction of 0.31 c/gal for the total transport diesel pool. Without the subsidy, transport diesel costs are increased by $25 million per year, or 0.04 c/gal.

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.[72] That study provided the foundation 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 the case where the minimum volume of ethanol is used to meet the requirements of the RFS (7.2 bill gal/yr) and for the projected case where the volume of ethanol used is 9.6 bill gal/yr. 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 bill gal/yr of ethanol would be used in 2010, and the second assumed that 10 bill gal/yr of ethanol would be used in the 2015 timetable. We interpolated between these two cases to provide an estimate of the capital costs to support the use of 7.2 bill gal/yr of ethanol in 2012.[73] The 10 bill gal/yr case examined in the DOE study was used to represent the projected case examined in today's rule of 9.6 bill gal/yr of ethanol.[74] Table VII.B.1.a–1 contains 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, the total capital costs equate to approximately one cent per gallon. We performed a sensitivity analysis where we increased reliance on rail use at the expense of barge use in transporting ethanol. The costs were relatively insensitive, increasing to just 1.1 cents per gallon.

TABLE VII.B.1.A–1.—ESTIMATED ETHANOL DISTRIBUTION INFRASTRUCTURE CAPITAL COSTS ($M) RELATIVE TO A 3.9 BILLION GALLON PER YEAR REFERENCE CASE

	7.2 billion gallons (per year)	9.6 billion gallons (per year)
Fixed Facilities:		
Retail	24	44
Terminals	142	246
Mobile Facilities:		
Transport Trucks	38	50
Barges	30	52
Rail Cars	104	161
Total Capital Costs	317	542

b. *Ethanol Freight Costs.* The DOE study contains ethanol freight costs for each of the 5 PADDs. The Energy Information Administration translated these cost estimates to a census division basis.[75] We took the EIA projections and translated them into State-by-State ethanol freight costs. In conducting this translation, we accounted for increases in the cost in transportation fuels used to ship ethanol by truck, rail, and barge. We estimate that the freight cost to transport ethanol to terminals would range from 5 cents per gallon in the Midwest, to 18 cents per gallon to the West Coast, which averages 9.2 cents per gallon of ethanol on a national basis.

We estimate the total cost for producing and distributing ethanol to be between $1.30 and $1.36 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 28 million gallons.[76]

For the purposes of this analysis, we are assuming that to ensure consistent operations under cold conditions all terminals will install heated biodiesel storage tanks and biodiesel will be transported to terminals in insulated tank trucks and rail cars in the cold seasons.[77] Due to the developing nature of the biodiesel industry, specific information on biodiesel freight costs is lacking. The need to protect biodiesel from gelling during the winter may marginally increase freight costs over those for ethanol. Counterbalancing this is the likelihood that biodiesel shipping distances may be somewhat shorter due to the more geographically dispersed nature of biodiesel production facilities. In any event, the potential difference between biodiesel and ethanol freight costs is likely to be small and the cost of distributing biodiesel does not appreciably affect the results of our analysis. Therefore, we believe that

[72] Infrastructure Requirements for an Expanded Fuel Ethanol Industry, Downstream Alternatives Inc., January 15, 2002.

[73] See Chapter 7.3 of the Draft 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.

[74] For both the 7.2 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.

[75] 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.*

[76] 2004 baseline of 25 million gallons grown with diesel demand to 2012.

[77] See section VI.C. in today's preamble regarding the special handling requirements for biodiesel under cold conditions.

estimated freight costs for ethanol of 9.2 cents per gallon adequately reflects the freight costs for biodiesel for this analysis.

The capital costs associated with distribution of biodiesel will be somewhat higher per gallon than those associated with the distribution of ethanol due to the need for storage tanks, barges, tanker trucks and rail cars to be insulated and in many cases heated. We estimate that to handle the increased biodiesel volume will require a total capital cost investment of $49,813,000, which equates to about 2 cents per gallon of new biodiesel volume.

We estimate the total cost for producing and distributing biodiesel to be between $2.00 and $2.22 per gallon of biodiesel, on a nationwide average basis. This estimate includes both the capital costs to upgrade the distribution system and freight costs.

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 developed our own spreadsheet cost model. As described above in Section VI.A, the cost analysis is conducted by comparing a base year before the Energy Act's fuel changes to a modeled year with the fuel changes. We used 2004 as the base year. We grew the 2004 gasoline demand to 2012 to create a reference case assuming that the 2004 fuel demand scenario remained the same (fuel quality remained constant). The sum of fuel changes, including the increased use of ethanol, the phase-out of MTBE and the conversion of a part of the MTBE feedstocks to alkylate, is all assumed to occur by 2012 and is compared to the 2012 reference case. This analysis considers the production cost, distribution cost as well as the cost for balancing the octane and RVP caused by these fuel changes.

In addition to assessing the cost at 7.2 and 9.6 billion gallons of total ethanol use in gasoline, we considered that ethanol could be used at different levels in RFG. Instead of picking a single point for ethanol use in RFG, we assessed a range (see Section VI.A above). At the high end of the range, ethanol is used in RFG in both summer and winter. At the low end of the range, ethanol is still used in wintertime RFG, but to only a very limited extent in summertime RFG. The lower rate of ethanol use in summertime RFG may occur because the RVP increase associated with ethanol will cause refiners to incur a cost to further control the volatility of their summertime RFG.

1. RVP Cost for Blending Ethanol Into Summertime RFG

Blending ethanol into summertime RFG causes about a 1 PSI (pounds per square inch) increase in RVP. To enable this gasoline to continue to be sold into the summertime RFG market, this vapor pressure increase must be accounted for by adjusting the RVP of the base gasoline. The vapor pressure adjustment is made by reducing of volume of pentanes in the gasoline boiling that comes from the fluid catalytic cracking unit (FCCU). To reduce the pentane content FCC naphtha, refiners would likely have to add a distillation column called a depentanizer, where pentanes and lighter hydrocarbons are removed from the hydrocarbon feed and drawn off the top of the column while the heavier C6+ hydrocarbons are removed from the bottom. While the pentanes would be removed from the summertime RFG pool, they are expected to be reblended into either summertime CG or wintertime CG and RFG. To rebalance the RVP of the nonsummertime RFG pool or wintertime RFG or CG pool caused by relocated pentanes, butanes are estimated to be removed from the gasoline pool. When ethanol is blended into summertime RFG, about 10 percent of the base gasoline is lost due to the removed pentanes. We believe that refiners would reblend these removed pentanes into summertime CG or wintertime CG and RFG and rebalance the RVP of the gasoline pool into which the pentanes are being reblended by removing butanes, thus reducing the volume loss to one fifth of that if the pentanes were permanently removed. There is an opportunity cost to removing butanes from gasoline. In 2004 butanes sold into the butane market were valued 36 cents per gallon less than gasoline, however, this opportunity cost would be much greater if pentanes were permanently removed from gasoline.

We developed cost estimates for adding and operating a new depentanizer distillation column for the removal of pentanes from FCC naphtha in each refinery. The feed rate for an average FCC unit was estimated by PADD and ranged from 7 to 35 thousand barrels per day. Once the capital and operating costs were estimated, the total costs were averaged over the entire gasoline pool, which ranged from about two to three times the volume of FCC naphtha. When ethanol is being blended newly into summertime RFG, the capital and operating costs will both apply. However, when we model ethanol coming out of a summertime RFG market, we only reduce the depentanizer operating costs since the capital costs are sunk.

Our analysis showed that the RVP blending costs for blending ethanol into summertime RFG ranges from 1 to 1.4 cents per gallon of RFG. If the ethanol is coming out of summertime RFG, which occurs in some of the scenarios that we modeled, there would be a cost savings of 0.8 to 1.2 cents per gallon of RFG.

In the cost of refinery gasoline section below, we took into account that butanes have a lower energy density compared to the gasoline pool from which the butanes were removed. This energy content adjustment will offset some of the cost for removing the butanes. Butane's energy density is 94,000 BTUs per gallon compared to 115,000 BTU per gallon for gasoline.

For further details on RVP reduction costs, see Section 7.4.2 of the RIA.

2. Cost Savings for Phasing Out Methyl Tertiary Butyl Ether (MTBE)

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

We determined the operating costs saved by shutting down these plants. The volumetric feedstock demands and the operating costs factors for each of these MTBE plants are taken from literature. We estimated the MTBE operating costs to be $1.40 per gallon for captive and ethylene cracker plants, $1.48 per gallon for propylene oxide plants and $1.55 per gallon for merchant operating costs. Weighted by the percentages for domestic MTBE production, the average cost savings for no longer producing MTBE is estimated to be $1.46 per gallon.

We also credited MTBE for its octane blending value. MTBE has a high octane value of 110 (R+M)/2 which increases its value compared to gasoline. This high octane value partially offsets its production cost. The cost of octane is presented above in subsection VII.(A)(1)(c) and is applied to the difference in octane value between MTBE and the average of the various gasoline grades (88 (R+M)/2). Accounting for MTBE's octane value reduces its cost down to $1.27 to $1.38 per gallon depending on the PADD. When accounting for the volume of

MTBE removed, we also adjust for its energy content, which is 93,500 BTU per gallon.

For further information on costs savings due to MTBE phaseout, see Section 7.4.3 of the RIA.

3. Production of Alkylate From MTBE Feedstocks

Discontinuing the blending of MTBE into U.S. gasoline is expected to result in the reuse of most of the primary MTBE feedstocks, isobutylene, to be used to produce alkylate. Alkylate is formed by reacting isobutylene together with isobutane. Prior to the establishment of the oxygen requirement for RFG, this isobutylene was, in most cases, used to make alkylate. Another option would be for reacting isobutylene with itself to form isooctene which would likely be hydrogenated to then form isooctane. However, our cost analysis found that alkylate is a more cost-effective way to reuse the isobutylene, even after considering isooctane's higher octane content. The cost for converting to alkylate is estimated to be $1.42 per gallon for captive (in-refinery) plants and ethylene cracker plants, $1.46 per gallon for propylene oxide plants and $1.52 per gallon for merchant MTBE plants. We believe that the cost for converting merchant MTBE plants to alkylate is too high to support its conversion, thus the conversion cost is estimated to be $1.43 per gallon, the average of the conversion costs for captive, ethylene cracker and propylene oxide MTBE plants. This projected percent of MTBE plant conversion results in 0.84 gallons of alkylate produced for each gallon of MTBE no longer produced.

The alkylate production cost is adjusted by PADD to account for the blending octane of alkylate, which varies by 1 to 2 cents per gallon depending on the value of octane in each PADD. Including its octane value, the cost of producing alkylate varies from $1.38 to $ 1.41 per gallon.

For further information on production of alkylate from MTBE feedstocks, see section 7.4.4 of the RIA.

4. Changes in Refinery Produced Gasoline Volume and Its Costs

In the sections above, we estimated changes in gasoline volume and the cost associated with those volume changes for ethanol, MTBE, alkylate and butane. As these various gasoline blendstocks are added to or removed from the gasoline pool, they affect the refinery production of gasoline (or oxygenate blendstock).

To estimate the changes in refinery gasoline production volumes, it was necessary to balance the total energy production of each control case to the reference case. The energy content of the reference case was estimated by multiplying the volumetric energy content of each gasoline pool blendstock, including MTBE, ethanol and refinery produced gasoline, by the associated gallons.

The increase or decrease in ethanol content in summertime RFG assumed under the different scenarios resulted in the change in the volumes of butane in RFG as described above. We identified that the increase or decrease in ethanol in wintertime RFG and CG could cause reductions or increases in the amount of butanes blended into wintertime gasoline. Wintertime gasoline is limited in vapor pressure by the American Standard for Testing Materials (ASTM) RVP and V/L (vapor-liquid) standards. According to a refiner with extensive refining capacity, and also Jacobs Engineering, a refining industry consulting firm, refineries are blending their wintertime gasoline up to those standards today and are limited from blending more butane available to them. If this is the case, for each gallon of summertime RFG and wintertime RFG and CG blended with ethanol 2 percent of the base gasoline volume would be lost in terms of butane removed. However, some refineries may have room to blend more butane. Also, we are aware that some states offer 1 PSI waivers for blending of ethanol into wintertime gasoline, presumably to accommodate splash blending of ethanol.[78] Consequently, it may be possible to accommodate the 1 PSI vapor pressure increase without forcing the removal of some or all of this butane. For this reason we assessed the costs as a range, on the upper end assuming that butane content would have to be removed to account for new ethanol blended into summertime RFG and wintertime RFG and CG , and on the low end assuming only that blending of ethanol into summertime RFG cause butanes to be removed.

For estimating the volume of butane which must be removed from the gasoline because of the addition of ethanol, we assumed that ethanol will be used at 10 volume percent except for California where it would continue to be used at 5.7 volume percent. Development of the estimates for winter vs. summer ethanol consumption for the control cases is discussed in Chapter 2.1 of the RIA. For the reference case, we estimated that 55 percent of the ethanol would be used in the winter and 45 percent in the summer. Table VII.C.4–1 summarizes the summertime RFG and wintertime RFG and CG volumes of ethanol and estimated change in butane content.

TABLE VII.C.4–1.—ESTIMATED CHANGES IN U.S. SUMMERTIME RFG ETHANOL VOLUMES AND THEIR IMPACT ON BUTANE BLENDING INTO GASOLINE

[Million gallons in 2012]

	Reference case	7.2 Bil gals max RFG	7.2 Bil gals min RFG	9.6 Bil gals max RFG	9.6 Bil gals min RFG
Summertime RFG Ethanol	1,155	1,932	244	1,932	244
Wintertime RFG & CG Ethanol.	2,178	3,999	4,812	5,303	6,132
Change in Butane		−140 to −456	164 to −297	−140 to −690	164 to −535

The change in volume of ethanol, MTBE, alkylate, and butane for each control case is adjusted for energy content. The volume of refinery gasoline is then adjusted to maintain the same energy content as that of the reference gasoline pool. The refinery gasoline production is estimated by dividing the BTU content of gasoline, estimated to be 115,000 BTU per gallon, into the total amount of BTUs for the entire gasoline pool after accounting for the BTUs of the other blendstocks. The BTU-balanced gasoline pool volumes for each control case are shown in Table

[78] Most people are aware of the 1 PSI RVP waiver that ethanol is provided for the summertime, but some states offer a similar waiver to ethanol for wintertime blending as well.

VII.C.4–2. The changes are shown for both assumptions with respect to the need to remove butane from winter gasoline to accommodate more ethanol blending.

TABLE VII.C.4–2.—ESTIMATED 2012 VOLUMES

[Million gallons]

	7.2 Bil gals, max RFG		7.2 Bil gals, min RFG		9.6 Bil gals, max RFG		9.6 Bil gals, min RFG	
Total Ethanol	7,200		7,200		9,600		9,600	
Increase in Ethanol	3,302		3,302		5,702		5,702	
Change in MTBE	−2091		−2091		−2091		−2091	
New Alkylate	1,763		1,764		1,764		1,764	
Butane Removed in Winter	Yes	No	Yes	No	Yes	No	Yes	No
Change in Butane	−456	−140	−297	164	−690	−140	−535	164
Gasoline	143,486	143,228	143,357	142,980	142,092	141,642	141,965	141,394
Change in Gasoline	−1,873	−2,131	−2,002	−2,379	−3,267	−3,716	−3,394	−3,965
Change in Gasoline (%)	−1.3	−1.5	−1.4	−1.6	−2.2	−2.6	−2.3	−2.7

Based on our estimated impacts on volumes shown in table VII.C.4–2, refinery produced gasoline demand will be reduced by a range of 1.3 percent to 2.7 percent compared to the reference case, which would result in less imported finished petroleum products and/or less crude oil use. The projected impacts on refinery-produced gasoline demand depend on the volume of new ethanol blended into gasoline, on the volume of ethanol blended into summertime RFG and on whether butane blending into wintertime gasoline will be affected or not. To put this reduction in refinery-produced gasoline volume in perspective, the yearly annual growth in gasoline demand in this country is about 1.7 percent.

The cost for changes to refinery produced gasoline volume is assumed to be represented by the bulk price of gasoline in each PADD from EIA's 2004 Petroleum Marketing Annual. The 2004 gasoline cost is adjusted to 2012 using the ratio of the projected crude oil price in 2012 of $47 per barrel to that in the 2004 base case of $41 per barrel. The cost for distributing the gasoline to terminals is added on, which is estimated to be 4 cents per gallon. The estimated cost for producing and distributing gasoline to terminals (wholesale price at the terminal rack) ranges from $1.30 per gallon in the Gulf Coast, to $1.53 per gallon in California.

Crude oil prices are much higher today which decreases the relative cost of producing and blending in more ethanol into gasoline. For this reason, we conducted a sensitivity analysis assuming that crude oil is priced at around $70 per barrel. Since this is only a sensitivity analysis, we simply ratioed the gasoline production costs, MTBE and alkylate feedstock costs and butane value upwards by the same ratio. The ratio is determined by the projected increase in the wholesale gasoline price relative to the increase in crude oil price. We extrapolated this relationship to crude oil priced at $70 per barrel compared to the price in 2004 which was $41 per barrel, which results in about a 1.4 ratio factor. We did not adjust other costs and assumptions which are much less sensitive to the price of crude oil and therefore not likely to change much (e.g., distribution costs, refinery utility costs, incremental octane costs, and ethanol production costs). At a $70 per barrel crude oil price, the cost for production and distribution of gasoline to the terminal ranges from $2.05 in the Gulf Coast to $2.43 per gallon in California.

For further information on gasoline cost see section 7.4.5 in the RIA.

5. Overall Impact on Fuel Cost

We combined the costs and volume impacts described in the previous sections to estimate an overall fuel cost impact due to the changes in gasoline occurring with the projected fuel changes. This aggregated cost estimate includes the costs for producing and distributing ethanol, the blending costs of ethanol in summertime RFG, ending the production and distribution of MTBE, and reusing the MTBE feedstock isobutylene for producing alkylate, reducing the content of butane in summertime RFG and wintertime gasoline and for reducing the volume of refinery-produced gasoline. We also present the costs for the scenario that butanes would not need to be removed when ethanol is blended into wintertime gasoline. The costs for each control case are estimated by multiplying the change in volume for each gasoline blendstock, relative to the reference case, times its production, distribution and octane blending costs.

The costs of these fuels changes 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. The second way we express the cost is with the ethanol consumption subsidies included since the subsidized portion of the renewable fuels costs will be 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. For both cases we express the costs with and without butanes being removed due to changes in wintertime blending of ethanol. We evaluated the fuel costs using ranges in different assumptions to bound the many uncertainties in the cost analysis (see the DRIA for more discussion concerning the cost uncertainties).

a. *Cost without Ethanol Subsidies.* Table VII.C.5.a–1 summarizes the costs without ethanol subsidies for each of the four control cases, including the cost for each aspect of the fuels changes, and the aggregated total and the per-gallon costs for all the fuel changes.[79] 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. We excluded Federal and state ethanol consumption subsidies

[79] 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.

which avoids the transfer payments caused by these subsidies that would hide a portion of the program's costs.

caused by these subsidies that would hide a portion of the program's costs.

TABLE VII.C.5.A–1.—ESTIMATED COST WITHOUT ETHANOL CONSUMPTION SUBSIDIES ($47/BBL CRUDE)

[million dollars, except where noted]

	7.2 Bil gals, max RFG		7.2 Bil gals, min RFG		9.6 Bil gals, max RFG		9.6 Bil gals, min RFG	
Adding Ethanol	3,769		3,837		6,852		6,897	
RFG RVP Cost	72		−74		72		−74	
Eliminating MTBE	−2,821		−2,821		−2,821		−2,821	
Adding Alkylate	2,520		2,520		2,521		2,521	
Butane Removed in Winter	Yes	No	Yes	No	Yes	No	Yes	No
Changing Butane Volume	−439	−133	−275	174	−667	−133	−510	174
Additional Gasoline Production	−2,484	−2,826	−2,638	−3,141	−4,350	−4,948	−4,507	−5,270
Total Cost Excluding Subsidies	619	582	548	496	1,606	1,542	1,507	1,426
Per-Gallon Cost Excluding Subsidies (cents per gallon)	0.41	0.38	0.38	0.33	1.05	1.01	0.99	0.93

Our analysis shows that when considering all the costs associated with these fuel changes resulting from the expanded use of subsidized ethanol that these various possible gasoline use scenarios will cost the U.S. $0.5 billion to around $1.6 billion in the year 2012. Expressed as per-gallon costs, these fuel changes would cost the U.S. 0.3 to just over 1 cent per gallon of gasoline.

b. Gasoline Costs Including Ethanol Consumption Tax Subsidies. Table VII.C.5.b–1 expresses the total and per-gallon gasoline costs for the four 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 are estimated by multiplying the subsidy times the volume of new ethanol estimated to be used in the state. The costs are presented for the case that ethanol causes butanes to be withheld from the wintertime gasoline pool, and for the case that the blending of butanes remains unchanged.

TABLE VII.C.5.B–1.—ESTIMATED COST INCLUDING SUBSIDIES ($47/BBL CRUDE)

[million dollars, except where noted]

	7.2 Bil Gals Max RFG		7.2 Bil Gals Min RFG		9.6 Bil Gals Max RFG		9.6 Bil Gals Min RFG	
Butane Removed in Winter	Yes	No	Yes	No	Yes	No	Yes	No
Total Cost without Subsidies	619	582	548	496	1,606	1,542	1,507	1,426
Federal Subsidy	−1,684	−1,684	−1,684	−1,684	−2,908	−2,908	−2,908	−3,908
State Subsidies	−180	−180	−173	−173	−189	−189	−176	−176
Total Cost Including Subsidies	−1,245	−1,282	−1,308	−1,361	−1,491	−1,555	−1,578	−1,657
Per-Gallon Cost Including Subsidies (cents/gallon)	−0.82	−0.84	−0.86	−0.89	−0.98	−1.02	−1.03	−1.08

The cost including subsidies better represents gasoline's production cost as might be reflected to the fuel industry as a whole and to consumers "at the pump" because the Federal and state subsidies tends to hide a portion of the actual costs. Our analysis suggests that the fuel industry and consumers will see a 0.8 to 1.1 cent per gallon decrease in the apparent cost of producing gasoline with these changes to gasoline.

c. *Cost Sensitivity Case Assuming $70 per Barrel Crude Oil.* As described above, we analyzed a sensitivity analysis with the future price of crude oil remained at today's prices which is around $70 per barrel. This analysis was conducted by applying about a 1.4 multiplication factor times the 2004 gasoline production costs, MTBE and alkylate feedstock costs and butane value. This factor was derived by examining the historical association between increasing wholesale gasoline prices with increasing crude oil prices. We did not adjust the distribution costs, any of the utility costs, octane value and ethanol prices based on the assumption that these would change much less and therefore we kept them the same as that used in the primary analysis. The cost results of the sensitivity analysis are provided with and without the ethanol consumption subsidies in Table VII.C.5.c–1.

TABLE VII.C.5.C–1.—ESTIMATED COSTS FOR CRUDE OIL PRICED AT $70 PER BARREL

[Million dollars and cents per gallon]

	7.2 Bil gals, max RFG		7.2 Bil gals, min RFG		9.6 Bil gals, max RFG		9.6 Bil gals, min RFG	
Butane Removed in Winter	Yes	No	Yes	No	Yes	No	Yes	No

TABLE VII.C.5.C–1.—ESTIMATED COSTS FOR CRUDE OIL PRICED AT $70 PER BARREL—Continued

[Million dollars and cents per gallon]

Total Cost without Subsidies ($million)	−171	−187	−223	−245	222	196	138	105
Per-Gallon Cost without Subsidies (c/gal)	−0.11	−0.12	−0.15	−0.16	0.15	0.13	0.09	0.07
Total Cost Including Subsidies ($million)	−2,035	−2,051	−2,080	−2,102	−2,875	−2,901	−2,945	−2,978
Per-Gallon Cost Including Subsidies (c/gal)	−1.34	−1.35	−1.37	−1.38	−1.88	−1.90	−1.93	−1.95

If crude oil stays priced at around $70 per barrel, the cost of these fuel changes would decrease significantly. In fact, we estimate that the 7.2 billion gallon ethanol case would result in a cost savings to the U.S. even if butanes are removed from the wintertime gasoline pool when ethanol is added. When considering the ethanol subsidies, the incentive to blend in ethanol becomes much stronger at today's crude oil prices likely causing a rapid increase in ethanol production volume.

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 required under the Energy Policy Act of 2005 (Energy Act or the Act). 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 VI, we expect that total renewable fuel use in the U.S. in 2012 to exceed 7.5 billion gallons even in the absence of the RFS program. Thus, a traditional regulatory impact analysis would have shown no impact on emissions or air quality.

Strictly speaking, if the same volume and types of renewable fuels are produced and used with and without the RFS program, the RFS program is having 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 removal of MTBE while still producing the required volume of RFG which meets both commercial and EPA regulatory specifications. 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 still exists as to the effect of these gasoline components on emissions from both motor vehicle and nonroad equipment, particularly from the latest models equipped with the most advanced emission controls. 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. The results of this testing will not be available for inclusion in the analyses supporting this rulemaking. 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.[80]

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 this proposal, we estimate the impact of ethanol use on gasoline quality using fuel survey data obtained by Alliance of Automobile Manufacturers (AAM) from 2001–2005.[81] We estimate the impact of removing MTBE from gasoline based on refinery modeling performed in support of the RFG rulemaking. We plan to update these estimates for the FRM using refinery modeling which is currently underway. In general, as shown in Table VIII.A.1.a–1, adding ethanol to gasoline is expected to reduce levels of aromatics and olefins in conventional gasoline, as well as reduce mid and high distillation temperatures (e.g., T50 and T90). RVP is expected to increase, as most areas of the country grant ethanol blends a 1.0 RVP waiver of the applicable RVP standards in the summer. With the exception of RVP, the effect of removing MTBE results in essentially the opposite impacts. Please see Chapter 2 of the DRIA for a detailed description of the methodologies used and the specific changes in projected fuel quality.

[80] Subject to funding.

[81] Alliance of Automobile Manufacturers North American Fuel Survey 2005. For the final rule, we intend to supplement this empirical approach with the results of refinery modeling which might better capture all of the effects of ethanol blending on gasoline quality.

TABLE VIII.A.1.A–1.—CG FUEL QUALITY WITH AND WITHOUT OXYGENATES

Fuel parameter	Typical 9 RVP CG	MTBE CG blend	Ethanol CG blend
RVP (psi)	8.7	8.7	9.7
T50	218	206	186
T90	332	324	325
Aromatics (vol%)	32	25.5	27
Olefins (vol%)	7.7	7.7	6.1
Oxygen (wt%)	0	2	3.5
Sulfur (ppm)	30	30	30
Benzene (vol%)	1.0	1.0	1.0

The effect of adding ethanol and removing MTBE on the quality of RFG is expected to very limited. RFG must meet stringent VOC, NO_X and toxics performance standards. Thus, the natural effects of MTBE and ethanol blending on gasoline must often be addressed through further refining. The largest differences are expected to exist in terms of the distillation temperatures, due to the relatively low boiling point of ethanol. Other fuel parameters are expected to be very similar. For this analysis we have assumed no changes to fuel parameters other than ethanol and MTBE content for RFG.

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 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.[82] Thus, we assumed at the time that changes to gasoline quality would not affect VOC, CO and NO_X exhaust emissions from these vehicles. Very little additional data has been collected since that time on which to modify this assumption. Consequently, for our primary analysis for today's proposal we have maintained the assumption that changes to gasoline do not affect exhaust emissions from Tier 1 and later technology vehicles.

There is 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). The results of this program indicate that emissions from these late model year vehicles may be at least as sensitive to changes to these three fuel properties as Tier 0 vehicles on a percentage basis.[83] However, because this study is the first of its kind and not all relevant fuel properties have yet been studied, in our primary analysis we continue to assume that exhaust emissions from Tier 1 and later vehicles are not sensitive to fuel quality. Based on the indications of the CRC E–67 study, we also conducted a sensitivity analysis where the exhaust VOC and NO_X emission impacts for all vehicles were assumed to be as sensitive to fuel quality as Tier 0 vehicles (*i.e.*, as indicated by the EPA Predictive Models).

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.[84] 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.

[82] 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.

[83] The VOC and NO_X emissions from the 2000–2004 model year vehicles are an order of magnitude lower than those from the Tier 0 vehicles used to develop the EPA Complex and Predictive Models. Thus, a similar impact of a fuel parameter in terms of percentage means a much smaller impact in terms of absolute emissions.

[84] 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.*

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

[a] Average per vehicle effects for the 2012 fleet during summer conditions.

As can be seen, the oxygenated RFG blends are predicted to produce a greater reduction in exhaust VOC and CO emissions than 9 RVP conventional gasoline, but a larger increase in NO_X emissions. This comparison assumes that all gasoline meets EPA's Tier 2 gasoline sulfur standard of 30 ppm. Prior to this program, RFG contained less sulfur than conventional gasoline and produced less NO_X emissions. Non-exhaust VOC emissions with the exception of permeation are roughly the same due to the fact that the RVP level of the three blends is the same. However, the increased permeation emissions associated with ethanol reduces the overall effectiveness of ethanol RFG.

An increase in ethanol use will also impact emissions of air toxics. We evaluated effects on four air toxics affected by fuel parameter changes in the Complex Model-benzene, formaldehyde, acetaldehyde and 1,3-butadiene. The most notable effect on toxic emissions in percentage terms is the increase in acetaldehyde with the use of ethanol. Acetaldehyde emissions more than double. However, as will be seen below, base acetaldehyde emissions are low relative to the other toxics. Thus, the absolute increase in total emissions of these four air toxics is still relatively low.

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	−27
Formaldehyde		+10	+3
Acetaldehyde		−8	+141
1,3-Butadiene		−12	−27
Non-Exhaust VOC	MOBILE6.2	0	+17
Non-Exhaust Benzene	MOBILE6.2 & Complex Models	−10	+13

[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.

As was the case with the RFG blends, the two oxygenated blends both reduce exhaust VOC and CO emissions, but increase NO_X emissions. The MTBE blend does not increase non-exhaust VOC emissions, but the ethanol blend does due to the commonly granted waiver of the RVP standard. Both blends have lower exhaust benzene and 1,3-butadiene emissions. As above, ethanol increases non-exhaust benzene and acetaldehyde emissions.

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 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.

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

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	−15	−1	−1
Non-Exhaust VOC 0	0	26	0	26
CO	−13	−21	−8	−12
NO_X	+24	+37	+12	+18

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 NPRM addressing mobile air toxic emissions, EPA replaced the toxic-related fuel effects contained in NMIM with those from MOBILE6.2 for onroad vehicles.[85] 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.[86] At that time, most of the data available was for pre-1998 model year onroad diesel engines. The results are summarized in Table VIII.A.2–1. As shown, it indicated that biodiesel tended to reduce emissions of VOC, CO and PM. The NO_X emission effect was more variable, showing a very small increase on average.

TABLE VIII.A.2–1.—EFFECT OF 20 VO% BIODIESEL BLENDS ON DIESEL EMISSIONS (%)

Pollutant	2002 draft EPA study (percent)	Recent test results	
		Engine testing	Vehicle testing
VOC	−21	−12% (−35% to +14%)	+10% (−33% to +113%)
CO	−11	−14% (−28% to +1%)	+4% (−11% to +44%)
NO_X	+2	+1% (−3% to +6%)	+2% (−1% to +9%)
PM	−10	−20% (−31%+6%)	−3% (−57% to +40%)

We collected relevant engine and vehicle emission test data developed since the time of the 2002 study. The results of our analysis of this data are also shown in Table VIII.A.2–1. There, we show the average change in the emissions of each pollutant across all the engines or vehicles tested, as well as the range of effects found for each engine or vehicle. As can be seen, the variability in the emission effects is quite large, but the results of the more recent testing generally corroborate the findings of the 2002 study. Refer to DRIA Tables 3.1–15 and 3.1–16, and their corresponding discussion, for more detail on the data in the above table.

Overall, data indicating the effect of biodiesel on emissions is still quite limited. The emission effects also appear to be dependent on the load and speed of the engine (or driving cycle and vehicle type in the case of vehicle testing). However, the data are too limited to determine the specific way in which this occurs. Also, with the implementation of stringent NO_X and PM emission standards to onroad and nonroad diesels in the 2007–2010 timeframe, any effect on a percentage basis will rapidly decrease in magnitude on a mass basis as base emission inventory level decreases. As additional testing is performed over the next several years we will update this assessment.

3. Renewable Fuel Production and Distribution

The primary impact of renewable fuel production and distribution regards ethanol, since it is expected to be the

[85] 71, **Federal Register**, 15804, March 29, 2006.

[86] ''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.*

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 1.6. We also include emissions related to distributing the renewable fuels and take credit for reduced emissions related to distributing displaced 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	Ethanol	Biodiesel
VOC	3.6	41.5
CO	4.4	25.1
NO_X	10.8	44.3
PM10	6.1	1.5
SO_X	7.2	7.5

[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 and the two different cases for ethanol use in RFG.

TABLE VIII.B.1.–1.—2012 EMISSIONS NATIONWIDE FROM GASOLINE VEHICLES AND EQUIPMENT UNDER SEVERAL ETHANOL USE SCENARIOS—PRIMARY ANALYSIS

[Tons per year]

Pollutant	Inventory	Change in inventory in control cases			
	Reference case	7.2 Billion gallons of ethanol	9.6 Billion gallons of ethanol		
		Minimum RFG use	Maximum RFG use	Minimum RFG use	Maximum RFG use
VOC	5,837,000	31,000	8,000	57,000	29,000
NO_X	2,576,000	19,000	20,000	40,000	39,000
CO	64,799,000	−843,000	−1,229,000	−1,971,000	−2,319,000
Benzene	177,000	−6,000	−3,000	−11,000	−8,000
Formaldehyde	40,200	300	0	800	500
Acetaldehyde	19,800	6,200	5,000	9,600	8,500
1,3-Butadiene	18,200	−500	−300	−800	−600

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. Emissions of formaldehyde are also projected to increase slightly, on the order of 1–3 percent. Emissions of 1,3-butadiene and CO are projected to decrease by about 1–4 percent. Benzene emissions are projected to decrease by 2–6 percent. The largest change is in acetaldehyde emissions, an increase of 25–48 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 20–140 times the increase in VOC emissions in the four 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.

In addition to these changes in emissions due to ethanol use, biodiesel use is expected to have a minor impact on diesel emissions. Table VIII.B.1–2 shows the expected emission reductions associated with an increase in biodiesel fuel use from the reference case of 28 million gallons in 2012 to approximately 300 million gallons per year in 2012. This represents an increase from 0.06 to 0.6 percent of onroad diesel fuel consumption. In terms of a 20 percent biodiesel blend

(B20), it represents an increase from 0.3 to 3.2 percent of onroad diesel fuel consumption.

TABLE VIII.B.1–2.—ANNUAL EMISSIONS NATIONWIDE FROM ONROAD DIESELS IN 2012

[Tons per year]

	Reference inventory: 28 mill gal biodiesel per year	Change in emissions Inventory: 300 mill gal biodiesel per year
VOC	135,000	−800
NO_X	1,430,000	800
CO	353,000	−1,100
Fine PM	27,000	−100

As can be seen, the emission impacts due to biodiesel use are roughly two orders of magnitude smaller than those due to ethanol use.

There will also be some increases in emissions due to ethanol and biodiesel production. Table VIII.B.1–3 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.

TABLE VIII.B.1–3.—ANNUAL EMISSIONS NATIONWIDE FROM ETHANOL PRODUCTION AND TRANSPORTATION

[Tons per year]

	Reference inventory	Increase in emissions	
		7.2 Billion gallons of ethanol	9.6 Billion gallons of ethanol
VOC	15,929	12,744	22,301
NO_X	47,716	38,173	66,802
CO	19,389	15,511	27,144
PM_{10}	27,094	21,675	37,931
SO_X	31,760	25,408	44,464

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.

Table VIII.B.1–4 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.

TABLE VIII.B.1–4.—ANNUAL EMISSIONS NATIONWIDE FROM BIODIESEL PRODUCTION AND TRANSPORTATION

[Tons per year]

Pollutant	Reference inventory: 28 mill gal biodiesel per year	Change in emissions Inventory: 300 mill gal biodiesel per year
VOC	1,300	12,700
NO_X	1,400	13,600
CO	800	7,200
PM_{10}	50	1,000
SO_X	200	1,800

The potential emission increases related to biodiesel production and distribution are generally much smaller, with the possible exception of VOC emissions. Again, these emissions are generally expected to be in ozone attainment areas.

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 and the two cases of ethanol use in RFG. CO emissions are the same as in the primary analysis, as they are not affected by the EPA Predictive Models.

TABLE VIII.B.2–1.—2012 EMISSIONS NATIONWIDE FROM GASOLINE VEHICLES AND EQUIPMENT UNDER SEVERAL ETHANOL USE SCENARIOS: SENSITIVITY ANALYSIS

[Tons per year]

Pollutant	Inventory	Change in inventory in control cases			
		7.2 Billion gallons of ethanol		9.6 Billion gallons of ethanol	
	Reference case	Minimum RFG use	Maximum RFG use	Minimum RFG use	Maximum RFG use
VOC	5,775,000	4,000	−8,000	14,000	−5,000
NO_X	2,610,000	49,000	45,000	95,000	89,000
CO	64,799,000	−843,000	−1,229,000	−1,971,000	−2,319,000
Benzene	175,000	−9,000	−5,000	−14,000	− 10,000
Formaldehyde	39,300	0	−200	300	0
Acetaldehyde	19,200	5,800	4,700	9,000	8,000
1,3-Butadiene	17,900	−600	−400	−1,100	−800

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 either decreases substantially or 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 and NO_X 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 and NO_X emission inventories for these three types of areas. While ethanol use is going up in the vast majority of the nation, ethanol use in RFG areas under the ''Minimum Use in RFG'' scenarios is actually decreasing compared to the 2012 reference case. This is important to note in order to understand the changes in emissions indicated.

TABLE VIII.B.3–1.—CHANGE IN EMISSIONS FROM GASOLINE VEHICLES AND EQUIPMENT IN COUNTIES WHERE ETHANOL USE CHANGED SIGNIFICANTLY—PRIMARY ANALYSIS

Ethanol use	7.2 Billion gallons		9.6 Billion gallons	
Ethanol use in RFG	Minimum	Maximum	Minimum	Maximum
RFG Areas				
Ethanol Use	Down	Up	Down	Up.
VOC	1.6%	0.4%	1.6%	0.4%.
NO_X	−5.2%	2.4%	−5.2%	2.4%.
Low RVP Areas				
Ethanol Use	Up	Up	Up	Up.
VOC	3.1%	3.2%	4.1%	3.5%.
NO_X	4.1%	6.0%	4.8%	4.4%.
Other Areas				
Ethanol Use	Up	Up	Up	Up.
VOC	4.1%	4.1%	5.4%	4.4%.
NO_X	4.6%	6.0%	5.8%	4.8%.

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. The reader is referred to Chapter 2 of the DRIA for discussion of how ethanol levels will change at the state-level.

Table VIII.B.3–2 presents the percentage change in VOC and NO_X

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.—CHANGE IN EMISSIONS FROM GASOLINE VEHICLES AND EQUIPMENT IN COUNTIES WHERE ETHANOL USE CHANGED SIGNIFICANTLY—SENSITIVITY ANALYSIS

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

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 7.2 Billion Gallon 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 7.2 billion gallon ethanol use case. The changes in diesel emissions are negligible in comparison. We did not include the estimated changes in emissions from renewable fuel production and distribution, because of their more approximate nature. Their geographical concentration also makes it more difficult to simulate with the Ozone RSM.

The Ozone RSM was created using multiple runs of the Comprehensive Air Quality Model with Extensions (CAMx). Base and proposed control CAMx 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 the Chapter 5 of the DRIA for this proposal.

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 Table 5.1–2 of the DRIA, 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	
	Min RFG Use	Max RFG Use	Min RFG Use	Max RFG Use
Minimum Change	−0.030	−0.025	−0.180	0.000
Maximum Change	0.395	0.526	0.637	0.625
Average Change [b]	0.137	0.171	0.294	0.318
Population-Weighted Change [b]	0.134	0.129	0.268	0.250

[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 0.129–0.134 ppb. Since the 8-hour ambient ozone standard is 80 ppb, this increase represents about 0.16 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 roughly twice as high, or 0.250–0.268 ppb. This increase represents about 0.32 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 unlikely 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.

Moving to health effects, exposure to ozone has been linked to a variety of respiratory effects including premature mortality, hospital admissions and illnesses resulting in school absences. Ozone can also adversely affect the agricultural and forestry sectors by decreasing yields of crops and forests. 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, particularly the portion of this PM comprised of organic carbon. 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, as described above. Thus, the possibility exists that ambient nitrate PM levels could increase. Increased ethanol is generally expected to increase VOC emissions, which could also impact the formation of secondary organic PM. However, some VOC emissions, namely exhaust VOC emissions, are expected to decrease, while non-exhaust VOC emissions are expected to increase and the impact on PM is a function of the type of VOC emissions.

The formation of secondary organic PM is very complex, due in part to the wide variety of VOCs emitted into the atmosphere. Whether or not a specific gaseous VOC reacts to form PM in the atmosphere depends on the types of reactions that VOC undergoes, which in turn can depend on other pollutants present, such as 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 concentration of the gaseous VOC and the 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 ability 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 such as dependence on foreign sources of petroleum. Because significantly more renewable fuel is expected to be consumed over the next few years than has been consumed in the past, there is increased interest in the degree to which their increased use will impact greenhouse gas emissions and fossil fuel consumption.

Based on our analysis, we estimate that increases in the use of renewable fuels will reduce fossil fuel consumption and GHG emissions as shown in Table IX–1 in 2012. The results represent the percent reduction in total transportation sector emissions and energy use. The ranges result from different cases evaluated of the amount of renewable fuel (7.5 billion gallons versus 9.9 billion gallons) that will actually be produced in 2012.

TABLE IX–1.—LIFECYCLE IMPACTS OF INCREASED RENEWABLE FUEL USE RELATIVE TO THE 2012 REFERENCE CASE

	7.5 Billion case [a]	9.9 Billion case [b]
Percent Reduction in Transportation Sector Petroleum Energy Use	1.0	1.6
Percent Reduction in Transportation Sector Fossil Fuel Energy Use	0.5	0.8
Percent Reduction in Transportation Sector GHG Emissions	0.4	0.6
Percent Reduction in Transportation Sector CO_2 Emissions	0.6	0.9

[a] 7.2 billion gallons of ethanol.
[b] 9.6 billion gallons of ethanol.

This section provides a summary of our analysis of the fossil fuel impacts of the RFS rule.

A. Lifecycle Modeling

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.

A variety of approaches are available to conduct lifecycle analysis. This variety largely reflects different assumptions about (1) the boundary conditions and (2) the estimates of input factors. The boundary conditions determine the scope of the analysis. For example, a lifecycle analysis could include energy required to make farm equipment as part of the estimate of energy required to grow corn. The agency chose a lifecycle analytic boundary that encompasses the fuel-cycle and does not include the example used above. Differing estimates on input factors (e.g. amount of fertilizer to grow corn) can also affect the results of the lifecycle analysis.

For this proposed rulemaking, we have made use of a fuel-cycle model, GREET,[87] developed at Argonne National Laboratory (ANL) under the sponsorship of the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE). 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 instance, GREET provides lifecycle assessments for ethanol made from corn and cellulosic materials, biodiesel made from soybean oil, and petroleum-based gasoline and diesel fuel. Thus GREET provides a means for calculating the relative greenhouse gas (GHG) and petroleum impacts of renewable fuels that displace conventional motor vehicle fuels. For this proposal, we used version 1.7 of the GREET model, with a few modifications to its input assumptions as described in more detail below.

We do not believe that it would be appropriate at this time to base the regulatory provisions for this rule on lifecycle modeling, as described in more detail in Section III.B.4. Although the GREET model does provide a peer-reviewed source for lifecycle modeling, a consensus on all the assumptions, including point estimates, that are used as inputs into that model does not exist.[88] Also, given the short timeframe available for the development of this proposal, we have not had the opportunity to initiate the type of public dialogue on lifecycle modeling that would be necessary before such analyses could be incorporated into a regulatory framework. We have therefore chosen to use lifecycle modeling only as a means to estimate the impacts of the increased use of renewable fuel.

In addition to the GREET model tool, EPA has also developed a lifecycle modeling tool that is specific to individual fuel producers. This FUEL-CO2 model is intended to help fuel producers estimate the lifecycle greenhouse gas emissions and fossil energy use for all stages in the development of their specific fuel. EPA will evaluate whether the FUEL-CO2 model would be an appropriate tool for fuel providers who wish to demonstrate their actual reductions in greenhouse gas emissions and fossil energy use. This may also be the best way for ethanol producers to quantify the benefits of their renewable process energy use when qualifying corn ethanol as cellulosic biomass ethanol (an option for ethanol producers, stipulated in the Act).

[87] Greenhouse gases, Regulated Emissions, and Energy use in Transportation.

[88] See Chapter 6.1.2 of the RIA for further discussion of input assumptions used for the GREET modeling. Also see IX.A.2 of this preamble section for a discussion about the differing estimates.

1. Modifications to GREET Assumptions

GREET is subject to periodic updates by ANL, each of which results in some changes to the inputs and assumptions that form the basis for the lifecycle estimates of emissions generated and energy consumed. These updates generally focus on those input values for those fuels or vehicle technologies that are the focus of ANL at the time. As a result there are a variety of other inputs related to ethanol and biodiesel that have not been updated in some time. In the context of the RFS program, we determined that some of the GREET input values that were either based on outdated information or did not appropriately reflect market conditions under a renewable fuels mandate should be examined more closely, and updated if necessary.

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

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

The contract focuses on the potential fuel production developments and efficiency improvements that could occur within the time-frame of the RFS program. The GREET input value changes resulting from this work are projected to be available in the fall of 2006, not in time for this proposal, but they will be incorporated into revised lifecycle assessments for the final rule.

We did not investigate the input values associated with the production of petroleum-based gasoline or diesel fuel in the GREET model for this proposal. However, the refinery modeling discussed in Section VII will provide some additional information on the process energy requirements associated with the production of gasoline and diesel under a renewable fuels mandate. We will use information from this refinery modeling for the final rule to determine if any GREET input values should be changed.

A summary of the GREET corn ethanol input values we investigated and modified for this proposal is given below. We also examined several other GREET input values, but determined that the default GREET values should not be changed for a variety of reasons. These included ethanol plant process efficiency, corn and ethanol transport distances and modes, corn farming inputs, CO_2 emissions from corn farming land use change, 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 proposal.

a. *Wet-Mill Versus Dry Mill Ethanol Plants.* The two basic methods for producing ethanol from corn are wet milling and dry milling. In the wet milling process, the corn is soaked to separate the starch, used to make ethanol, from the other components of the corn kernel. In the dry milling process, the entire corn kernel is ground and fermented to produce ethanol. The remaining components of the corn are then dried for animal feed (dried distillers grains with solubles, or DDGS). Wet milling is more complicated and expensive than dry milling, but it produces more valuable products (ethanol plus corn syrup, corn oil, and corn gluten meal and feeds). The majority of ethanol plants in the United States are dry mill plants, which produce ethanol more simply and efficiently. The GREET default is 70 percent dry mill, 30 percent wet mill.

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. Therefore, it was assumed that essentially all new ethanol facilities would be dry mill plants.

b. *Coal Versus Natural Gas in Ethanol Plants.* The type of fuel used within the ethanol plant for process energy, to power the various components that are used in ethanol production (dryers, grinders, heating, etc.) can vary among ethanol plants. The type of fuel used has an impact on the energy usage, efficiency, and emissions of the plant, and is primarily determined by economics. Most new plants built in the last few years have used natural gas. Based on specific situations and economics, some new plants are using coal. In addition, EPA is promoting the use of combined heat and power, or cogeneration, in ethanol plants to improve plant energy-efficiency and to reduce air emissions. This technology, in the face of increasing natural gas prices, may make coal a more attractive energy source for new ethanol plants.

GREET assumes that 20 percent of plants will be powered by coal. However, our review of plants under construction and those planned for the near future indicates that coal will only be used for approximately 10% of the plants. This is the value we assumed in GREET for our analysis. However, as new plants are constructed to meet the demands of the RFS, this percentage is expected to go up. Future work in preparation for the final rule will evaluate the potential trends for combined heat and power and coal as process fuel.

c. *Ethanol Production Yield.* It is generally assumed that 1 bushel of corn yields 2.7 gallons of ethanol. However, the development of new enzymes continues to increase the potential ethanol yield. We used a value of 2.71 gal/bu in our analysis. This value represents pure ethanol production (*i.e.* no denaturant). This value is consistent with the cost modeling of corn ethanol discussed in Section VII.

2. Controversy Concerning the Ethanol Energy Balance

Although we have made use of lifecycle impact estimates from ANL's GREET model, there are a variety of lifecycle impact analyses from other researchers that provide alternative and sometimes significantly different estimates. The lifecycle energy balance for corn-ethanol, in particular, has been the subject of numerous and sometimes contentious debates.

Several metrics are commonly used to describe the energy efficiency of renewable fuels. We have chosen to use displacement indexes for this proposal because they provide the least ambiguous and most relevant mechanism for estimating the impacts of renewable fuels on GHGs and petroleum consumption. However, other metrics, such as the net energy balance and energy efficiency, have more commonly been used in the past. The use of these metrics has served to complicate the issue since they do not involve a direct comparison to the gasoline that the ethanol is replacing.

Among researchers who have studied the lifecycle energy balance of corn-ethanol, the primary differences of opinion appear to center on fossil energy associated with fertilizers, the energy required to convert corn into ethanol, and the value of co-products. As a result of these differences, the net energy balance has been estimated to be somewhere between −34 and +31 thousand Btu/gal, and the energy efficiency has been estimated to be somewhere between 0.6 and 1.4.[89] A concern arises in cases where a researcher concludes that the net energy balance is negative, or the energy efficiency is less than 1.0. Such cases would indicate that the fossil energy used in the production and transportation of ethanol exceeds the energy in the ethanol itself, and this is generally interpreted to mean that lifecycle fossil fuel use negates the benefits of replacing gasoline with ethanol. However, since the metrics used do not actually compare ethanol to gasoline, such interpretations are unwarranted.

The primary studies that conclude that the energy balance is negative were conducted by Dr. David Pimental of Cornell University and Dr. T. Patzek of University of California, Berkeley[90 91]. Many other researchers, however, have criticized that work as being based on out-dated farming and ethanol production data, including data not normally considered in lifecycle analysis for fuels, and not following the standard methodology for lifecycle analysis in terms of valuing co-products. Furthermore, several recent surveys have concluded that the energy balance is positive, although they differ in their numerical estimates.[92 93 94] Authors of the GREET model have also concluded that the lifecycle amount of fossil energy used to produce ethanol is less than the amount of energy in the ethanol itself. Based on our review of all the available information, we have concluded that the energy balance is indeed positive, and we believe that the GREET model provides an accurate basis for quantifying the lifecycle impacts.

B. Overview of Methodology

The GREET model does not provide estimates of energy consumed and emissions generated in total, such as the total amount of natural gas consumed in the U.S. in a given year by ethanol production facilities. Instead, it provides estimates on a national average, per fuel unit basis, such as the amount of natural gas consumed for the average ethanol production facility per million Btus of ethanol produced. As a result we could not use GREET directly to estimate the nationwide impacts of replacing some gasoline and diesel with renewable fuels.

Instead, we used GREET to generate comparisons between renewable fuels and the petroleum-based fuels that they displace. These comparisons allowed us to develop displacement indexes that represent the amount of lifecycle GHGs or fossil fuel reduced when a Btu of renewable fuel replaces a Btu of gasoline or diesel. In order to estimate the incremental impacts of increased use of renewable fuels on GHGs and fossil fuels, we combined those displacement indexes with our renewable fuel volume scenarios and GHG emissions and fossil fuel consumption data for the conventional fuels replaced. For example, to estimate the impact of corn-ethanol use on GHGs, these factors were combined in the following way:

$$S_{GHG,corn\ ethanol} = R_{corn\ ethanol} \times LC_{gasoline} \times DI_{GHG,corn\ ethanol}$$

Where:

$S_{GHG,corn\ ethanol}$ = Lifecycle GHG emission reduction relative to the 2012 reference case associated with use of corn ethanol (million tons of GHG).

$R_{corn\ ethanol}$ = Amount of gasoline replaced by corn ethanol on an energy basis (Btu).

$LC_{gasoline}$ = Lifecycle emissions associated with gasoline use (million tons of GHG per Btu of gasoline).

$DI_{GHG,corn\ ethanol}$ = Displacement Index for GHGs and corn ethanol, representing the percent reduction in gasoline lifecycle GHG emissions which occurs when a Btu of gasoline is replaced by a Btu of corn ethanol.

Variations of the above equation were also generated for impacts on all four endpoints of interest (emissions of CO2, emissions of GHGs, fossil fuel consumption, and petroleum consumption) as well as all three renewable fuels examined (corn-ethanol, cellulosic ethanol, and biodiesel). Each of the variables in the above equation are discussed in more detail below. Section 6 of the DRIA provides details of the analysis.

1. Amount of Conventional Fuel Replaced by Renewable Fuel (R)

In general, the volume fraction (R) represents the amount of conventional fuel no longer consumed—that is, displaced—as a result of the use of the replacement renewable fuel. Thus R represents the total amount of renewable fuel used under each of our renewable fuel volume scenarios, in units of Btu. We make the assumption that vehicle energy efficiency will not be affected by the presence of renewable fuels (i.e., efficiency of combusting one Btu of ethanol is equal to the efficiency of combusting one Btu of gasoline).

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 a base case representing 2004 renewable fuel production levels, projected to 2012. This scenario provided the point of comparison for the other two scenarios. The other two renewable fuel scenarios for 2012 represented the RFS program requirements and the volume projected by EIA. In both scenarios, we assumed that the biodiesel production volume would be 0.3 billion gallons based on an EIA projection, and that the cellulosic ethanol production volume would be 0.25 billion gallons based on the Energy Act's requirement that 250 million gallons of cellulosic ethanol be produced starting in the next year, 2013. The remaining renewable fuel volumes in each scenario would be ethanol made from corn. The total volumes for all three scenarios are shown in Table IX.B.1–1. For the purposes of calculating the R values, we assumed the ethanol volumes are 5% denatured, and the volumes were converted to total Btu using the appropriate volumetric energy content values (76,000 Btu/gal for ethanol, and 118,000 Btu/gal for biodiesel).

[89] A net energy balance of zero, or an energy efficiency of 1.0, would indicate that the full lifecycle fossil fuels used in the production and transportation of ethanol are exactly equal to the energy in the ethanol itself.

[90] Pimentel, David "Ethanol Fuel: Energy Balance, Economics, and Environmental Impacts are Negative", Vol. 12, No. 2, 2003 International Association for Mathematical Geology, Natural Resources Research.

[91] Pimentel, D.; Patzek, T. "Ethanol production using corn, switchgrass, and wood; biodiesel production using soybean and sunflower." Nat. Resour. Res. 2005, 14 (1), 65–76.

[92] Hammerschlag, R. "Ethanol's Energy Return on Investment: A Survey of the Literature 1990—Present." Environ. Sci. Technol. 2006, 40, 1744–1750.

[93] Farrell, A., Pelvin, R., Turner, B., Joenes, A., O'Hare, M., Kammen, D., "Ethanol Can Contribute to Energy and Environmental Goals", Science, 1/27/2006, Vol. 311, 506–508.

[94] Hill, J., Nelson, E., Tilman, D., Polasky, S., Tiffany, D., "Environmental, economic, and energetic costs and benefits of biodiesel and ethanol biofuels", Proceedings of the National Academy of Sciences, 7/25/2006, Vol. 103, No. 30, 11206–11210.

TABLE IX.B.1–1.—VOLUME SCENARIOS IN 2012

[billion gallons]

	Reference case	RFS required volume: 7.5 B gal	Projected volume: 9.9 B gal
Corn-ethanol	3.9	6.95	9.35
Cellulosic ethanol	0.0	0.25	0.25
Biodiesel	0.028	0.3	0.3
Total volume	3.928	7.5	9.9

Since the impacts of increased renewable fuel use were measured relative to the 2012 reference case, the value of R actually represented the incremental amount of renewable fuel between the reference case and each of the two other scenarios.

2. Lifecycle Impacts of Conventional Fuel Use (LC)

In order to determine the lifecycle impact that increased renewable fuel volumes may have on any particular endpoint (fossil fuel consumption or emissions of GHGs), we also needed to know the conventional fuel inventory on a lifecycle basis. Since available sources of GHG emissions are provided on a direct rather than a lifecycle basis, we converted these direct emission and energy estimates into their lifecycle counterparts. We used GREET to develop multiplicative factors for converting direct (vehicle-based) emissions of GHGs and energy use into full lifecycle factors. Table IX.B.2–1 shows the total lifecycle petroleum and GHG emissions associated with direct use of a Btu value of gasoline and diesel fuel.

TABLE IX.B.2–1.—LIFECYCLE EMISSIONS AND ENERGY (LC VALUES)

	Gasoline	Diesel
Petroleum (Btu/Btu)	1.11	1.10
Fossil fuel (Btu/Btu)	1.22	1.21
GHG (Tg-CO_2-eq/QBtu)	99.4	94.5
CO_2 (Tg-CO_2/QBtu)	94.2	91.9

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:

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

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. 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.

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.B.3–1. Details of these calculations can be found in Chapter 6 of the RIA. As noted previously, different models can result in different estimates. For example, whereas GREET estimates a net GHG reduction of about 26% for corn ethanol compared to gasoline, the previously cited works by Farrell et al. estimates around a 13% reduction.

TABLE IX.B.3–1.—DISPLACEMENT INDEXES DERIVED FROM GREET

	Corn ethanol (percent)	Cellulosic ethanol (percent)	Biodiesel (percent)
$DI_{Petroleum}$	92.3	92.7	84.6
$DI_{Fossil\ Fuel}$	40.1	96.0	47.9
DI_{GHG}	25.8	98.1	53.4

TABLE IX.B.3–1.—DISPLACEMENT INDEXES DERIVED FROM GREET—Continued

	Corn ethanol (percent)	Cellulosic ethanol (percent)	Biodiesel (percent)
DI_{CO_2}	43.9	110.1	56.8

The displacement indexes in this table represent the impact of replacing a Btu of gasoline or diesel with a Btu of renewable fuel. Thus, for instance, for every Btu of gasoline which is replaced by corn ethanol, the total lifecycle GHG emissions that would have been produced from that Btu of gasoline would be reduced by 25.8 percent. For every Btu of diesel which is replaced by biodiesel, the total lifecycle petroleum energy that would have been consumed as a result of burning that Btu of diesel fuel would be reduced by 84.6 percent.

Note that our DI estimates for cellulosic ethanol assume that the ethanol in question was in fact produced from a cellulosic feedstock, such as wood, corn stalks, or switchgrass. However, the definition of cellulosic biomass ethanol given in the Energy Act also includes ethanol made from non-cellulosic feedstocks if 90 percent of the process energy used to operate the facility is derived from a renewable source. In the context of our cost analysis, we have assumed this latter definition of cellulosic ethanol. Further discussion of this issue can be found in Chapter 1, Section 1.2.2 of the RIA.

C. Impacts of Increased Renewable Fuel Use

We used the methodology described above to calculate impacts of increased use of renewable fuels on consumption of petroleum and fossil fuels and also on emissions of CO_2 and GHGs. This section describes our results.

1. Fossil Fuels and Petroleum

We used the equation for S above to calculate the reduction associated with the increased use of renewable fuels on lifecycle fossil fuels and petroleum. These values are then compared to the total U.S. transportation sector emissions to get a percent reduction. The results are presented in Tables IX.C.1–1 and IX.C.1–2.

TABLE IX.C.1.–1.—FOSSIL FUEL IMPACTS OF INCREASED USE OF RENEWABLE FUELS IN THE TRANSPORTATION SECTOR IN 2012, RELATIVE TO THE 2012 REFERENCE CASE

	RFS Required volume: 7.5 Bgal	Projected volume: 9.9 Bgal
Reduction (quadrillion Btu)	0.2	0.3
Percent reduction	0.5	0.8

TABLE IX.C.1.–2.—PETROLEUM IMPACTS OF INCREASED USE OF RENEWABLE FUELS IN THE TRANSPORTATION SECTOR IN 2012, RELATIVE TO THE 2012 REFERENCE CASE

	RFS Required volume: 7.5 Bgal	Projected volume: 9.9 Bgal
Reduction (billion gal)	2.3	3.9
Percent reduction	1.0	1.6

2. Greenhouse Gases and Carbon Dioxide

One issue that has come to the forefront in the assessment of the environmental impacts of transportation fuels relates to the effect that the use of such fuels could have on emissions of greenhouse gases (GHGs). The combustion of fossil fuels has been identified as a major contributor to the increase in concentrations of atmospheric carbon dioxide (CO_2) since the beginning of the industrialized era, as well as the build-up of trace GHGs such as methane (CH_4) and nitrous oxide (N_2O). This lifecycle analysis evaluates the impacts of renewable fuel use on greenhouse gas emissions.

The relative global warming contribution of emissions of various greenhouse gases is dependant on their radiative forcing, atmospheric lifetime, and other considerations. For example, on a mass basis, the radiative forcing of CH_4 is much higher than that of CO_2, but its effective atmospheric residence time is much lower. The relative warming impacts of various greenhouse gases, taking into account factors such as atmospheric lifetime and direct warming effects, are reported on a CO_2-equivalent basis as global warming potentials (GWPs). The GWPs used by GREET were developed by the UN Intergovernmental Panel on Climate Change (IPCC) as listed in their Third Assessment Report [95], and are shown in Table IX.C.2–1.

TABLE IX.C.2–1.—GLOBAL WARMING POTENTIALS FOR GREENHOUSE GASES

Greenhouse gas	GWP
CO_2	1
CH_4	23
N_2O	296

Greenhouse gases are measured in terms of CO_2-equivalent emissions, which result from multiplying the GWP for each of the three pollutants shown in the above table by the mass of emission for each pollutant. The sum of

[95] IPCC ''Climate Change 2001: The Scientific Basis'', Chapter 6; Intergovernmental Panel on Climate Change; J. T. Houghton, Y. Ding, D. J. Griggs, M. Noguer, P. J. van der Linden, X. Dai, C. A. Johnson; and K. Maskell, eds.; Cambridge University Press. Cambridge, U. K. 2001. *http://www.grida.no/climate/ipcc_tar/wg1/index.htm.*

impacts for CH_4, N_2O, and CO_2, yields the total effective GHG impact.

We used the equation for S above to calculate the reduction associated with the increased use of renewable fuels on lifecycle emissions of CO_2. These values are then compared to the total U.S. transportation sector emissions to get a percent reduction. The results are presented in Table IX.C.2–2.

TABLE IX.C.2–2.—CO_2 EMISSION IMPACTS OF INCREASED USE OF RENEWABLE FUELS IN THE TRANSPORTATION SECTOR IN 2012, RELATIVE TO THE 2012 REFERENCE CASE

	RFS Required volume: 7.5 Bgal	Projected Volume: 9.9 Bgal
Reduction (million metric tons CO_2)	12.6	19.8
Percent reduction	0.6 %	0.9 %

Carbon dioxide is a subset of GHGs, along with CH_4 and N_2O as discussed above. It can be seen from Table IX.B.3–1 that the displacement index of CO_2 is greater than for GHGs for each renewable fuel. This indicates that lifecycle emissions of CH_4 and N_2O are higher for renewable fuels than for the conventional fuels replaced. Therefore, reductions associated with the increased use of renewable fuels on lifecycle emissions of GHGs are lower than the values for CO_2. The results for GHGs are presented in Table IX.C.2–3.

TABLE IX.C.2–3.—GHG EMISSION IMPACTS OF INCREASED USE OF RENEWABLE FUELS IN THE TRANSPORTATION SECTOR IN 2012, RELATIVE TO THE 2012 REFERENCE CASE

	RFS Required volume: 7.5 Bgal	Projected Volume: 9.9 Bgal
Reduction (million metric tons $CO_{2\text{-eq.}}$)	9.0	13.5
Percent reduction	0.4%	0.6%

D. Implications of Reduced Imports of Petroleum Products

This section only considers the impacts on imports of oil and petroleum products. Expanded production and use of renewable fuels could have other economic impacts such as on the exports of agricultural products like corn. See section X of the preamble for a discussion on agricultural sector impacts.

In 2005, the United States imported almost 60 percent of the oil it consumed. This compares to just over 35 percent oil imports in 1975.[96] Transportation accounts for 70% 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 socially beneficially, which would depend on the scarcity value of domestically produced ethanol versus that of imported petroleum products.

To assess the impact of the RFS program on petroleum imports, the fraction of domestic consumption derived from foreign sources was estimated using results from the AEO 2006. In section 6.4.1 of the DRIA we describe how fuel producers change their mix in response to a decrease in fuel demand. We do not expect the projected reductions in petroleum consumption (0.3 to 0.57 Quads) to impact world oil prices by a measurable amount. We base this assumption on the overall size of worldwide petroleum demand and analysis of the AEO 2006 cases. As a consequence, domestic crude oil production for the 7.5 or 9.9 cases would not be expected to change significantly versus the RFS reference case. Thus, petroleum reductions will come largely from reductions in net petroleum imports. This conclusion is confirmed by comparing the AEO 2006 low macroeconomic growth case to the AEO 2006 reference case, as discussed in the RIA 6.4.1. The AEO 2006 shows that for a reduction in petroleum demand on the order of the reductions estimated for the RFS, net imports will account for approximately 95% of the reductions. However, if petroleum reductions were large enough to impact world oil prices, the mix of domestic crude oil, imports of finished products, and imports of crude oil used by fuel producers would change. We discuss this uncertainty in more detail in section 6.4.1 of the RIA and solicit comments to the extent by which the RFS may have a price effect and impact the imports of crude oil and refined products.

We quantified the fraction of net petroleum imports that would be crude oil versus finished products. Comparison of same cases in the AEO 2006 shows that finished products initially compose all the net import reductions, followed by imported crude oil once reductions in consumption reach beyond 1.2 Quads of petroleum product. However, there is significant uncertainty in quantifying how refineries will change their mix of sources with a decrease in petroleum demand, particularly at the levels estimated for the RFS. For example, a comparison between the AEO low price case (as opposed to low macroeconomic growth case) and the reference case would yield a 50–50 split between product and crude imports. We believe that the actual refinery response could range between these two points, so that finished product imports would compose between 50 to 100% of the net import reductions, with crude oil imports making up the remainder. For the purposes of this rulemaking, we show values for the case where net import reductions come entirely from imports of finished products, as shown below in Table IX.D–1. We compare these reductions in imports against the AEO projected levels of net petroleum imports. The range of reductions in net petroleum imports are estimated to be between 1 to 2%, as shown in Table IX.D–2.

TABLE IX.D–1.—REDUCTIONS IN IMPORTS OF FINISHED PRODUCTS

[barrels per day]

Cases	2012
7.5	145,454
9.9	240,892

[96] Davis, Stacy C.; Diegel, Susan W., Transportation Energy Data Book: 25th Edition, Oak Ridge National Laboratory, U.S. Department of Energy, ORNL–6974, 2006.

TABLE IX.D–2.—PERCENT REDUCTIONS IN PETROLEUM IMPORTS COMPARED TO AEO2006 IMPORT PROJECTIONS

Cases	2012
7.5	1.1%
9.9	1.7%

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

To understand the energy security implications of the RFS, EPA will work with Oak Ridge National Laboratory (ORNL). As a first step, ORNL will update and apply the approach used in the 1997 report Oil Imports: An Assessment of Benefits and Costs, by Leiby, Jones, Curlee and Lee.[97] This paper was cited and its results utilized in previous DOT/NHTSA rulemakings, including the 2006 Final Regulatory Impact Analysis of CAFE Reform for Light Trucks.[98] This approach is consistent with that used in the Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards Report conducted by the National Research Council/National Academy of Sciences in 2002. Both reports estimate the marginal benefits to society, in dollars per barrel, of reducing either imports or consumption. This ''oil premium'' approach emphasizes identifying those energy-security related costs that are not reflected in the market price of oil, and which may change in response to an incremental change in the level of oil imports or consumption.[99]

Since the 1997 publication of this report changes in oil market conditions, both current and projected, suggest that the magnitude of the ''oil premium'' may have changed. Significant factors that should be reconsidered include: Oil prices, current and anticipated levels of OPEC production, U.S. import levels, potential OPEC behavior and responses, and disruption likelihoods. ORNL will apply the most recently available careful quantitative assessment of disruption likelihoods, from the Stanford Energy Modeling Forum's 2005 workshop series, as well as other assessments [100]. ORNL will also revisit the issue of the macroeconomic consequences of oil market disruptions and sustained higher oil prices. Using the ''oil premium'' calculation methodology which combines short-run and long-run costs and benefits, and accounting for uncertainty in the key driving factors, ORNL will provide an updated range of estimates of the marginal energy security implications of displacing oil consumption with renewable fuels. The results of this work effort are not available for this proposal but will be part of the assessment of impacts of the RFS in the final rule. Although not directly applicable, financial economics literature has examined risk diversification. The agency is interested in ways to examine changes in risks associated with diversifying energy sources in general and solicits comments as such.

We also calculate the decreased expenditures on petroleum imports and compare this with the U.S. trade position measured as U.S. net exports of all goods and services economy-wide. All reductions in petroleum imports are expected to be from finished petroleum products rather than crude oil. The reduced expenditures in petroleum product imports were calculated by multiplying the reductions in gasoline and diesel imports by their corresponding price. According to the EIA, the price of imported finished products is the market price minus domestic local transportation from refineries and minus taxes.[101] An estimate was made by using the AEO 2006 gasoline and distillate price forecasts and subtracting the average Federal and state taxes based on historical data.[102]

We compare these avoided petroleum import expenditures against the projected value of total U.S. net exports of all goods and services economy-wide. Net exports is a measure of the difference between the value of exports of goods and services by the U.S. and the value of U.S. imports of goods and services from the rest of the world. For example, according to the AEO 2006, the value of total import expenditures of goods and services exceeds the value of U.S. exports of goods and services to the rest of the world by $695 billion for 2006 (for a net export level of minus $695 billion).[103] This net exports level is projected to diminish to minus $383 billion by 2012. In Table IX.D–3, we compare the avoided expenditures in petroleum imports versus the total value of U.S. net exports of goods and services for the whole economy for 2012. Relative to the 2012 projection, the avoided petroleum expenditures due to the RFS would represent 0.9 to 1.5% of economy-wide net exports.

[97] 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 1, 1997. (*http://pzl1.ed.ornl.gov/energysecurity.html*).

[98] US DOT, NHTSA 2006. ''Final Regulatory Impact Analysis: Corporate Average Fuel Economy and CAFE Reform for MY 2008–2011 Light Trucks,'' Office of Regulatory Analysis and Evaluation, National Center for Statistics and Analysis, March. (*http://www.nhtsa.dot.gov/staticfiles/DOT/NHTSA/Rulemaking/Rules/Associated%20Files/2006_FRIAPublic.pdf*).

[99] For instance, the 1997 ORNL study gave a range for the ''oil premium'' $0 to $13 per barrel (adjusted to $2004) based on 1994 market conditions. The actual value depended on assumptions about the market power of foreign exporters and the monopsony power of the U.S., the risk of future oil price shocks and the employment of hedging strategies, and the connections between oil shocks and GNP.

[100] Stanford Energy Modeling Forum, Phillip C. Beccue and Hillard G. Huntington, 2005. ''An Assessment of Oil Market Disruption Risks,'' FINAL REPORT, EMF SR 8, October 3. (*http://www.stanford.edu/group/EMF/publications/search.htm*).

[101] EIA (September 1997), ''Petroleum 1996: Issues and Trends'', Office of Oil and Gas, DOE/EIA–0615, p. 71. (*http://tonto.eia.doe.gov/FTPROOT/petroleum/061596.pdf*)

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

[103] For reference, the U.S. Bureau of Economic Analysis (BEA) reports that the 2005 import expenditures. on energy-related petroleum products totaled $235.5 billion (2004$) while petroleum exports totaled $13.6 billion—for a net of $221.9 billion in expenditures. Net petroleum expenditures made up a significant fraction of the $591.3 billion current account deficit in goods and services for 2005 (2004$). (*http://www.bea.gov/*)

TABLE IX.D–3.—AVOIDED PETROLEUM IMPORT EXPENDITURES FOR 2012

[$2004 billion]

AEO2006 total net exports	RFS Cases	Avoided expenditures in petroleum imports	Percent versus total net exports (Percent)
−$383	7.5	3.5	0.9
	9.9	5.8	1.5

X. Agricultural Sector Economic Impacts

As described in more detail in the Draft Regulatory Impact Analysis accompanying this proposal, we plan to evaluate the economic impact on the agricultural sector. However, due to the timing of that analysis, it will not be completed until the final rule. In the meantime, we briefly describe here (and in more detail in the draft RIA) our planned analyses and the sources of assumptions which could critically impact those assessments. Finally, we ask for specific comment on the best sources of information we use in these analyses.

We will be using the Forest and Agricultural Sector Optimization Model (''FASOM'') developed over the past 30 years by Bruce McCarl, Texas A&M University and others. This is a constrained optimization model which seeks to allocate resources and production to maximize producer plus consumer surpluses. We have consulted with a range of experts both within EPA as well as at our sister agencies, the U.S. Departments of Agriculture and Energy and they support the use of this model for assessing the economic impacts on the agricultural sector of various renewable fuel pathways evaluated in this rule. The objective of this modeling assessment is to predict the economic impacts that will directly result from the expanded use of farm products for transportation fuel production. We anticipate that the growing demand for corn for ethanol production in particular but also soybeans and other agricultural crops such as rapeseed and other oil seeds for biodiesel production will increase the production of these feedstocks and impact farm income. The additional corn to produce ethanol may come from several sources, including (1) more intensive cultivation of existing land that currently produces corn, (2) switching production from soybean and cotton to corn, (3) additional acres of land being cultivated, or (4) diversion from corn exports. The implications to U.S. net exports and environment effects partially depend on which source supplies more corn. Eventually various cellulose sources such as corn stover and switchgrass for cellulose-based ethanol production may well become highly demanded and also significantly impact the agricultural sector.

Using the FASOM model, we will estimate the direct impact on farm income resulting from higher demand for corn and soybeans, for example. Additionally, we will estimate impacts on farm employment. Since we expect the higher demand for feedstock will increase both the supply and cost of feedstock, we will also consider how the higher renewable fuel feedstock cost impacts the cost of other agricultural products (corn and soy meal are important sources not only for directly making food for human consumption but also as feed for farm animals). As an estimate of the impact on corn and soybeans prices, we are relying on the estimates provided by the U.S. Department of Agriculture[104] rather than using the FASOM model to derive these price impacts. Additionally, we will rely on the Energy Information Agency's estimates for fuel mix in predicting the amount of ethanol and biodiesel in the fuel pool. Other than these external constraints, we expect to use FASOM as the basic model for estimating economic impacts on farm sector and how these might more generally impact the U.S. economy. Note that this FASOM analysis is a partial equilibrium analysis, focusing almost exclusively on impacts in the U.S. agricultural sector. As a result, it cannot be utilized to make broader assessments of net social benefits resulting from this rulemaking, which for example would require evaluation of the transfer payments to farmers and ethanol producers from consumers and refiners.

XI. Public Participation

We request comments on all aspects of this proposal. The comment period for this proposed rule will be November 12, 2006. Comments can be submitted to the Agency through any of the means listed under **ADDRESSES** above.

We will hold a public hearing on October 13, 2006. The public hearing will start at 10 a.m. (Central) at the Sheraton Gateway Suites Chicago O'Hare, 6501 North Mannheim Road, Rosemont, Illinois 60018. If you would like to present testimony at the public hearing, we ask that you notify the contact person listed under **FOR FURTHER INFORMATION CONTACT** above at least ten days beforehand. You should estimate the time you will need for your presentation and identify any needed audio/visual equipment. We suggest that you bring copies of your statement or other material for the EPA panel and the audience. It would also be helpful if you send us a copy of your statement or other materials before the hearing.

We will arrange for a written transcript of the hearing and keep the official record of the hearing open for 30 days to allow for the public to supplement the record. You may make arrangements for copies of the transcript directly with the court reporter.

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 proposed rule. Even though EPA has estimated that renewable fuel use through 2012 will be sufficient to meet the levels required in the standard, the proposed 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 proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction

[104] ''USDA Agricultural Baseline Projections to 2015.''

Act, 44 U.S.C. 3501 et seq. The Information Collection Request (ICR) document prepared by EPA has been assigned EPA ICR number 2242.01.

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 Act will be satisfied through a program utilizing Renewable Identification Numbers (RIN), which serve as a surrogate for renewable fuel consumption. Our proposed RIN-based program would fulfill all the functions of a credit trading program, and thus would meet the Energy Act's requirements. For each calendar year, each obligated party would be required to submit a report to the Agency documenting the RINs it acquired, and showing that the sum of all RINs acquired were 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. The Agency will then calculate the total amount of renewable fuel produced each year.

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 3.1 hours per response. 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 which have subsequently changed; 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.

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. The estimates contained in the docket are briefly summarized here:

Estimated total number of potential respondents: 4,945.

Estimated total number of responses: 4,970.

Estimated total annual burden hours: 15,560.

Estimated total annual costs: $2,911,000, including $1,806,240 in purchased services.

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.

To comment on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques, EPA has established a public docket for this rule, which includes this ICR, under Docket ID number EPA–OAR–2005–0161. Submit any comments related to the ICR for this proposed rule to EPA and OMB. See the **ADDRESSES** section at the beginning of this notice for where to submit comments to EPA. Send comments to OMB at the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, Attention: Desk Office for EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after publication in the **Federal Register**, a comment to OMB is best assured of having its full effect if OMB receives it by October 30, 2006. The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

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 and a crude capacity of ≤125,000 bpcd[b]	324110

[a] North American Industrial Classification System.
[b] barrels of crude per day.

2. Background—Small Refiners Versus Small Refineries

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 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." This term is different from a small refiner, which is what the Regulatory Flexibility Act is concerned with. A small refiner is a small business that meets the criteria set out in SBA's regulations at 13 CFR 121.201; whereas 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.

Previous EPA fuel regulations have afforded regulatory flexibility provisions to small refiners, as we believe that refineries owned by small businesses generally face unique economic challenges, compared to larger refiners. As small refiners generally lack the resources available to larger companies (including those larger companies that own small-capacity refineries) to raise capital for any necessary investments for meeting regulatory requirements, these flexibility provisions were provided to reduce the disproportionate burden on those refiners that qualified as small refiners.

3. Summary of Potentially Affected Small Entities

The refiners that are potentially affected by this proposed rule are those that produce gasoline. For our recent proposed rule ''Control of Hazardous Air Pollutants From Mobile Sources'' (71 FR 15804, Wednesday, March 29, 2006), we performed an industry characterization of potentially affected gasoline refiners; we used that industry characterization to determine which refiners would also meet the SBA definition of a small refiner under this proposal. From the industry characterization, we determined that there were 20 gasoline refiners that met the definition of a small refiner. Of these 20 refiners, 17 owned refineries that also met the Energy Policy Act's definition of a small refinery.

4. 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, were specified in the Energy Policy Act. As shown above in Table III.D.3.c–2, the annual projections of ethanol production 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. If there were a shortage of RINs, or if any party were to 'hoard' RINs, the cost of a RIN could be high; however with excess RINs, we believe that this program will not impose a significant economic burden on small refineries, small refiners, or any other obligated party. Further, we have determined that this proposed 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 proposed regulatory flexibilities to decrease the burden on these entities in compliance with the requirements of the RFS program

5. Small Refiner Outreach

Although we do not believe that the RFS program would have a significant economic impact on a substantial number of small entities, EPA nonetheless has tried to reduce the impact of this rule on small entities. 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. As stated above, 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 temporary exemption that the Act specifies for small refineries. Regarding the small refiners' second and third suggestions regarding credits, our proposed 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.

6. Conclusions

After considering the economic impacts of today's proposed rule on small entities, we certify that this action will not have a significant economic impact on a substantial number of small entities.

While the Energy Policy Act provided for a temporary exemption for small refineries from the requirements of today's proposed rule, these parties will have to comply with the requirements following the exemption period. However, we still believe that small refiners generally lack the resources available to larger companies, and therefore find it necessary to extend the small refinery temporary exemption to all small refiners. Thus, we are proposing to allow the small refinery temporary exemption, as set out in the Act, to all qualified small refiners. In addition, past fuels rulemakings have included a provision that, to qualify for EPA's small refiner flexibilities, a refiner must have no more than 1,500 total corporate employees and have a crude capacity of no more than 155,000 bpcd (slightly higher than SBA's crude capacity limit of 125,000 bpcd). To be consistent with these previous rules, we are also proposing to allow those refiners that meet these criteria to be considered small refiners for this rulemaking. Lastly, we are proposing that small refiners may separate RINs from batches and trade or sell these RINs prior to 2011 if the small refiner operates as a blender

We continue to be interested in the potential impacts of this proposed rule on small entities and welcome comments on issues related to such impacts.

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 proposals 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.

This rule contains no Federal mandates for State, local, or tribal governments as defined by the provisions of Title II of the UMRA. The rule imposes no enforceable duties on any of these governmental entities. Nothing in the rule would significantly or uniquely affect 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 proposed 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 solicits comment on this proposed rule from State and local officials.

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 proposed rule does not have tribal implications, as specified in Executive Order 13175. This rule would be implemented at the Federal level and collectively apply to refiners, blenders, and importers. EPA expects these entities to meet the standards on a collective basis through 2012 even without imposition of any RFS obligations on any individual party. 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. EPA specifically solicits additional comment on this proposed rule from tribal officials.

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 Executive Order 13045 as applying only to those regulatory actions that are based on health or safety risks, such that the analysis required under Section 5–501 of the Order has the potential to influence the regulation. This proposed rule is not subject to Executive Order 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. Nevertheless, the rule is an important part of the nation's efforts to reduce dependence on foreign oil. 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

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (''NTTAA''), Public Law 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 proposed rulemaking does not involve technical standards. Therefore, EPA is not considering the use of any voluntary consensus standards.

XIII. Statutory Authority

Statutory authority for the rules proposed 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 proposal, including the proposed 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: September 7, 2006.

Stephen L. Johnson,

Administrator.

40 CFR part 80 is proposed to be amended as follows:

PART 80—REGULATION OF FUELS 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.* The definitions of § 80.2 and the following additional definitions apply to this section only.

(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 purposes of this subpart.

(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, which 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.

(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 and which comply with the recordkeeping requirements of § 80.1151(a)(4).

(b) *Other waste materials* means either of the following:

(1) Waste materials that are residues rather than being produced solely for the purpose of being combusted to produce energy (e.g., residual tops, branches, and limbs from a tree farm could be waste materials while wood chips used as fuel and which come from plants grown solely for such purpose would not be waste materials).

(2) Waste heat that is captured from an off-site combustion process (e.g., furnace, boiler, heater, or chemical process).

(c) *Otherwise used* means either of the following:

(1) The direct combustion of the waste materials to make thermal energy.

(2) The use of waste heat as a source of thermal energy.

(d) *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.

(e) *Biogas* means methane or other hydrocarbon gas produced from decaying organic material, including landfills, sewage waste treatment plants, and animal feedlots.

(f) *Renewable fuel.* (1) Renewable fuel is 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 is produced from either 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; or 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.

(2) The term ''Renewable fuel'' includes cellulosic biomass ethanol, waste derived ethanol, biodiesel (mono-alkyl ester), non-ester renewable diesel, and blending components derived from renewable fuel.

(3) Small volume additives less than 1.0 percent of the total volume of a renewable fuel shall be counted as part of the total renewable fuel volume.

(4) 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.

(g) *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).

(h) *Motor vehicle* has the meaning given in Section 216(2) of the Clean Air Act (42 U.S.C. 7550).

(i) *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.

(j) *Biodiesel (mono-alkyl ester)* means a motor vehicle fuel or fuel additive which:

(1) Is registered as a motor vehicle fuel or fuel additive under 40 CFR part 79;

(2) Is a mono-alkyl ester;

(3) Meets ASTM D–6751–02a;

(4) Is intended for use in engines that are designed to run on conventional diesel fuel, and

(5) Is derived from nonpetroleum renewable resources (as defined in paragraph (o) of this section).

(k) *Non-ester renewable diesel* means a motor vehicle fuel or fuel additive which:

(1) Is registered as a motor vehicle fuel or fuel additive under 40 CFR part 79;

(2) Is not a mono-alkyl ester;

(3) Is intended for use in engines that are designed to run on conventional diesel fuel; and

(4) Is derived from nonpetroleum renewable resources (as defined in paragraph (o) of this section).

(l) *Biocrude* means plant oils or animal fats that are used as feedstocks to any production unit in a refinery that normally processes crude oil to make gasoline or diesel fuels.

(m) *Biocrude-based renewable fuels* are renewable fuels that are gasoline or diesel products resulting from the processing of biocrudes in atmospheric distillation or other process units at refineries that normally process petroleum-based feedstocks.

(n) *Importers*, for the purposes of this subpart only, are those persons who:

(1) Are considered importers under § 80.2(r); and

(2) Are persons who bring gasoline into the 48 contiguous states of the United States from areas that have not chosen to opt in to the program requirements of this subpart (per § 80.1143).

(o) *Nonpetroleum renewable resources* include, but are not limited to, either of 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.

(p) *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 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.

(q) *Renewable Identification Number (RIN)*, is a unique number generated to represent a volume of renewable fuel in accordance with § 80.1126.

(r) *Standard-value* is a RIN generated to represent renewable fuel with an equivalence value up to and including 1.0.

(s) *Extra-value RIN* is a RIN generated to represent renewable fuel with an equivalence value greater than 1.0.

(t) *Batch-RIN* is a RIN that represents a batch of renewable fuel containing multiple gallons. A batch-RIN uniquely identifies all of the gallon-RINs in that batch.

(u) *Gallon-RIN* is a RIN that represents an individual gallon of renewable fuel.

§§ 80.1102–80.1103 [Added and Reserved]

4. Sections 80.1102 and 80.1103 are added and reserved.

5. Sections 80.1104 through 80.1107 are added to read as follows:

§ 80.1104 What are the implementation dates for the Renewable Fuel Standard Program?

The RFS standards and other requirements of this subpart are effective beginning the day after [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**.

§ 80.1105 What is the Renewable Fuel Standard?

(a) The annual value of the renewable fuel standard for 2007 shall be 3.71 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:

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

Where:

$RFStd_i$ = Renewable Fuel Standard in year i, in percent.

RFV_i = 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).

$Cell_i$ = 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).

(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:

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

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 (250,000,000 gallons minimum).

§ 80.1106 To whom does the Renewable Volume Obligation apply?

(a)(1) An obligated party is a refiner or blender which produces gasoline within the 48 contiguous states, or an importer which imports gasoline into the 48 contiguous 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 ''obligated party'' shall include any refiner or blender which produces gasoline within that state or territory, or an importer which imports gasoline into that state or territory.

(b)(1) For each calendar year starting with 2007, any obligated party is required to demonstrate, pursuant to § 80.1127, that they have satisfied the Renewable Volume Obligation for that calendar year, as specified in § 80.1107(a), except as otherwise provided in this section.

(2) The deficit carryover provisions in § 80.1127(b) only apply if all of the requirements specified in § 80.1127(b) are fully satisfied.

(c) Any blender whose sole blending activity in a calendar year is to blend a renewable fuel (or fuels) into gasoline, RBOB, CBOB, or diesel fuel is not required to meet the renewable volume obligation specified in § 80.1107(a) for that gasoline for that calendar year.

§ 80.1107 How is the Renewable Volume Obligation calculated?

For the purposes of this section, all reformulated gasoline, conventional gasoline and blendstock, collectively called ''gasoline'' unless otherwise specified, is subject to the requirements under this subpart, as applicable.

(a) The Renewable Volume Obligation for an obligated party is determined according to the following formula:

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

Where:

RVO_i = The Renewable Volume Obligation for a refiner, blender, or importer for calendar year i, in gallons of renewable fuel.

$RFStd_i$ = The renewable fuel standard for calendar year i from § 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, in 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:

$$GV_i = \sum_{x}^{n} G_x - \sum_{x}^{n} RB_x$$

Where:

x = Batch.

n = Total number of batches of gasoline produced or imported.

G_x = Total volume of gasoline produced or imported, per paragraph (c) of this section, in gallons.

RB_x = Total volume of renewable fuel blended into gasoline, in gallons.

(c) For the purposes of this section, all of the following products that are produced or imported during a calendar year 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.

(2) Conventional gasoline.

(3) Reformulated gasoline blendstock for oxygenate blending (''RBOB'').

(4) Conventional gasoline blendstock that becomes finished conventional gasoline upon the addition of oxygenate (''CBOB'').

(5) Gasoline treated as blendstock (''GTAB'').

(6) Blendstock that has been combined with other blendstock or finished gasoline to produce gasoline.

(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(f).

(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 during the period that such exemptions are in effect.

(5) Gasoline exported for use outside the United States.

(6) For blenders, the volume of finished gasoline, RBOB, or CBOB to which a blender adds blendstocks.

(e) *Compliance period.* (1) For 2007, the compliance period is [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**] through December 31, 2007.

(2) Beginning in 2008, and every year thereafter, the compliance period is January 1 through December 31.

§§ 80.1108–80.1114 [Added and Reserved]

6. Sections 80.1108 through 80.1114 are added and reserved.

7. Section 80.1115 is added to read as follows:

§ 80.1115 How are equivalence values assigned by renewable fuel producers?

(a) Each gallon of a renewable fuel shall be assigned an equivalence value. The equivalence value is a number assigned to every renewable fuel that is used to determine how many gallon-RINs can be generated for a batch of renewable fuel according to § 80.1126. Equivalence Values for certain renewable fuels are assigned in paragraph (d) of this section. For other renewable fuels, the equivalence value shall be calculated using the following formula:

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

Where:

EV = Equivalence Value for the renewable fuel.

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, of the renewable fuel that comes from a renewable feedstock.

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

(b) Technical justification and approval of calculation of the Equivalence Value.

(1) Producers of renewable fuels must prepare a technical justification of the calculation of the Equivalence Value for the renewable fuel including a description of the renewable fuel, its feedstock and production process.

(2) Producers shall submit the justification to the EPA for approval.

(3) The Agency will review the technical justification and assign an appropriate Equivalence Value to the renewable fuel based on the procedure in paragraph (c) of this section.

(c) The equivalence value is assigned as follows:

(1) A value rounded to the nearest tenth if such value is less than 0.9.

(2) 1.0 if the calculated equivalence value is in the range of 0.9 to 1.2.

(3) 1.3, 1.5, or 1.7, for calculated values over 1.2, whichever value is closest to the calculated equivalence value, based on the positive difference between the calculated equivalence value and each of these three values, except as specified in paragraphs (c)(4) and (c)(5) of this section.

(4) 2.5 for cellulosic biomass ethanol that is produced on or before December 31, 2012.

(5) 2.5 for waste derived ethanol.

(d) Equivalence values for some renewable fuels are as given in the following table:

TABLE 1 OF § 80.1115.—EQUIVALENCE VALUES FOR SOME RENEWABLE FUELS

Renewable fuel type	Equivalence value (EV)
Cellulosic biomass ethanol and waste derived ethanol produced on or before December 31, 2012	2.5
Ethanol from corn, starches, or sugar	1.0
Biodiesel (mono-alkyl ester)	1.5
Non-ester renewable diesel	1.7
Butanol	1.3
ETBE from corn ethanol	0.4

§§ 80.1116—80.1124 [Added and Reserved]

8. Sections 80.1116 through 80.1124 are added and reserved.

9. Sections 80.1125 through 80.1131 are added to read as follows:

§ 80.1125 Renewable Identification Numbers (RINs).

Each RIN is a 34 character numerical code of the following form:

YYYYCCCCFFFFFBBBBBRRDKSSSSSS EEEEEE

(a) 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.

(b) CCCC is the registration number assigned according to § 80.1150 to the producer or importer of the batch of renewable fuel.

(c) FFFFF is the registration number assigned according to § 80.1150 to the facility at which the batch of renewable fuel was produced or imported.

(d) BBBBB is a serial number assigned to the batch which:

(1) Is chosen by the producer or importer of the batch such that no two batches have the same value in a given calendar year;

(2) Begins with the value 00001 for the first batch produced or imported by a facility in a given calendar year; and

(3) Increases sequentially for subsequent batches produced or imported by that facility in that calendar year.

(e) RR is a number representing the equivalence value of the renewable fuel.

(1) Equivalence values are specified in § 80.1115.

(2) Multiply the equivalence value by 10 to produce the value for RR.

(f) 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.

(2) D has the value of 2 if the renewable fuel cannot be categorized as cellulosic biomass ethanol.

(g) K is a number identifying the type of RIN as follows:

(1) K has the value of 1 if the batch-RIN is a standard-value RIN.

(2) K has the value of 2 if the batch-RIN is an extra-value RIN.

(h) SSSSSS is a number representing the first gallon associated with a batch of renewable fuel.

(i) EEEEEE is a number representing the last gallon associated with a batch of renewable fuel. EEEEEE will be identical to SSSSSS in the case of a gallon-RIN. Assign the value of EEEEEE as described in § 80.1126.

§ 80.1126 How are RINs 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, 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, must be assigned a RIN.

(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.* Pursuant to § 80.1154, producers with renewable fuel production facilities 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 through 80.1152. However, for those producers and importers that voluntarily generate and assign RINs, all the requirements of this subpart apply.

(c) *Generation of RINs.* (1) The producer or importer of a batch of renewable fuel must generate the RINs associated with that batch. However, a producer of a batch of renewable fuel for export is not required to generate a RIN for that batch if that producer is also the exporter and exports the renewable fuel.

(2) 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 (c).

(3) Standard-value RINs shall be generated separately from extra-value RINs, and distinguished from one another by the K component of the RIN.

(4) When a standard-value batch-RIN or an extra-value batch-RIN is initially generated by a renewable fuel producer or importer, the value of SSSSSS in the batch-RIN shall be 000001 to represent the first gallon in the batch of renewable fuel.

(5) *Generation of standard-value batch-RINs.* (i) Except as provided in paragraph (c)(5)(ii) of this section, a standard-value batch-RIN shall be generated to represent the gallons in a batch of renewable fuel. The value of EEEEEE when a batch-RIN is initially generated by a renewable fuel producer or importer shall be determined as follows:

(A) For renewable fuels with an equivalence value of 1.0 or greater, the value of EEEEEE shall be the standardized volume of the batch in gallons.

(B) For renewable fuels with an equivalence value of less than 1.0, the value of EEEEEE shall be the applicable volume, in gallons, calculated according to the following formula:

$$V_a = EV * V_s$$

Where:

V_a = Applicable volume of renewable fuel, in gallons, for use in designating the value of EEEEEE.

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.

(ii) For biocrude-based renewable fuels, a standard-value batch-RIN shall be generated to represent the gallons of biocrude rather than the gallons of renewable fuel. The value of EEEEEE shall be the standardized volume of the biocrude in gallons.

(6) *Generation of extra-value batch-RINs.* (i) Extra-value batch-RINs may be generated for renewable fuels having an equivalence value greater than 1.0.

(ii) The value for EEEEEE in an extra-value batch-RIN when a batch-RIN is initially generated by a renewable fuel producer or importer shall be the applicable volume of renewable fuel calculated according to the following formula:

$$V_a = (EV - 1.0) * V_s$$

Where:

V_a = Applicable volume of renewable fuel, in gallons, for use in designating the value of EEEEEE.

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.

(7) *Standardization of volumes.* In determining the standardized volume of a batch of renewable fuel for purposes of generating standard-value batch-RINs or extra-value batch-RINs, pursuant to paragraphs (c)(5) and (c)(6) of this section, the batch volumes shall be adjusted to a standard temperature of 60 °F.

(i) For ethanol, the following formula shall be used:

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

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:

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

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.

(d) *Assignment of batch-RINs to batches.* (1) The producer or importer of a batch of renewable fuel must assign standard-value RINs to the batch of renewable fuel that those batch-RINs represent.

(2) The producer or importer of a batch of renewable fuel may assign extra-value batch-RINs to the batch of renewable fuel that those batch-RINs represent.

(3) A batch-RIN is assigned to a batch when the batch-RIN is recorded in a prominent location on a product transfer document assigned to that batch of renewable fuel per § 80.1153.

§ 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 an exporter of renewable fuels, must demonstrate that it has acquired sufficient RINs to satisfy the following equation:

$$(\Sigma RINVOL)_i + (\Sigma RINVOL)_{i-1} = RVO_i$$

Where:

$(\Sigma RINVOL)_i$ = Sum of all acquired gallon-RINs that were generated in year i and are being applied towards the RVO_i, in gallons.

$(\Sigma RINVOL)_{i-1}$ = Sum of all acquired gallon-RINs that were generated in year i–1 and are being applied towards the RVO_i, in gallons.

RVO_i = The Renewable Volume Obligation for the obligated party or renewable fuel exporter for calendar year i, in gallons.

(2) For compliance for calendar years 2009 and later, the value of $(\Sigma RINVOL)_{i-1}$ may not exceed a value determined by the following inequality:

$$(\Sigma RINVOL)_{i-1} \leq 0.20 * RVO_i$$

Where:

$(\Sigma RINVOL)_{i-1}$ = Sum of all acquired gallon-RINs that were generated in year i–1 and are being applied towards the RVO_i, in gallons.

(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 acquire a RIN only if that RIN is obtained in accordance with §§ 80.1128 and 80.1129.

(5) Gallon-RINs that can be used for compliance with the RVO shall be calculated from the following formula:

$$RINVOL = EEEEEE - SSSSSS + 1$$

Where:

RINVOL = Gallon-RINs associated with a batch-RIN, in gallons.

EEEEEE = Batch-RIN component identifying the last gallon associated with the batch of renewable fuel that the batch-RIN represents.

SSSSSS = Batch-RIN component identifying the first gallon associated with the batch of renewable fuel that the batch-RIN represents.

(b) *Deficit carryovers.* (1) An obligated party or an exporter of renewable fuel that fails to meet the requirements of paragraph (a)(1) 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.

(2) A deficit is calculated according to the following formula:

$$D_i = RVO_i - [(\Sigma RINVOL)_i + (\Sigma RINVOL)_{i-1}]$$

Where:

D_i = The deficit generated in calendar year i that must be carried over to year i+1 if allowed pursuant to paragraph (b)(1)(i) of this section, in gallons.

RVO_i = The Renewable Volume Obligation for the obligated party or renewable fuel exporter for calendar year i, in gallons.

$(\Sigma RINVOL)_1$ = Sum of all acquired gallon-RINs that were generated in year i and are being applied towards the RVO_i, in gallons.

$(\Sigma RINVOL)_{i-1}$ = 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 batches of renewable fuel.* (1) Except as provided in § 80.1129 and paragraph (a)(3) of this section, as title to a batch of renewable fuel is transferred from one party to another, a batch-RIN that has been assigned to that batch according to § 80.1126(d) must remain assigned to an equivalent renewable fuel volume having the same equivalence value.

(i) A batch-RIN assigned to a batch shall be identified on product transfer documents representing the batch pursuant to § 80.1153.

(ii) Any documentation used to transfer custody of or title to a batch from one party to another must identify the batch-RINs assigned to that batch.

(2) If two or more batches of renewable fuel are combined into a single batch, then all the batch-RINs assigned to all the batches involved in the merger shall be assigned to the final combined batch.

(3) If a batch of renewable fuel is split into two or more smaller batches, any batch-RINs assigned to the parent batch must likewise be split and assigned to the daughter batches.

(i) If the Equivalence Value for the renewable fuel in the parent batch is equal to or greater than 1.0, then there shall be at least one gallon-RIN for every gallon in each of the daughter batches.

(ii) If the Equivalence Value for the renewable fuel in the parent batch is less than 1.0, then the ratio of gallon-RINs to gallons in the parent batch shall be preserved in all daughter batches.

(iii) For purposes of this paragraph (a)(3), the volume of each parent and daughter batch shall be standardized to 60 °F pursuant to § 80.1126(c)(7).

(b) *RINs not assigned to batches of renewable fuel.* (1) *Unassigned RIN* means one of the following:

(i) It is a RIN that contains a K value identifying it as an extra-value RIN and was not assigned to a batch of renewable fuel by the producer or importer of that batch; or

(ii) It is a RIN that was separated from the batch to which it was assigned in accordance with § 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 two batch-RINs, each representing a smaller number of gallon-RINs if all of the following conditions are met:

(i) All RIN components other than SSSSSS and EEEEEE are identical for the parent and daughter RINs.

(ii) The sum of the gallon-RINs associated with the two daughter batch-RINs is equal to the gallon-RINs associated with the parent batch.

§ 80.1129 Requirements for separating RINs from batches.

(a)(1) Separation of a RIN from a batch means termination of the assignment of the RIN from a batch of renewable fuel.

(2) A RIN that has been assigned to a batch of renewable fuel according to § 80.1126(d) may be separated from a batch only under one of the following conditions:

(i) A party that is an obligated party according to § 80.1106 may separate any RINs that have been assigned to a batch if they own the batch.

(ii) Except as provided in paragraph (a)(2)(v) of this section, any party that owns a batch of renewable fuel shall have the right to separate any RINs that have been assigned to that batch once the batch is blended with gasoline or diesel to produce a motor vehicle fuel.

(iii) Any party that exports a batch of renewable fuel shall have the right to separate any RINs that have been assigned to the exported batch.

(iv) Except as provided in paragraph (a)(2)(v) of this section, any renewable fuel producer that owns a batch of renewable fuel shall have the right to separate any RINs that have been assigned to that batch if the renewable fuel is designated as motor vehicle fuel in its neat form and is used as motor vehicle fuel in its neat form.

(v) RINs assigned to batches of biodiesel (mono-alkyl esters) can only be separated from those batches once the biodiesel is blended into diesel fuel at a concentration of 80 volume percent biodiesel or less.

(b) Upon separation from its associated batch, a RIN shall be removed from all documentation that:

(1) Is used to identify custody or title to the batch; or

(2) Is transferred with the batch.

(c) RINs that have been separated from batches of renewable fuel become unassigned RINs subject to the provisions of § 80.1128(b).

§ 80.1130 Requirements for exporters of renewable fuels.

(a)(1) Any party that exports any amount of renewable fuel shall acquire sufficient RINs to offset a Renewable Volume Obligation representing the exported renewable fuel.

(2) Only exporters located in the applicable region described in § 80.1126(a) are subject to the requirements of this section.

(b) *Renewable Volume Obligations*. An exporter of renewable fuel shall determine its Renewable Volume Obligation from the volumes of the batches exported.

(1) A renewable fuel exporter's total Renewable Volume Obligation shall be calculated according to the following formula:

$$RVO_i = \Sigma(VOL_k * EV_k) + D_{i-1}$$

Where:

k = Batch.

RVO_i = The Renewable Volume Obligation for the exporter for calendar year i, in gallons of renewable fuel.

VOL_k = The standardized volume of batch k of exported renewable fuel, in gallons.

EV_k = The equivalence value for batch k.

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

(2)(i) For exported batches of renewable fuel that have assigned RINs, the equivalence value may be determined from the RR component of the RIN.

(ii) If a batch of renewable fuel does not have assigned RINs but its equivalence value may nevertheless be determined pursuant to § 80.1115(d) based on its composition, then the appropriate equivalence value shall be used in the calculation of the exporter's Renewable Volume Obligation.

(iii) If the equivalence value for a batch of renewable fuel cannot be determined, the value of EV_k shall be 1.0.

(3) If the exporter of a batch of renewable fuel is also the producer of that batch, and no RIN was generated to represent that batch, then the volume of that batch shall be excluded from the calculation of the Renewable Volume Obligation.

(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:

(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; or

(5) Was otherwise improperly generated.

(b) In the case of RINs that have been determined to be invalid, the following provisions apply:

(1) Invalid RINs cannot be used to achieve compliance with the transferee's Renewable Volume Obligation, regardless of the transferee's good faith belief that the RINs were valid.

(2) The refiner or importer who used the invalid RINs, and any transferor of the invalid RINs, must adjust their records, reports, and compliance calculations as necessary to reflect the deletion of invalid RINs.

(3) Any valid RINs remaining after deleting invalid RINs, and after an obligated party applies valid RINs as needed to meet the RVO at the end of the compliance year, must first be applied to correct the invalid transfers before the transferor trades or banks the RINs.

(4) In the event that the same RIN is transferred to two or more parties, the RIN will be deemed to be invalid, and any party to any transfer of the invalid RIN will be deemed liable for any violations arising from the transfer or use of the invalid RIN.

(5) A RIN will not be deemed invalid where it can be determined that the RIN was properly created and transferred.

§§ 80.1132–80.1140 [Added and Reserved]

10. Sections 80.1132 through 80.1140 are added and reserved.

11. Sections 80.1141 through 80.1143 are added to read as follows:

§ 80.1141 Small refinery exemption.

(a)(1) Pursuant to § 80.1107(d), gasoline produced by a refiner at a small refinery is qualified for an exemption from the renewable fuels standards of § 80.1105 if that refinery meets the definition of a small refinery under § 80.1101(i) for calendar year 2004.

(2) This exemption shall apply through December 31, 2010, unless a refiner chooses to opt-in to the program requirements of this subpart (per paragraph (g) of this section) prior to this date.

(b)(1) To apply for an exemption under this section, a refiner must submit an application to EPA containing 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 application is true to the best of his/her knowledge, and that the company owned the refinery as of January 1, 2006; and

(iii) Name, address, phone number, facsimile number, and E-mail address of a corporate contact person.

(2) Applications must be submitted by September 1, 2007.

(c) Within 60 days of EPA's receipt of a refiner's application for a small refinery exemption, EPA will notify the refiner if the exemption is not approved or of any deficiencies in the application. In the absence of such notification from EPA, the effective date of the small refinery exemption is 60 days from EPA's receipt of the refiner's submission.

(d) If EPA finds that a refiner provided false or inaccurate information on its application for a small refinery exemption, the exemption will be void ab initio upon notice from EPA.

(e) 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.

(f)(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.

(2) 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.

(3) 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.

(4) The Administrator shall act on such a petition not later than 90 days after the date of receipt of the petition.

(g) 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.

(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 (m) of this section.

(h) A refiner that acquires a refinery from either an approved small refiner (under § 80.1142) 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.

(i) Applications under paragraph (b) of this section, petitions for hardship extensions under paragraph (f) of this section, and small refinery exemption waivers under paragraph (g) of this section shall be sent to one of the following addresses:

(1) *For U.S. mail:* U.S. EPA—Attn: RFS Program, Transportation and Regional Programs Division (6406J), 1200 Pennsylvania Avenue, NW., Washington, DC 20460; or

(2) *For overnight or courier services:* U.S. EPA, Attn: RFS Program, Transportation and Regional Programs Division (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) A refiner qualifies for a small refiner exemption if the refiner does not meet the definition of a small refinery under § 80.1101(i) but meets all of the following criteria:

(i) The refiner produced gasoline at the refinery 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 opt-in to the program requirements of this subpart (per paragraph (g) of this section) prior to this date.

(b) To apply for an exemption under this section, a refiner must submit an application 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; approval of an exemption application will be based on all information submitted under this paragraph and any other relevant information:

(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 application.

(3) 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 application is true to the best of his/her knowledge, and that the company owned the refinery as of January 1, 2006.

(4) Name, address, phone number, facsimile number, and e-mail address of a corporate contact person.

(c) Applications under paragraph (b) of this section must be submitted by September 1, 2007. EPA will notify a refiner of approval or disapproval of its small refiner status in writing.

(d) 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.

(e) If EPA finds that a refiner provided false or inaccurate information on its application for small refiner status under this subpart, the small refiner's exemption will be void ab initio upon notice from EPA.

(f) If a small refiner is complying on an aggregate basis for multiple refineries, the refiner may exclude those refineries from the compliance calculations under § 80.1125.

(g) (1) An approved small refiner may, at any time, waive the exemption under paragraph (a) of this section upon notification to EPA.

(2) An approved small refiner's notice to EPA that it intends to waive the exemption under paragraph (a) of this section 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 fuels standard of § 80.1105.

(3) The waiver must be sent to EPA at one of the addresses listed in paragraph (i) of this section.

(h) A 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.

(i) Applications under paragraph (b) of this section shall be sent to one of the following addresses:

(1) *For U.S. Mail:* U.S. EPA—Attn: RFS Program, Transportation and Regional Programs Division (6406J), 1200 Pennsylvania Avenue, NW., Washington, DC 20460; or

(2) *For overnight or courier services:* U.S. EPA, Attn: RFS Program, Transportation and Regional Programs Division (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 petition must be signed by the Governor of the state or his authorized representative (or the equivalent official of the territory).

(c) The Administrator will approve the petition if it meets the provisions of paragraphs (b) and (d) of this section.

(d)(1) A petition submitted under this section must be received by the Agency by October 31 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 one of the following addresses:

(i) *For U.S. Mail:* U.S. EPA–Attn: RFS Program, Transportation and Regional Programs Division (6406J), 1200 Pennsylvania Avenue, NW., Washington, DC 20460; or

(ii) *For overnight or courier services:* U.S. EPA, Attn: RFS Program, Transportation and Regional Programs

Division (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 producers 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.

§§ 80.1144–80.1149 [Added and Reserved]

12. Sections 80.1144 through 80.1149 are added and reserved.

13. Sections 80.1150 through 80.1154 are added to read as follows:

§ 80.1150 What are the registration requirements under the RFS program?

(a)(1) Any obligated party as defined in § 80.1106 and any exporter of renewable fuel that is subject to a renewable fuels standard under this subpart, as of [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**], 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. In addition, for each import facility, the same identifying information as required for each refinery under § 80.76(c) must be provided. Registrations must be submitted by no later than [DATE 90 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**].

(2) Any obligated party, as defined in § 80.1106, or any exporter of renewable fuel that becomes subject to a renewable fuels standard under this subpart after the date specified in paragraph (a)(1) of this section, must provide EPA the information specified for registration 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 engaging in any transaction involving RINs. Additionally, for each import facility, the same identifying information as required for each refinery under § 80.76(c) must be provided.

(b)(1) Any producer of a renewable fuel that is subject to a renewable fuels standard under this subpart as of [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**], must provide EPA the information specified under § 80.76, if such information has not already been provided under the provisions of this part, by no later than [DATE 90 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**] .

(2) Any producer of renewable fuel that becomes subject to a renewable fuels standard under this subpart after the date specified in paragraph (b)(1) of this section, must provide EPA the information specified for registration 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 creating any RINs.

(c) Any party 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 EPA-issued company and facility identification numbers prior to owning any RINs.

(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 with [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**], any obligated party as defined under § 80.1106 or exporter of renewable fuel that is subject to the renewable fuels standard under § 80.1105 must keep all the following records:

(1) The applicable product transfer documents under § 80.1153.

(2) Copies of all reports submitted to EPA under § 80.1152(a).

(3) Records related to each transaction involving the sale, purchase, brokering, and trading of RINs, which includes all the following:

(i) A list of the RINs owned or transferred.

(ii) The parties involved in each transaction including the transferor, transferee, and any broker or agent.

(iii) The location, time, and 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, for compliance, which includes all the following:

(i) Methods and variables used to calculate the Renewable Volume Obligation pursuant to § 80.1107.

(ii) List of RINs surrendered to EPA used to demonstrate compliance.

(iii) Additional information related to details of RIN use for compliance.

(5) Verifiable records of all the following:

(i) 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 ethanol as defined in § 80.1101(a)(2).

(ii) 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 ethanol as defined in § 80.1101(a)(2).

(b) Beginning with [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**], any importer or producer of renewable fuel as defined under § 80.1101(e) must keep all the following records:

(1) The applicable product transfer documents under § 80.1153.

(2) Copies of all reports submitted to EPA under § 80.1152(b).

(3) Records related to the generation of RINs, for each facility, including all of the following:

(i) Batch Volume.

(ii) RIN number as assigned under § 80.1126.

(iii) Identification of those batches meeting the definition of cellulosic biomass ethanol.

(iv) Date of production or import.

(v) Results of any laboratory analysis of batch chemical composition or physical properties.

(vi) Additional information related to details of RIN generation.

(4) Records related to each transaction involving the sale, purchase, brokering, and trading of RINs, including all of the following:

(i) A list of the RINs acquired, owned or transferred.

(ii) The parties involved in each transaction including the transferor, transferee, and any broker or agent.

(iii) The location, time, and date of the transfer of the RIN(s).

(iv) Additional information related to details of the transaction and its terms.

(c) Beginning with [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**], 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) The applicable product transfer documents under § 80.1153.

(2) Copies of all reports submitted to EPA under § 80.1152(c).

(3) Records related to each transaction involving the sale, purchase, brokering, and trading of RINs, including all of the following:

(i) A list of the RINs acquired, owned, or transferred.

(ii) The parties involved in each transaction including the transferor, transferee, and any broker or agent.

(iii) The location, time, and date of the transfer of the RIN(s).

(iv) Additional information related to details of the transaction and its terms.

(d) 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.

(e) 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 which shall be provided to the Administrator's authorized representative.

§ 80.1152 What are the reporting requirements under the RFS program?

(a) Beginning with [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**], any obligated party as defined in § 80.1106 or exporter of renewable fuel that is subject to the renewable fuels standard under § 80.1105, and continuing for each year thereafter, must submit to EPA annual reports that contain the information required in this section and such other information as EPA may require:

(1) A summary report of the annual gasoline volume produced or imported, or volume of renewable fuel exported, and whether the party is complying on a corporate (aggregate) or facility-by-facility basis. This report shall include all of the following:

(i) The obligated party's name.

(ii) The EPA company registration number.

(iii) The EPA facility registration number(s).

(iv) The production volume of finished gasoline, RBOB as defined in § 80.1107(c) and CBOB as defined in § 80.1107(c).

(v) The renewable volume obligation (RVO), as defined in § 80.1127(a) for obligated parties and § 80.1130 for exporters of renewable fuel, for the reporting year.

(vi) Any deficit RVO carried over from the previous year.

(vii) Any deficit RVO carried into the subsequent year.

(viii) The total number of RINs used for compliance.

(ix) A list of all RINs used for compliance.

(x) Any additional information that the Administrator may require.

(2) A report documenting each transaction of RINs traded between two parties, shall include all of the following:

(i) The submitting party's name.

(ii) The submitter's EPA company registration number.

(iii) The submitter's EPA facility registration number(s).

(iv) The compliance period,

(v) Transaction type (e.g. purchase, sale).

(vi) Transaction date.

(vii) Trading partner's name.

(viii) Trading partner's EPA company registration number.

(ix) Trading partner's EPA facility registration number.

(x) RINs traded.

(xi) Any additional information that the Administrator may require.

(3) A report that summarizes RIN activities for a given compliance year shall include all of the following information:

(i) The total prior-years RINs carried over into the current year (on an annual basis beginning January 1).

(ii) The total current-year RINS acquired.

(iii) The total prior-years RINs acquired.

(iv) The total current-year RINs sold.

(v) The total prior-years RINs sold.

(vi) The total current-year RINs used.

(vii) The total prior-years RINs used.

(viii) The total current-year RINs expired.

(ix) The total prior-years RINs expired.

(x) The total current-year RINs to be carried into next year.

(xi) Any additional information that the Administrator may require.

(4) Reports shall be submitted on forms and following procedures as prescribed by EPA.

(5) Reports shall be submitted by February 28 for the previous compliance year.

(6) All reports 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) Beginning with [DATE 60 DAYS AFTER PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**], any producer or importer of a renewable fuel that is subject to the renewable fuels standard under § 80.1105, and continuing for each year thereafter, must submit to EPA annual reports that contain all of the following information:

(1) An annual report that includes all of the following information on a per-batch basis, where ''batch'' means a discreet quantity of renewable fuel produced and assigned a unique RIN:

(i) The renewable fuel producer's name.

(ii) The EPA company registration number.

(iii) The EPA facility registration number(s).

(iv) The 34 character RINs generated for each batch according to § 80.1126.

(v) The production date of each batch.

(vi) The renewable fuel type as defined in § 80.1101(f).

(vii) Information related to the volume of denaturant and applicable equivalence value.

(viii) The volume produced.

(ix) Any additional information the Administrator may require.

(2) A report documenting each transaction of RINs traded between two parties, shall include all of the following information:

(i) The submitting party's name.

(ii) The submitter's EPA company registration number.

(iii) The submitter's EPA facility registration number(s).

(iv) The compliance period.

(v) Transaction type (e.g. purchase, sale).

(vi) Transaction date.

(vii) Trading partner's name.

(viii) Trading partner's EPA company registration number.

(ix) Trading partner's EPA facility registration number;

(x) RINs traded.

(xi) Any additional information the Administrator may require.

(3) A report that summarizes RIN activities for a compliance year shall include all of the following information:

(i) The total prior-years RINs carried over into the current year (on an annual basis beginning January 1).

(ii) The total current-year RINs generated.

(iii) The total current-year RINS acquired.

(iv) The total prior-years RINs acquired.

(v) The total current-years RINs sold.

(vi) The total prior-years RINs sold.

(vii) The total current-years RINs expired.

(viii) The total prior-years RINs expired.

(ix) The total current-year RINs to be carried into next year.

(x) Any additional information the Administrator may require.

(4) Reports shall be submitted on forms and following procedures as prescribed by EPA.

(5) Reports shall be submitted by February 28 for the previous year.

(6) All reports 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, other than those parties covered in paragraphs (a) and (b) of this section, who owns RINs must submit to EPA annual reports that contain all of the following information:

(1) A report documenting each transaction of RINs traded between two parties shall include all of the following:

(i) The submitting party's name.

(ii) The submitter's EPA company registration number.

(iii) The submitter's EPA facility registration number(s).

(iv) The compliance period.

(v) Transaction type (e.g. purchase, sale).

(vi) Transaction date.

(vii) Trading partner's name.

(viii) Trading partner's EPA company registration number.

(ix) Trading partner's EPA facility registration number.

(x) RINs traded.

(xi) Any additional information the Administrator may require.

(2) A report that summarizes RIN activities for a compliance year shall include all of the following information:

(i) The total prior-years RINs carried over into the current year (on an annual basis beginning January 1).

(ii) The total current-year RINS acquired.

(iii) The total prior-years RINs acquired.

(iv) The total current-years RINs sold.

(v) The total prior-years RINs sold.

(vi) The total current-years RINs expired.

(vii) The total prior-years RINs expired.

(viii) The total current-year RINs to be carried into next year.

(ix) Any additional information the Administrator may require.

(3) Reports shall be submitted on forms and following procedures as prescribed by EPA.

(4) Reports shall be submitted by February 28 for the previous year.

(5) All reports 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.

§ 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, and when RINs continue to accompany the renewable fuel, the transferor must provide to the transferee documents identifying the renewable fuel and 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 transferor's and transferee's EPA facility registration number.

(4) The volume of renewable fuel that is being transferred.

(5) The location of the renewable fuel at the time of transfer.

(6) The date of the transfer.

(7) The RINs assigned to the volume of renewable fuel that is being 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)(7) 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 production facilities 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 exempt from the following requirements of 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; and

(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.

§§ 80.1155–80.1159 [Added and Reserved]

14. Sections 80.1155 through 80.1159 are added and reserved.

15. Sections 80.1160 through 80.1165 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 that is not assigned the proper RIN value or identified 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) Transfer to any person an invalid RIN or a RIN that is not properly identified as required under § 80.1125.

(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 obligation under § 80.1127.

(2) Fail to acquire sufficient RINs to meet the party's renewable fuel obligation under § 80.1130.

(d) *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 (c) is liable for the violation of that prohibition.

(2) Any person who causes another person to violate a prohibition under § 80.1160(a) through (c) is liable for a violation of § 80.1160(d).

(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]

§ 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 fuels obligation or causing another party to fail to meet a renewable fuels 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?

In addition to the requirements for attest engagements under §§ 80.125 through 80.133, and other applicable attest engagement provisions, 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(b) or exporter of renewable fuel that is subject to the renewable fuel standard under § 80.1105:

(1) *Annual summary report.* (i) Obtain and read a copy of the annual summary report required under § 80.1152(a)(1) which contains information regarding:

(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); and

(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) Agree 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.

(iv) 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.

(v) 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.

(vi) 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 agree with the report to EPA.

(2) *RIN transaction report.* (i) Obtain and read a copy of the RIN transaction report required under § 80.1152(a)(2) which contains information regarding RIN trading transactions.

(ii) Obtain contracts or other documents for all RIN transactions with another party during the year being reviewed; compute and report as a finding the transaction types, transaction dates and RINs traded; and agree with the report to EPA.

(3) *RIN activity report.* (i) Obtain and read a copy of the RIN activity report required under § 80.1152(a)(3) which contains information regarding RIN activity for the compliance year.

(ii) Obtain documentation of all RINs acquired, used for compliance (including current-year RINs used and previous-year RINs used) transferred, sold, and expired during the year being reviewed; compute and report as a finding the total RINs acquired, used for compliance, transferred, sold, and expired as represented in these documents; and agree with the report to EPA.

(b) The following attest procedures shall be completed for any renewable fuel producer:

(1) *Annual batch report.* (i) Obtain and read a copy of the annual batch report required under § 80.1152(b)(1) which contains information regarding renewable fuel batches.

(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 agree with the report to EPA.

(iii) Verify that the proper number of RINs were generated 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 report.* (i) Obtain and read a copy of the RIN transaction report required under § 80.1152(b)(2) which contains information regarding RIN trading transactions.

(ii) Obtain contracts or other documents for all RIN transactions with another party during the year being reviewed; compute and report as a finding the transaction types, transaction dates, and the RINs traded; and agree with the report to EPA.

(3) *RIN activity report.* (i) Obtain and read a copy of the RIN activity report required under § 80.1152(b)(3) which contains information regarding RIN activity for the compliance year.

(ii) Obtain documentation of all RINs owned (including RINs created and acquired), transferred, sold and expired during the year being reviewed; compute and report as a finding the total RINs owned, transferred, sold and expired as represented in these documents; and agree with the report to EPA.

(c) For each averaging period, 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 each year.

§ 80.1165 What are the additional requirements under this subpart for gasoline produced at foreign refineries?

(a) *Definitions.* The following definitions apply for this section:

(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.

(b) *General requirements for RFS–FRGAS foreign small refiners.* (1) A foreign refiner that has a small refinery exemption under § 80.1141 or a small refiner exemption under § 80.1142 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 refiner that has received a small refinery exemption under § 80.1141 or a small refiner exemption under § 80.1142 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 the following requirements:

(i) The certification shall include the report of the independent third party under paragraph (d) of this section, and 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; and,

(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 the following information as part of the product transfer document information:

(i) Designation of the gasoline as RFS–FRGAS; and

(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 small foreign refiner shall have an independent third party:

(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; and

(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 (i)(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(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 small foreign 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 (j) 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 shall include the volume of gasoline from the importer's RFS compliance calculations.

(f) *Foreign refiner commitments.* Any small foreign 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:

(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; and

(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 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 as benzene foreign refiner under this subpart.

(1) The foreign refiner shall post a bond of the amount calculated using the following equation:

$$\text{Bond} = G * \$\,0.01$$

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:

(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; and

(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 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; and

(iii) Importer testing 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 required by 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.* Importers of RFS–FRGAS, for each annual compliance period, must arrange to have an attest engagement performed of the underlying documentation that forms the basis of any report or document required under this subpart. The attest engagement must comply with the procedures and requirements that apply to importers under §§ 80.125 through 80.130, and other applicable attest engagement provisions, and must be submitted to the Administrator of EPA by August 31 of each year for the prior annual compliance period. The following additional procedures shall be carried out for any importer of RFS–FRGAS.

(1) Obtain listings of all tenders of RFS–FRGAS. Agree the total volume of tenders from the listings to the gasoline inventory reconciliation analysis in § 80.128(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, 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 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) of this section, and determine whether the foreign refiner adjusted its refinery calculations as required in paragraph (e) of this section.

(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 § 80.128(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 80.130 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 80.130 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 (g) 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.''

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