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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 80

[EPA–HQ–OAR–2005–0161; FRL–8903–1]

RIN 2060–A081

Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of proposed rulemaking.

SUMMARY: Under the Clean Air Act, as amended by Sections 201, 202, and 210 of the Energy Independence and Security Act of 2007, the Environmental Protection Agency is required to promulgate regulations implementing changes to the Renewable Fuel Standard program. The revised statutory requirements specify the volumes of cellulosic biofuel, biomass-based diesel, advanced biofuel, and total renewable fuel that must be used in transportation fuel each year, with the volumes increasing over time. The revised statutory requirements also include new definitions and criteria for both renewable fuels and the feedstocks used to produce them, including new greenhouse gas emission thresholds for renewable fuels. For the first time in a regulatory program, an assessment of greenhouse gas emission performance is being utilized to establish those fuels that qualify for the four different renewable fuel standards. As mandated by the revised statutory requirements, the greenhouse gas emission assessments must evaluate the full lifecycle emission impacts of fuel production including both direct and indirect emissions, including significant emissions from land use changes. The proposed program is expected to reduce U.S. dependence on foreign sources of petroleum by increasing domestic sources of energy. Based on our lifecycle analysis, we believe that the expanded use of renewable fuels would provide significant reductions in greenhouse gas emissions such as carbon dioxide that affect climate change. We recognize the significance of using lifecycle greenhouse gas emission assessments that include indirect impacts such as emission impacts of indirect land use changes. Therefore, in this preamble we have been transparent in breaking out the various sources of greenhouse gas emissions included in the analysis and are seeking comments on our methodology as well as various options for determining the lifecycle greenhouse gas emissions (GHG) for each fuel. In addition to seeking comments on the information in this document and its supporting materials, the Agency is conducting peer reviews of critical aspects of the lifecycle methodology. The increased use of renewable fuels would also impact criteria pollutant emissions, with some pollutants such as volatile organic compounds (VOC) and nitrogen oxides (NO_X) expected to increase and other pollutants such as carbon monoxide (CO) and benzene expected to decrease. The production of feedstocks used to produce renewable fuels is also expected to impact water quality.

This action proposes regulations designed to ensure that refiners, blenders, and importers of gasoline and diesel would use enough renewable fuel each year so that the four volume requirements of the Energy Independence and Security Act would be met with renewable fuels that also meet the required lifecycle greenhouse gas emissions performance standards. Our proposed rule describes the standards that would apply to these parties and the renewable fuels that would qualify for compliance. The proposed regulations make a number of changes to the current Renewable Fuel Standard program while retaining many elements of the compliance and trading system already in place.

DATES: Comments must be received on or before July 27, 2009, 60 days after publication in the **Federal Register**. Under the Paperwork Reduction Act, comments on the information collection provisions are best assured of having full effect if the Office of Management and Budget (OMB) receives a copy of your comments on or before June 25, 2009, 30 days after date of publication in the **Federal Register**.

Hearing: We will hold a public hearing on June 9, 2009 at the Dupont Hotel in Washington, DC. The hearing will start at 10 a.m. local time and continue until everyone has had a chance to speak. If you want to testify at the hearing, notify the contact person listed under **FOR FURTHER INFORMATION CONTACT** by June 1, 2009.

Workshop: We will hold a workshop on June 10–11, 2009 at the Dupont Hotel in Washington, DC to present details of our lifecycle GHG analysis. During this workshop, we intend to go through the lifecycle GHG analysis included in this proposal. The intent of this workshop is to help ensure a full understanding of our lifecycle analysis, the major issues identified and the options discussed. We expect that this workshop will help ensure that we receive submission of the most thoughtful and useful comments to this proposal and that the best methodology and assumptions are used for calculating GHG emissions impacts of fuels for the final rule. While this workshop will be held during the comment period, it is not intended to replace either the formal public hearing or the need to submit comments to the docket.

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

- *www.regulations.gov:* Follow the on-line instructions for submitting comments.
- *E-mail: asdinfo@epa.gov.*
- *Mail:* Air and Radiation Docket and Information Center, Environmental Protection Agency, *Mailcode:* 2822T, 1200 Pennsylvania Ave., NW., Washington, DC 20460. 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 West Building, Room 3334, 1301 Constitution Ave., NW., Washington, DC 20004. 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–HQ–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. For additional information about EPA's public docket visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm.* For additional instructions on submitting comments, go to Section XI, Public Participation, of the **SUPPLEMENTARY INFORMATION** section of this document.

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 Air and Radiation Docket and Information Center, EPA/DC, EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

Hearing: The public hearing will be held on June 9, 2009 at the Dupont Hotel, 1500 New Hampshire Avenue, NW., Washington, DC 20036. See Section XI, Public Participation, for more information about the public hearing.

FOR FURTHER INFORMATION CONTACT: Julia MacAllister, Office of Transportation and Air Quality, Assessment and Standards Division, Environmental Protection Agency, 2000 Traverwood Drive, Ann Arbor, MI 48105; Telephone number: 734–214–4131; *Fax number:* 734–214–4816; *E-mail address: macallister.julia@epa.gov,* or Assessment and Standards Division Hotline; telephone number (734) 214–4636; E-mail address *asdinfo@epa.gov.*

SUPPLEMENTARY INFORMATION:

General Information

A. Does This Proposal Apply to Me?

Entities potentially affected by this proposal are those involved with the production, distribution, and sale of transportation fuels, including gasoline and diesel fuel or renewable fuels such as ethanol and biodiesel. Regulated categories 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 rather provides a guide for readers regarding entities likely to be regulated by this proposed action. This table lists the types of entities that EPA is now aware could potentially be regulated by this proposed action. Other types of entities not listed in the table could also be regulated. To determine whether your activities would be regulated by this proposed action, you should carefully examine the applicability criteria in 40 CFR part 80. If you have any questions regarding the applicability of this proposed action to a particular entity, consult the person 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 confidential business information (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:

- Explain your views as clearly as possible.
- Describe any assumptions that you used.
- Provide any technical information and/or data you used that support your views.
- If you estimate potential burden or costs, explain how you arrived at your estimate.
- Provide specific examples to illustrate your concerns.
- Offer alternatives.
- Make sure to submit your comments by the comment period deadline identified.
- To ensure proper receipt by EPA, identify the appropriate docket identification number in the subject line on the first page of your response. It would also be helpful if you provided the name, date, and **Federal Register** citation related to your comments.

We are primarily seeking comment on the proposed 40 CFR Part 80 Subpart M regulatory language that is not directly included in 40 CFR Part 80 Subpart K. For the proposed subpart M regulatory language that is unchanged from subpart K, we are only soliciting comment as it relates to its use for the RFS2 rule.

Outline of This Preamble

I. Introduction

The current Renewable Fuel Standard program (RFS1) was originally adopted by EPA to implement the provisions of the Energy Policy Act of 2005 (EPAct), which added section 211(o) to the Clean Air Act (CAA). With the passage of the Energy Independence and Security Act of 2007 (EISA), Congress recently made several important revisions to these renewable fuel requirements. This Notice proposes to revise the RFS program regulations to implement these EISA provisions. The proposed changes would apply starting January 1, 2010. For the remainder of 2009, the current RFS1 regulations would apply. However, in anticipation of the biomass-based diesel standard proposed for 2010, obligated parties may find it in their best interest to plan accordingly in 2009.

A. Renewable Fuels and the Transportation Sector

For the past several years, U.S. renewable fuel use has been rapidly increasing for a number of reasons. In the early 1990's, certain oxygenated gasoline fuel programs required by the CAA amendments of 1990 established new market opportunities for renewable fuels, primarily ethanol. At the same time, growing concern over U.S. dependence on foreign sources of crude placed increasing focus on renewable fuels as a replacement for petroleum-based fuels. More recently, several state bans on the use of methyl tertiary butyl ether (MTBE) in gasoline resulted in a large, sudden increase in demand for ethanol. 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, which have resulted in a large economic incentive for the increased development and use of renewable fuels.

In 2005, Congress introduced a new approach to supporting renewable fuels. EPAct established a major new federal renewable fuel volume mandate. EPAct required a ramp up to 7.5 billion gallons of renewable fuel as motor vehicle fuel by 2012 and set annual volume targets for each year leading up to 2012. For 2013 and beyond, EPA was directed to establish the annual required renewable fuel volumes, but at a percentage level no less than that required for 2012. While the market forces described above ultimately caused renewable fuel use to far exceed the EPAct mandates, this program provided certainty that at least a minimum amount of renewable fuel would be used in the U.S. transportation market, which in turn provided assurance for investment in production capacity.

The subsequent passage of EISA made significant changes to both the structure and the magnitude of the renewable fuel program. The renewable fuel program established by EISA, hereafter referred to as RFS2, mandates the use of 36 billion gallons of renewable fuel by 2022. This is nearly a five-fold increase over the highest volume specified by EPAct and constitutes a 10-year extension of the scheduled production ramp-up period provided for in that legislation. It is clear that the volumes required by EISA will push the market to new levels—far beyond what current market conditions would achieve alone. In addition, EISA specifies four separate categories of renewable fuels, each with a separate volume mandate. The categories are renewable fuel, advanced biofuel, biomass-based diesel, and cellulosic biofuel. There is a notable increase in the mandate for cellulosic biofuels in particular. EISA increased the cellulosic biofuel mandate from 250 million in EPAct to 1.0 billion gallons by 2013, with additional yearly increases to 16 billion gallons by 2022. These requirements will provide a strong foundation for investment in cellulosic production and position cellulosic fuel to become a major portion of the renewable fuel pool over the next decade.

The implications of the volume expansion of the program are not trivial. Development of infrastructure capable of delivering, storing and blending these volumes in new markets and expanding existing market capabilities will be needed. For example, the market's absorption of increased volumes of ethanol may ultimately require new "outlets" beyond E10 blends (i.e., gasoline containing 10% ethanol by volume), such as an expansion of the number of flexible-fuel E85 vehicles and the number of retail outlets selling E85.

B. Renewable Fuels and Greenhouse Gas Emissions

Another significant aspect of the RFS2 program is the focus on the greenhouse gas impact of renewable fuels, from a lifecycle perspective. The lifecycle GHG emissions means the aggregate quantity of GHGs related to the full fuel cycle, including all stages of fuel and feedstock production and distribution, from feedstock generation and extraction through distribution and delivery and use of the finished fuel. EISA established specific greenhouse gas emission thresholds for each of four types of renewable fuels, requiring a percentage improvement compared to a baseline of the gasoline and diesel used in 2005. EPA must conduct a lifecycle analysis to determine whether or not renewable fuels produced under varying conditions will meet the greenhouse gas (GHG) thresholds for the different fuel types for which EISA establishes mandates. While these thresholds do not constitute a control on greenhouse gases for transportation fuels (such as a low carbon fuel standard),[1] they do require that the volume mandates be met through the use of renewable fuels that meet certain lifecycle GHG reduction thresholds when compared to

[1] *See* Section IV.D of EPA's advanced notice of proposed rulemaking, Regulating Greenhouse Gas Emissions under the Clean Air Act, for a discussion of EPA's possible authority under section 211(c) of the CAA to establish GHG standards for renewable and alternative fuels. 73 FR 44354, July 30, 2008.

the baseline lifecycle emissions of petroleum fuel they replace. Compliance with the thresholds requires a comprehensive evaluation of renewable fuels, as well as of gasoline and diesel, on the basis of their lifecycle emissions. As mandated by EISA, the greenhouse gas emission assessments must evaluate the full lifecycle emission impacts of fuel production including both direct and indirect emissions, including significant emissions from land use changes. We recognize the significance of using lifecycle greenhouse gas emission assessments that include indirect impacts such as emission impacts of indirect land use changes. Therefore, in this preamble, we have been transparent in breaking out the various sources of greenhouse gas emissions included in the analysis. As described in detail in Section VI, EPA has analyzed the lifecycle GHG impacts of the range of biofuels currently expected to contribute significantly to meeting the volume mandates of EISA through 2022. In these analyses we have used the best science available. Our analysis relies on peer reviewed models and the best estimate of important trends in agricultural practices and fuel production technologies as these may impact our prediction of individual biofuel GHG performance through 2022. We have identified and highlighted assumptions and model inputs that particularly influence our assessment and seek comment on these assumptions, the models we have used and our overall methodology so as to assure the most robust assessment of lifecycle GHG performance for the final rule.

Because lifecycle analysis is a new part of the RFS program, in addition to the formal comment period on the proposed rule, EPA is making multiple efforts to solicit public and expert feedback on our proposed approach. EPA plans to hold a public workshop focused specifically on lifecycle analysis during the comment period to assure full understanding of the analyses conducted, the issues addressed and the options that are discussed. We expect that this workshop will help ensure that we receive submission of the most thoughtful and useful comments to this proposal and that the best methodology and assumptions are used for calculating GHG emissions impacts of fuels for the final rule. Additionally, between this proposal and the final rule, we will conduct peer-reviews of key components of our analysis. As explained in more detail in the Section VI, EPA is specifically seeking peer review of: Our use of satellite data to project future the type of land use changes; the land conversion GHG emissions factors estimates we have used for different types of land use; our estimates of GHG emissions from foreign crop production; methods to account for the variable timing of GHG emissions; and how the several models we have relied upon are used together to provide overall lifecycle GHG estimates.

In addition to the GHG thresholds, EISA included several provisions for the RFS2 program designed to address the long-term environmental sustainability of expanded biofuels production. The new law limits the crops and crop residues used to produce renewable fuel to those grown on land cleared or cultivated at any time prior to enactment of EISA, that is either actively managed or fallow, and non-forested. EISA also generally requires that forest-related slash and tree thinnings used for renewable fuel production pursuant to the Act be harvested from non-federal forest lands.

To address potential air quality concerns, EPA is required by section 209 of EISA to determine whether the RFS2 volumes will adversely impact air quality as a result of changes in vehicle and engine emissions and then to issue fuel regulations that mitigate—to the extent achievable—these impacts. The Agency is also required by section 204 of EISA to conduct a broad study of environmental and resource conservation impacts of EISA, including impacts on water quality and availability, soil conservation, and biodiversity. Congress set specific deadlines for both of these provisions, which are separate from this rulemaking and will be carried out as part of a future effort. However, this NPRM does include EPA's initial assessment of the air and water quality impacts of the EISA volumes.

While the above described changes are significant, it is important to note that Congress left other structural elements of the RFS program basically intact. The various modifications are discussed throughout this preamble.

C. Building on the RFS1 Program

In designing this proposed RFS2 program, the Agency is utilizing and building on the same programmatic structure created to implement the current renewable fuel program (hereafter referred to as RFS1). For example, we propose to continue to use the Renewable Identification Number (RIN) system currently in place to track compliance with the RFS1 program, with modifications to implement the EISA provisions. This approach is in keeping with the Agency's overall intent for RFS1—to design a flexible and enforceable system that could continue to operate effectively regardless of the level of renewable fuel use or market conditions in the transportation fuel sector.

A key component of the Agency's work to build a successful RFS1 program was early and sustained engagement with our stakeholders. In developing this proposed rulemaking, we have again worked closely with a wide variety of stakeholders. Because EISA created new obligated parties and established new, complex provisions such as the lifecycle GHG thresholds and previous cropland requirements, EPA has extended its stakeholder engagement to include dozens of meetings with stakeholders from a broad spectrum of perspectives. For example, the Agency has had multiple meetings and discussions with renewable fuel producers, technology companies, petroleum refiners and importers, agricultural associations, lifecycle experts, environmental groups, vehicle manufacturers, states, gasoline and petroleum marketers, pipeline owners and fuel terminal operators.

II. Overview of the Proposed Program

This section provides an overview of the RFS2 program requirements that EPA proposes to implement as a result of EISA. The RFS2 program would replace the RFS1 program promulgated on May 1, 2007 (72 FR 23900).[2] We are also proposing a number of changes to make the program more flexible based on what we learned from the operation of the RFS1 program since it began on September 1, 2007. Details of the proposed requirements can be found in Sections III and IV. We request comment on our proposed regulatory requirements and the alternatives that we have considered.

This section also provides a summary of EPA's impacts assessment of the use of higher renewable fuel volumes. Impacts that we assessed include: emissions of pollutants such as greenhouse gases (GHG), oxides of nitrogen (NO_X), hydrocarbons, particulate matter (PM), and toxics; reductions in petroleum use and related impacts on national energy security; impacts on the agriculture sector; impacts on costs of transportation fuels; economic costs and benefits; and impacts on water. Details of these

[2] To meet the requirements of EPAct, EPA had previously adopted a limited program that applied only to calendar year 2006. The RFS1 program refers to the general program adopted in the May 2007 rulemaking.

analyses can be found in Sections V through X and in the Draft Regulatory Impact Analysis (DRIA).

A. Summary of New Provisions of the RFS Program

Today's notice proposes new regulatory requirements for the RFS program that would be implemented through a new Subpart M to 40 CFR Part 80. EPA is generally proposing to maintain many elements of the RFS1 program such as regulations governing the generation, transfer, and use of Renewable Identification Numbers (RINs). At the same time, we seek comment on a number of RFS1 provisions that may require adjustment under an expanded RFS2 program, including whether or not to require that all qualifying renewable fuels have RINs generated for it (discussed in Section III.B.4.b.ii), and whether a rollover cap on RINs other than 20 percent might be appropriate (discussed in Section IV.D). Furthermore, EPA is proposing several new provisions and seeking comment on alternatives on aspects of the program for which EISA grants EPA discretion and flexibility, such as the grandfathering of existing renewable fuel production facilities (discussed in Section III.B.3), the potential inclusion of electricity for credit (discussed in Section III.B.1.a), and how renewable fuels are categorized based on the results of lifecycle analyses (discussed in Section VI.B). We believe these and other aspects of the program are important because they will affect available volumes of qualifying renewable fuel, regulated parties' ability to comply with the program and, ultimately, the program's environmental and societal impacts. A full description of all the changes we are proposing to the RFS program to implement the requirements in EISA is provided in Section III, while Section IV includes extensive discussion of other changes to the RFS program under consideration.

1. Required Volumes of Renewable Fuel

The primary purpose of the RFS program is to require a minimum volume of renewable fuel to be used each year in the transportation sector. Under RFS1, the required volume was 4.0 billion gallons in 2006, ramping up to 7.5 billion gallons by 2012. Starting in 2013, EPAct required that the total volume of renewable fuel represent at minimum the same volume fraction of the gasoline fuel pool as it did in 2012, and that the total volume of renewable fuel contains at least 250 million gallons of fuel derived from cellulosic biomass.

EISA makes three primary changes to the volume requirements of the RFS program. First, it substantially increases the required volumes and extends the timeframe over which the volumes ramp up through at least 2022. Second, it divides the total renewable fuel requirement into four separate categories, each with its own volume requirement. Third, it requires that each of these mandated volumes of renewable fuels achieve certain minimum thresholds of GHG emission performance. The volume requirements in EISA are shown in Table II.A.1–1.

TABLE II.A.1–1—RENEWABLE FUEL VOLUME REQUIREMENTS FOR RFS2

[Billion gallons]

	Cellulosic biofuel requirement	Biomass-based diesel requirement	Advanced biofuel requirement	Total renewable fuel requirement
2009	n/a	0.5	0.6	11.1
2010	0.1	0.65	0.95	12.95
2011	0.25	0.80	1.35	13.95
2012	0.5	1.0	2.0	15.2
2013	1.0	[a]	2.75	16.55
2014	1.75	[a]	3.75	18.15
2015	3.0	[a]	5.5	20.5
2016	4.25	[a]	7.25	22.25
2017	5.5	[a]	9.0	24.0
2018	7.0	[a]	11.0	26.0
2019	8.5	[a]	13.0	28.0
2020	10.5	[a]	15.0	30.0
2021	13.5	[a]	18.0	33.0
2022	16.0	[a]	21.0	36.0
2023+	[b]	[b]	[b]	[b]

[a] To be determined by EPA through a future rulemaking, but no less than 1.0 billion gallons.
[b] To be determined by EPA through a future rulemaking.

As shown in the table, the volume requirements are not exclusive, and generally result in nested requirements. Any renewable fuel that meets the requirement for cellulosic biofuel or biomass-based diesel is also valid for meeting the advanced biofuel requirement. Likewise, any renewable fuel that meets the requirement for advanced biofuel is also valid for meeting the total renewable fuel requirement. *See* Section VI.E for further discussion of which specific types of fuel meet the requirements for one of the four categories shown in Table II.A.1–1.

We are co-proposing and taking comment on two options for how to treat the volumes of different renewable fuels for purposes of complying with the volume mandates of RFS2: As either ethanol-equivalent gallons, based on energy content, as finalized in the RFS1 program, or as actual volume in gallons. Consideration of the actual volume option would recognize that EISA now guarantees a market for specific categories of renewable fuel and assigns a GHG requirement to each category in the form of minimum GHG thresholds that each must meet. The approach taken in RFS1 would continue to assign value, in terms of gallons, to all renewable fuels based on their energy value in comparison with ethanol. Further discussion of the rationale and implications of these two approaches can be found in Section III.D.1.

The statutorily-prescribed phase-in period ends in 2012 for biomass-based diesel and in 2022 for cellulosic biofuel, advanced biofuel, and total renewable fuel. Beyond these years, EISA requires EPA to determine the applicable volumes based on a review of the implementation of the program up to that time, and an analysis of a wide variety of factors such as the impact of the production of renewable fuels on the environment, energy security, infrastructure, costs, and other factors. For these future standards, EPA must promulgate rules establishing the applicable volumes no later than 14 months before the first year for which such applicable volumes would apply. For biomass-based diesel, this would mean that final rules would need to be issued by October 31, 2011 for application starting on January 1, 2013. In today's proposed rulemaking, we are not suggesting any specific volume requirements for biomass-based diesel for 2013 and beyond that would be appropriate under the statutory criteria that we must consider. Likewise, we are not suggesting any specific volume requirements for the other three renewable fuel categories for 2023 and beyond. However, the statute requires that the biomass-based diesel volume in 2013 and beyond must be no less than 1.0 billion gallons, and that advanced biofuels in 2023 and beyond must represent at a minimum the same percentage of total renewable fuel as it does in 2022.

2. Changes in How Renewable Fuel Is Defined

Under the existing Renewable Fuel Standard, (RFS1) renewable fuel is defined generally as ''any motor vehicle fuel that is used to replace or reduce the quantity of fossil fuel present in a fuel mixture used to fuel a motor vehicle''. The RFS1 definition includes motor vehicle fuels produced from biomass material such as grain, starch, fats, greases, oils and biogas.

The definitions of renewable fuels under today's proposed rule (RFS2) are based on the new statutory definitions in EISA. Like the existing rules, the definitions in RFS2 include a general definition of renewable fuel, but unlike RFS1, we are including a separate definition of ''Renewable Biomass'' which identifies the feedstocks from which renewable fuels may be made.

Another difference in the definitions of renewable fuel is that RFS2 contains three subcategories of renewable fuels: (1) Advanced Biofuel, (2) Cellulosic Biofuel and (3) Biomass-Based Diesel.

''Advanced Biofuel'' is a renewable fuel other than ethanol derived from corn starch and which must achieve a lifecycle GHG emission displacement of 50%, compared to the gasoline or diesel fuel it displaces.

Cellulosic biofuel is any renewable fuel, not necessarily ethanol, derived from any cellulose, hemicellulose, or lignin each of which must originate from renewable biomass. It must achieve a lifecycle GHG emission displacement of 60%, compared to the gasoline or diesel fuel it displaces for it to qualify as cellulosic biofuel.

The RFS1 definition provided 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% or more of the fossil fuel normally used in the production of ethanol.'' This provision was not included in EISA, and therefore does not appear in the definitions pertaining to cellulosic biofuel in today's proposed rule.

The statutory definition of ''renewable biomass'' in EISA does not include a reference to municipal solid waste (MSW) as did the definition of ''cellulosic biomass ethanol'' in EPAct, but instead includes ''separated yard waste and food waste. EPA's proposed definition of renewable biomass in today's proposed rule includes the language present in EISA. As discussed in Section III.B.1.a, we invite comment on whether this definition should be interpreted as including or excluding MSW containing yard and/or food waste from the definition of renewable biomass. EPA intends to resolve this matter in the final rule, and EPA solicits comment on the approach that it should take.

Under today's proposed rule ''Biomass-based diesel'' includes biodiesel (mono-alkyl esters), non-ester renewable diesel and any other diesel fuel made from renewable biomass, as long as they are not ''co-processed'' with petroleum. EISA requires that such fuel achieve a lifecycle GHG emission displacement of 50%, compared to the gasoline or diesel fuel it displaces. As discussed in Section III.B.1.d, we are proposing that co-processing is considered to occur only if both petroleum and biomass feedstock are processed in the same unit simultaneously. Thus, if serial batch processing in which 100% vegetable oil is processed one day/week/month and 100% petroleum the next day/week/month occurs, the fuel derived from renewable biomass would be assigned RINs with a D code identifying it as biomass-based diesel. The resulting products could be blended together, but only the volume produced from renewable biomass would count as biomass-based diesel.

For other renewable fuels, EISA makes a distinction between fuel from new and existing facilities. Only renewable fuel from new facilities is required to achieve a lifecycle GHG emission displacement of 20%. As discussed in Section III.B.3, this requirement applies only to renewable fuel that is produced from certain facilities which commenced construction after December 19, 2007.

EISA defines ''additional renewable fuel'' as fuel produced from renewable biomass that is used to replace or reduce fossil fuels used in home heating oil or jet fuel. The Act provides that EPA may allow for the generation of RFS credits for such fuel. This represents a change from RFS1, where renewable fuel qualifying for credits was limited to fuel used in motor vehicles. We propose to modify the regulatory requirements to allow RINs assigned to renewable fuel blended into heating oil or jet fuel to be valid for compliance purposes. The fuel would still have to meet all the other criteria to qualify as a renewable fuel, including being made from renewable biomass. For example, RINs generated for advanced biofuel or biomass-based diesel that could be used in automobiles would still be valid, and would not need to be retired, if the fuel producer instead sells the fuels for use in heating oil or jet fuel.

''Renewable biomass'' is defined in EISA to include a number of feedstock types, such as planted crops and crop residue, planted trees and tree residue, animal waste, algae, and yard and food waste. However, the EISA definition limits many of these feedstocks according to the management practices for the land from which they are derived. For example, planted crops and crop residue must be harvested from agricultural land cleared or cultivated at any time prior to December 19, 2007, that is actively managed or fallow, and non-forested. Therefore, planted crops and crop residue derived from land that does not meet this definition cannot be used to produce renewable fuel for credit under RFS2.

Under today's proposed rule, we describe several options for ensuring that feedstocks used to produce renewable fuel for which credits are generated under RFS2 meet the definition of renewable biomass. Our proposed approach places overall responsibility for verifying a feedstock's source on the party who generates a RIN for the renewable fuel produced from the feedstock. We also present options for how a party could or should verify his or her feedstock, and we seek comment on these options. A full discussion of the definition and implementation options for ''renewable biomass'' is presented in Section III.B.4.

3. Analysis of Lifecycle Greenhouse Gas Emissions and Thresholds for Renewable Fuels

As shown in Table II.A.3–1, EISA requires that a renewable fuel must meet minimum thresholds for their reduction in lifecycle greenhouse gas emissions: A 20% reduction in lifecycle GHG emissions for any renewable fuel produced at new facilities; a 50% reduction in order to be classified as biomass-based diesel or advanced biofuel; and a 60% reduction in order to be classified as cellulosic biofuel. The lifecycle GHG emissions means the aggregate quantity of GHG emissions related to the full fuel cycle, including all stages of fuel and feedstock production and distribution, from feedstock generation or extraction through distribution and delivery and use of the finished fuel. As mandated by EISA, it includes direct emissions and significant indirect emissions such as significant emissions from land use changes. EPA believes that compliance with the EISA mandate—determining the aggregate GHG emissions related to the full fuel lifecycle, including both direct emissions and significant indirect emissions such as land use changes—make it necessary to assess those direct and indirect impacts that occur not just within the United States but also those that occur in other countries. This applies to determining the lifecycle emissions for petroleum-based fuels to determine the baseline, as well as the lifecycle emissions for biofuels. For biofuels, this includes evaluating significant emissions from indirect land use changes that occur in other countries as a result of the increased domestic production or importation of biofuels into the U.S. As detailed in Section VI, we have included the GHG emission impacts of international land use changes including the indirect land use changes that result from domestic production of biofuel feedstocks. We recognize the significance of including international land use emission impacts and, in our analysis presentation in Section VI, have been transparent in breaking out the various sources of GHG emissions so that the reader can readily see the impact of including international land use impacts.

TABLE II.A.3–1—LIFECYCLE GHG THRESHOLDS SPECIFIED IN EISA

[Percent reduction from baseline]

Renewable fuel [a]	20
Advanced biofuel	50
Biomass-based diesel	50
Cellulosic biofuel	60

[a] The 20% criterion generally applies to renewable fuel from new facilities that commenced construction after December 19, 2007.

The lifecycle GHG emissions of the renewable fuel are compared to the lifecycle GHG emissions for gasoline or diesel (whichever is being replaced by the renewable fuel) sold or distributed as transportation fuel in 2005. EISA provides some limited flexibility for EPA to adjust these GHG percentage thresholds downward by up to 10 percent under certain circumstances. As discussed in Section VI.D, we are proposing that the GHG threshold for advanced biofuels be adjusted to 44% or potentially as low as 40% depending on the results from the analyses that will be conducted for the final rule. This adjustment would allow ethanol produced from sugarcane to count as advanced biofuel and would help ensure that the volume mandate for advanced biofuel could be met.

The regulatory purpose of the lifecycle greenhouse gas emissions analysis is to determine whether renewable fuels meet the GHG thresholds for the different categories of renewable fuel. As described in detail in Section VI, EPA has analyzed the lifecycle GHG impacts of the range of biofuels currently expected to contribute significantly to meeting the volume mandates of EISA through 2022. In these analyses we have used the best science available. Our analysis relies on peer reviewed models and the best estimate of important trends in agricultural practices and fuel production technologies as these may impact our prediction of individual biofuel GHG performance through 2022. We have identified and highlighted assumptions and model inputs that particularly influence our assessment and seek comment on these assumptions, the models we have used and our overall methodology so as to assure the most robust assessment of lifecycle GHG performance for the final rule.

In addition to the many technical issues addressed in this proposal, Section VI discusses the emissions decreases and increases associated with the different parts of the lifecycle emissions of various biofuels and the timeframes in which these emissions changes occur. The need to determine a single lifecycle value that best represents this combination of emissions increases and decreases occurring over time led EPA to consider various alternative ways to analyze the timeframe of emissions changes related to biofuel production and use as well as options for adjusting or discounting these emissions to determine their net present value. Section VI highlights two options. One option assumes a 30 year time period for assessing future GHG emissions impacts of the anticipated increase in biofuel production to meet the mandates of EISA, both emissions increases and decreases, and values all these emission impacts the same regardless of when they occur during that time period (i.e., no discounting). The second option assesses emissions impacts over a 100 year time period but then discounts future emissions 2% annually to arrive at an estimate of a net present value of those emissions. Several other variations of time period and discount rate are also discussed. The analytical time horizon and the choice whether to discount GHG emissions and, if so, at what appropriate rate can have a significant impact on the final assessment of the lifecycle GHG emissions impacts of individual biofuels as well as the overall GHG impacts of these EISA provisions and this rule.

We believe that our lifecycle analysis is based on the best available science and recognize that in some aspects it represents a cutting edge approach to addressing lifecycle GHG emissions. Because of the varying degrees of uncertainty in the different aspects of our analysis, we conducted a number of sensitivity analyses which focus on key parameters and demonstrate how our assessments might change under alternative assumptions. By focusing attention on these key parameters, the comments we receive as well as additional investigation and analysis by EPA will allow narrowing of uncertainty concerns for the final rule. In addition to this sensitivity analysis approach, we will also explore options for more formal uncertainty analyses for the final rule to the extent possible.

Because lifecycle analysis is a new part of the RFS program, in addition to the formal comment period on the proposed rule, EPA is making multiple efforts to solicit public and expert feedback on our proposed approach. EPA plans to hold a public workshop focused specifically on lifecycle analysis during the comment period to assure full understanding of the analyses conducted, the issues addressed and the options that are discussed. We expect that this workshop will help ensure that we receive submission of the most thoughtful and useful comments to this proposal and that the best methodology and assumptions are used for calculating GHG emissions impacts of fuels for the final rule. Additionally, between this proposal and the final rule, we will conduct peer reviews of key components of our analysis. As explained in more detail in Section VI, EPA is specifically seeking peer review of: Our use of satellite data to project future types of land use changes; the land conversion GHG emissions factors estimates we have used for different types of land use; our estimates of GHG emissions from foreign crop production; methods to account for the variable timing of GHG emissions; and how the several models we have relied upon are used together to provide overall lifecycle GHG estimates.

Some renewable fuel is not required to meet the 20% GHG threshold. Section 211(o)(2)(A) provides that only renewable fuel produced from new facilities which commenced construction after December 19, 2007 must meet the 20% threshold. Facilities that commenced construction on or before December 19, 2007 are exempt or ''grandfathered'' from the 20% threshold requirement. In addition, section 210(a) of EISA provides a further exemption from the 20% threshold requirement for ethanol plants that commenced construction in 2008 or 2009 and are fired with natural gas, biomass, or any combination thereof. The renewable fuel from such facilities is deemed to be in compliance with the 20% threshold, and would thus also be ''grandfathered.''

We are proposing and taking comment on one approach to the grandfathering provisions in today's rule, and seeking comment on five additional options. The proposed approach would provide an indefinite time period for grandfathering status but with restrictions to the baseline volume of renewable fuel that is grandfathered. The alternative options are (1) Expiration of exemption for grandfathered status when facilities undergo sufficient changes to be considered ''reconstructed''; (2) Expiration of exemption 15 years after EISA enactment, industry-wide; (3) Expiration of exemption 15 years after EISA enactment with limitation of exemption to baseline volume; (4) ''Significant'' production components are treated as facilities and grandfathered or deemed compliant status ends when they are replaced; and (5) Indefinite exemption and no limitations placed on baseline volumes. Our proposal and the alternative options are discussed in further detail in Section III.B.3.c.

While renewable fuels would be required to meet the GHG thresholds shown in Table II.A.3–1 in order to be valid for compliance purposes under the RFS2 program, we are not proposing that an individual facility-specific lifecycle GHG emissions value would have to be determined in order to show that the biofuel produced or imported at an individual facility complies with the threshold. Instead, EPA has determined lifecycle GHG values for specific combinations of fuel type, feedstock, and production process, using average values for various lifecycle model inputs. As a result of these assessments, we propose to assign each combination of fuel type, feedstock, and production process to one of the four renewable fuel categories specified in EISA or, alternatively, make a determination that the biofuel combination has been disqualified from generating RINs (except as may be allowed for grandfathered renewable fuel) due to a failure to meet the minimum 20% GHG threshold. Section VI.E discusses our proposed assignments. We are also proposing a mechanism to allow biofuels whose lifecycle GHG emissions have not been assessed to participate in the RFS program under certain limited conditions. These conditions are described in Section III.D.5.

4. Coverage Expanded to Transportation Fuel, Including Diesel and Nonroad Fuels

EPAct only mandated the blending of renewable fuels into gasoline, though it gave credit for renewable fuels blended into diesel fuel. EISA expanded the program to generally cover transportation fuel, which is defined as fuel for use in motor vehicles, motor vehicle engines, nonroad vehicles, or nonroad engines. This includes diesel fuel intended for use in highway vehicles and engines, and nonroad, locomotive, and marine engines and vessels, as well as gaseous or other fuels used in these vehicles, engines, or vessels. EISA also specifies that ''transportation fuels'' do not include fuels for use in ocean-going vessels.

EPA is required to ensure that transportation fuel contains at least the specified volumes of renewable fuel. Under EISA, renewable fuel now includes fuel that is used to displace fossil fuel present in transportation fuel, and as in RFS1, EPA is required to determine the refiners, blenders, and importers of transportation fuel that are subject to the renewable volume obligation. As discussed in Section III.F, while we are seeking comment on alternatives, EPA is proposing consistent with RFS1 that these provisions could best be met by requiring that the renewable volume obligation apply to refiners, blenders, and importers of motor vehicle or nonroad gasoline or diesel (with limited flexibilities for small refineries and small refiners), and that their percentage obligation would apply to the amount of gasoline or diesel they produce for such use. We propose to use the current definition of motor vehicle, nonroad, locomotive, and marine diesel fuel (MVNRLM)—as defined at § 80.2(qqq)—to determine the obligated volumes of non-gasoline transportation fuel for this rule.

We request comment on these aspects of our proposed program.

5. Effective Date for New Requirements

Under CAA section 211(o) as modified by EISA, EPA is required to revise the RFS1 regulations within one year of enactment, or December 19, 2008. Promulgation by this date would have been consistent with the revised volume requirements shown in Table II.A.1–1 that begin in 2009 for certain categories of renewable fuel. However, due to the addition of complex lifecycle assessments to the determination of eligibility of renewable fuels, the extensive analysis of impacts that we are conducting for the higher renewable fuel volumes, the various complex changes to the regulatory program that require close collaboration with stakeholders, and various statutory limitations such as the Small Business Regulatory Enforcement Flexibility Act (SBREFA) and a 60 day Congressional review period for all significant actions, we were not able to promulgate final RFS2 program requirements by December 19, 2008. As a result, we are proposing that the RFS2 regulatory program go into effect on January 1, 2010.

In order to successfully implement the RFS2 program, parties that generate RINs, own and/or transfer them, or use them for compliance purposes will need to re-register under the RFS2 provisions and modify their information technology (IT) systems to accommodate the changes we are proposing today. As described more fully in Section III, these changes would include redefining the D code within the RIN, adding a process for verifying that feedstocks meet the renewable biomass definition, and calculating compliance with four standards instead of one. Regulated parties will need to establish new contractual relationships to cover the different types of renewable fuel required under RFS2. Parties that produce MVNRLM diesel but not gasoline will be newly obligated parties and may be establishing IT systems for the RFS program for the first time. For RFS1, regulated parties had four months between promulgation of the final rulemaking on May 1, 2007 and the start of the program on September 1, 2007. However, this was for a new program that had not existed before. For the RFS2 program, most regulated parties will already be familiar with the general requirements for RIN generation, transfer, and use, and the attendant recordkeeping and reporting requirements. We believe that with proper attention to the implementation requirements by regulated parties, the RFS2 program can be implemented on January 1, 2010 following release of the final rule.

Although we are proposing that the RFS2 regulatory program begin on January 1, 2010, we seek comment on whether a start date later than January 1, 2010 would be necessary. Alternative effective dates for the RFS2 program include January 1, 2011 and a date after January 1, 2010 but before January 1, 2011. We are requesting comment on all issues related to such an alternative effective date, including the need for such a delayed start, treatment of diesel producers and importers, whether the standards for advanced biofuel, cellulosic biofuel and biomass-based diesel should apply to the entire 2010 production or just the production that would occur after the RFS2 effective date, and the extent to which RFS1 RINs should be valid to show compliance with RFS2 standards. Further discussion of alternative effective dates for RFS2 can be found in Section III.E.1.d.

6. Treatment of Required Volumes Preceding the RFS2 Effective Date

We are proposing that the RFS2 regulatory program begin on January 1, 2010. Under CAA section 211(o), the requirements for refiners, blenders, and importers (called ''obligated parties'') as well as the requirements for producers of renewable fuel and others, stem from the regulatory provisions adopted by EPA. In effect while EPAct and EISA both call for EPA to issue regulations that achieve certain results, the various regulated parties are not subject to these requirements until EPA issues the regulations establishing their obligations. The changes brought about by EISA, such as the 4 separate standards, the lifecycle GHG thresholds, changes to obligated parties, and the revised definition of renewable biomass do not become effective until today's proposal is finalized. Rather, the current RFS1 regulations continue to apply until EPA amends them to implement EISA, and any delay in issuance of the RFS2 regulations means that parties would continue to be subject to the RFS1 regulations until the RFS2 regulations were in effect. Therefore, regulated parties would continue to be subject to the existing regulations at 40 CFR Part 80 Subpart K through December 31, 2009, or later if the effective date of the RFS2 program were later than January 1, 2010.

Under the RFS1 regulations the annual percentage standards that are applicable to obligated parties are determined by a formula set forth in the regulations. The formula uses gasoline volume projections from the Energy Information Administration (EIA) and the required volume of renewable fuel provided in Clean Air Act section 211(o)(2)(B). Since EISA modified the required volumes in this section of the Clean Air Act, EPA believes that the new statutory volumes can be used under the RFS1 regulations in generating the standards for 2009. Therefore, in November 2008 we used the new total renewable fuel volume of 11.1 billion gallons as the basis for the 2009 standard, and not the 6.1 billion gallons that was required by EPAct.[3]

While this approach will ensure that the total renewable fuel volume of 11.1 billion gallons required by EISA for 2009 will be used, the RFS1 regulatory structure does not provide a mechanism for implementing the 0.5 billion gallon requirement for biomass-based diesel nor the 0.6 billion gallon requirement for advanced biofuel. As described in more detail in Section III.E.2, we are proposing to address this issue by increasing the 2010 biomass-based diesel requirement by 0.5 billion gallons and allowing 2009 biodiesel and renewable diesel RINs to be used to meet this combined 2009/2010 requirement. Doing so would also allow most of the 2009 advanced biofuel requirement to be met. We believe this would provide a similar incentive for biomass-based diesel use in 2009 as would have occurred had we been able to implement this standard for 2009. We propose that this requirement would apply to all obligated parties under RFS2, including producers and importers of diesel fuel.

As noted above, EPA is proposing a start date for the RFS2 program of January 1, 2010, and is also seeking comment on alternative start dates of sometime during 2010 or January 1, 2011. If the start date is other than January 1, 2010, EPA would need to determine what renewable fuel volumes to require in the interim between January 1, 2010 and the start of the RFS2 program. While we could apply the same approach, described above, that we have used for 2009, doing so could mean that 2009 biodiesel RINs would be valid for compliance purposes in 2011, which would run counter to the statutory valid life of two years. Nevertheless, we request comment on whether this potential approach or another approach is warranted based on the differing volumes and types of renewable fuel specified for use in EISA for 2010.

7. Waivers and Credits for Cellulosic Biofuel

Section 202(e) of EISA provides that for any calendar year in which the projected volume of cellulosic biofuel production is less than the minimum applicable volume required by the statute, EPA will waive a portion of the cellulosic biofuel standard by using the projected volume as the basis for setting the applicable standard. In this event, EISA also allows but does not require EPA to reduce the required volume of advanced biofuel and total renewable fuel. The process of projecting the volume of cellulosic biofuel that may be produced in the next year, and the associated process of determining whether and to what degree the advanced biofuel and total renewable fuel requirements should be lowered, will involve considerations that extend beyond the simple calculation based on gasoline demand that was used to set the annual standards under RFS1. As a result, we believe that this process should be subject to a notice-and-comment rulemaking process. Moreover, since we must make these determinations every year for application to the following year, we expect to conduct these rulemakings every year.

In determining whether the advanced biofuel and/or total renewable fuel volume requirements should also be adjusted downward in the event that projected volumes of cellulosic biofuel fall short of the statutorily required volumes, we believe it would be appropriate to allow excess advanced biofuels to make up some or all of the shortfall in cellulosic biofuel. For instance, if we determined that sufficient biomass-based diesel was available, we could decide that the required volume of advanced biofuel need not be lowered, or that it should be lowered to a smaller degree than the required cellulosic biofuel volume. We would then lower the total renewable fuel volume to the same degree that we

[3] 73 FR 70643, November 21, 2008.

would lower the advanced biofuel volume. We do not believe it would be appropriate to lower the advanced biofuel standard but not the total renewable standard, as this would allow conventional biofuels to effectively be used to meet the standards Congress specifically set for cellulosic and advanced biofuels.

If EPA reduces the required volume of cellulosic biofuel, EPA must offer a number of credits no greater than the reduced cellulosic biofuel standard. EISA dictates the cost of these credits and ties them to inflation. The Act also dictates that we must promulgate regulations on the use of these credits and offers guidance on how these credits may be offered and used. We propose that their uses will be very limited. The credits would not be allowed to be traded or banked for future use, but would be allowed to meet the cellulosic biofuel standard, advanced biofuel standard and total renewable fuel standard. Further discussion of the implementation of these provisions can be found in Section III.I.

8. Proposed Standards for 2010

Once the RFS2 program is implemented, we expect to conduct a notice-and-comment rulemaking process each year in order to determine the appropriate standards applicable in the following year. We therefore intend to issue an NPRM in the spring and a final rule by November 30 of each year as required by statute.

However, for the 2010 compliance year, today's action provides a means for seeking comment on the applicable standards. Therefore, rather than issuing a separate NPRM for the 2010 standard, we are proposing the 2010 standards in today's notice. We will consider comments received during the comment period associated with today's NPRM, and we expect to issue a **Federal Register** notice by November 30, 2009 setting the applicable standards for 2010.

We propose that the RFS2 program be effective on January 1, 2010. Therefore, all EISA volume mandates for 2010 would be implemented in that year, unless EPA exercised its authority to waive one or more of the standards. Based on information from the industry, we believe that there are sufficient plans underway to build plants capable of producing 0.1 billion gallons of cellulosic biofuel in 2010, the minimum volume of cellulosic biofuel required by EISA for 2010. However, we recognize that cellulosic biofuel is at the very earliest stages of commercialization and current economic concerns could have significant impacts on these near term plans. Therefore, while based on industry plans available to EPA, we are not proposing that any portion of the cellulosic biofuel requirement for 2010 be waived, we are seeking additional and updated information that would be available prior to November 30, 2009 which could result in a change in this conclusion. Similarly, we are not aware of the need to waive any other volume mandates for 2010. Therefore, we are proposing that the volumes shown in Table II.A.1–1 for all four renewable fuel categories be used as the basis for the applicable standards for 2010. The proposed standards are shown in Table II.A.8–1, each representing the fraction of a refiner's or importer's gasoline and diesel volume which must be renewable fuel.

TABLE II.A.8–1—PROPOSED STANDARDS FOR 2010

[Percent]

Cellulosic biofuel	0.06
Biomass-based diesel	0.71
Advanced biofuel	0.59
Renewable fuel	8.01

Note that the proposed 2010 standards shown in Table II.A.8–1 were based on currently available projections of 2010 gasoline and diesel volumes. The final standards will be calculated on the basis of gasoline and diesel volume projections from the Energy Information Administration's (EIA) Short-Term Energy Outlook and published by November 30, 2009. Additional discussion of our proposed 2010 standards can be found in Section III.E.1.b.

Note also that the proposed standards assume an effective date of January 1, 2010 for RFS2. We are taking comment on alternative effective dates for RFS2, including January 1, 2011 and a date after January 1, 2010 but before January 1, 2011. Such alternative effective dates would raise issues with regard to the calculation and application of the standards for total renewable fuel and the other standards required under EISA, as well as the generation and application of RINs under RFS1 and RFS2. As described more fully in Section III.E.1.d, we request comment on the issues associated with alternative effective dates for RFS2.

B. Impacts of Increasing Volume Requirements in the RFS2 Program

The displacement of gasoline and diesel with renewable fuels has a wide range of environmental and economic impacts. As we describe below, we have assessed many of these impacts for the RFS2 proposal and we will have more complete assessments, including a cost-benefit comparison, for the final rule. These assessments provide important information to the wider public policy considerations of renewable fuels, climate change, and national energy security. They are also an important component of all significant rulemakings.

However, because the volumes of renewable fuel were specified by statute, they would not be based on or revised by our analysis of impacts. In addition, because we have very limited discretion to pursue regulatory alternatives, the proposal does not include a systematic alternatives analysis. We have investigated regulatory alternatives in some areas to the degree that EISA provides discretion.

As one point of reference to assess the impacts of the volume requirements for the RFS2 program, we used projections for renewable fuel use in 2022 that EIA issued through their 2007 Annual Energy Outlook (AEO), and for transportation fuel consumption through their 2008 AEO. This reference case, referred to as the ''AEO Reference Case,'' represents a projection of the demand for renewable fuels prior to enactment of EISA while still reflecting the new Corporate Average Fuel Economy (CAFE) requirements in EISA, and the 2008 AEO projections for the future price of crude oil ($53 to $92 per barrel). Further discussion of the Reference Case can be found in Section V.A.1. Other points of reference include the renewable fuel volumes mandated by EPAct for the RFS1 program, renewable fuel use prior to implementation of the RFS1 program, and the full impacts of renewable fuel use compared to a petroleum-only economy.

Given the short time provided by Congress to conduct a rulemaking, many of our analyses were done in parallel for this proposal. As a result, some analyses were conducted without the benefit of waiting for the conclusion of another analysis that could prove influential. Thus, for example, impacts on food prices assume that soy-based biodiesel and sugarcane ethanol will qualify as advanced fuels under the proposed RFS2 program, even though the analyses conducted for this proposal might preclude such eligibility. We have highlighted such inconsistencies in results and assumptions throughout the proposal. Additionally, since we have identified many issues and analytical options in our assessment of which biofuel pathways would comply with the GHG thresholds, the assessment we conducted for this proposal may not reflect the final rule in all cases. We will be addressing these issues of analytical consistency between analyses more fully in the final rule.

In a similar fashion, while we recognize uncertainty in our assessment of impacts of the proposed RFS2 program, we do not present a formal, comprehensive analysis of uncertainty. For this proposal, many of the analyses are without precedent, and as a result we have identified the more uncertain aspects of these analyses and have worked to assess their potential impact on the results through sensitivity analyses. We intend to continue these assessments for the final rule, and expect that comments on this proposal will allow us to reduce our uncertainty in a number of areas. In addition to this sensitivity analysis approach, we will also explore options for more formal uncertainty analyses for the final rule to the extent possible.

1. Greenhouse Gases and Fossil Fuel Consumption

Our analyses of GHG impacts consider the full useful life assessment of the production of biofuels compared to the petroleum-based fuels they would replace. The analysis compared the AEO reference case transportation fuel pool in 2022 without the EISA mandates with the same fuel pool in 2022, but assuming the greater volumes of biofuel as mandated by EISA replace an energy equivalent amount of petroleum-based fuel. The incremental volumes of each biofuel type were then evaluated to determine their average impact on GHG emissions compared to the 2005 baseline petroleum fuel they would be displacing. These average GHG emission reduction results can then be compared to the threshold performance levels for each fuel type.

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.

The definition of lifecycle greenhouse gas emissions in EISA requires the Agency to look broadly at lifecycle analyses and to develop a methodology that accounts for the significant secondary or indirect impacts of expanded biofuels use. These indirect effects include both the domestic and international impact of land use change from increased biofuel feedstock production and the secondary agricultural sector GHG impacts from increased biofuel feedstock production (e.g., changes in livestock emissions due to changes in agricultural commodity prices). Today no single model can capture all of the complex interactions required to conduct a complete lifecycle assessment as required by Congress. As a result, the methodology EPA has currently evaluated uses a number of models and tools to provide a comprehensive estimate of GHG emissions. We have used a combination of peer reviewed models including Argonne National Laboratory's GREET model, Texas A&M's Forestry and Agricultural Sector Optimization Model (FASOM) and Iowa State University's Food and Agricultural Policy Research Institute's (FAPRI) international agricultural models as well as the Winrock International database to estimate lifecycle GHG emissions estimates. These models are described in more detail in Section VI and have been used in combination to provide the lifecycle GHG estimates presented in this proposal. However, we recognize other models and sources of information can also be used and these are also discussed in Section VI.

Based on the combined use of these models we have estimated the lifecycle GHG emissions for a number of pathways for producing the increased volumes of renewable fuels as mandated by EISA. Section VI of this proposal outlines the approach taken and describes the key assumptions and parameters used in this analysis. In addition, this section highlights the impacts of varying these key inputs on the overall results.

We estimate the greater volumes of biofuel mandated by RFS2 will reduce lifecycle GHG emissions from transportation by approximately 6.8 billion tons of CO_2 equivalent emissions when accounting for all the emissions changes over 100 years and then discounting this emission stream by 2% per year. This is equivalent to an average annualized emission rate of 160 million metric tons of CO_2-eq. emissions per year over the entire 100 year modeling time frame if that average annualized emission rate is also discounted at 2% per year. Determining lifecycle GHG emissions values for renewable fuels using a 0% discount rate over 30 years would result in an estimated total reduction of 4.5 billion tons of CO_2-eq. over the 30 year period or an average annualized emission rate reduction of 150 million metric tons of CO_2-eq. GHG emissions per year. (See Section VI.F of this preamble for additional information on how these emission reductions were calculated).

Our analysis of the petroleum consumption impacts took a similar lifecycle approach. For the year 2022, we estimate that the 36 billion gallons of renewable fuel mandated by these rules will increase renewable fuel usage by approximately 22 billion gallons which will displace about 15 billion gallons of petroleum-based gasoline and diesel fuel. This represents about 8% of annual oil consumed by the transportation sector in 2022.

2. Economic Impacts and Energy Security

The substantially increased volumes of renewable fuel that would be required under RFS2 would produce a variety of different economic impacts. These would include changes in the cost of gasoline and diesel, a reduction in nationwide expenditures on petroleum imports and the associated increase in energy security, and increases in the prices of agricultural commodities such as corn and soybeans.

The RFS program is projected to significantly impact the cost of gasoline and diesel, though the estimated costs vary based on the price of crude oil that is assumed. In our analysis we used both $92 and $53 per barrel crude oil based on price projections made by EIA. At these two crude oil price points, we estimate that gasoline costs would increase by about 2.7 and 10.9 cents per gallon, respectively, by 2022. Likewise, diesel fuel costs could experience a small cost reduction of 0.1 cents per gallon, or increase by about 1.2 cent per gallon, respectively. For the nation as a whole, these costs are equivalent to $4 and $18 billion in 2022, respectively (in 2006 dollars, and amortizing capital costs using a 7% before-tax rate of return). These costs represent the nationwide average impacts including the costs of producing and distributing both renewable fuels and gasoline and diesel, as well as blending costs, but without consideration of either the tax subsidies and import tariff for ethanol or tax subsidies for biodiesel and renewable diesel fuel.

EPA's estimates of economic impacts of fuels do not consider other societal benefits. For example, the displacement of petroleum-based fuel (largely imported) by renewable fuel (largely produced in the United States), should reduce our consumption of imported oil and fuel. We estimate that 91% 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 $12.4 billion in 2022 due to increased volumes of renewable fuels mandated by RFS2 in comparison to the AEO reference case. Net U.S. expenditures on petroleum imports in 2022 are projected to be about $208 billion.

Furthermore, the above estimate of reduced U.S. petroleum import expenditures only partly assesses the economic impacts of this proposal. 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 U.S. dependence on any one source, the risks, both financial as well as strategic, of a potential disruption in supply of a particular energy source are reduced. EPA has worked with researchers at Oak Ridge National Laboratory (ORNL) to update a study they previously published that has been used or cited in several government actions impacting U.S. oil consumption. This updated study went through an independent, third-party peer review process and a final draft report of this updated study was developed. This peer-reviewed report is being made available in the docket at this time for further consideration. Using the updated ORNL estimate, the total energy security benefits associated with a reduction of U.S. imported oil is $12.38 per barrel of imported oil that is reduced. Based on these values, we estimate that the total annual energy security benefits would be $3.7 billion in 2022 (in 2006 dollars).

We recognize that our current energy security analysis does not take into account risk-shifting that might occur as the U.S. reduces its dependency on petroleum by increasing its use of biofuels. For example, our analysis did not take into account other energy security implications associated with biofuels, such as possible supply disruptions of corn-based ethanol. We will attempt to broaden our energy security analysis to incorporate estimates of overall motor fuel supply and demand flexibility and reliability for the final rule, along with impacts of possible agricultural sector market disruptions. A complete discussion of the Agency's plans for this analysis can be found in Section IX.B.2. of this preamble.

While increased use of renewable fuel will reduce expenditures on imported oil, it will also increase expenditures on renewable fuels and in turn on the sources of those renewable fuels. The RFS program is likely to spur the increased use of renewable transportation fuels made principally from agricultural crops and it is expected that most of these crops will be 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 domestic agricultural sector impacts, EPA selected the Forest and Agricultural Sector Optimization Model (FASOM) developed by Professor Bruce McCarl of Texas A&M University and others over the past thirty years. FASOM is a dynamic, nonlinear programming model of the agriculture and forestry sectors of the U.S.

In Section IX of this preamble, we estimate the change in the price of various agricultural products as a result of this rulemaking. By 2022, we estimate the price of corn would increase by $0.15 per bushel (4.6%) above the Reference Case price of $3.19 per bushel. By 2022, U.S. soybean prices would increase by $0.29 per bushel (2.9%) above the Reference Case price of $9.97 per bushel. Due to higher commodity prices, FASOM estimates that U.S. food costs would increase by $10 per person per year by 2022, relative to the Reference Case. Total farm gate food costs would increase by $3.3 billion (0.2%) in 2022. As a result of increased renewable fuel requirements, FASOM predicts that net U.S. farm income would increase by $7.1 billion dollars in 2022 (10.6%), relative to the Reference Case.

Due to higher commodity prices, FASOM estimates that U.S. corn exports would drop from 2.7 billion bushels under the Reference Case to 2.4 billion bushels (a 10% decrease) by 2022. In value terms, U.S. exports of corn would fall by $487 million in 2022. FASOM estimates that U.S. exports of soybeans would decrease from 1.03 billion bushels to 943 million bushels (an 8% decrease) in 2022. In value terms, U.S. exports of soybeans would decrease by $691 million in 2022.

Assuming current subsidies remain in place, the Renewable Fuels Standard, by encouraging the use of biofuels, will result in an expansion of subsidy payments by the U.S. government. If this resulting loss of tax revenue were offset by an increase in taxes, this could have a distortionary impact on the economy. We intend to consider the impact of the expansion of biofuel subsidies associated with the RFS2 in the context of the economy-wide modeling to be conducted for the final rule.

We note that the economic analyses that support this proposal do not reflect all of the potentially quantifiable economic impacts. There are several key impacts that remain incomplete as a result of time and resource constraints, including the economic impact analysis (see Section IX) and the air quality and health impacts analysis (see Section II.B.3). As a result, this proposal does not combine economic impacts in an attempt to compare costs and benefits, in order to avoid presenting an incomplete and potentially misleading characterization. For the final rule, when the planned analyses are complete and current analyses updated, we will provide a consistent cost-benefit comparison.

3. Emissions, Air Quality, and Health Impacts

Analysis of criteria and toxic emission impacts was performed relative to three different reference case ethanol volumes, ranging from 3.64 to 13.2 billion gallons per year. To assess the total impact of the RFS program, emissions were analyzed relative to the RFS1 rule base case of 3.64 billion gallons in 2004. To assess the impact of today's RFS2 proposal relative to the current mandated volumes, we analyzed impacts relative to RFS1 mandate of 7.5 billion gallons of renewable fuel use by 2012, which was estimated to include 6.7 billion gallons of ethanol.[4] In order to assess the impact of today's proposal relative to the level of ethanol projected to be used in 2022 without RFS2, the AEO2007 projection of 13.2 billion gallons of ethanol in 2022 was analyzed.

We are also presenting a range of impacts meant to bracket the impacts of ethanol blends on light-duty vehicle emissions. Similar to the approach presented in the RFS1 rule, we present a ''less sensitive'' and ''more sensitive'' case to present a range of the possible

[4] RFS1 base and mandated ethanol levels were projected to remain essentially unchanged in 2022 due to the flat energy demands projected by EIA.

emission impacts of E10 on recent model year light duty gasoline vehicles. As detailed in Section VII.C, ''less sensitive'' does not apply any E10 effects to NO_X or HC emissions for later model year vehicles, or E85 effects for any pollutant, while ''more sensitive'' does.

Our projected emission impacts for the ''less sensitive'' and ''more sensitive'' cases are shown in Table II.B.3–1 and II.B.3–2, showing the expected emission changes for the U.S. in 2022, and the percent contribution of this impact relative to the total U.S. inventory across all sectors. Overall we project the proposed program will result in significant increases in ethanol and acetaldehyde emissions—increasing the total U.S inventories of these pollutants by up to 30–40% in 2022 relative to the RFS1 mandate case. We project more modest but still significant increases in acrolein, NO_X, formaldehyde and PM. We project today's action will result in decreased ammonia emissions (due to reductions in livestock agricultural activity), decreased CO emissions (driven primarily by the impacts of ethanol on exhaust emissions from vehicles and nonroad equipment), and decreased benzene emissions (due to displacement of gasoline with ethanol in the fuel pool). Discussion and a breakdown of these results by the fuel production/distribution and vehicle and equipment emissions are presented in Section VII.

TABLE II.B.3–1—RFS2 ''LESS SENSITIVE'' CASE EMISSION IMPACTS IN 2022 RELATIVE TO EACH REFERENCE CASE

Pollutant	RFS1 base		RFS1 mandate		AEO2007	
	Annual short tons	% of total U.S. inventory	Annual short tons	% of total U.S. inventory	Annual short tons	% of total U.S. inventory
NO_X	312,400	2.8	274,982	2.5	195,735	1.7
HC	112,401	1.0	72,362	0.6	−8,193	−0.07
PM_{10}	50,305	1.4	37,147	1.0	9,276	0.3
$PM_{2.5}$	14,321	0.4	11,452	0.3	5,376	0.16
CO	−2,344,646	−4.4	−1,669,872	−3.1	−240,943	−0.4
Benzene	−2,791	−1.7	−2,507	−1.5	−1,894	−1.1
Ethanol	210,680	36.5	169,929	29.4	83,761	14.5
1,3-Butadiene	344	2.9	255	2.1	65	0.5
Acetaldehyde	12,516	33.7	10,369	27.9	5,822	15.7
Formaldehyde	1,647	2.3	1,348	1.9	714	1.0
Naphthalene	5	0.03	3	0.02	−1	−0.01
Acrolein	290	5.0	252	4.4	174	3.0
SO_2	28,770	0.3	4,461	0.05	−47,030	−0.5
NH_3	−27,161	−0.6	−27,161	−0.6	−27,161	−0.6

TABLE II.B.3–2—RFS2 ''MORE SENSITIVE'' CASE EMISSION IMPACTS IN 2022 RELATIVE TO EACH REFERENCE CASE

Pollutant	RFS1 base		RFS1 mandate		AEO2007	
	Annual short tons	% of total U.S. inventory	Annual short tons	% of total U.S. inventory	Annual short tons	% of total U.S. inventory
NO_X	402,795	3.6	341,028	3.0	210,217	1.9
HC	100,313	0.9	63,530	0.6	−15,948	−0.14
PM_{10}	46,193	1.3	33,035	0.9	5,164	0.15
$PM_{2.5}$	10,535	0.3	7,666	0.2	1,589	0.05
CO	−3,779,572	−7.0	−3,104,798	−5.8	−1,675,869	−3.1
Benzene	−5,962	−3.5	−5,494	−3.3	−4,489	−2.7
Ethanol	228,563	39.6	187,926	32.5	105,264	18.2
1,3-Butadiene	−212	−1.8	−282	−2.4	−430	−3.6
Acetaldehyde	16,375	44.0	14,278	38.4	9,839	26.5
Formaldehyde	3,373	4.7	3,124	4.3	2,596	3.6
Naphthalene	−175	−1.2	−178	−1.3	−187	−1.3
Acrolein	253	4.4	218	3.8	143	2.5
SO_2	28,770	0.3	4,461	0.05	−47,030	−0.5
NH_3	−27,161	−0.6	−27,161	−0.6	−27,161	−0.6

We note that the aggregate nationwide emission inventory impacts presented here will likely lead to health impacts throughout the U.S. due to changes in future-year ambient air quality. However, emissions changes alone are not a good indication of local or regional air quality and health impacts, as there may be highly localized impacts such as increased emissions from ethanol plants and evaporative emissions from cars, and decreased emissions from gasoline refineries. In addition, the atmospheric chemistry related to ambient concentrations of $PM_{2.5}$, ozone and air toxics is very complex, and making predictions based solely on emissions changes is extremely difficult. Full-scale photochemical modeling is necessary to provide the needed spatial and temporal detail to more completely and accurately estimate the changes in ambient levels of these pollutants. As discussed in Section VII.D, timing and resource constraints precluded EPA from conducting a full-scale photochemical air quality modeling analysis in time for the NPRM. For the final rule, however, a national-scale air quality modeling analysis will be performed to analyze the impacts of the proposed standards on $PM_{2.5}$, ozone, and selected air toxics (i.e., benzene, formaldehyde, acetaldehyde, ethanol, acrolein and 1,3-butadiene). As described in Section VII.D.2, EPA intends to use a 2005-based Community Multi-scale Air Quality (CMAQ) modeling platform as the tool for the air quality modeling. The CMAQ modeling system is a comprehensive three-dimensional grid-based Eulerian air quality model designed to estimate the formation and fate of oxidant precursors, primary and secondary PM concentrations and deposition, and air toxics, over regional and urban spatial scales (e.g., over the contiguous U.S.).

The lack of air quality modeling data also precluded EPA from conducting its standard analysis of human health impacts, where CMAQ output data are used as inputs to the Environmental Benefits Mapping and Analysis Program (BenMAP). Section IX.D of this preamble describes the human health impacts that will be quantified and monetized for the final rule, as well as the unquantified impacts that will be qualitatively described.

4. Water

As the production of biofuels increases to meet the requirements of this proposed rule, there may be adverse impacts on both water quality and quantity. Increased production of biofuels may lead to increased application of fertilizer and pesticides and increased soil erosion, which could impact water quality. Since ethanol production uses large quantities of water, the supply of water could also be significantly impacted in some locations.

EPA focused the water quality analysis for this proposal on the impacts of corn produced for ethanol for several reasons. Corn has the highest fertilizer and pesticide use per acre and accounts for the largest share of nitrogen fertilizer use among all crops. Furthermore, corn-based ethanol is expected to be a large component of the biofuels mix.

Fertilizer nutrients that are not used by the crops are available to runoff to surface water or leach into groundwater. Nutrient enrichment due to human activities is one of the leading problems facing our nation's lakes, reservoirs, and estuaries, and also has negative impacts on aquatic life in streams; adverse health effects on humans and domestic animals; and impairs aesthetic and recreational use. Excess nutrients can lead to excessive growth of algae in rivers and streams, and aquatic plants in all waters. Nutrient pollution is widespread. The most widely known examples of significant nutrient impacts include the Gulf of Mexico and the Chesapeake Bay, however waterbodies in virtually every state and territory are impacted by nutrient-related degradation. A more detailed discussion of nutrient pollution can be found in Section X of this preamble and in Chapter 6 of the DRIA.

To provide a quantitative estimate of the impact of this proposal and production of corn ethanol generally on water quality, EPA conducted an analysis that modeled the changes in loadings of nitrogen, phosphorus, and sediment from agricultural production in the Upper Mississippi River Basin (UMRB). The UMRB is representative of the many potential issues associated with ethanol production, including its connection to major water quality concerns such as Gulf of Mexico hypoxia, large corn acreage, and numerous ethanol production plants. The UMRB contributes 39% of nitrogen loads and 26% of phosphorus loads to the Gulf of Mexico.

EPA selected the SWAT (Soil and Water Assessment Tool) model to assess nutrient loads from changes in agricultural production in the UMRB. SWAT is a physical process model developed to quantify the impact of land management practices in large, complex watersheds. In conducting its analysis EPA quantified the impacts from a baseline that preceded the current high production of ethanol from corn to four future years—2010, 2015, 2020 and 2022.

Table II.B.4–1 summarizes the model outputs at the outlet of the UMRB in the Mississippi River at Grafton, Illinois for each of the four scenario years. The local impact in smaller watersheds within the UMRB may be significantly different. The decreasing nitrogen load over time is likely attributed to the increased corn yield production, resulting in greater plant uptake of nitrogen. The relatively stable sediment loadings are likely due to the fact that corn was modeled assuming that corn stover is left on the fields following harvest.

TABLE II.B.4–1—CHANGES FROM THE 2005 BASELINE TO THE MISSISSIPPI RIVER AT GRAFTON, ILLINOIS FROM THE UPPER MISSISSIPPI RIVER BASIN

	2005 Baseline	2010	2015	2020	2022
Average corn yield (bushels/acre)	141	150	158	168	171
Nitrogen	1433.5 million lbs	+5.5%	+4.7%	+2.5%	+1.8%
Phosphorus	132.4 million lbs	+2.8%	+1.7%	+0.98%	+0.8%
Sediment	6.4 million tons	+0.5%	+0.3%	+0.2%	+0.1%

After evaluating comments on this proposal, if time and resources permit, EPA may conduct additional water quality analyses using the SWAT model in the UMRB. Potential future analyses could include: (1) Determination of the most sensitive assumptions in the model, (2) water quality impacts from the changes in ethanol volumes between the reference case and this proposal, (3) removing corn stover for cellulosic ethanol, and (4) a case study of a smaller watershed to evaluate local water quality impacts that are impossible to ascertain at the scale of the UMRB.

EPA also qualitatively examined other water issues, which are also discussed in detail in Section X of this Preamble, and Chapter 6 of the DRIA.

5. Agricultural Commodity Prices

The recent increase in food prices, both domestically and internationally, has raised the issue of whether diverting grains and oilseeds for fuel production is having a large impact on commodity markets. While we share the concern that food prices have increased significantly over the same time period in which renewable fuel production has increased, many factors have contributed to recent increases in food prices. As described by the U.S. Department of Agriculture (USDA), the Department of Energy (DOE), the Council of Economic Advisors (CEA), and others, the recent increase in commodity prices has been influenced by factors as diverse as world economic growth, droughts in Australia, China and Eastern Europe, increasing oil prices, changes in investment strategies, and the declining value of the U.S. dollar. While the increase in renewable fuel production has contributed to the increase in commodity prices, the magnitude of the contribution of the RFS has most likely been minor, as market conditions have continued to push renewable fuel use beyond the mandated levels.

As the mandated levels of renewable fuels continue to rise in the future, our economic modeling suggests that the impact of the RFS2 program on food prices will continue to be modest, particularly with the expansion of cellulosic biofuels. Table II.B.5–1 summarizes the changes in prices for some commodities we have estimated for this proposal. Further discussion can be found in Section IX.A.

TABLE II.B.5–1—CHANGE IN U.S. COMMODITY PRICES FOR 2022 IN COMPARISON TO THE REFERENCE CASE

[2006$]

Corn	$0.15/bushel.
Soybeans	$0.29/bushel.
Sugarcane	$13.34/ton.
Beef	$0.93/hundred pounds.

II. What Are the Major Elements of the Program Required Under EISA?

While EISA made a number of changes to CAA section 211(o) that must be reflected in the RFS program regulations, it left many of the basic program elements intact, including the mechanism for translating national renewable fuel volume requirements into applicable standards for individual obligated parties, requirements for a credit trading program, geographic applicability, treatment of small refineries, and general waiver provisions. As a result, we propose that many of the regulatory requirements of the RFS1 program would remain largely or, in some cases, entirely unchanged. These provisions would include the distribution of RINs, separation of RINs, use of RINs to demonstrate compliance, provisions for exporters, recordkeeping and reporting, deficit carryovers, and the valid life of RINs.

The primary elements of the RFS program that we propose changing to implement the requirements in EISA fall primarily into the following five areas:

(1) Expansion of the applicable volumes of renewable fuel

(2) Separation of the volume requirements into four separate categories of renewable fuel, with corresponding changes to the RIN and to the applicable standards

(3) Changes to the definition of renewable fuels and criteria for determining which if any of the four renewable fuel categories a given renewable fuel is eligible to meet

(4) Expansion of the fuels subject to the standards (and applicable to refiners, blenders, and importers of those fuels) to include diesel and certain nonroad fuels

(5) Inclusion of specific types of waivers and EPA-generated credits for cellulosic biofuel.

EISA does not change the basic requirement under CAA 211(o) that the RFS program include a credit trading program. In the May 1, 2007 final rulemaking implementing the RFS1 program, we described how we reviewed a variety of approaches to program design in collaboration with various stakeholders. We finally settled on a RIN-based system for compliance and credit purposes as the one which met our goals of being straightforward, maximizing flexibility, ensuring that volumes are verifiable, and maintaining the existing system of fuel distribution and blending. RINs represent the basic framework for ensuring that the statutorily required volumes of renewable fuel are produced and used as transportation fuel in the U.S. The use of RINs is predicated on the fact that once renewable fuels are produced or imported, there is very high confidence that, setting aside exports, all but de minimus quantities will in fact be used as transportation fuel in the U.S. Focusing on production of renewable fuel as a surrogate for the later actual blending and use of such fuel has many benefits as far as streamlining the RFS program and minimizing the impact that the program has on the business operations of the regulated industries. Since the RIN-based system generally has been successful in meeting EPA's goals, we propose to maintain much of its structure under RFS2.

This section describes the regulatory changes we propose to implement the new EISA provisions. Section IV describes other changes to the RFS program that we have considered or are proposing, including a concept for an EPA-moderated RIN trading system that would provide a context within which all RIN transfers could occur.

A. Changes to Renewable Identification Numbers (RINs)

Under RFS2, we propose that each RIN would continue to represent one gallon of renewable fuel for compliance purposes consistent with our approach under RFS1, and the RIN would continue to have 38 digits. In general the codes within the RIN would have the same meaning under RFS2 as they do under RFS1, with the exception of the D code which would be expanded to cover the four categories of renewable fuel defined in EISA. The proposed change to the D code is described in Table III.A–1.

TABLE III.A–1—PROPOSED CHANGE TO D CODE

D value	Meaning under RFS1	Meaning under RFS2
1	Cellulosic biomass ethanol	Cellulosic biofuel.
2	Any renewable fuel that is not cellulosic biomass ethanol	Biomass-based diesel.
3	Not applicable	Advanced biofuel.
4	Not applicable	Renewable fuel.

The determination of which D code would be assigned to a given batch of renewable fuel is described in more detail in Section III.D.2 below.

As described in Section II.A.5, we are proposing that the RFS2 program go into effect on January 1, 2010. However, we are also taking comment on other potential start dates including January 1, 2011 and dates between January 1, 2010 and January 1, 2011. If we were to start the RFS2 program during 2010 but after January 1, some 2010 RINs would be generated under the RFS1 requirements and others would be generated under the RFS2 requirements, but all RINs generated in 2010 would need to be valid for meeting the appropriate 2010 annual standards. Since RFS1 RINs and RFS2 RINs would differ in the meaning of the D codes, we would need a mechanism for distinguishing between these two categories of RINs in order to appropriately apply them to the standards. One straightforward way of accomplishing this would be to use values for the D code under RFS2 that do not overlap the values for the D code under RFS1. Table III.A–2 describes the D code definitions under such an alternative approach.

TABLE III.A–2—ALTERNATIVE D CODE DEFINITIONS

D value	Meaning under RFS1	Meaning under RFS2
1	Cellulosic biomass ethanol	Not applicable.
2	Any renewable fuel that is not cellulosic biomass ethanol	Not applicable.
3	Not applicable	Cellulosic biofuel.
4	Not applicable	Biomass-based diesel.
5	Not applicable	Advanced biofuel.
6	Not applicable	Renewable fuel.

In this alternative approach, D code values of 1 and 2 would only be relevant for RINs generated under RFS1, and D code values of 3, 4, 5, and 6 would only be relevant for RINs generated under RFS2. As a result, 2010 RINs generated under RFS1 would be subject to our proposed RFS1/RFS2 transition provisions wherein they would be assigned to one of the four annual standards that would apply in 2010 using their RR and/or D codes. See Section III.G.3 for further description of how we propose using RFS1 RINs to meet standards under RFS2.

Under RFS2, each batch-RIN generated would continue to uniquely identify not only a specific batch of renewable fuel, but also every gallon-RIN assigned to that batch. Thus the RIN would continue to be defined as follows:

RIN: KYYYYCCCCFFFFFBBBBBR RDSSSSSSSSEEEEEEEE

Where:

K = Code distinguishing assigned RINs from separated RINs
YYYY = Calendar year of production or import
CCCC = Company ID
FFFFF = Facility ID
BBBBB = Batch number
RR = Code identifying the Equivalence Value
D = Code identifying the renewable fuel category
SSSSSSSS = Start of RIN block
EEEEEEEE = End of RIN block

B. New Eligibility Requirements for Renewable Fuels

Aside from the higher volume requirements, most of the substantive changes that EISA makes to the RFS program affect the eligibility of renewable fuels in meeting one of the four volume requirements. Eligibility would be determined based on the types of feedstocks that can be used, the land that can be used to grow feedstocks for renewable fuel production, the processes that can be used to convert those feedstocks into fuel, and the lifecycle greenhouse gas (GHG) emissions that can be emitted in comparison to the gasoline or diesel that the renewable fuel displaces. This section describes these eligibility criteria and how we propose to include them in the RFS2 program.

1. Changes in Renewable Fuel Definitions

Under the existing Renewable Fuel Standard (RFS1), renewable fuel is defined generally as ''any motor vehicle fuel that is used to replace or reduce the quantity of fossil fuel present in a fuel mixture used to fuel a motor vehicle''. The RFS1 definition includes motor vehicle fuels produced from biomass material such as grain, starch, fats, greases, oils, and biogas. The definition specifically includes cellulosic biomass ethanol, waste derived ethanol, and biodiesel, all of which are defined separately. (*See* 72 FR 23915.)

The definitions of renewable fuels under today's proposed rule (RFS2) are based on the new statutory definition in EISA. Like the existing rules, the definitions in RFS2 include a general definition of renewable fuel, but unlike RFS1, we are including a separate definition of ''Renewable Biomass'' which identifies the feedstocks from which renewable fuels may be made.

Another difference in the definitions of renewable fuel is that RFS2 contains three subcategories of renewable fuels: (1) Advanced Biofuel, (2) Cellulosic Biofuel and (3) Biomass-Based Diesel. Each must meet threshold levels of reduction of greenhouse gas emissions as discussed in Section III.B.2. The specific definitions and how they differ from RFS1 follow below.

a. Renewable Fuel and Renewable Biomass

''Renewable Fuel'' is defined as fuel produced from renewable biomass and that is used to replace or reduce the quantity of fossil fuel present in a transportation fuel. The definition of ''Renewable Fuel'' now refers to ''transportation fuel'' rather than referring to motor vehicle fuel. ''Transportation fuel'' is also defined, and means fuel used in motor vehicles, motor vehicle engines, nonroad vehicles or nonroad engines (except for ocean going vessels).

We propose to allow fuel producers and importers to include electricity, natural gas, and propane (i.e., compressed natural gas (CNG) and liquefied petroleum gas (LPG)) as a RIN-generating renewable fuel in today's program only if they can identify the specific quantities of their product which are actually used as a transportation fuel, and if the fuel is produced from renewable biomass. This may be possible for some portion of electricity, natural gas, and propane since many of the affected vehicles and equipment are in centrally-fueled fleets supplied under contract by a particular producer or importer of natural gas or propane. A producer or importer of electricity, natural gas, or propane who could document the use of his product in a vehicle or engine would be allowed to generate RINs to represent that product, if it met the definition of renewable fuel. Given that the primary use of electricity, natural gas, and propane is not for fueling vehicles and engines, and the producer generally does not know how it will be used, we cannot require that producers or importers of these fuels generate RINs for all the volumes they produce as we do with other renewable fuels.

Our proposal to allow electricity, natural gas, and propane to generate RINs under certain conditions is consistent with our treatment of neat renewable fuels under RFS1 and EISA's requirement that all transportation fuels be included in RFS2. With specific regard to renewable electricity, Section 206 of EISA requires the EPA to conduct a study of the feasibility of issuing credits under the RFS2 program for renewable electricity used by electric vehicles. Once completed, this study will provide additional information regarding the means by which renewable electricity is able to generate RINs under the RFS2 program.

As an alternative to allowing producers and importers of electricity, natural gas, and propane to generate RINs if they can demonstrate that their product is a renewable fuel and it is used as transportation fuel, we could allow or require parties who supply these fuels to centrally fueled fleets to generate the RINs even if they are not the producer of the fuel. This approach would treat the supplier of the fuel to the fleet as the producer or importer who then generates RINs, as they are the party who in effect changes the fuel from a fuel that can be used in a variety of ways and ensures that it is in fact used as transportation fuel. This alternative approach might enable a larger volume of electricity, natural gas, and propane that is made from renewable biomass and which is actually used in vehicles or engines to be included in our proposed fuels program as RIN-generating, since in many cases a supplier could document the use of these fuels in vehicles or engines, while a producer could not. In addition, in this case the supplier is the party who causes the fuel to transition from general fuel supply to fuel designated for use in motor vehicles or nonroad applications—in that sense, the supplier is more like a producer or importer than the upstream producer or importer. However, if we were to allow the supplier of renewable electricity, natural gas, or propane to generate RINs in such cases, it may also be appropriate to require suppliers of fossil-based electricity, natural gas, or propane to determine a Renewable Volume Obligation (RVO) that includes these fuels used as transportation fuel. See Section III.F.3 for further discussion. We request comment on this alternative approach for generating RINs for renewable electricity, natural gas and propane.

The term ''Renewable Biomass'' as defined in EISA, means:

1. Planted crops and crop residue,
2. Planted trees and tree residues,
3. Animal waste material and byproducts,
4. Slash and pre-commercial thinnings (from non-federal forestlands),
5. Biomass cleared from the vicinity of buildings and other areas to reduce the risk of wildfire,
6. Algae, and
7. Separated yard waste or food waste.

Section III.B.4 of this preamble outlines our proposed interpretations for most of the key terms contained in the EISA definition of ''renewable biomass'' and possible approaches for implementing the land restrictions on renewable biomass that are included in EISA. It is worth noting here, however, that the statutory definition of ''renewable biomass'' does not include a reference to municipal solid waste (MSW) as did the definition of ''cellulosic biomass ethanol'' in the Energy Policy Act of 2005 (EPAct), but instead includes ''separated yard waste and food waste. EPA's proposed definition of renewable biomass in today's regulation includes the language present in EISA, and we propose to clarify in the regulations that ''yard waste'' is leaves, sticks, pine needles, grass and hedge clippings, and similar waste from residential, commercial, or industrial areas. Nevertheless, EPA invites comment on whether the definition of ''renewable biomass'' should be interpreted as including or excluding MSW from the definition of renewable biomass.

While the lack of a reference to MSW and the new listing of separated yard waste and food waste could be readily interpreted to exclude MSW as a qualifying feedstock under RFS2, EPA believes there are indications of ambiguity on this issue and solicits comment on whether EPA can and should interpret EISA as including MSW that contains yard and/or food waste within the definition of renewable biomass. On the one hand, the reference in the statutory definition to ''separated yard waste and food waste,'' and the lack of reference to other components of MSW (such as waste paper and wood waste) suggests that only yard and food wastes physically separated from other waste materials satisfy the definition of renewable biomass as opposed to the yard and food waste present in MSW. This view would exclude unprocessed MSW from any role in the development of renewable fuel under EISA, and would also likely severely limit the amount of yard and food waste available as feedstock for EISA-qualifying fuel, since large quantities of these materials are disposed of as unprocessed MSW.

On the other hand, there are some indications that Congress may not have specifically intended to exclude MSW from playing a role in the development of renewable fuels under EISA. For example, ethanol ''derived from waste material'' and biogas ''including landfill gas'' are specifically identified as ''eligible for consideration'' in the definition of advanced biofuel. While landfill gas is generated primarily by the yard waste and food waste in a landfill, these wastes typically are not separated from each other in a landfill. In addition, Congress did not define the term ''separated'' and did not otherwise specify the degree of ''separation'' required of yard and food waste in the definition of renewable biomass. Thus, it might be reasonable to consider these items sufficiently ''separated'' from other materials, including non-waste materials, when food and yard waste is present in MSW. In addition, the processing of MSW to fuel will effectively separate out the materials in MSW that cannot be made into fuel, such as glass and metal, and non-biomass portions of MSW (for example, pastics) could be excluded from getting credit under the RFS program as described in Section III.D.4. EPA invites comment on whether there is enough separation of food and yard waste in MSW used in renewable fuel production for MSW containing yard and food waste to meet the definition of renewable biomass.

Approximately 35% by weight of MSW is paper wastes, and another 6% by weight from wood wastes. Combined with food and yard wastes, more than 60% by weight of MSW is biomass that could be used to make ethanol and other renewable fuels.[5] The volume of ethanol associated with MSW as a feedstock is described in more detail in Section 1.1 of the Draft Regulatory Impact Analysis (DRIA).

Our discussions with stakeholders indicate that a potential concern with interpreting the definition of renewable biomass to include MSW containing yard and/or food waste is that this approach may cause some decrease in the amount of paper that is separated from the MSW waste stream and recycled into paper products. We believe, however, that current waste handling practices and current and anticipated market conditions would continue to provide a strong incentive for paper separation and recycling. A narrow reading of the statute to exclude MSW-derived renewable fuel would directionally reduce the options available for meeting the goal of EISA to reduce our dependence on foreign sources of energy.

By including MSW containing yard and/or food waste in the definition of renewable biomass, we could also allow renewable fuel to be produced in part from certain plastics in the MSW waste stream. We believe this could be appropriate given that plastics that would otherwise be destined for landfills can be used for fuel and energy production. We recognize that the definition of renewable biomass generally includes only materials of a non fossil-fuel origin, and ask that commenters consider this issue in their comments on whether: (1) MSW containing yard and food waste should qualify as renewable biomass, (2) if non-fossil portions of MSW should be included in the definition of renewable biomass, and (3) if non-fossil portions of

[5] Construction and demolition (C&D) wastes are not typically considered as elements of MSW. Because they are significant feedstocks for the production of ethanol, we include such wastes in our economic analysis (Section V). Therefore, for all practical purposes, the discussion here as it pertains to whether MSW should be included in the definition of ''renewable biomass'' also applies to C&D wastes.

MSW should not be included, whether the approach discussed in Section III.D.4 can provide an appropriate means for excluding the non-fossil portions.

Although we are proposing to exclude MSW from the definition of ''renewable biomass'' for the proposed rule, our analysis of renewable fuel volume (discussed in Section V) assumes that MSW is included for purposes of quantifying the potential future volume of renewable fuel. EPA intends to resolve this matter in the final rule, and we solicit comment on the approach that we should take.

b. Advanced Biofuel

''Advanced Biofuel'' is a renewable fuel other than ethanol derived from corn starch and which must also achieve a lifecycle GHG emission displacement of 50%, compared to the gasoline or diesel fuel it displaces. As such, advanced biofuel would be assigned a D code of 3 as shown in Table III.A–1.

''Advanced biofuel'' also may be biomass-based diesel, biogas (including landfill gas and sewage waste treatment gas), butanol or other alcohols produced through conversion of organic matter from renewable biomass, and other fuels derived from cellulosic biomass, as long as it meets the proposed 40–44% GHG emission reduction threshold. ''Advanced Biofuel'' is a renewable fuel other than ethanol derived from corn starch and for which lifecycle GHG emissions are at least 40–44% less than the gasoline or diesel fuel it displaces. Advanced biofuel would be assigned a D code of 3 as shown in Table III.A–1.

While ''Advanced Biofuel'' specifically excludes ethanol derived from corn starch, it includes other types of ethanol derived from renewable biomass, including ethanol made from cellulose, hemicellulose, lignin, sugar or any starch other than corn starch, as long as it meets the proposed 40–44% GHG emission reduction threshold. Thus, even if corn starch-derived ethanol were made so that it met the proposed 40–44% GHG reduction threshold, it would still be excluded from being defined as an advanced biofuel. Such ethanol, while not an advanced biofuel, would still qualify as a renewable fuel for purposes of meeting the standards.

''Advanced biofuel'' also may be biomass-based diesel, biogas (including landfill gas and sewage waste treatment gas), butanol or other alcohols produced through conversion of organic matter from renewable biomass, and other fuels derived from cellulosic biomass, as long as it is derived from renewable biomass and meets the proposed 40–44% GHG emission reduction threshold.

c. Cellulosic Biofuel

Cellulosic biofuel is renewable fuel, not necessarily ethanol, derived from any cellulose, hemicellulose, or lignin each of which must originate from renewable biomass. It must also achieve a lifecycle GHG emission reduction of at least 60%, compared to the gasoline or diesel fuel it displaces. Cellulosic biofuel is assigned a D code of 1 as shown in Table III.A–1. Cellulosic biofuel in general also qualifies as both ''advanced biofuel'' and ''renewable fuel''.

The proposed definition of cellulosic biofuel for RFS2 is broader in some respects than the RFS1 definition of ''cellulosic biomass ethanol''. That definition included only ethanol, whereas the RFS2 definition of cellulosic biofuels includes any biomass-to-liquid fuel in addition to ethanol. The definition of ''cellulosic biofuel'' in RFS2 differs from RFS1 in another significant way. The RFS1 definition provided 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% or more of the fossil fuel normally used in the production of ethanol.'' This provision was not included in EISA, and therefore does not appear in the definitions pertaining to cellulosic biofuel in today's proposed rule.

d. Biomass-Based Diesel

Under today's proposed rule ''Biomass-based diesel'' includes both biodiesel (mono-alkyl esters) and non-ester renewable diesel (including cellulosic diesel). The definition is the same very broad definition of ''biodiesel'' that was in EPAct and in RFS1, with three exceptions. First, EISA requires that such fuel be made from renewable biomass. Second, its lifecycle GHG emissions must be at least 50% less than the gasoline or diesel fuel it displaces. Third, the statutory definition of ''Biomass-based diesel'' excludes renewable fuel derived from co-processing biomass with a petroleum feedstock. In drafting the proposed definition, we considered two options for how co-processing could be treated. The first option would consider co-processing to occur only if both petroleum and biomass feedstock are processed in the same unit simultaneously. The second option would consider co-processing to occur if renewable biomass and petroleum feedstock are processed in the same unit at any time; i.e., either simultaneously or sequentially. Under the second option, if petroleum feedstock was processed in the unit, then no fuel produced from such unit, even from a biomass feedstock, would be deemed to be biomass-based diesel.

We are proposing the first option to be used in the definition in today's rule. Under this approach, a batch of fuel qualifying for the D code of 2 that is produced in a processing unit in which only renewable biomass is the feedstock for such batch, would meet the definition of ''Biomass-Based Diesel. Thus, serial batch processing in which 100% vegetable oil is processed one day/week/month and 100% petroleum the next day/week/month could occur without the activity being considered ''co-processing.'' The resulting products could be blended together, but only the volume produced from vegetable oil would count as biomass-based diesel. We believe this is the most straightforward approach and an appropriate one, given that it would allow RINs to be generated for volumes of fuel meeting the 50% GHG reduction threshold that is derived from renewable biomass, while not providing any credit for fuel derived from petroleum sources. In addition, this approach avoids the need for potentially complex provisions addressing how fuel should be treated when existing or even mothballed petroleum hydrotreating equipment is retrofitted and placed into new service for renewable fuel production or vice versa.

Under today's proposal, any fuel that does not satisfy the definition of biomass-based diesel only because it is co-processed with petroleum would still meet the definition of ''Advanced Biofuel'' provided it meets the 50% GHG threshold and other criteria for the D code of 3. Similarly it would meet the definition of renewable fuel if it meets a GHG emission reduction threshold of 20%. In neither case, however, would it meet the definition of biomass-based diesel.

This restriction is only really an issue for renewable diesel and biodiesel produced via the fatty acid methyl ester (FAME) process. For other forms of biodiesel, it is never made through any sort of co-processing with petroleum.[6]

[6] The production of biodiesel (mono alkyl esters) does require the addition of methanol which is usually derived from natural gas, but which contributes a very small amount to the resulting product. We do not believe that this was intended by the statute's reference to ''co-processing'' which we believe was intended to address only renewable fats or oils co-processed with petroleum in a hydrotreater to produce renewable diesel.

Producers of renewable diesel must therefore specify whether or not they use ''co-processing'' to produce the fuel in order to determine the correct D code for the RIN.

e. Additional Renewable Fuel

The statutory definition of ''additional renewable fuel'' specifies fuel produced from renewable biomass that is used to replace or reduce fossil fuels used in home heating oil or jet fuel. EISA indicates that EPA may allow for the generation of credits for such additional renewable fuel that will be valid for compliance purposes. Under the RFS program, RINs operate in the role of credits, and RINs are generated when renewable fuel is produced rather than when it is blended. In most cases, however, renewable fuel producers do not know at the time of fuel production (and RIN generation) how their fuel will ultimately be used.

Under RFS1, only RINs assigned to renewable fuel that was blended into motor vehicle fuel are valid for compliance purposes. As a result, we created special provisions requiring that RINs be retired if they were assigned to renewable fuel that was ultimately blended into nonroad fuel. The new EISA provisions regarding additional renewable fuel make the RFS1 requirement for retiring RINs unnecessary if renewable fuel is blended into heating oil or jet fuel. As a result, we propose modifying the regulatory requirements to allow RINs assigned to renewable fuel blended into heating oil or jet fuel to continue to be valid for compliance purposes.

2. Lifecycle GHG Thresholds

As part of the new definitions that EISA creates for cellulosic biofuel, biomass-based diesel, advanced biofuel, and renewable fuel, EISA also sets minimum performance measures or ''thresholds'' for lifecycle GHG emissions. These thresholds represent the percent reduction in lifecycle GHGs that is estimated to occur when a renewable fuel displaces gasoline or diesel fuel. Table III.B.2–1 lists the thresholds required by EISA.

TABLE III.B.2–1—REQUIRED LIFECYCLE GHG THRESHOLDS

[Percent reduction from a 2005 gasoline or diesel baseline]

Renewable fuel	20
Advanced biofuel	50
Biomass-based diesel	50
Cellulosic biofuel	60

There are also special provisions for each of these thresholds:

Renewable fuel: The 20% threshold only applies to renewable fuel from new facilities that commenced construction after December 19, 2007, with an additional exemption from the 20% threshold for ethanol plants that commenced construction in 2008 or 2009 and are fired with natural gas, biomass, or any combination thereof. Facilities not subject to the 20% threshold would be ''grandfathered.'' *See* Section III.B.3 below for a complete discussion of grandfathering. Also, EPA can adjust the 20% threshold to as low as 10%, but the adjustment must be the minimum possible, and the resulting threshold must be established at the maximum achievable level based on natural gas fired corn-based ethanol plants.

Advanced biofuel and biomass-based diesel: The 50% threshold can be adjusted to as low as 40%, but the adjustment must be the minimum possible and result in the maximum achievable threshold taking cost into consideration. Also, such adjustments could be made only if it was determined that the 50% threshold was not commercially feasible for fuels made using a variety of feedstocks, technologies, and processes. As described more fully in Section VI.D, we are proposing that the GHG threshold for advanced biofuels be adjusted to 44% or potentially as low as 40% depending on the results from the analyses that will be conducted for the final rule.

Cellulosic biofuel: Similarly to advanced biofuel and biomass-based diesel, the 60% threshold applicable to cellulosic biofuel can be adjusted to as low as 50%, but the adjustment must be the minimum possible and result in the maximum achievable threshold taking cost into consideration. Also, such adjustments could be made only if it was determined that the 60% threshold was not commercially feasible for fuels made using a variety of feedstocks, technologies, and processes.

Our analyses of lifecycle GHG emissions, discussed in detail in Section VI, included all GHGs related to the full fuel cycle, including all stages of fuel and feedstock production and distribution, from feedstock generation and extraction through distribution, delivery, and use of the finished fuel. They included direct emissions and any significant indirect emissions such as significant emissions from land use changes. These lifecycle analyses were used to determine whether the thresholds shown in Table III.B.2–1 should be adjusted downwards and which specific combinations of feedstock, fuel type, and production process met those thresholds under the assumption of a 100-year timeframe and 2% discount rate for GHG emission impacts.

We are not proposing to adjust any of these thresholds. However, we may adjust the GHG threshold for biomass-based diesel and/or advanced biofuel downward for the final rule based on additional lifecycle GHG analyses and further assessments of the market potential for volumes that can meet the requirements for these categories of renewable fuel. As explained in more detail in Section VI.D, ethanol produced from sugarcane sugar has been estimated to have a lifecycle GHG performance of 44% (under the assumption of a 100 year timeframe and 2% discount rate), short of the 50% threshold specified in EISA. Ethanol from sugarcane is one of the few currently commercial pathways that have the potential to meet the requirements for advanced biofuel in the near term (in addition to cellulosic biofuel and biomass-based diesel which are a subset of advanced biofuel, and any other new fuels that may arise), and the only such pathway that was subjected to lifecycle analysis to date. If ethanol from sugarcane does not qualify as advanced biofuel, it is likely that it would not be commercially feasible for the advanced biofuel volume requirements to be met in the near term. We request comment on whether it would be necessary to adjust the GHG threshold for advanced biofuel. For similar reasons, as discussed in more detail in Section VI.D, we are also seeking comment on the need to adjust the GHG threshold for biomass-based diesel.

3. Renewable Fuel Exempt From 20 Percent GHG Threshold

EISA amends section 211(o) of the Clean Air Act to provide that renewable fuel produced from new facilities which commenced construction after December 19, 2007 must achieve at least a 20% reduction in lifecycle greenhouse gas emissions compared to baseline lifecycle greenhouse gas emissions.[7] Facilities that commenced construction before December 19, 2007 are ''grandfathered'' and thereby exempt from the 20% GHG reduction requirement.

[7] Section 211(o)(2)(A)(i) of the Clean Air Act as amended by EISA. Note that this is not a prohibition—facilities that make ethanol can continue to do so. It is a minimum requirement for facilities to generate RINs under today's proposed rule; failure to meet such requirements means that the ethanol produced from such facilities cannot generate RINs.

For facilities that produce ethanol and for which construction commenced after December 19, 2007, section 210 of EISA states that ''for calendar years 2008 and 2009, any ethanol plant that is fired with natural gas, biomass, or any combination thereof is deemed to be in compliance with the 20% threshold.'' We refer to these facilities as ''deemed compliant.'' This provision does not specify whether such facilities are deemed to be in compliance only for the period of 2008 and 2009, or indefinitely. Nor does EISA specify a date by which such qualifying facilities must have started operation. Although the Act is unclear as to whether their special treatment is only for 2008/2009, or for a longer time period, we believe that it would be a harsh result for investors in these new facilities, and generally inconsistent with the energy independence goals of EISA, for these new facilities to only be guaranteed two years of participation in the RFS2 program. We propose that the statute be interpreted to mean that fuel from such qualifying facilities, regardless of date of startup of operations, would be exempt from the 20% GHG threshold requirement for the same time period as facilities that commence construction prior to December 19, 2007, *provided* that such plants commence construction prior to December 31, 2009, complete such construction in a reasonable amount of time, and continue to burn only natural gas, biomass, or a combination thereof. Therefore, we believe that they should be treated like grandfathered facilities. We seek comment, however, on the alternative in which after 2009, such plants must meet the 20% threshold in order to generate RINs for renewable fuel produced.

Based on our survey of ethanol plants in operation, as well as those not yet in operation but which commenced construction prior to December 19, 2007, it is likely that production capacity of ethanol from all such facilities will reach 15 billion gallons. (See Section 1.5.1.4 of the DRIA.) This volume of ethanol will be excluded from having to meet the 20% GHG threshold by the grandfathering and deemed compliant provisions of EISA.[8] For ease of reference, we will refer to both these provisions as the ''exemption provisions'' of EISA.

EISA does not define the term ''new facility'' and, as mentioned above, does not clarify whether ''deemed compliant'' facilities have that status for only 2008 and 2009, or for a longer time period. EPA seeks, in interpreting these terms, to avoid long-term backsliding with respect to environmental performance and to also provide a level playing field for future investments. Thus, we want to avoid incentives that would allow overall GHG performance to worsen via expansion at older plants with poorer GHG performance or by modifications such as switches to more polluting process heat sources, such as coal. At the same time, we also want to offer protection for historical business investments that were made prior to enactment of EISA, and we want future significant investments to meet the GHG reduction standards of the Act. Finally we want to avoid excessive case-by-case decision making where possible, and seek instead a rule that offers ease of implementation while providing certainty to EPA and the regulated industry.

We are proposing one basic approach to the exemption provisions and seeking comment on five additional options. In fashioning the basic proposal and alternative options for exempted facilities, we considered aspects of exemption approaches elsewhere in the CAA and EPA regulations to evaluate whether they would foster the above-described objectives. We are only looking to these other provisions for guidance and are not bound to follow any already-established approach for a different statutory provision (especially as those other provisions may contain definitions that Congress did not incorporate here).

a. Definition of Commence Construction

In defining ''commence'' and ''construction'', we wanted a clear designation that would be broad enough to avoid facility-specific issues, but narrow enough to prevent new facilities (i.e., post-December 19, 2007) from being grandfathered. We believe that the definitions of ''commence'' and ''Begin actual construction'' in the Prevention of Significant Deterioration (PSD) regulations, which draws upon definitions in the Clean Air Act, served this purpose. (40 CFR 52.21(b)(9) and (11)). Specifically, under the PSD regulations, ''commence'' means that the owner or operator has all necessary preconstruction approvals or permits and either has begun a continuous program of actual on-site construction to be completed in a reasonable time, or entered into binding agreements which cannot be cancelled or modified without substantial loss.'' Such activities include, but are not limited to, ''installation of building supports and foundations, laying underground pipe work and construction of permanent storage structures.'' We have added language to the definition that is currently not in the PSD definition with respect to multi-phased projects. We are proposing that for multi-phased projects, commencement of construction of one phase does not constitute commencement of construction of any later phase, unless each phase is ''mutually dependent'' on the other on a physical and chemical basis, rather than economic.

The PSD regulations provide additional conditions beyond what constitutes commencement. Specifically, the regulations require that the owner or operator ''did not discontinue construction for a period of 18 months or more and completed construction within a reasonable time.'' (40 CFR 52.21(i)(4)(ii)(c). While ''reasonable time'' may vary depending on the type of project, we believe that with respect to renewable fuel facilities, a reasonable time to complete construction is no greater than 3 years from initial commencement of construction. We seek comment on the use of these definitions.

b. Definition and Boundaries of a Facility

We propose that the grandfathering and deemed compliant exemptions apply to ''facilities.'' Our proposed definition of this term is similar in some respects to the definition of ''building, structure, facility, or installation'' contained in the PSD regulations in 40 CFR 52.21. We have modified the definition, however, to focus on the typical renewable fuel plant. We therefore propose to describe the exempt ''facilities'' as including all of the activities and equipment associated with the manufacture of renewable fuel which are located on one property and under the control of the same person or persons.

c. Options Proposed in Today's Rulemaking

We are proposing one basic approach to the grandfathering provisions and seeking comment on five additional options. The basic approach would provide an indefinite extension of grandfathering and deemed compliant status but with a limitation of the exemption from the 20% GHG threshold to a baseline volume of renewable fuel. The five additional options for which we seek comment are: (1) Expiration of exemption for grandfathered and ''deemed compliant'' status when facilities undergo sufficient changes to

[8] The grandfathering and deemed compliant provisions in EISA sections 202 and 210 do not apply to the advanced biofuels, biomass-based diesel or cellulosic biofuel standards for which the Act requires a 50 or 60% GHG reduction threshold to be met regardless of when the facilities producing such fuels are constructed.

be considered ''reconstructed''; (2) Expiration of exemption 15 years after EISA enactment, industry-wide; (3) Expiration of exemption 15 years after EISA enactment with limitation of exemption to baseline volume; (4) ''Significant'' production components are treated as facilities and grandfathered or deemed compliant status ends when they are replaced; and (5) Indefinite exemption and no limitations placed on baseline volumes.

i. Basic Approach: Grandfathering Limited to Baseline Volumes

We are proposing and seeking comments on an option which generally limits the volume of any renewable fuel for which a grandfathered and deemed compliant facility can generate RINs without complying with the 20% GHG reduction threshold to the capacity volume specified in a state or Federal air permit or the greater of nameplate capacity or actual production. This approach is similar to how we have treated small refiner flexibilities under our other fuel rules. As a sub-option to this approach, we also seek comment on a provision whereby facilities would lose their status if they switch to a process fuel or feedstock which results in an increase of GHG emissions.

(1) Increases in Volume of Renewable Fuel Produced at Grandfathered Facilities due to Expansion

For facilities that commenced construction prior to December 19, 2007, we are proposing to define the baseline volume of renewable fuel exempt from the 20% GHG threshold requirement to be the maximum volumetric capacity of the facility as allowed in any applicable state air permit or Federal Title V operating permit. If the capacity of a facility is not stipulated in such air permits, then the grandfathered volume is the greater of the nameplate capacity of the facility or historical annual peak production prior to enactment of EISA. Volumes greater than this amount which may typically be due to expansions of the facility which occur after December 19, 2007, would be subject to the 20% GHG reduction requirement in order for the facility to generate RINs for the incremental expanded volume. The increased volume would be considered as if produced from a ''new facility'' which commenced construction after December 19, 2007. Changes that might occur to the mix of renewable fuels produced within the facility would remain grandfathered as long as the overall volume fell within the baseline volume.

The baseline volume would be defined as above for deemed compliant facilities with the exception that if the maximum capacity is not stipulated in air permits, then the exempt volume would be the maximum annual peak production during the plant's first three years of operation. In addition, any production volume increase that is attributable to construction which commenced prior to December 31, 2009 would be exempt from the 20% GHG threshold, provided that the facility continued to use natural gas, biomass or a combination thereof for process energy. Because deemed compliant facilities owe their status to the fact that they use natural gas, biomass or a combination thereof for process heat, we propose that their status would be lost, and they would be subject to the 20% GHG threshold requirement, at any time that they change to a process energy source other than natural gas and/or biomass. Finally, because EISA limits deemed compliant facilities to ethanol facilities, we propose that if there are any changes in the mix of renewable fuels produced by the facility that only the ethanol volume remain grandfathered. We solicit comment, however, on whether the statute could be read to allow deemed compliant facilities to be treated the same as grandfathered facilities by allowing a mix of renewable fuels.

Volume limitations contained in air permits may be defined in terms of peak hourly production rates or a maximum annual capacity. If they are defined only as maximum hourly production rates, they would need to be converted to an annual rate. We believe that assuming 24-hour per day production over 365 days per year (8,760 production hours) may overstate nameplate capacity. In other regulations that pertain to refinery operations, we have assumed a conversion rate of 90% of the total hours in a year (7884 production hours). We seek comment on what would be an appropriate conversion rate for renewable fuel facilities.

The facility registration process (*see* Section III.C) would be used to define the baseline volume for individual facilities. Owners and operators would submit information substantiating the nameplate capacity of the plant, as well as historical annual peak capacity if such is greater than nameplate capacity. Subsequent expansions at a grandfathered that result in an increase in volume would subject the increase in volume to the 20% GHG emission reduction threshold (but not the original baseline volume). Thus, any new expansions would need to be designed to achieve the 20% GHG reduction threshold if the facility wants to generate RINs for that volume. Such determinations would be made on the basis of EPA-defined corn ethanol fuel pathway categories that are deemed to represent such 20% reduction. As an alternative approach to the greater of nameplate capacity or historical annual peak capacity, we seek comment on an approach in which the baseline volume is the actual volume of renewable fuel produced during the 2006 calendar year, where adequate data is available. Since there has been a particularly high demand for ethanol in recent years, the use of 2006 data may be a fair representation of the real production capacity for most plants. For plants that have not operated for an adequate shake down period, the information in the state or Federal air permit could be used and if this is not available, the nameplate capacity could be used. As mentioned above, deemed compliant facilities would be exempt from the 20% GHG threshold for baseline volumes and any additional volumes regarding which construction commenced prior to December 31, 2009.

We recognize, however, that some debottlenecking type changes may cause increases in volume that are within a plant's inherent capacity. To account for this in past regulations (e.g., 40 CFR 80.552 and 554) we allowed for an increase of 5% above the baseline volume. Based on conversations with builders of ethanol plants, however, such plants have often been debottlenecked to exceed nameplate capacity by 20% and sometimes much higher. We seek comment on whether we should allow a 10% tolerance on the baseline volume for which RINs can be generated without complying with the 20% GHG reduction threshold. Once that 10% increase in volume is exceeded, the total increase above baseline volume would then be subject to the 20% GHG reduction requirement in order to generate RINs. We also seek comment on tolerance values in the 5 to 20% range.

Our guiding philosophy of protecting historical business investments that were made to comply with the provisions of RFS1 is realized by allowing production increases within a plant's inherent capacity. At the same time, the alternative of requiring compliance with the 20% GHG reduction requirement for increases in volume above 10% over the baseline volume, would place new volumes from grandfathered facilities on a level playing field with product from new grass roots facilities. We believe that a level playing field for new investments is fair and consistent with the provisions of EISA.

(2) Replacements of Equipment

If production equipment such as boilers, conveyors, hoppers, storage tanks and other equipment are replaced, it would not be considered construction of a ''new facility'' under this option of today's proposal—the baseline volume of fuel would continue to be exempt from the 20% GHG threshold. We discuss in a sub-option in III.B.3.c.i(4) below in which if the replacement unit uses a higher polluting fuel in terms of GHG emissions such replacement would render the facility a new facility, and it would no longer be exempt from the 20% GHG threshold. We also solicit comment on an approach that would require that if coal-fired units are replaced, that the replacement units must be fired with natural gas or biofuel for the product to be eligible for RINs that do not satisfy the 20% GHG threshold.

(3) Registration, Recordkeeping and Reporting

Facility owner/operators would be required to provide evidence and certification of commencement of construction. Owner/operators must provide annual records of process fuels used on a BTU basis, feedstocks used and product volumes. For facilities that are located outside the United States (including outside the Commonwealth of Puerto Rico, the U.S. Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Mariana Islands) owners would be required to provide certification as well. Since the definition of commencement of construction includes having all necessary air permits, we would require that facilities outside the United States to certify that such facilities have obtained all necessary permits for construction and operation required by the appropriate national and local environmental agencies.

(4) Sub-Option of Treatment of Future Modifications

We seek comment on a sub-option to the basic approach whereby facilities would lose their grandfathered status if they switch to a process fuel or feedstock which results in an increase of GHG emissions. Some facilities may keep production volumes the same, but change some or all of their feedstocks and energy sources, thus causing a facility's product to fall further below the GHG performance for the fuel pathway it produced at the time of enactment. We are therefore seeking comment on an approach to limit the initial grandfathering only for the fuel pathways that applied during 2007, when establishing the volume baseline. Table III.B.3.c.i–1 below presents a ranking of fuels and feedstock by fuel pathway in order of life cycle GHG emissions (as discussed further in Section VI.E). (Table III.B.3.c.i–1 is based on the table of fuel pathways contained in proposed regulations 40 CFR 80.1426.) Since the majority of facilities under consideration in this portion of the rulemaking consists of ethanol plants, the table below is limited to those types. Any changes to a facility that shift it to a feedstock or use of a process energy source that results in higher GHG emissions on the basis of the ranking categories in Table III.B.3.c.i–1 below would terminate the facility's grandfathered status.

For example, an ethanol dry mill plant using natural gas for process heat, as well as combined heat and power (CHP), is ranked as ''2'' in the table below. If the plant (or any portion of the plant) switches to coal, it is ranked as ''4''. The higher number indicates an increase in GHG emissions. Therefore in this example, the plant is considered to have undertaken a modification that increases GHG emissions, would render the facility as ''new'' and its grandfathered status would end. Similarly, replacements of equipment that worsen GHG emissions would also terminate grandfathered status. (For replacements of equipment that do not change the fuel, nor result in an increase in volume of renewable fuel, the grandfathered status of the plant would remain, as discussed in Section III.B.3.c.i(2) above.)

TABLE III.B.3.c.i–1—GROUPS OF RENEWABLE FUEL FACILITIES BY FUEL FEEDSTOCK AND PROCESS ENERGY

Feedstock	Production process requirements	Ranking
Starch from corn, wheat, barley, oats, rice, or sorghum	—Process heat derived from biomass	1
Starch from corn, wheat, barley, oats, rice, or sorghum	—Dry mill plant —All process heat derived from natural gas. —Combined heat and power (CHP). —Fractionation of feedstocks. —Dried distillers grains.	2
Starch from corn, wheat, barley, oats, rice, or sorghum	—Dry mill plant —All process heat derived from natural gas. —Wet distillers grains.	3
Starch from corn, wheat, barley, oats, rice, or sorghum	—Dry mill plant —All or part of process heat derived from coal. —Combined heat and power (CHP). —Fractionation of feedstocks. —Membrane separation of ethanol. —Raw starch hydrolysis. —Dried distillers grains.	4
Starch from corn, wheat, barley, oats, rice, or sorghum	—Dry mill plant —All or part of process heat derived from coal. —Combined heat and power (CHP). —Fractionation of feedstocks. —Membrane separation of ethanol. —Wet distillers grains.	5
Sugarcane sugar	—Process heat derived from sugarcane bagasse	1
Sugarcane sugar	—Process heat derived from natural gas	2
Sugarcane sugar	—Process heat derived from coal	3

We considered whether improvements at a facility (i.e., a fuel switch from coal to natural gas) that still result in GHG performance less than 20% should be credited to allow the facility to increase its baseline volume. We decided not to propose such an approach because it would take away an incentive for new plants that achieve greater than 20% GHG reduction to be constructed. As such, this would go against our guiding principle of providing equal opportunities for future investments in new plants.

We recognize that there may be combinations of changes made at a plant, some of which may worsen GHG emissions and others which may cause an improvement and that not all such combinations can be taken into account in a single table of fuel pathways. We seek comment on ways to address such combinations.

ii. Alternative Options for Which We Seek Comment

(1) Facilities That Meet the Definition of ''Reconstruction'' Are Considered New

An alternative approach on which we are seeking comment would consider whether a facility is effectively a ''new'' facility with respect to the costs incurred in maintaining the plant over time. Starting in 2010, we would require facility owners to report annually (specifically by January 31) to EPA the expenses for replacements, additions, and repairs undertaken at facilities since start up of the facility through the year prior to reporting. The Agency would then determine whether the degree of such activities warrants considering the facility as effectively ''new''. That substantial rebuilding or modernization may render an existing facility a new facility for regulatory purposes finds analogies in other Clean Air Act regulatory programs. For example, under the New Source Performance Standards (NSPS) equipment that has been ''reconstructed'' as defined in 40 CFR 60.15 is considered new. Specifically, ''reconstruction'' is defined in 40 CFR 60.15 as ''the replacement of components of an existing facility to such an extent that the fixed capital cost of the new components exceeds 50% of the fixed capital cost that would be required to construct a comparable entirely new facility. In addition to the NSPS program, regulations such as the recently promulgated standards for locomotive and marine engines (73 FR 25160; May 6, 2008) use a more encompassing concept of reconstruction and consider a vessel to be new if it is modified such that the value of the modifications exceeds 50% of the value of the modified vessel. We are seeking comment on an approach wherein upon the Agency's determination that costs of replacements, repairs and upgrades conducted since the start-up of the facility meet the test of ''reconstruction'' (i.e., the costs equal or exceed 50% of what it would cost to rebuild), that the facility would be considered effectively new, and would be subject to the 20% GHG reduction requirements.

The application of the definition of reconstruction in the NSPS program occurs on an equipment-wide rather than on a plant-wide basis. Under this option, we would apply the concept of a ''new'' facility on a plant-wide basis similar to the approach we have taken in the recently promulgated locomotive and marine standards. We believe that a plant-wide approach is appropriate under RFS2 because it is not the emissions from individual pieces of equipment that are being regulated. Rather, the 20% GHG reduction standard applies to the renewable fuel produced by the facility, and it is logical to consider all of the equipment and structures at the facility involved in producing the product in evaluating when a grandfathered facility has been reconstructed. For these reasons, we believe that it would be reasonable to apply the definition of ''new'' on a plant-wide basis. Also, since upgrades, replacements and repairs will occur on an ongoing basis we would consider rebuilding or reconstruction to occur over time as the accumulation of all individual upgrades, replacements and repairs.

The NSPS definition also requires that it be ''technologically and economically feasible for the reconstructed facility to meet applicable standards that apply to new facilities.'' We do not think that EISA requires this additional consideration, and also do not believe that there is any compelling public policy justification for allowing a reconstructed facility to continue to make renewable fuel that does not meet the 20% GHG reduction standard based upon a claim that it is technologically or economically infeasible. EPA's experience in the New Source Review (NSR) program has demonstrated that it is extremely difficult to clearly define what the terms ''technologically and economically feasible'' mean. Aside from such definitional difficulties, however, and as discussed in Section III.B.3.c.ii(2) below, we believe that it is technologically feasible to meet the 20% GHG reduction and with proper planning would be economically so, as well. Therefore, this alternative option would not require such a showing.

Our assessment of whether a facility has been reconstructed would be based on application of an appropriate cost model such as U.S. Department of Agriculture's cost estimation model for construction of new ethanol plants described by Kwiatkowski, J. et al. (2006) [9]. Costs associated with the costs of repair and replacement of all parts (including the labor associated with replacement and repair), would be included in such calculation, regardless of the parts' intended useful life. We seek comment on whether to also include costs associated with employee labor related to routine maintenance, and also whether the costs of repairs and replacements at the facility should be limited only to the property directly related to the production of biofuels.[10]

Under this alternative option, the volume of renewable fuel that qualifies for an exemption from the 20% GHG threshold would remain fixed at the baseline volume as in the basic option described in III.B.3(c)(i). However, we also seek comment on whether the volume of renewable fuel at a grandfathered facility should be allowed to increase above baseline volumes under this option. Specifically, increases in volume could be exempt until such time as the entire plant is deemed to have been reconstructed. In making such assessment and applying the 50% test, the basis for the cost of a ''comparable entirely new facility'' would be a facility with the original baseline volume. For example, if an existing plant has a 100 million gallon per year capacity and expands its volume to 120 million gallons per year, reconstruction would occur if the costs incurred over time equal or exceed 50% of the cost of a comparable 100 million gallon per year facility.

Under this alternative option, owner/operators or other responsible parties would be required to provide records of costs incurred for additions, replacements, and repairs that have

[9] Kwiatkowski, J.R., McAloon, A., Taylor, F. Johnson, D. 2006. ''Modeling the process and costs of fuel ethanol production by the corn dry-grind process.'' *Industrial Crops and Products* 23 (2006) 288–296.

[10] We note that under NSPS the costs considered in determining whether the definition of reconstruction has been met are restricted to the capital costs of equipment and materials. The RFS2 program is authorized from EISA which does not rely on the definitions of ''modification'' and ''routine maintenance and repair'' that are in NSPS and other new source programs (e.g., New Source Review, National Emission Standards for Hazardous Pollutants). Since our application of the term ''reconstruction'' assumes that over time, renewable fuel facilities may become substantially rebuilt it is therefore appropriate to consider not only equipment replacements but some of the labor costs associated with such replacements.

occurred since start-up. Such records would be provided on an annual basis to EPA by May 31, and would include cumulative cost information up to the prior year.

We recognize that implementation of a facility-wide definition of ''reconstruction'' would be complex. Records of costs since start-up may not be available for older facilities. Also, this alternative option requires EPA enforcement staff to have sufficient financial knowledge and experience to be able to evaluate the veracity of claims regarding various types of expenditures. Calculating the costs of repairs and replacements also poses challenges. Specifically, as discussed above, we seek comment on whether the costs of routine maintenance and repair should be included in such assessments. Were such costs to be included, the determination of whether a replacement or a repair is routine may not always be straightforward. In addition to the recordkeeping and implementation issues, however, there is an important policy consideration that is also significant. As in the case of the NSR program, where many industry representatives have argued that the program has a chilling effect on projects that could provide environmental benefits, the reconstruction approach in this alternative option could also provide a disincentive to implementation of safety and environmental projects. Thus, this option could have the unintended consequence of causing facilities to refrain from investing in projects that will increase safety and efficiency and reduce emissions in order to avoid triggering the 50% cost threshold. We seek comment on this issue.

(2) Expiration Date of 15 Years for Exempted Facilities

The above discussion highlights potential complexities in implementing the option of considering reconstruction of exempted facilities on a case-by-case basis. These include potential disputes over how to calculate costs, as well as verifying records of expenditures. In addition, that option has as a potential unintended consequence, a disincentive for investment in projects that could improve safety, efficiency and environmental performance. As an alternative to the case-by case approach described above, this option offers a practical way of implementing the reconstruction concept by establishing an expiration date for all grandfathered and deemed compliant facilities after a period of 15 years from enactment of EISA (i.e., after December 31, 2022), regardless of when such facilities commenced construction or began operation. Under such option, the grandfathered and deemed compliant facilities would be subject to the 20% GHG threshold starting on January 1, 2023. Renewable fuel produced from these facilities after this date would be required to comply with the 20% threshold requirement in order to generate RINs.

Based on our discussions with companies that construct ethanol plants, we believe that facility owners will make decisions about equipment replacements and technology upgrades that will continue to improve the overall operating costs and energy efficiency of the plant which ultimately lead to improvements in GHG emission performance as well. In particular, energy-intensive processes in the plant are likely to be replaced or upgraded to increase fuel and operating efficiency, thus reducing operating costs of the plant, and increasing output. Nilles (2006) reports that the first line of next-generation dry-grind ethanol plants was built with mild steel components and that in 10 or 15 years, those components will need to be replaced entirely—most likely with stainless steel. Of particular importance is that durable materials as well as weaker materials all require maintenance and replacement. As such, the components and equipment in ethanol facilities are designed to be easily replaced and to allow simple maintenance.[11]

Using cost data contained in the U.S. Department of Agriculture's cost estimation model for construction of new ethanol plants described by Kwiatkowski, J. et al (2006), we calculated the cost of a replacement of specific components in a hypothetical 100 million gallon ethanol facility.[12 13] We assumed that all steel tanks are replaced with stainless steel tanks, and that specific combustion equipment is replaced. Combining replacement costs with maintenance, repairs, upgrades and supply costs (at 2% of the capital cost of the facility per year), we calculated that over 15 years, the accumulated costs range from 50% to 75% of the capital cost of an equivalent facility.[14]

As discussed in Section 1.5.1.3 of the DRIA, per our conversations with builders of ethanol plants, the changes and upgrades would be made to improve competitiveness which will also improve operating and fuel efficiency, thus tending to improve overall GHG performance of the plant. The high price of natural gas has many ethanol plants considering alternative fuel sources. Greater biofuel availability and potential low life cycle green house gas emissions incentives may further encourage ethanol producers to switch from fossil fuels for process heat to biomass based fuels. In addition, ethanol producers may consider energy saving changes to the ethanol production process. Several process changes, including raw starch hydrolysis, corn fractionation, corn oil extraction, and membrane separation, are likely to be adopted to varying degrees. Since such changes would be consistent with ultimately achieving the 20% GHG reduction required of new facilities, we believe it is reasonable to expect that the newly rebuilt facilities could meet the 20% GHG reduction threshold, based on the results of a life cycle analysis.[15]

We solicit further information and data, particularly evidence of the types of replacements and ongoing maintenance that has occurred at existing plants and what is projected to occur in the future. We will evaluate such information along with other comments received during the public comment period. We also solicit comment on whether a period other than 15 years may be more appropriate.

Under this approach, facilities that are exempted could expand their volume of renewable fuel production, or could switch fuels or feedstocks within the 15 year exemption period without fear of losing their temporary exemption. While some of these activities have the potential to worsen GHG emissions further below the 20% threshold requirement, we believe that the imposition of an expiration date will result in modifications to facilities that tend to increase the efficiency and GHG performance of the plant rather than worsen them. The need for compliance with the 20% threshold requirement by a date certain would provide an incentive for owners and operators of

[11] Nilles, D. 2006. ''Time Testing''; Ethanol Producer Magazine, May, Vol. 12, No. 5.

[12] Op Cit., Kwiatkowski, *et al.* (2006).

[13] Note to Docket (EPA–HQ–OAR–2005–0161), ''Analysis of Costs of Replacements and Repairs at a Hypothetical 100 MM GPY Ethanol Facility''; from Barry Garelick, Environmental Protection Specialist, Assessment and Standards Division, Office of Transportation and Air Quality; October 16, 2008.

[14] The USDA model gives the installed capitol cost of a 40 million GPY facility at approximately $60 million (2006 dollars). The model also gives replacement costs of individual components (steel tanks and the ring dryer) at about $13 million. Ongoing maintenance costs are estimated at about $6 million per year.

[15] Unless and until EPA conducts facility specific life cycle analyses, however, compliance with the 20% GHG reduction threshold would be made on the basis of fuel pathways as described in Section III.D.2.

such plants to ensure the changes they make over time would bring them into compliance with the 20% requirement at the end of the 15 year period.

While the facilities built in 2008 and 2009 would be in operation for less than 15 years, the majority of ethanol plants will have been in operation for 15 years or longer. As discussed in Section V.B.1, approximately 15 billion gallons of corn ethanol production capacity is currently online, idled or under construction. While some of these plants/projects are currently on hold due to the economy, we anticipate that this corn ethanol capacity will come online in the future under the proposed RFS2 program. And the majority of these plants commenced construction prior to 2008. We solicit comment, however, on whether there should be a plant-specific expiration date of 15 years after commencement of operations for deemed compliant facilities that commenced construction in 2008 or 2009. Under this sub-option, the expiration date for such plants would be 15 years from the time the facility began operation, per registration made by the owner of the facility.

The option of limiting the exemption period to 15 years or other specific time period offers certainty to industry for a 15 year period, and also certainty that at the end of that time period they will be subject to the 20% GHG reduction threshold. This time period could be used by facility owners to ensure the facility will ultimately meet the requirement. Finally, the option ensures that investments made in equipment to comply with RFS1 requirements are protected with respect to being fully depreciated for tax purposes.[16] Furthermore, this approach is easy to implement, and avoids case-by-case determinations that can extremely be time-consuming, contentious, and costly for both industry and EPA. In addition, because the exemption expiration date would apply to all facilities, this option would provide no incentive to delay modifications that increase energy efficiency, safety, or improve environmental performance unlike the option described above involving case-by-case consideration of reconstruction.

[16] Specifically, Table B–2 of IRS Publication 946, ''How To Depreciate Property'' provides class lives and recovery periods for use in computing depreciation for asset classes categorized by SIC codes. Ethanol facilities (which are in SIC 28, Manufacture of Chemical and Allied Products) is given a class life of 10 years. For facilities that qualify for Modified Accelerated Cost Recovery System (MACRS), the period is 7 years.

(3) Expiration Date of 15 Years for Grandfathered Facilities and Limitation on Volume

We also seek comment on a hybrid approach in which an expiration date of 15 years is established for grandfathered and deemed compliant facilities, but prior to then, the facilities' exemption from the 20% GHG threshold would be limited to their baseline volumes, as in the option described in Section III.B.3.c.

(4) ''Significant Production Units'' Are Defined as Facilities

We seek comment on an approach in which ''facility'' would be defined on the basis of ''significant production units''. For example, the regulations regarding air toxic emissions for the miscellaneous organic chemical manufacturing industry (which includes ethanol manufacturing plants) under NESHAPS (40 CFR 2440(c)) apply to miscellaneous chemical process units and heat exchangers within a single facility. This option, therefore, would follow a similar approach, and treat as new facilities subject to the 20% GHG reduction requirement any new significant production units.

Defining ''facility'' as a significant production unit would raise the question of when an increase in volume due to the addition of specific pieces of equipment should be considered augmenting current production lines as opposed to being a new production line. We solicit comment on this approach as well as how the term ''significant production unit'' would need to be defined in the regulations to avoid ambiguity. Any incidental increases in volume due to the addition of pieces of equipment that would not constitute a new ''significant production unit'' line would continue to be grandfathered, as would increases in volume associated with changes made to debottleneck the facility.

(5) Indefinite Grandfathering and No Limitations Placed on Volume

Under our basic option, described in Section III.B.3.c.i, we would interpret the statutory language to mean that expansions of grandfathered facilities after enactment of EISA and which expand volume beyond a plant's inherent capacity are not among those that qualify for an exemption from the 20% GHG reduction requirement. Otherwise, a facility that qualifies for grandfathering could be expanded by any amount, and the additional volume would also receive protection. We do not believe that this was the intent of the language in EISA. Nevertheless, we recognize that there are alternative interpretations of the statute and therefore seek comment on an alternative that places no limitations on the volume of renewable fuel from grandfathered or deemed compliant facilities. Under such option, ''new facility'' would be defined solely as a new ''greenfield'' plant.

4. Renewable Biomass With Land Restrictions

As explained in Section III.B.1.a, EISA lists seven types of feedstock that qualify as ''renewable biomass'':

1. Planted crops and crop residue.
2. Planted trees and tree residue.
3. Animal waste material and animal byproducts.
4. Slash and pre-commercial thinnings.
5. Biomass obtained from the vicinity of buildings at risk from wildfire.
6. Algae.
7. Separated yard or food waste.

EISA limits not only the types of feedstocks that can be used to make renewable fuel, but also the land that several of these renewable fuel feedstocks may come from. Specifically, EISA's definition of renewable biomass incorporates land restrictions for planted crops and crop residue, planted trees and tree residue, slash and pre-commercial thinnings, and biomass from wildfire areas. EISA does not prohibit the production of renewable fuel feedstock that does not meet the definition of renewable biomass, nor does it prohibit the production of renewable fuel from feedstock that does not meet the definition of renewable biomass. It does, however, prohibit the generation of RINs for renewable fuel made from feedstock that does not meet the definition of renewable biomass, which includes not meeting the associated land restrictions. The following sections discuss the challenges of implementing the land restrictions contained in the definition of renewable biomass and propose approaches for establishing a workable implementation scheme.

a. Definitions of Terms

EISA's descriptions of four feedstock types noted above—planted crops and crop residue, planted trees and tree residue, slash and pre-commercial thinnings, and biomass from wildfire areas—contain terms that can be interpreted in multiple ways. The following sections discuss our proposed interpretations for many of the terms contained in EISA's definition of renewable biomass. In developing this proposal, we consulted many sources, including the USDA, as well as stakeholder groups, in order to determine the range of possible interpretations for these different terms. We have made every attempt to define these terms as consistently with USDA and industry standards as possible, while keeping them workable for purposes of program implementation. We seek comment on our proposed definitions of important terms in the following sections.

i. Planted Crops and Crop Residue

The first type of renewable biomass described in EISA is planted crops and crop residue harvested from agricultural land cleared or cultivated at any time prior to December 19, 2007, that is either actively managed or fallow, and nonforested. We propose to interpret the term ''planted crops'' to include all annual or perennial agricultural crops that may be used as feedstock for renewable fuel, such as grains, oilseeds, and sugarcane, as well as energy crops, such as switchgrass, prairie grass, and other species, providing that they were intentionally applied to the ground by humans either by direct application as seed or nursery stock, or through intentional natural seeding by mature plants left undisturbed for that purpose. Many energy crops that could be used for cellulosic biofuel production, especially perennial cover plants, are currently grown in the U.S. without significant agronomic inputs such as fertilizer, pesticides, or other chemical treatment. These crops may be introduced or indigenous to the area in which they grow, and may have been originally planted decades ago. We propose to include this type of vegetation as a planted crop with the recognition that it may include some plants that were intentionally naturally generated, i.e., resulted from natural seeding from existing plants, and not planted through direct human intervention. We believe that given the increasing importance under RFS2 of biofuels produced from cellulosic feedstocks, such as switchgrass and other grasses, such a definition is appropriate. We note that because EISA contains specific provisions for planted trees and tree residue from tree plantations, we propose that the definition of planted crops in EISA exclude planted trees, even if they may be considered planted crops under some circumstances.

We further propose that ''crop residue'' be limited to the residue left over from the harvesting of planted crops, such as corn stover and sugarcane bagasse. However, we seek comment on an alternative interpretation that would include as crop residue biomass from agricultural land removed for purposes of invasive species control or fire management. In that context ''crop residue'' would include any biomass removed from agricultural land that facilitates crop management, whether or not the crop itself is part of the residue.

Our proposed regulations would restrict planted crops and crop residue to that harvested from existing agricultural land. With respect to what land would qualify as agricultural land, we first turned to the mutually exclusive categories of land defined by USDA's Natural Resources Conservation Service (NRCS) in its annual Natural Resources Inventory (NRI), a statistical survey designed to estimate natural resource conditions and trends on non-federal U.S. lands.[17] The categories used in the NRI are cropland, pastureland, rangeland, forest land, Conservation Reserve Program (CRP) land, federal land, developed land, and ''other rural land.'' We have chosen to include in our proposed definition of agricultural land three of these land categories—cropland, pastureland, and CRP land. Using the NRI descriptions of these land types as models, we developed definitions for these land types for this proposal.

We propose to define cropland as land used for the production of crops for harvest, including cultivated cropland for row crops or close-grown crops and non-cultivated cropland for horticultural crops. Corn, wheat, barley, and soybeans are renewable fuel feedstocks that would be grown on cropland. We propose to define pastureland as land managed primarily for the production of indigenous or introduced forage plants for livestock grazing or hay production, and to prevent succession to other plant types. Under this proposed definition, land would qualify as pastureland if it is maintained for grazing or hay production and not allowed to develop greater ecological diversity. Switchgrass is one example of a renewable fuel feedstock that could be grown on pastureland.

We also propose that CRP land be counted as ''agricultural land'' under RFS2. The CRP is administered by USDA's Farm Service Agency and is designed to promote restoration of environmentally sensitive lands by offering annual rental payments in return for removing land from cultivation over a period of several years. To qualify for the CRP, land had to have been used for agricultural production for at least three years prior to entering the program. For this reason, we believe it is appropriate to propose that CRP land be included under the rubric of agricultural land.

In addition, we seek comment on whether rangeland should be included as agricultural land under RFS2. Rangeland is land on which the indigenous or introduced vegetation is predominantly grasses, grass-like plants, forbs or shrubs and which—unlike cropland or pastureland—is predominantly managed as a natural ecosystem. Given the relative lower degree of management of such lands, it is questionable whether any rangeland should qualify as ''actively managed'' under EISA (a general discussion on our proposed interpretation of the term ''actively managed'' is presented later in this section). On the other hand, we understand that there is frequently some degree of management on such lands, such as controlling invasive species, managing grazing rates, fencing, etc.

Therefore, we believe that there may be merit in allowing planted crops and crop residue from rangeland to qualify as renewable biomass under this program. This would allow, for example, existing switchgrass or native grasses on rangeland to be used for renewable fuel production that qualifies for RIN generation under this program. However, we are not proposing to include rangeland as agricultural land due to our own implementation concerns as well as issues raised by stakeholders over the potential for providing any incentive for increased crop production in rangeland areas. We seek comment on the issue and on the points raised in the following discussion.

Allowing rangeland to qualify as agricultural land under RFS2 would make millions of acres of additional non-cropland, non-forested land qualify for renewable fuel feedstock production in the U.S. This additional land could be important to support future expansion of dedicated energy crops, such as switchgrass and tall prairie grass, which currently grow or could grow on such lands. The availability of rangeland could alleviate some of the competition on cropland and pastureland for space to grow crops for biofuel feedstocks, thereby allowing continued growth of food crops on land best suited for that specific purpose. It would also provide rangeland owners with the potential for increased revenues from their lands by producing feedstocks for renewable fuel, and decrease the pressure for such lands to be converted to cropland for food crop production.

[17] Natural Resource Conservation Service, USDA, ''Natural Resources Inventory 2003 Annual NRI,'' February 2007. Available at *http://www.nrcs.usda.gov/technical/NRI/2003/Landuse-mrb.pdf.*

However, we recognize that rangeland is a term that can be used to describe a wide variety of ecosystems, including certain grasslands, savannas, wetlands, deserts, and even tundra. These types of ecosystems represent land that at best could serve only marginally well for producing renewable fuel feedstocks, and at worst could suffer significantly if intensive agricultural practices were imposed upon them for purposes of producing crops. We also recognize that if we were to include rangeland as agricultural land under RFS2, there is a risk that some rangeland, including native grasslands and shrublands, could be converted to produce monoculture crops. We raise these concerns for two reasons. First, certain rangeland cannot be used sustainably for agricultural crop production, and any such short-term use could seriously diminish the long-term potential of these lands to be used for less-intensive forage production or even to return to their previous ecological state. Second, conversion of relatively undisturbed rangeland to the production of annual crops could in some cases result in large releases of GHGs that have been stored in the soil. EPA believes that Congress enacted the renewable biomass definition in part to minimize GHG releases from land conversion, a goal that could be undermined by conversion of rangeland to intensive crop production under RFS2. On the other hand, it may be argued that while GHGs would be emitted initially, planting dedicated energy crops rather than food crops on such land could yield more positive than negative results over time. Such could be the case if the alternative were to grow energy crops on cropland, consequently displacing food crops to other lands, either in the U.S. or abroad. This displacement could lead to overall higher direct and indirect GHG emissions. EPA solicits comment on the potential GHG effects if rangeland were included as eligible agricultural land under RFS2. We are especially interested in data that could help us to quantify such impacts.

While enforcement of the overall renewable biomass provisions under the final RFS2 program is expected to be challenging, it is possible that including rangeland as qualifying agricultural land under the RFS2 program would increase enforcement complexity. As discussed later in this section, in order to qualify as renewable biomass under RFS2, agricultural products must come from agricultural land that was cleared or cultivated at any time prior to enactment of EISA, and either actively managed or fallow, and nonforested. We believe that evidence of past intensive use and management of rangeland may be considerably more rare, and considerably less definitive, than for other types of agricultural land. In addition, given the continuous, open nature of some rangeland, there would likely be difficulty in identifying the precise boundaries of a parcel of qualifying rangeland. EPA seeks comment on these issues.

We thus seek comment on whether or not we should include rangeland in the definition of ''existing agricultural land'' in the final RFS2 program, as well as comment on whether or not the benefits of including rangeland exceed the disadvantages. We also seek comment on how best to define rangeland, and whether we can define rangeland in a meaningful way such that sensitive ecosystems that may generally be described as rangeland can be protected from cultivation for renewable fuel feedstock production.

Furthermore, EPA solicits comment on an alternative option that would include rangeland as agricultural land, but that would interpret the EISA ''actively managed'' criterion in the renewable biomass definition (again, discussed later in this section) to limit the types of planted crops or crop residues from specific parcels of land that can qualify as renewable biomass by reference to the type of management (cropland, pastureland, or rangeland) being practiced on the date EISA was enacted. For example, if at some point in the future corn or other row crops are grown on land that was pastureland or rangeland when EISA was enacted, such row crops would not qualify as renewable biomass under RFS2. This approach could thus reduce the incentives for pastureland and rangeland owners to convert their land to cropland. We believe that this approach could have less environmental harm than allowing unrestricted use of qualifying rangeland for the production of crops for renewable fuel production.

While our proposed implementation approach and alternatives are presented later in this section, it is important to note here that the principal drawback to this alternative option involves its implementation and enforcement. This approach would require that land types (again, cropland, pastureland, or rangeland) be identified as of the date of EISA enactment in order to determine which feedstocks grown on such land would qualify as renewable biomass. In practical terms, such an approach may mean, for example, that a renewable fuel producer would need to be able to identify not only whether a given shipment of corn was grown on agricultural land cleared or cultivated prior to enactment of EISA, but also that the land was not previously pastureland or rangeland that had been converted to cropland after enactment of EISA. If it was, it would not qualify as renewable biomass. We are concerned that adding this additional feedstock verification criterion to those already contained in this proposal could render the program unworkable and unenforceable. However, we invite comment on this option, and specifically request comment on how this option could be implemented in a workable and enforceable manner.

In keeping with the statutory definition for renewable biomass, we propose to include in our definition of existing agricultural land the requirement that the land was cleared or cultivated prior to December 19, 2007, and that, since December 19, 2007, it has been continuously actively managed (as agricultural land) or fallow, and nonforested. We believe the language ''cleared or cultivated at any time'' prior to December 19, 2007, describes most cultivable land in the U.S., since so much of the country's native forests and grasslands were cleared in the 17th, 18th, and 19th centuries, if not before, for agriculture. We further believe that land that was cropland, pastureland, or CRP land on December 19, 2007, would automatically satisfy this particular criterion, and that therefore it is not of significant concern from an implementation or enforcement perspective.

In the event that we were to include rangeland as agricultural land under the final RFS2 program, satisfying the ''cleared or cultivated'' criterion could pose significant challenges. Some rangeland has never been cleared or cultivated, or may have been cleared or cultivated prior to December 19, 2007, but no evidence exists to confirm this. Therefore, we could not assume that it would necessarily meet the ''cleared or cultivated'' criterion. For instance, grasslands in the Midwest and West that during the Dust Bowl of the 1930s had been used for cultivation could meet this criterion, but other western grasslands and prairies used for cattle grazing may not. We seek comment on how best to verify that rangeland to be used for renewable fuel feedstock production was cleared or cultivated at some point prior to December 2007. We also seek comment on whether the challenge associated with applying this criterion to rangeland is sufficient (alone or combined with the concerns raised earlier about the inclusion of rangeland in the definition of agricultural land) to exclude rangeland from the final definition of agricultural land.

We believe that the more restrictive, and therefore more important, criteria is whether agricultural land is actively managed or fallow, and nonforested, per the statutory language. We propose to interpret the phrase ''that is actively managed or fallow, and nonforested'' as meaning that land must have been actively managed or fallow, and nonforested, on December 19, 2007, and continuously thereafter in order to qualify for renewable biomass production. We believe this interpretation of the legislative language is reasonable and appropriate for the following reason. The EISA language uses the present tense (''is actively managed * * *'') rather than the past tense to describe qualifying agricultural land. We interpret this language to mean that at the time the planted crops or crop residue are harvested (i.e., now or at some time in the future), the land from which they come must be actively managed or fallow, and nonforested. However, assuming that the land was cleared or cultivated at some point in time, then any land converted to agricultural land after December 19, 2007, and used to produce crops or crop residue would inherently meet the definition of ''is actively managed or fallow, and nonforested,'' and the EISA land restriction for planted crops and crop residue would have little meaning (except in cases where it could be established that the land in question had never been cleared or cultivated). We believe that in order for this provision to have meaning, we must require that agricultural land remain ''continuously'' either actively managed or fallow, and nonforested, since December 19, 2007. In this way, the upper bound on acreage that qualifies for planted crop and crop residue production under RFS2 would be limited to existing agricultural land—cropland, pastureland, or CRP land—as of December 19, 2007, and the phrase ''is actively managed or fallow, and nonforested'' would be interpreted in a meaningful way.

We propose that ''actively managed'' would mean managed for a predetermined outcome as evidenced by any of the following: sales records for planted crops, crop residue, or livestock; purchasing records for land treatments such as fertilizer, weed control, or reseeding; a written management plan for agricultural purposes; documentation of participation in an agricultural program sponsored by a Federal, state or local government agency; or documentation of land management in accordance with an agricultural certification program. Examples of government programs or product certification programs that would indicate active agricultural land management include USDA's certified organic program or the Federal Crop Insurance program.

We realize that it may be difficult to conclude that certain land has been actively managed continuously since December 2007 based solely on the existence of receipts for fertilizer or seed. However, we have included sales and purchasing records in the list of written documentation that could be used to indicate active management due to the fact that there may be qualifying land that is not registered with any formal agricultural program, for which the owner does not receive government benefits, and for which no written management plan exists (or existed as of December 2007). We believe this may be the case especially for pastureland from which no crops are harvested or sold. Other evidence that could be used regarding the consistent management of pastureland since December 2007 are records associated with the sale of livestock that grazed on the land. We seek comment on our proposal to include relevant records of sales and purchasing as adequate documentation to prove that land was actively managed since December 2007 and whether there may be other records, such as tax or insurance records, which could satisfy this requirement more effectively.

The term ''fallow'' is generally used to describe cultivated land taken out of production for a finite period of time. We believe it may be argued that fallow land is actively managed land because there is a clear purpose or goal for taking the land out of production for a period of time (e.g., to conserve soil moisture). Nonetheless, because the EISA language clearly identifies a difference between actively managed agricultural land and fallow agricultural land, we propose to define fallow to mean agricultural land that is intentionally left idle to regenerate for future agricultural purposes, with no seeding or planting, harvesting, mowing, or treatment during the fallow period. While fallow agricultural land is characterized by a lack of activity on the land, we believe that the decision to let land lie fallow is made deliberately and intentionally by a land owner or farmer such that there should be documentation of such intent. We seek comment on this assumption and on whether there are other means of verifying whether land was fallow, particularly as of December 2007. We also seek comment on whether we should specify in the regulations a time period after which land that is not actively managed for agricultural purposes should be considered to have been abandoned for agriculture (and not eligible for renewable biomass production under RFS2), as opposed to being left fallow. If specifying such a time limit is appropriate, we seek comment on what the time period should be, and if there should be a distinction between allowable fallow periods for different types of agricultural land.

Finally, in order to define the term ''nonforested,'' we first propose to define the term ''forestland'' as generally undeveloped land covering a minimum area of 1 acre upon which the predominant vegetative cover is trees, including land that formerly had such tree cover and that will be regenerated. We are also proposing that forestland would not include tree plantations. Under this proposal, ''nonforested'' land would be land that is not forestland. We believe this definition is sufficient to make distinctions between forestland and land that is considered nonforested in the field. However, we seek comment on whether we should incorporate into our definition of forestland more quantitative descriptors, such as a minimum percentage of canopy cover or minimum or maximum tree height, to help clarify what would be considered forestland. For example, the NRI definition of forestland includes a minimum of twenty-five percent canopy cover. We also seek comment on whether the one-acre minimum size designation is appropriate.

ii. Planted Trees and Tree Residue

The definition of renewable biomass in EISA includes planted trees and tree residue from actively managed tree plantations on non-federal land cleared at any time prior to December 19, 2007, including land belonging to an Indian tribe or an Indian individual, that is held in trust by the United States or subject to a restriction against alienation imposed by the United States. We propose to define the term ''planted trees'' to include not only trees that were established by human intervention such as planting saplings and artificial seeding, but also trees established from natural seeding by mature trees left undisturbed for such a purpose. We understand that, depending on the particular conditions at a plantation, certain trees in a stand may be harvested, while others are maintained, for the express purpose of naturally regenerating new trees. We believe that trees established in such a fashion, and which meet the conditions for planted trees in every other way, should not be excluded from qualifying as renewable biomass under RFS2.

Rather than using the term ''tree residue,'' we propose to use the term ''slash'' in our regulations as a more descriptive, but otherwise synonymous, term. According to the Dictionary of Forestry (1998, p. 168), slash is ''the residue, e.g., treetops and branches, left on the ground after logging or accumulating as a result of a storm, fire, girdling, or delimbing.'' We believe that this substitution will simplify our regulations, since paragraph (iv) of the EISA definition of renewable biomass also uses the term ''slash.'' Furthermore, the term ''slash'' is a common term that has a specific meaning to industry. As noted earlier, we have attempted to define terms in RFS2 using existing and commonly understood definitions to the extent possible. The term ''slash'' is more descriptive than ''tree residue,'' and yet in practice means the same thing, so we are proposing to use it rather than ''tree residue.'' We also propose to clarify that slash can include tree bark and can be the result of any natural disaster, including flooding.

In concert with our proposed definition for ''planted trees,'' we propose to define a ''tree plantation'' as a stand of no fewer than 100 planted trees of similar age and comprising one or two tree species, or an area managed for growth of such trees covering a minimum of 1 acre. Given that only trees from a tree plantation may be used as renewable biomass under RFS2, we believe that the definition should be clear and easily applied in the field. We recognize that this proposed definition is more specific than the Dictionary of Forestry's definition of ''tree plantation,'' which is ''a stand composed primarily of trees established by planting or artificial seeding.'' We seek comment on all aspects of our proposed definition of tree plantation.

We also propose to apply the same management restrictions on tree plantations as on agricultural land and to interpret the EISA language as requiring that to qualify for renewable biomass production under RFS2, a tree plantation must have been cleared at any time prior to December 19, 2007, and continuously actively managed since December 19, 2007. Similar to our proposal for actively managed agricultural land, we propose to define the term ''actively managed'' in the context of tree plantations as managed for a predetermined outcome as evidenced by any of the following: Sales records for planted trees or slash; purchasing records for seeds, seedlings, or other nursery stock; a written management plan for silvicultural purposes; documentation of participation in a silvicultural program sponsored by a Federal, state or local government agency; or documentation of land management in accordance with an agricultural or silvicultural product certification program. Silvicultural programs such as those of the Forest Stewardship Council, the Sustainable Forestry Initiative, the American Tree Farm System, or USDA are examples of the types of programs that could indicate actively managed tree plantations.

iii. Slash and Pre-Commercial Thinnings

The EISA definition of renewable biomass includes slash and pre-commercial thinnings from non-federal forestlands, including forestlands belonging to an Indian tribe or an Indian individual, that are held in trust by the United States or subject to a restriction against alienation imposed by the United States. It excludes slash and pre-commercial thinnings from forests or forestlands that are ecological communities with a global or State ranking of critically imperiled, imperiled, or rare pursuant to a State Natural Heritage Program, old growth forest, or late successional forest.

As described in Sec. III.B.4.a.i of this preamble, our proposed definition of ''forestland'' is generally undeveloped land covering a minimum area of 1 acre upon which the primary vegetative species are trees, including land that formerly had such tree cover and that will be regenerated. Also as noted in Sec. III.B.4.a.ii of this preamble, we propose to adopt the definition of slash listed in the Dictionary of Forestry. As for ''pre-commercial thinnings,'' the Dictionary of Forestry defines the act of such thinning as ''the removal of trees not for immediate financial return but to reduce stocking to concentrate growth on the more desirable trees.'' [18] Because what may now be considered pre-commercial may eventually be saleable as renewable fuel feedstock, we propose not to include any reference to ''financial return'' in our definition, but rather to define pre-commercial thinnings as those trees removed from a stand of trees in order to reduce stocking to concentrate growth on more desirable trees. We propose to include diseased trees in the definition of pre-commercial thinnings due to the fact that they can threaten the integrity of an otherwise healthy stand of trees, and their removal can be viewed as reducing stocking to promote the growth of more desirable trees. We seek comment on whether our definition of pre-commercial thinnings should include a maximum diameter and, if so, what the appropriate maximum diameter should be.

We understand that the State Natural Heritage Programs referred to in EISA are those comprising a network associated with NatureServe, a non-profit conservation and research organization. The network includes local programs in each of the 50 United States, other U.S. territories and regions including the Navajo Nation and Tennessee Valley Authority, eleven Canadian provinces and territories, and eleven Latin American countries. Individual Natural Heritage Programs collect, analyze, and distribute scientific information about the biological diversity found within their jurisdictions. As part of their activities, these programs survey and apply NatureServe's rankings, such as critically imperiled (S1), imperiled (S2), and rare (S3) to species and ecological communities within their respective borders. NatureServe meanwhile uses data gathered by these Natural Heritage Programs to apply its global rankings, such as critically imperiled (G1), imperiled (G2), or vulnerable (the equivalent of the term ''rare,'' or G3), to species and ecological communities found in multiple States or territories. We propose to prohibit slash and pre-commercial thinnings from all forest ecological communities with global or State rankings of critically imperiled, imperiled, or vulnerable (''rare'' in the case of State rankings) from being used for renewable fuel for which RINs may be generated under RFS2. We seek comment on our interpretation that the statutory language implies including global rankings determined by NatureServe, including the ranking of vulnerable (G3), in the land restrictions under RFS2 since State Natural Heritage Programs, which were explicitly referenced in EISA, do not establish global rankings.

The various state-level Natural Heritage Programs in the U.S. and abroad differ in organizational affiliation, with some operated as agencies of state or provincial government and others residing within universities or non-profit organizations. According to the NatureServe Web site, ''consistent standards for collecting and managing data allow information from different programs to be shared and combined regionally, nationally, and internationally. The nearly 800 staff from across the network are experts in their fields, and include some of the most knowledgeable field biologists and

[18] Helms, John, ed. ''The Dictionary of Forestry.'' Bethesda, MD: Society of American Foresters, 2003.

conservation planners in their regions.'' Different Natural Heritage Programs have different processes for initiating and performing surveys of ecological communities. In many cases, the programs respond to requests for environmental reviews or surveys from parties interested in specific locations, oftentimes for a fee. They do not make available for public consumption detailed information on the location of a ranked ecological community in some cases to protect the communities themselves and in other cases to protect private property interests. Additionally, the datasets maintained by different Natural Heritage Programs may not completely represent all of the vulnerable ecological communities in their respective States or territories simply due to the fact that surveys have not been performed for all areas.

NatureServe, however, interacts with each of the State Natural Heritage Programs to update their central database to include each State program's ecological community rankings. We propose to use data compiled by NatureServe and published in a special report to identify ''ecologically sensitive forestland.'' The report would list all forest ecological communities in the U.S. with a global ranking of G1, G2, or G3, or with a State ranking of S1, S2, or S3, and would include descriptions of the key geographic and biologic attributes of the referenced ecological community. The document would be incorporated by reference into the definition of renewable biomass in the final RFS2 regulations, and the effect would be to identify specific ecological communities from which slash and pre-commercial thinnings could not be used as feedstock for the production of renewable fuel that would qualify for RINs under RFS2. In the future, it may be necessary to update this list as appropriate through notice and comment rulemaking.

We will place a draft version of this document in the docket for the proposed rule as soon as it is available. EPA solicits comment both on this general incorporation-by-reference approach and on each individual listing in the document. We also seek comment on whether EPA should include in the document forest ecological communities outside of the 50 United States (such as in Canada or Latin American countries) that have natural heritage rankings of G1, G2, or G3 or S1, S2, or S3. In addition, we request comment on other ways that EPA may be able to provide the protections that Congress intended for important ecological communities with state-level rankings pursuant to a State Natural Heritage Program.

To complete the definition of ''ecologically sensitive forestland,'' we propose to include old growth and late successional forestland which is characterized by trees at least 200 years old.[19] We seek comment on this definition, including the proposed 200-year tree age, on whether we should specify a process for determining when a forest is ''characterized by'' trees of this or another age, and on other ways to identify old growth or late successional forestland.

iv. Biomass Obtained From Certain Areas at Risk From Wildfire

The EISA definition of renewable biomass includes biomass obtained from the immediate vicinity of buildings and other areas regularly occupied by people, or of public infrastructure, at risk from wildfire. We propose to clarify in the regulations that ''biomass'' is organic matter that is available on a renewable or recurring basis, and that it must be obtained from within 200 feet of buildings, campgrounds, and other areas regularly occupied by people, or of public infrastructure, such as utility corridors, bridges, and roadways, in areas at risk of wildfire. We propose to define ''areas at risk of wildfire'' as areas located within—or within one mile of—forestland, tree plantations, or any other generally undeveloped tract of land that is at least one acre in size with substantial vegetative cover.

It is our understanding that 100 to 200 feet is the minimum distance recommended for clearing trees and brush away from homes and other property in certain wildfire-prone areas, depending on slope and vegetation.[20] We propose that under RFS2, the term ''immediate vicinity'' would mean within 200 feet of a given structure or area, but we seek comment on the appropriateness of limiting the distance to within 100 feet.

[19] Old-growth forest is defined in the Dictionary of Forestry as ''the (usually) late successional stage of forest development. **Note:** Old-growth forests are defined in many ways; generally, structural characteristics used to describe old-growth forests include (a) live trees: Number and minimum size of both seral and climax dominants, (b) canopy conditions: Commonly including multilayering, (c) snags: Minimum number of specific size, and (d) down logs and coarse woody debris: Minimum tonnage and numbers of pieces of specific size. **Note:** Old-growth forests generally contain trees that are large for their species and site and sometimes decadent (overmature) with broken tops, often a variety of trees sizes, large snags and logs, and a developed and often patchy understory * * *.''

[20] *See* Cohen, Jack. ''Reducing the Wildland Fire Threat to Homes: Where and How Much?'' USDA Forest Service Gen.Tech.Rep. PSW–GTR–173. 1999. See also U.S. Federal Emergency Management Agency (FEMA) Web site *http://www.fema.gov/hazard/wildfire/index.shtm.*

A great deal of work has been done to identify communities and areas on the landscape in the vicinity of public lands that are at risk of wildfire by States in cooperation and consultation with the U.S. Forest Service, Bureau of Land Management, and other federal, State, and local agencies and tribes. In order to take advantage of this work, we seek comment on two possible implementation alternatives. The first alternative would incorporate into our definition of ''areas at risk of wildfire'' any communities identified as ''communities at risk'' through a process defined within the ''Field Guidance—Identifying and Prioritizing Communities at Risk'' (National Association of State Foresters, June 2003) and covered by a community wildfire protection plan (CWPP) developed in accordance with ''Preparing a Community Wildfire Protection Plan—A Handbook for Wildland-Urban Interface Communities'' (Society of American Foresters, March 2004) and certified by a State Forester or equivalent. We believe that it may make sense to include communities with CWPPs in the definition of ''areas at risk of wildfire'' since they represent specific areas around the U.S. that are identified and agreed upon through a public process that includes local and state representatives, federal agencies, and stakeholders. Additionally, CWPP guidelines indicate that normally three entities must mutually agree to the contents of the CWPPs: The applicable local government, the local fire department or departments, and the state entity responsible for forest management (State Forester or equivalent). As of June 2008, there were roughly 52,000 total ''communities at risk'' and 5,000 ''communities at risk'' covered by a CWPP.

We seek comment on incorporating by reference into the final RFS2 regulations a list of ''communities at risk'' with an approved CWPP. Similar to the document proposed for Natural Heritage Rankings, this document would be incorporated by reference into the definition of ''areas at risk of wildfire'' in the final RFS2 regulations. Because this list does not currently exist, EPA would be required to seek data from each State in order to assemble the document. The effect of this incorporation by reference would be to identify specific areas in the U.S. at risk of wildfire and from which biomass obtained from the immediate vicinity of buildings and other areas regularly occupied by people, or of public infrastructure, could be easily identified and documented as renewable biomass. In the future, it may be necessary to update this list as appropriate through notice and comment rulemaking.

The second implementation approach on which we seek comment would incorporate into our definition of ''areas at risk of wildfire'' any areas identified as wildland urban interface (WUI) land, or land in which houses meet wildland vegetation or are mixed with vegetation. The concept of the WUI was established as part of the Healthy Forests Restoration Act (Pub. L. 108–148) which provided a means for prioritizing, planning, and executing hazardous fuels reduction projects on federal lands. SILVIS Lab, in the Department of Forest Ecology and Management and the University of Wisconsin, Madison, has, with funding provided by the U.S. Forest Service, mapped WUI lands based on data from the 2000 U.S. Census and U.S. Geological Survey National Land Cover Data.[21] We seek comment on whether and how best to make use of this WUI map and data to help implement the land restrictions for biomass obtained from areas at risk of wildfire under RFS2.

b. Issues Related to Implementation and Enforceability

Incorporating the new definition of renewable biomass into the RFS2 program raises issues that we did not have to consider when designing the RFS1 program. Under RFS1, the source of a renewable fuel feedstock was not a central concern, and it was a relatively straightforward matter to require all fuel made from specified renewable feedstocks to be assigned RINs. However, with the terms ''renewable fuel'' and ''renewable biomass'' being defined differently under EISA, we must consider potential issues related to implementation and enforcement to ensure that renewable fuel for which RINs are generated is produced from qualifying renewable biomass.

Our proposed approach to the treatment of renewable biomass under RFS2 is intended to define the conditions under which RINs can be generated as well as the conditions under which renewable fuel can be produced or imported without RINs. Both of these areas are described in more detail below.

i. Ensuring That RINs Are Generated Only for Fuels Made From Renewable Biomass

The effect of adding EISA's definition of renewable biomass to the RFS program is to ensure that renewable fuels are only allowed to participate in the program if the feedstocks from which they were made come from certain types of land. In the context of our regulatory program, this means that RINs could only be generated if it can be established that the feedstock from which the fuel was made came from these types of lands. Otherwise, no RINs could be generated to represent the renewable fuel produced or imported.

We have considered the possibility that land restrictions contained within the definition of renewable biomass may not, in practice, result in a significant change in agricultural practices. For example, a farmer wishing to expand his production by cutting forested land could grow feedstock for renewable fuel on his existing agricultural land and move production for food, animal feed, and fiber production to newly cultivated land. While the EISA language is fairly clear about what lands may be used for harvesting renewable fuel feedstocks, it does not specifically address the potential for switching non-feedstock crops to new lands. Our proposed options recognize the potential for this behavior but do not attempt to prohibit it as we believe doing so would be beyond our mandate under EISA. EPA believes that Congress would have specifically directed EPA to regulate this practice if they intended EPA to do so.

Another major issue we have considered is the treatment of domestically produced renewable fuel feedstocks versus imported feedstocks and imported renewable fuel, since the new EISA language does not distinguish between domestic renewable fuel feedstocks and renewable fuel and feedstocks that come from abroad. Under RFS1, RINs must be generated for imported renewable fuel by the renewable fuel importer. Foreign renewable fuel producers may not participate as producers in the program (i.e., may not generate RINs for their fuel) unless they produce cellulosic biomass or waste-derived ethanol and register with EPA. Because RFS1 does not define renewable fuel by its source, assigning RINs to imported renewable fuel under RFS1 is a straightforward responsibility of the importer.

However, under RFS2, ensuring that the feedstock used to produce imported renewable fuel meets the definition of renewable biomass presents additional challenges to designing a program that can apply to both domestic and imported renewable fuel. The options contained in today's proposal attempt to address this additional constraint, as discussed in Section III.B.4.d of this preamble.

ii. Ensuring That RINs Are Generated for All Qualifying Renewable Fuel

Under RFS1, virtually all renewable fuel is required to be assigned a RIN by the producer or importer. This requirement was developed and finalized in the RFS1 rulemaking in order to address stakeholder concerns, particularly from obligated parties, that the number of available RINs should reflect the total volume of renewable fuel used in the transportation sector in the U.S. and facilitate program compliance. The only circumstances under which a batch of fuel is not assigned a RIN in RFS1 is if the feedstock used to produce the fuel is not among those listed in the regulatory definition of renewable fuel at § 80.1101(d), the producer or importer of the fuel produces or imports less than 10,000 gallons per year, or the fuel is produced and used for off-road or other non-motor vehicle purposes. As a result, we believe that almost all renewable fuel produced or imported into the U.S. is assigned RINs under the RFS1 program, and thus the number of RINs available to obligated parties represents as accurately as possible the volume of renewable fuel being used in the U.S. transportation sector.

EISA has dramatically increased the mandated volumes of renewable fuel that obligated parties must ensure are produced and used in the U.S. At the same time, EISA makes it more difficult for renewable fuel producers to demonstrate that they have fuel that qualifies for RIN generation by restricting qualifying renewable fuel to that made from ''renewable biomass,'' defined to include restrictions on the types of land from which feedstocks may be harvested, as discussed in this section. The inclusion of such land restrictions under RFS2 may mean that, in some situations, a renewable fuel producer would prefer to forgo the benefits of RIN generation to avoid the cost and difficulty of ensuring that its feedstocks qualify for RIN generation. If a sufficient number of renewable fuel producers acted in this way, it could lead to a situation in which not all qualifying fuel is assigned RINs, thus resulting in a short RIN market that could force obligated parties into non-compliance. Another possible outcome would be that the demand for and price of RINs would increase significantly, making compliance by obligated parties more costly and difficult than necessary and raising prices for consumers.

In order to avoid situations in which obligated parties cannot comply with

[21] *See http://silvis.forest.wisc.edu/projects/US_WUI_2000.asp.*

their annual RVOs and the volume mandates in EISA are not met, or instances where the requirements are met but at an inflated price, we believe that our proposal should ensure that RINs are generated for all fuel made from feedstock that meets the definition of renewable biomass and which meets the GHG emissions reduction thresholds set out in EISA. This would require eliminating any incentive for renewable fuel producers to avoid ascertaining where their feedstocks come from. As described in Section III.B.4.d below, we propose to require a demonstration of the type of land used to produce any feedstock used in the production of renewable fuel, regardless of whether RINs are generated or not, and to require that RINs be generated for all qualifying fuel.

However, we also seek comment on an alternative approach wherein a renewable fuel producer would not be required to make any demonstration with regard to the origin of feedstocks used in fuel production if the fuel producer were not generating RINs. In this situation, we would rely on the price of RINs in the market to encourage renewable fuel producers to generate RINs where possible. This approach would have the advantage of lessening the regulatory burden for renewable fuel producers using feedstock that is not renewable biomass, and would generally simplify the regulations relating to implementation of the renewable biomass definition. The disadvantage to this approach, as discussed above, would be the increased potential for a RIN shortage caused by renewable fuel producers choosing not to generate RINs for qualifying renewable fuel and a concurrent increase in the price of RINs that do exist. Under such circumstances, it is likely that some obligated parties could not acquire sufficient RINs for compliance purposes, while others could comply but at an inflated cost.

A further step that we could take to streamline not just the implementation of the renewable biomass definition, but also the tracking and trading of RINs, would be to remove the restriction established under the RFS1 rule requiring that RINs be assigned to batches of renewable fuel and transferred with those batches. Instead, renewable fuel producers could sell RINs (with a K code of 2 rather than 1) separately from volumes of renewable fuel. While this alternative approach could potentially place obligated parties at greater risk of market manipulation by renewable fuel producers, it could also provide a greater incentive for producers to demonstrate that the renewable biomass definition has been met for their feedstocks. That is, by having the flexibility to sell RINs independent from volume, producers could potentially command higher prices for those RINs. This would make RINS more valuable to them, and provide an incentive to generate as many RINs as possible. As a result, producers would be motivated to demonstrate that their feedstocks meet the renewable biomass definition. However, this approach could also increase compliance costs for obligated parties. For further discussion of this approach, see Section III.H.4.

c. Review of Existing Programs

i. USDA Programs

To inform our approach for designing an implementation scheme for the renewable biomass land restrictions under RFS2, we reviewed a number of programs and models that track, certify, or verify agricultural and silvicultural products or land use in the U.S. and abroad. First we looked at several existing programs administered by USDA that involve data collection from agricultural land owners, farmers, and forest owners. However, while USDA obtains and maintains valuable data from agricultural land owners, producers, and forest owners for assessing the status of agricultural land, forest land, and other types of land that could be used for renewable fuel feedstock production, Section 1619 of the Food, Conservation, and Energy Act of 2008 (the 2008 Farm Bill) and policies of certain USDA agencies significantly limit EPA's ability to access such data in a timely and meaningful way. Given that agricultural land owners, producers, and forest owners already report a great deal of information to USDA, having access to such information could enable EPA to avoid having to require duplicative reporting or recordkeeping and thereby minimize any burden that RFS2 may place on parties in the renewable fuel feedstock supply chain, from feedstock producer to renewable fuel producer, while still allowing us to ensure that the land restrictions on renewable biomass production are adhered to. We request comment on how EPA could acquire the type of information submitted by parties such as agricultural land owners, producers, and forest owners to USDA agencies in order to aid in administering RFS2. Having access to such information could be valuable to EPA in informing our enforcement actions.

ii. Third-Party Programs

To inform our options for how we might verify and track renewable biomass, we also explored non-governmental, third-party verification programs used for certifying and tracking agricultural and forest products from point of origin to point of use both within the U.S. and outside the U.S. The United Kingdom and the EU are looking to such third-party verification programs to implement the sustainability provisions of their biofuels programs. There is no third-party organization that certifies agricultural land, managed tree plantations, and forests; rather, each generally focuses on one area. Due to this constraint, we examined third party organizations that certify specific types of biomass from croplands and organizations that certify forest lands.

We examined third-party organizations that focus on a particular type of feedstock used for renewable fuel production, including the Roundtable on Sustainable Palm Oil and the Basel Criteria for Responsible Soy Production. These initiatives have outlined traceable certification programs for industry to follow. Two other cooperative organizations whose primary concern is renewable fuel production from biomass are the Roundtable on Sustainable Biofuels (RSB) and the Better Sugarcane Initiative (BSI). At present, the RSB and BSI are still in their developmental stages and do not have fully developed certification processes.

We also examined the work of the international Soy Working Group, comprised of representatives from industry, the Brazilian government, and international non-governmental organizations (NGOs), which recently announced a one-year extension of a moratorium on the use of soy harvested from recently deforested lands in the Brazilian Amazon. This moratorium is the result of a negotiated voluntary agreement through which companies that purchase Brazilian soy work with their suppliers to ensure that they source their soy from farms cultivated prior to August 2006. The Brazilian Association of Vegetable Oil Industries (ABIOVE) and Brazil's National Association of Grain Exporters (ANEC) have used aerial photography to identify whether any newly deforested areas were used to grow soy, and Greenpeace, one of the NGOs involved in the agreement, uses satellite imagery and aerial photography to perform spot checks for enforcement purposes.

Another new example of a renewable fuel feedstock verification system is the

Verified Sustainable Ethanol initiative, which established a series of criteria for ethanol produced in Brazil and sold to Swedish ethanol importer SEKAB. The Brazilian sugarcane ethanol industry trade association, UNICA, its member companies, and SEKAB established the criteria to promote environmental and social sustainability of sugarcane ethanol exported to Sweden. The agreement is between companies, and it relies on a third-party auditor to inspect Brazilian feedstock and ethanol production facilities to verify compliance with the criteria.

We also examined third-party organizations that specialize in certifying sustainable forest lands. The Sustainable Agriculture Network (SAN), through the Rainforest Alliance, provides comprehensive certification of wooded areas used for commercial development through sustainable processes in the United States and Latin American countries. The SAN certifies approximately 10 million acres of land worldwide, with minimal agricultural land certified in the U.S.[22]

We examined the certification process of the Forest Stewardship Council (FSC) because of their international recognition for certifying sustainable forests and their recordkeeping requirement for ''chain of supply'' certification for products. The FSC certifies 22 million acres of land in the U.S. according to certification standards designed for nine separate regions within the U.S., and it provides an example for chain-of-custody and product segregation requirements.[23] Finally, we examined the American Tree Farm program and Sustainable Forestry Initiative (SFI).

The criteria used to certify participants through third-party verification systems are overall more comprehensive and generally more stringent than the land restrictions contained within the definition of renewable biomass. However, three issues emerged through our investigation of these existing third-party verification systems that would make it difficult to adopt or incorporate any one of them into our regulations for the land restriction provisions under EISA. First, as previously noted, many of these third-party certifiers are limited in the scope of products that they certify. Second, the acreage of agricultural land or actively managed tree plantations certified through third parties in the U.S. covers only a small portion of the total available land and forests estimated to qualify for renewable biomass production under the EISA definition. Third, none of the existing third-party systems had definitions or criteria that perfectly matched the land use definitions and restrictions contained in the EISA definition of renewable biomass. Thus, we have determined that at this time we cannot rely on any existing third-party verification program solely to implement the land restrictions on renewable biomass under RFS2. We believe there is potential benefit in utilizing third-party verification programs if these issues can be addressed, and in the following section we offer one possible scenario as an implementation alternative. Nonetheless, we seek comment on our conclusion that there are currently no appropriate third-party verification systems for renewable biomass that could be adopted under RFS2. We further seek comment on whether any existing program or combination of programs would be able to meet the definitions and adopt the land restriction criteria proposed for RFS2 to assist industry in meeting their obligations under this proposed program.

d. Approaches for Domestic Renewable Fuel

Consistent with RFS1, renewable fuel producers would be responsible for generating RINs under RFS2. In order to make a determination whether or not their fuel is eligible for RINs, renewable fuel producers would need to have at least basic information about the origin of their feedstock. The following approaches for implementing the land restrictions on renewable biomass contained in EISA illustrate the variety of ways that renewable fuel feedstocks could be handled under RFS2. These options are presented singly, but we seek comment on how they might be combined to create the most appropriate, practical, and enforceable implementation scheme for renewable biomass under RFS2.

One approach for ensuring that producers generate RINs properly would be for EPA to require that renewable fuel producers obtain documentation about their feedstocks from their feedstock supplier(s) and take the measures necessary to ensure that they know the source of their feedstocks and can demonstrate to EPA that they have complied with the EISA definition of renewable biomass. Under this approach, EPA would require renewable fuel producers who generate RINs to certify on their renewable fuel production reports that the feedstock used for each renewable fuel batch meets the definition of renewable biomass. We would require renewable fuel producers to maintain sufficient records to support these claims. Specifically, renewable fuel producers who use planted crops or crop residue from existing agricultural land, or who use planted trees or slash from actively managed tree plantations, would be required to have copies of their feedstock producers' written records that serve as evidence of land being actively managed (or fallow, in the case of agricultural land) since December 2007, such as sales records for planted crops or trees, livestock, crop residue, or slash; a written management plan for agricultural or silvicultural purposes; or, documentation of participation in an agricultural or silvicultural program sponsored by a Federal, state or local government agency. In the case of all other biomass, we would require renewable fuel producers to have, at a minimum, written certification from their feedstock supplier that the feedstock qualifies as renewable biomass. We seek comment on whether we should also require renewable fuel producers that use slash and pre-commercial thinnings from non-federal forestland and biomass from areas at risk of wildfire to maintain additional records to support the claim that these feedstocks meet the definition of renewable biomass. These records could include sworn statements from licensed or registered foresters, contracts for tree or slash removal or documentation of participation in a fire mitigation program. We seek comment on other methods of verifying renewable fuel producers' claims that feedstocks qualify for these categories of renewable biomass. A review of such records would become part of the producer's annual attest engagement, the annual audit of their records by an independent third party (*see* Section IV.A for a full discussion of attest engagement requirements).

A renewable fuel producer would only be permitted to produce and sell renewable fuel without RINs if he demonstrates that the feedstocks used to produce his fuel do not meet the definition of renewable biomass. This approach would ensure that renewable fuel producers could not avoid the generation of RINs simply by failing to make a demonstration regarding the land used to produce their feedstocks. Thus, renewable fuel producers would be required to keep records of their feedstock source(s), regardless of

[22] Forest acreage taken from USDA Economic Research Service, *Major uses of Land in the United States, 2002,* Economic Information Bulletin No. (EIB–14), May 2006.

[23] FSC certified acreage taken from FSC–US, *Prospectus,* 2005.

whether RINs were generated or not. At a minimum, renewable fuel producers who do not generate RINs would need to have certification from their feedstock supplier that their feedstock does not meet the definition of renewable biomass. In the event that some portion of a load of feedstock does meet the definition of renewable biomass and some portion does not, the renewable fuel producer would need to maintain documentation from their supplier that states the percentage of each portion. All of these records would be included as part of the renewable fuel producer's annual attest engagement. The renewable fuel producer would also indicate on his renewable fuel production report that he did not generate RINs for fuel made from feedstock that did not meet the definition of renewable biomass.

Some stakeholders have expressed concern about EPA specifying the records that a renewable fuel producer must obtain from their feedstock supplier. We therefore seek comment on an approach that would require renewable fuel producers to certify on their renewable fuel production reports that their feedstock either met or did not meet the definition of renewable biomass and would require producers to maintain sufficient records to support their claims, but would stop short of specifying what those records would have to include. We anticipate that a large portion of feedstocks that qualify as renewable biomass will be obtained from existing agricultural land or actively managed tree plantations, for which, by definition, documentation already exists. We believe that, in most other cases, feedstock producers will have or will be able to create other forms of documentation that could be provided to renewable fuel producers in order to provide adequate assurance that the feedstock in question meets the definition of renewable biomass. As described above, there are many existing programs, such as those administered by USDA and independent third-party certifiers, that could be useful to verify that feedstock from certain land qualifies as renewable biomass.

We anticipate that these self-certification approaches would result in renewable fuel producers amending their contracts and altering their supply chain interactions to satisfy their need for documented assurance and proof about their feedstock's origins. Enforcement under either of these approaches would rely in part on EPA's review of renewable fuel production reports and attest engagements of renewable fuel producers' records. EPA would also consult other data sources, including any data made available by USDA, and could conduct site visits or inspections of feedstock producers' and suppliers' facilities. We seek comment on the feasibility and practical limitations of EPA working with publicly available USDA data to keep track of significant land use changes in the U.S. and around the world and to note general increases in feedstock supplier productivity that might signal cultivation of new agricultural land for renewable fuel feedstock production.

Either of these approaches would easily fold into existing and newly proposed registration, recordkeeping, reporting, and attest engagement procedures. They would also place the burden of implementation and enforcement on renewable fuel producers rather than bringing feedstock producers and suppliers directly under EPA regulation. In this way, they would minimize the number of regulated parties under RFS2. They would also allow, to varying degree, the renewable fuel industry to determine the most efficient means of verifying and tracking feedstocks from the point of production to the point of consumption, thereby minimizing any additional cost and administrative burden created by the EISA definition of renewable biomass.

Another alternative would be for EPA to establish a chain-of-custody tracking system from feedstock producer to renewable fuel producer through which renewable fuel producers would obtain information regarding the lands where their feedstocks were produced. This information would accompany each transfer of custody of the feedstock until the feedstock reaches the renewable fuel producer. Renewable fuel feedstock producers, suppliers and handlers would not have any reporting obligations. EPA would, however, require all feedstock producers, suppliers, and handlers to maintain as records these chain-of-custody documents for all biomass intended to be used as a renewable fuel feedstock. Renewable fuel producers would also be required to maintain these chain-of-custody tracking documents in their records and would have to include them as part of their records presented during their annual attest engagement.

An additional alternative would be for EPA to require renewable fuel producers to set up and administer a quality assurance program that would create an additional level of rigor in the implementation scheme for the EISA land restrictions on renewable biomass. The quality assurance program could include (1) an unannounced independent third party inspection of the renewable feedstock producer's facility at least once per quarter or once every 15 deliveries, whichever is more frequent, (2) an unannounced independent third party inspection of each intermediary facility that stores renewable fuel feedstock received by the renewable fuel producer at least once per quarter, and (3) on each occasion when the independent third party inspection reveals noncompliance, the renewable fuel producer must (a) conduct an investigation to determine the proper number of RINs that should have been generated for a volume of fuel and either generate or retire an equal number of RINs, depending on whether the fuel's feedstock did or did not meet the definition of renewable biomass, (b) conduct a root cause analysis of the violation, and (c) refuse to accept or process feedstock from the renewable fuel feedstock producer unless or until the feedstock producer takes appropriate corrective action to prevent future violations.

This alternative could provide a partial affirmative defense either for renewable producers that illegally generate RINs for fuel made from feedstocks that do not qualify as renewable biomass or for renewable fuel producers who do not generate enough RINs for fuel made from feedstocks that do qualify as renewable biomass. In either case, the producers must demonstrate that the violation was caused by a feedstock producer or supplier and not themselves; that the commercial documents (e.g., bills of lading) received with the feedstock indicated that the feedstock either met (in the case that RINs were generated illegally) or did not meet (in the case that an inadequate number of RINs were generated) the land restrictions for renewable biomass, and that they met EPA's quality assurance program requirements. A renewable fuel producer that generates RINs for fuel made from a feedstock that does not meet the definition of renewable biomass, but that qualifies for the partial affirmative defense, would still have to retire a number of RINs equal to the illegally generated RINs. Likewise, a renewable fuel producer that does not generate sufficient RINs for fuel made from a feedstock that does meet the definition of renewable biomass, but that qualifies for the partial affirmative defense, would have to generate enough RINs to make up the difference. However, in neither case would they be subject to civil penalties.

As yet another alternative approach, EPA could bring together renewable fuel producers and renewable fuel feedstock producers and suppliers to develop an industry-wide quality assurance program for the renewable fuel production supply chain, following the model of the successful Reformulated Gasoline Survey Association. We believe that this alternative could be less costly than if each individual renewable fuel producer were to create their own quality assurance program, and it would add a quality assurance element to RFS2 while creating the possibility for a partial affirmative defense for renewable fuel producers and feedstock producers and suppliers.

The program would be carried out by an independent surveyor funded by industry and consist of a nationwide verification program for renewable fuel producers and renewable feedstock producers and handlers designed to provide independent oversight of the feedstock designations and handling processes that are required to determine if a feedstock meets the definition of renewable biomass. Under this alternative, a renewable fuel producer and its renewable feedstock suppliers and handlers would have to participate in the funding of an organization which arranges to have an independent surveyor conduct a program of compliance surveys. Compliance surveys would be carried out by an independent surveyor pursuant to a detailed survey plan submitted to EPA for approval by November 1 of the year preceding the year in which the alternative quality assurance sampling and testing program would be implemented. The survey plan would include a methodology for determining when the survey samples would be collected, the locations of the surveys, the number of inspections to be included in the survey, and any other elements that EPA determines are necessary to achieve the same level of quality assurance as the requirement included in the RFS2 regulations at the time.

Under this alternative, the independent surveyor would be required to visit renewable feedstock producers and suppliers to determine if they are properly designating their product and adhering to adequate chain of custody requirements. This nationwide sampling program would be designed to ensure even coverage of renewable feedstock producers and suppliers. The surveyor would generate and report the results of the surveys to EPA each calendar quarter. In addition, where the survey finds improper designations or handling, the liable parties would be responsible for identifying and addressing the root cause of the violation to prevent future violations. When a violation is detected, the renewable fuel producer that participates in the consortium would be deemed to have met the quality assurance criteria for a partial affirmative defense. If the renewable fuel producer met the other applicable criteria, he would have to take corrective action to retire or generate the appropriate number of RINs depending on the violation, but he would not be subject to civil penalties.

Some stakeholders have suggested that EPA take advantage of existing satellite and aerial imagery and mapping software and tools to implement the renewable biomass provisions of EISA. One way to do so would be for EPA to develop a renewable fuel mapping Web site to assist regulated parties in meeting their obligation to identify the location of land where renewable fuel feedstocks are produced. Such a Web site could include an interactive map that would allow renewable feedstock producers to trace the boundaries of their property and create an electronic file with information regarding the land where their renewable fuel feedstocks were produced, such as a code that identifies the plot of land. This would allow the feedstock producer to provide information, such as a standard land ID code, on all bills of lading or other commercial documents that identify the type and quantity of feedstock being delivered to the renewable fuel producer. Renewable fuel producers could then make a determination regarding whether or not the renewable fuel feedstock that they use meets the definition of renewable biomass, and is therefore eligible or not for RIN generation.

Feedstock producers would not necessarily be required to use this Internet-based tool to identify the location where renewable fuel feedstocks are produced, since many feedstock producers already participate in various government or insurance programs that have required them to map the location of their fields. But the map would enable renewable fuel producers to verify the accuracy of these descriptions and report these locations to EPA using the interactive mapping tool on EPA's Web site. EPA specifically solicits comment on the practicability of constructing an accurate map from existing data sources.

As noted above, EPA recognizes that land restrictions contained within the definition of renewable biomass may not, in practice, result in a significant change in agricultural practices. EPA also recognizes that the implementation options described in this proposal could impose costs and constraints on existing storage, transportation, and delivery systems for feedstocks, in particular for corn and soybeans in the U.S. We therefore seek comment on a stakeholder suggestion to establish a baseline level of production of biomass feedstocks such that reporting and recordkeeping requirements would be triggered only when the baseline production levels of feedstocks used for biofuels were exceeded. Such an approach would avoid imposing a new recordkeeping burden on the industry as long as biofuels demand is met with existing feedstock production. We seek comment on this alternative, including how to set the baseline production levels and information on appropriate data sources in the U.S. and in other countries that produce feedstocks that could be used for renewable fuel production, and on how to track whether the feedstock use for biofuels production has exceeded baseline production levels. We also solicit comment on whether this approach could be applied to all types of feedstocks on which EISA places land restrictions, or if it would only be appropriate for traditional agricultural crops such as corn, soybeans, and sugarcane for which historical acreage data exists both domestically and internationally.

EPA acknowledges that under this alternative, while there could be a net increase in lands being cultivated for a particular crop, we would presume that increases in cultivation would be used to meet non-biofuels related feedstock demand. We also acknowledge that such an approach would be difficult to enforce because data that could indicate that baseline production levels were exceeded in a given year would likely be delayed by many months, such that the recordkeeping requirements for renewable fuel producers would also be delayed. During the interim period, renewable fuel producers would have generated RINs for fuel that did not qualify for credit under the program, and any remedial steps to invalidate such RINs after the fact could be costly and burdensome to all parties in the supply chain. Nonetheless, we seek comment on the approach as described above.

We seek comment on all of these approaches and what combination of these approaches would be the most appropriate, enforceable, and practical for ensuring that the land restrictions on renewable biomass contained in EISA are implemented under RFS2. We also seek comment on whether there are other possible approaches that would be superior to those we have described above. We also note that we intend to monitor RIN generation and the trends in renewable fuel feedstock sources as RFS2 implementation gets underway, and that we may make changes to the approach we adopt in the final RFS2 regulations if renewable fuel feedstock production conditions change or if new, better renewable biomass verification tools become available.

e. Approaches for Foreign Renewable Fuel

EISA creates unique challenges related to the implementation and enforcement of the definition of renewable biomass for foreign-produced renewable fuel. In order to address these issues, we propose to require foreign producers of renewable fuel who export to the U.S. to meet the same compliance obligations as domestic renewable fuel producers. These obligations would include facility registration and submittal of independent engineering reviews (described in Section III.C below), and reporting, recordkeeping, and attest engagement requirements. They would also include the same obligations that domestic producers have for verifying that their feedstock meets the definition of renewable biomass as described above, such as certifying on each renewable fuel production report that their renewable fuel feedstock meets the definition of renewable biomass and working with their feedstock supplier(s) to ensure that they receive and maintain accurate and sufficient documentation in their records to support their claims. As under the RFS1 program for producers of cellulosic fuel, the foreign producer would be required to comply with additional requirements designed to ensure that enforcement of the regulations at the foreign production facility would not be compromised. For instance, foreign producers would be required to designate renewable fuel intended for export to the U.S. as such and segregate the volume until it reaches the U.S. and post a bond to ensure that penalties can be assessed in the event of a violation. Moreover, as a regulated party under the RFS2 program, foreign producers would have to allow for potential visits by EPA enforcement personnel to review the completeness and accuracy of records and registration information.

We propose that a foreign renewable fuel producer, like a domestic renewable fuel producer, could only produce and sell renewable fuel for export to the U.S. without RINs if he demonstrated that the land used to produce his feedstocks did not meet the definition of renewable biomass. This approach would ensure that foreign renewable fuel producers could not avoid the generation of RINs for fuel shipped to the U.S. simply by failing to make any demonstration regarding the land used to produce their feedstocks. Thus, foreign renewable fuel producers that export their product to the U.S. would be required to keep records of the type of land used to produce their feedstock regardless of whether RINs are generated or not. Section III.D.2.b outlines more specifically our proposed requirements for foreign renewable fuel producers.

Importers will likely have less knowledge than a foreign renewable fuel producer would about the point of origin of their fuel's feedstock and whether it meets the definition of renewable biomass. Therefore, we are proposing that in the event that a batch of foreign-produced renewable fuel does not have RINs accompanying it, an importer must obtain documentation from its producer that states whether or not the definition of renewable biomass was met by the fuel's feedstock. With such documentation, the importer would be required to generate RINs (if the definition of renewable biomass is met) or would be prohibited from doing so (if the definition is not met) prior to introducing the fuel into commerce in the U.S. Without such documentation, the fuel would not be permitted for importation. Section III.D.2.c outlines our proposed requirements for importers more fully.

We seek comment on whether and to what extent the approaches for ensuring compliance with the EISA's land restrictions by foreign renewable fuel producers could or should differ from the proposed approach for domestic renewable fuel producers. In light of the challenges associated with enforcing the EISA's land restrictions in foreign countries, we believe that it may be appropriate to require foreign renewable fuel producers to use an alternative method of demonstrating compliance with these requirements. We seek comment on whether foreign renewable producers exporting product to the U.S. should have to comply with any of the alternatives described for domestic renewable fuel producers under this section. For example, we seek comment on whether a foreign renewable fuel producer should have to demonstrate that it had a contract in place with its renewable feedstock producer that required designation and chain of custody and handling methods similar to one of the alternatives for domestic renewable fuel producers discussed above. We also seek comment on whether foreign renewable fuel producers that export product to the U.S. should have to provide EPA with the location of land from which they will or have acquired feedstocks, along with historical satellite or aerial imagery demonstrating that feedstocks from these lands meet the definition of renewable biomass. We seek comment on whether foreign renewable fuel producers should also be subject to the same quality assurance requirements relating to their feedstock sources as domestic renewable fuel producers, and whether they should have the same option to use an approved survey consortium in lieu of implementing their own individual quality assurance programs.

We also seek comment on an alternative that would provide foreign renewable fuel producers an option of participating in RFS2 (in a manner consistent with our main proposal), or not participating at all. If they elected not to participate in RFS2, they could export renewable fuel to the United States without RINs, and without providing any documentation as to whether or not the fuel was made with renewable biomass. However, they would also have to meet requirements for segregating their fuel from renewable fuel for which RINs were generated, and the importer of their fuel would be required to track it to ensure that the fuel remains segregated in the U.S. and is not used by a domestic company for illegal RIN generation. This alternative would provide foreign renewable fuel producers an option not available to domestic renewable fuel producers, who in all cases would be required to document whether or not their feedstock met the definition of renewable biomass, and who would be required to generate RINs for their product if it was. As discussed in Section III.B.4.b.ii of this preamble, EPA believes that in order for obligated parties to meet the increasing annual volume requirements under RFS2, all qualifying renewable fuel will need to have RINs generated for it. Nonetheless, this alternative recognizes the potential difficulty of applying renewable biomass verification procedures in the international context, and provides an exemption process that EPA expects would only be used by relatively small producers for whom the burden of participating in the RFS2 program would outweigh the benefits, and whose total production volume would be negligible.

C. Expanded Registration Process for Producers and Importers

In order to implement and enforce the new restrictions on qualifying renewable fuel under RFS2, we are proposing that the registration process for renewable fuel producers and importers be revised. Under the existing RFS1 program, all producers and importers of renewable fuel who produce or import more than 10,000 gallons of fuel annually must register with EPA's fuels program prior to generating RINs. Renewable fuel producer and importer registration under the existing RFS program consists of filling out two forms: 3520–20A (Fuels Programs Company/Entity Registration), which requires basic contact information for the company and basic business activity information (e.g., for an ethanol producer, they need to indicate that they are a RIN generator), and 3520–20B (Gasoline Programs Facility Registration) or 3520–20B1 (Diesel Programs Facility Registration), which requires basic contact information for each facility owned by the producer or importer. More detailed information on the renewable fuel production facility, such as production capacity and process, feedstocks, and products is not required for most producers or importers to generate RINs under RFS1 (producers of cellulosic biomass ethanol and waste-derived ethanol are the exception to this).

Due to the revised definitions of renewable fuel under EISA, as well as other changes, we believe it necessary to expand the registration process for renewable fuel producers and importers in order to implement the new program effectively. Specifically, generating and assigning a certain category of RIN to a volume of fuel is dependent on whether the feedstock used to produce the fuel meets the definition of renewable biomass, whether the lifecycle greenhouse gas emissions of the fuel meets a certain GHG reduction threshold and, in some cases, whether the renewable fuel production facility is considered to be grandfathered into the program. Unless we require producers, including foreign producers, and importers to provide us with information on their feedstocks, facilities, and products, we cannot adequately implement or enforce the program or have confidence that producers and importers are properly categorizing their fuel and generating RINs. In particular, our proposed approach for ensuring that the GHG emission reduction thresholds for each category of renewable fuel are met will require producers and importers to determine the proper category assignment for their fuel based on a combination of their feedstock, production processes, and products (see Section III.D.2 for the proposed list). Such information, therefore, is central to program implementation. Therefore, we are proposing new registration requirements for all domestic renewable fuel producers, importers, and foreign renewable fuel producers. We also plan on integrating registration procedures with the new EPA Moderated Transaction System, discussed in detail in Section IV.E of this preamble. We encourage those affected by the proposed registration requirements to review the document entitled ''Proposed Information Collection Request (ICR) for the Renewable Fuels Standard (RFS2) Program—EPA ICR 2333.01,'' and an Addendum to the proposed ICR, which have been placed in the public docket and to provide comments to us regarding the burdens associated with the proposed registration requirements.

1. Domestic Renewable Fuel Producers

The most significant proposed changes to the current registration system pertain to the information that a producer will need to provide EPA prior to generating RINs. As noted above, we are proposing that producers provide information about their products, feedstocks, and facilities in order to be registered for the RFS2 program. Information contained in a producer's registration would be used to verify the validity of RINs generated and their proper categorization as either cellulosic biofuel, biomass-based diesel, advanced biofuel, or other renewable fuel.

With respect to products, we are interested in the types of renewable fuel and co-products that a facility is capable of producing. With respect to feedstocks, we believe it is necessary to have on file a list of all the different feedstocks that a renewable fuel producer's facility is capable of converting into renewable fuel. For example, if a renewable fuel producer produces fuel from both cellulosic material, such as corn stover, and non-cellulosic material, such as corn starch, the producer may be eligible to generate RINs in two different categories (cellulosic biofuel and renewable fuel). This producer's registration information would be required to list both of these feedstocks before we would allow two different categories of RINs to be generated.

With respect to the producer's facilities, we are proposing two types of information that would need to be reported to the Agency. First, we believe it is important to have information on file that describes each facility's fuel production processes (e.g., wet mill, dry mill, thermochemical, etc.), and thermal/process energy source(s). Second, in order to determine what production volumes would be grandfathered and thus deemed to be in compliance with the 20% GHG threshold, we would require evidence and certification of the facility's qualification under the definition of ''commence construction'' as well as information necessary to establish it's renewable fuel baseline volume per the proposal outlined in Section III.B.3 of this preamble.

Under the existing RFS1 program, producers of cellulosic biomass and waste-derived ethanol are required to have an annual engineering review of their production records performed by an independent third party who is licensed Professional Engineer (P.E.) who works in the chemical engineering field. This independent third party need not be based in the United States, but must hold a P.E. Each review must be kept on file by both the producer and the engineer for five years. The independent third party must include documentation of its qualifications as part of the engineering review. Foreign producers of cellulosic biomass and waste-derived ethanol are also required to have an engineering review of their facilities, with a report submitted to EPA that describes in detail the physical plant and its operation. These requirements helps ensure that producers who claim to be producing such fuel, which earns 2.5 RINs per gallon rather than 1.0 RIN per gallon for corn-based ethanol under RFS1, are in fact doing so.

We believe that the requirement for an on-site engineering review is an effective implementation tool and propose to adopt the requirement under RFS2, with the following changes. First, we propose expanding the applicability of the requirement to all renewable fuel producers due to the variability of production facilities, the increase in the number of categories of renewable fuels, and the importance of generating RINs in the correct category. Second, we propose that every renewable fuel producer must have the on-site engineering review of their facility performed in conjunction with his or her initial registration for the new RFS program in order to establish the proper basis for RIN generation, and every three years thereafter to verify that the fuel pathways established in their initial registration are still applicable. These requirements would apply unless the renewable fuel producer updates its facility registration information to qualify for a new RIN category (i.e., D code), in which case the review would need to be performed within 60 days of the registration update. Finally, we propose that producers be required to submit a copy of their independent engineering review to EPA rather than simply maintaining it in their records. We believe that this extra step is necessary for verification and enforcement purposes.

In addition to the new registration requirements for all renewable fuel producers who produce greater than 10,000 gallons of product each year, we seek comment on whether to require renewable fuel producers and importers in the U.S. who produce or import less than 10,000 gallons per year to register basic information about their company and facility (or facilities) with EPA, similar to information currently required of renewable fuel producers under RFS1. This information would complement information submitted to EPA under the Fuels and Fuel Additives Registration System (FFARS) program to help ensure that EPA has a complete record of renewable fuel production and importation in the U.S.

2. Foreign Renewable Fuel Producers

Under the current RFS program, foreign renewable fuel producers of cellulosic biomass ethanol and waste-derived ethanol may apply to EPA to generate RINs for their own fuel. This allows a foreign producer of this renewable fuel to obtain the same benefits of higher credit value as domestic producers of this category of renewable fuel. Under the RFS1 regulations, the foreign fuel producer must meet a variety of requirements established to make the program effective and enforceable with respect to a foreign producer. These requirements mirror a number of similar fuel provisions that apply to foreign refiners in other fuels programs. For RFS2, we propose that foreign producers of renewable fuel must meet the same requirements as domestic producers, including registering information about their feedstocks, facilities, and products, as well as submitting an on-site independent engineering review of their facilities at the time of registration for the program and every three years thereafter. These requirements would apply to all foreign renewable fuel producers who export their products to the U.S., whether or not they qualify to generate RINs for their fuel. They would also be subject to the variety of enforcement related provisions that apply under RFS1 to foreign producers of cellulosic biomass or waste derived ethanol.

As discussed in Section III.C.1, the existing RFS1 program requires that the independent engineering review be conducted by an independent third party who is a licensed P.E. who works in the chemical engineering field. This P.E. need not be based in the United States. The independent third party must include documentation of its qualifications as part of the engineering review.

Since implementation of RFS1 we have received questions about engineers who are licensed by other countries that may have equivalent licensing requirements to those associated with the P.E. designation in the United States. The existing RFS1 program does not permit independent third party review by a party who is not a licensed P.E. We invite comment on whether or not we should permit independent third parties who are based in—and licensed by—foreign countries and who work in the chemical engineering field to demonstrate the foreign equivalency of a P.E. license.

We also seek comment on requiring foreign renewable fuel producers to provide EPA with the location of land from which they will acquire feedstocks, along with historical satellite or aerial imagery demonstrating that the lands from which they acquire feedstock are eligible under the definition of renewable biomass (*see* Section III.B.4 for a full discussion of our proposed and alternative approaches for foreign renewable fuel producers to verify their feedstocks meet the definition of ''renewable biomass'').

3. Renewable Fuel Importers

A renewable fuel importer is required under RFS1 to register basic information about their company with EPA prior to generating RINs. Under the proposed new RFS2 program, we are proposing that only in limited cases can importers generate RINs for imported fuel that they receive without RINs. In any case, whether they receive fuel with or without RINs, an importer must rely on his supplier, a foreign renewable fuel producer, to provide documentation to support any claims for their decision to generate or not to generate RINs. An importer may have an agreement with a foreign renewable fuel producer for the importer to generate RINs if the foreign producer has not done so already. However, the foreign renewable fuel producer must be registered with EPA as noted above. Section III.D.2.c describes our proposed RIN generating restrictions and requirements for importers under RFS2.

4. Process and Timing

We intend to make forms for expanded registration for renewable fuel producers and importers available electronically, with paper registration only in exceptional cases. We propose that registration forms will have to be submitted by January 1, 2010 (the proposed effective date of the final RFS2 regulations), or 60 days prior to a producer producing or importer importing any renewable fuel, whichever dates comes later. If a producer changes to a feedstock that is not listed in his registration information on file with EPA but the feedstock will not incur a change of RIN category for the fuel (i.e., a change in the appropriate D code), then we propose that the producer must update his registration information within seven (7) days of the change. However, if a producer's feedstock, facility (including industrial processes or thermal energy source), or products undergo changes that would qualify his renewable fuel for a new RIN category (and thus a new D code), then we propose that such an update would need to be submitted at least 60 days prior to the change, followed by submittal of a complete on-site independent engineering review of the producer's facility also within 60 days of the change.

D. Generation of RINs

Under RFS2, each RIN would continue to be generated by the producer or importer of the renewable fuel, as in the RFS1 program. In order to determine the number of RINs that must be generated and assigned to a batch of renewable fuel, the actual volume of the batch of renewable fuel must be multiplied by the appropriate Equivalence Value. The producer or importer must also determine the appropriate D code to assign to the RIN to identify which of the four standards the RIN can be used to meet. This section describes these two aspects of the generation of RINs. We propose that other aspects of the generation of RINs, such as the definition of a batch and temperature standardization, as well as the assignment of RINs to batches, should remain unchanged from the RFS1 requirements.

1. Equivalence Values

For RFS1, we interpreted CAA section 211(o) as allowing us to develop Equivalence Values representing the number of gallons that can be claimed for compliance purposes for every physical gallon of renewable fuel. We described how the use of Equivalence Values adjusted for renewable content and based on energy content in comparison to the energy content of ethanol was consistent with Congressional intent to treat different renewable fuels differently in different circumstances, and to provide incentives for use of renewable fuels in certain circumstances, as evidenced by the specific circumstances addressed by Congress. This included the direction that EPA establish ''appropriate'' credit values in certain circumstances, as well as provisions in the statute providing for different credit values to be assigned to the same volume of different types of renewable fuels (e.g., cellulosic and waste-derived fuels). We also noted that the use of Equivalence Values based on energy content was an appropriate measure of the extent to which a renewable fuel would replace or reduce the quantity of petroleum or other fossil fuel present in a fuel mixture. The result was an Equivalence Value for ethanol of 1.0, for butanol of 1.3, for biodiesel (mono alkyl ester) of 1.5, and for non-ester renewable diesel of 1.7. EPA stated that these provisions indicated that Congress did not intend to limit the RFS program solely to a straight volume measurement of gallons. EPA also noted that the use of Equivalence Values would not interfere with meeting the overall volume goals specified by Congress, given the various provisions that make achievement of the specified volumes imprecise. *See* 72 FR 23918–23920, and 71 FR 55570–55571.

EISA has not changed certain of the statutory provisions we looked to for support under RFS1 in establishing Equivalence Values based on relative volumetric energy content in comparison to ethanol. For instance, CAA 211(o) continues to give EPA the authority to determine an ''appropriate'' credit for biodiesel, and also directs EPA to determine the ''appropriate'' amount of credit for renewable fuel use in excess of the required volumes.

However, EISA made a number of other changes to CAA section 211(o) that impact our consideration of Equivalence Values in the context of the RFS2 program. For instance, EISA eliminated the 2.5-to-1 credit for cellulosic biomass ethanol and waste-derived ethanol and replaced this provision with large mandated volumes of cellulosic biofuel and advanced biofuels. Under the RFS1 program, an Equivalence Value of 2.5 applies to these types of ethanol through the end of 2012. Under the new RFS2 program, these types of ethanol would have an Equivalence Value of 1.0, consistent with all other forms of ethanol.

EISA also expanded the program to include four separate categories of renewable fuel (cellulosic biofuel, biomass-based diesel, advanced biofuel, and total renewable fuel) and included GHG thresholds in the definitions of each category. Each of these categories of renewable fuel has its own volume requirement, and thus there will exist a guaranteed market for each. As a result there may no longer be a need for additional incentives for certain fuels in the form of Equivalence Values greater than 1.0. In addition, the use of an energy-based approach to Equivalence Values raises some questions, discussed below, concerning the impact of such Equivalence Values on the biomass-based diesel volume requirement and in the initial years on the advanced biofuel volume requirement. Overall EPA believes that the statute continues to be ambiguous on this issue, and we are therefore co-proposing and seeking comment on two options for Equivalence Values:

1. Equivalence Values would be based on the energy content and renewable content of each renewable fuel in comparison to denatured ethanol, consistent with the approach under RFS1.

2. All liquid renewable fuels would be counted strictly on the basis of their measured volumes, and the Equivalence Values for all renewable fuels would be 1.0 (essentially, Equivalence Values would no longer apply).

While these two different approaches to volume would have an impact on the market values of renewable fuels with different energy contents as explained more fully below, the overall impact on the program would likely be small since we are projecting that the overwhelming majority of renewable fuels will be ethanol (*see* further discussion in Section V.A.2).

Under either option, non-liquid renewable fuels such as biogas and renewable electricity would continue to be valued based on the energy contained in one gallon of denatured ethanol. In the RFS1 final rulemaking, we specified that 77,550 Btu of biogas be counted as the equivalent of 1 gallon of renewable fuel with an assigned Equivalence Value of 1.0. We propose to maintain this approach to non-liquid renewable fuels under the RFS2 program under either approach to Equivalence Values, but with a small modification to make the ethanol energy content more accurate. The energy content of denatured ethanol was specified as 77,550 Btu/gal under RFS1, but a more accurate value would be 77,930 Btu/gal. Thus we propose to use 77,930 Btu to convert biogas and renewable electricity into volumes of renewable fuel under RFS2.

Under the second option in which all liquid renewable fuels would be counted strictly on the basis of their measured volumes, we would need to determine how to treat the small amount of denaturant in ethanol and the nonrenewable portion of biodiesel. Under RFS1, Equivalence Values were determined from a formula that included measures of both volumetric energy content and renewable content. The renewable content was intended to take into account the portion, if any, of a renewable fuel that originated from a fossil fuel feedstock. EISA eliminated the statutory language on which the inclusion of renewable content was based, and instead restricts renewable fuels that are valid under the RFS2 program to those produced from renewable biomass. In the case of fuels produced from both renewable and nonrenewable feedstocks, we have interpreted this to mean only that portion of the volume attributable to the renewable feedstocks (*see* further discussion in Section III.D.4 below). However, we do not believe that this approach is appropriate for the denaturant in ethanol and the small amount of non-renewable methanol used in the production of biodiesel, since Congress clearly intended that ethanol and biodiesel be included as a renewable fuel, and they are only used as a fuel under these circumstances. We therefore propose to treat the denaturant in ethanol and the nonrenewable portion of biodiesel as de minimus and thus count them as part of the renewable fuel volume under an approach to Equivalence Values in which all liquid renewable fuels would be counted strictly on the basis of their measured volumes. As a result, under this co-proposed approach we are proposing that the full formula used to calculate Equivalence Values under RFS1 be eliminated from the regulations and that the Equivalence Value for all renewable fuels be specified as 1.0. Nevertheless, we seek comment on this approach.

Although there are several reasons for a straight volume approach as discussed above, there are also several reasons to maintain the ethanol-equivalent energy content approach to Equivalence Values of RFS1. For instance, in our discussions with stakeholders, some have argued that the existence of four standards is not a sufficient reason to eliminate the use of energy-based Equivalence Values for RFS2. The four categories are defined in such a way that a variety of different types of renewable fuel could qualify for each category, such that no single specific type of renewable fuel will have a guaranteed market. For example, the cellulosic biofuel requirement could be met with both cellulosic ethanol or cellulosic diesel. As a result, the existence of four standards under RFS2 may not obviate the value of standardizing for energy content, which provides a level playing field under RFS1 for various types of renewable fuels based on energy content.

More importantly, they argue that a straight volume approach would be likely to create a disincentive for the development of new renewable fuels that have a higher energy content than ethanol in the same way as the current ethanol tax credit structure. For a given mass of feedstock, the volume of renewable fuel that can be produced is roughly inversely proportional to its energy content. For instance, one ton of biomass could be gasified and converted to syngas, which could then be catalytically reformed into either 90 gallons of ethanol (and other alcohols) or 50 gallons of diesel fuel (and naphtha).[24] If RINs were assigned on a straight volume basis, the producer could maximize the number of RINs he is able to generate and sell by producing ethanol instead of diesel. Thus, even if the market would otherwise lean towards demanding greater volumes of diesel, the greater RIN value for producing ethanol may favor its production instead. However, if the energy-based Equivalence Values were maintained, the producer could assign 1.7 RINs to each gallon of diesel made from biomass in comparison to 1.0 RIN to each gallon of ethanol from biomass, and the total number of RINs generated would be essentially the same for the diesel as it would be for the ethanol. The use of energy-based Equivalence Values could thus provide a level playing field in terms of the RFS program's incentives to produce different types of renewable fuel from the available feedstocks. The market would then be free to choose the most appropriate renewable fuels without any bias imposed by the RFS regulations, and the costs imposed on different types of renewable fuel through the assignment of RINs would be more evenly aligned with the ability of those fuels to power vehicles and engines, and displace fossil fuel-based gasoline or diesel.

Moreover, the technologies for producing more energy-dense fuels such as cellulosic diesel are still in the early stages of development and may benefit from not having to overcome the disincentive in the form of the same Equivalence Value based on straight volume. Given the projected tightness in the distillate market and relative excess supply in the gasoline market in the coming years, allowing the market to choose freely may be important to overall fuel supply. In the extreme, the cellulosic biofuel standard could then be met by roughly 10 billion gallons of a cellulosic diesel fuel instead of the 16 billion gallons of cellulosic ethanol assumed for the impacts analysis of this proposal. The same amount of petroleum energy would be displaced, but by different physical volumes.

As discussed above, there are no provisions in EISA that explicitly instruct the Agency to change from the approach to Equivalence Values adopted in RFS1. However, there is a question of how to address the biomass-based diesel requirement under such an approach. In that context, it does appear that Congress intended the required volumes of biomass-based diesel to be treated as diesel volumes rather than ethanol-equivalent volumes. Therefore EPA proposes that, for the biomass-based diesel volume mandate under an ethanol-equivalent energy content approach to Equivalence Values, the compliance calculations would be structured such that this requirement is treated in effect as a straight volume-based requirement.[25]

In addition, it is also clear that Congress established the advanced biofuel standard in EISA to begin to take affect in 2009. However, if we maintain the ethanol-equivalent energy content approach for RFS2, and biodiesel continues to have an Equivalence Value of 1.5, then from 2009–2012 the combination of the biomass-based diesel standard and the cellulosic biofuel standard will meet or exceed the advanced biofuel standard. Unless we were to waive a portion of either the biomass-based diesel standard or the cellulosic biofuel standard, the advanced biofuel standard would not have an independent effect until 2013. While EPA recognizes this, EPA believes that the long term benefits of an energy based Equivalence Value may be significantly greater than any temporary diminishment in the real world impact of the advanced biofuel mandate.

In recognition of the competing perspectives, we request comment on both co-proposed approaches to the Equivalence Values: (1) Retaining the energy-based approach of the RFS1 program, and (2) a straight volume approach measured in liquid gallons of renewable fuel.

2. Fuel Pathways and Assignment of D Codes

As described in Section III.A, we propose that RINs under RFS2 would continue to have the same number of digits and code definitions as under RFS1. The one change would be that, while the D code would continue to identify the standard to which the RIN could be applied, it would be modified to have four values corresponding to the four different renewable fuel categories defined in EISA. These four D code values and the corresponding categories are shown in Table III.A–1.

In order to generate RINs for renewable fuel that meets the various eligibility requirements (*see* Section III.B), a producer or importer must know which D code to assign to those RINs. We propose that a producer or importer would determine the appropriate D code using a lookup table in the regulations. The lookup table would list various combinations of fuel type, production process, and feedstock, and the producer or importer would choose the appropriate combination representing the fuel he is producing and for which he is generating RINs. Parties generating RINs would be required to use the D code specified in the lookup table and would not be permitted to use a D code representing a broader renewable fuel category. For example, a party whose fuel qualified as biomass-based diesel could not choose to categorize that fuel as advanced biofuel or general renewable fuel.

This section describes our proposed approach to the assignment of D codes to RINs for domestic producers, foreign producers, and importers of renewable fuel. Subsequent sections address the generation of RINs in special circumstances, such as when a production facility has multiple applicable combinations of feedstock, fuel type, and production process within a calendar year, production facilities that co-process renewable biomass and fossil fuels, and production

[24] Another example would be a fermentation process in which one ton of cellulose could be used to produce either 70 gallons of ethanol or 55 gallons of butanol.

[25] The proposed regulations and the ensuing discussion in Sections III and IV of this proposal reflect straight volume approach, however, the impacts analysis of the program are calculated using volumes based on ethanol-equivalent energy content. Were we to maintain the energy content approach to Equivalence Values, then we believe the biomass-based diesel standard should be treated in effect as a biodiesel volume, reflecting the nature of this standard, while the other three standards would be treated as ethanol-equivalent volumes. In order to effectuate this, we are considering two approaches. Under either approach all RINs would be generated based on ethanol-equivalent volume, including biomass-based diesel RINs. Under one approach, we would propose that the biomass-based diesel standard also be expressed as an ethanol-equivalent volume (e.g., 1.5 billion ethanol-equivalent gallons in 2012). Another approach would be to have the standard expressed as a volume of biomass-based diesel, and to require the biomass-based diesel RINs be adjusted back to a volume basis, with this adjustment just for purposes of the biomass-based diesel standard but not for purposes of the other fuels mandates. Either approach would have the same result.

facilities for which the lookup table does not provide an applicable D code.

a. Domestic Producers

For domestic producers, the lookup table would identify individual fuel ''pathways'' comprised of unique combinations of the type of renewable fuel being produced, the feedstock used to produce the renewable fuel, and a description of the production process. Each pathway would be assigned to one of the four specific D codes on the basis of the revised renewable fuel definitions provided in EISA and our assessment of the GHG lifecycle performance for that pathway. A description of the lifecycle assessment of each fuel pathway and the process we used for determining the associated D code can be found in Section VI. Note that the subsequent generation of RINs would also require as a prerequisite that the feedstocks used to make the renewable fuel meet the definition of ''renewable biomass'' as described in Section III.B.4, including applicable land use restrictions. Moreover, a domestic producer could not introduce renewable fuel into commerce without generating RINs unless he had records demonstrating that the feedstocks used to produce the fuel did not meet the definition of renewable biomass. *See* Section III.B.4.b.ii for further discussion of this issue.

Through our assessment of the lifecycle GHG impacts of different pathways and the application of the EISA definitions for each of the four categories of renewable fuel, including the GHG thresholds, we have determined that all four categories would have pathways that could be used to meet the Act's volume requirements. For example, ethanol made from corn stover or switchgrass in an enzymatic hydrolysis process would count as cellulosic biofuel. Biodiesel made from waste grease could count as biomass-based diesel. Ethanol made from sugarcane sugar may count as advanced biofuel depending on the results of the lifecycle assessment conducted for the final rule and a determination about whether the GHG threshold for advanced biofuel should be adjusted downward. Finally, under an assumed 100-year timeframe and 2% discount rate for GHG emissions impacts, a variety of pathways would count as generic renewable fuel under the RFS2 program, including ethanol made from corn starch in a facility powered by biomass combustion and biodiesel made from soybean oil. The complete list of pathways that would be valid under our proposed RFS program is provided in the regulations at § 80.1426(d), based upon an assumed 100-year timeframe and 2% discount rate for GHG emission impacts.

Domestic producers would choose the appropriate D code from the lookup table in the regulations based on the fuel pathway that describes their facility. The fuel pathway must be specified by the producer in the registration process as described in Section III.C. If there were changes to a domestic producer's facility or feedstock such that their fuel would require a D code that was different from any D code(s) which their existing registration information already allowed, the producer would be required to revise its registration information with EPA 30 days prior to changing the applicable D code it uses to generate RINs. Situations in which multiple fuel pathways could apply to a single facility are addressed in Section III.D.3 below.

For producers for whom none of the defined fuel pathways in the lookup table would apply, we propose two possible treatments. First, such producers may be able to generate RINs through our proposed system of default D codes as described in Section III.D.5 below. Second, if a producer meets the criteria for grandfathered status as described in Section III.B.3 and his fuel meets the definition of renewable fuel as described in Section III.B.1, he could continue to generate RINs for his fuel but would use a D code of 4 for those RINs generated under the grandfathering provisions. If a producer was not covered by either of these two treatments, we propose that he would not be permitted to generate RINs for his product until the lookup table in the regulations was modified to include a pathway applicable to his operations.

A diesel fuel product produced from cellulosic feedstocks that meets the 60% GHG threshold could qualify as either cellulosic biofuel or biomass-based diesel. As a result, we are proposing that the producer of such ''cellulosic diesel'' be given the choice of whether to categorize his product as either cellulosic biofuel or biomass-based diesel. This would allow the producer to market his product and the associated RINs on the basis of market demand. However, we request comment on an alternative approach as shown in Table III.D.2.a–1 in which an additional D code would be defined to represent cellulosic diesel and an obligated party would be given the choice of using cellulosic diesel RINs either to meet his or her RVO for cellulosic biofuel or for biomass-based diesel.

TABLE III.D.2.a–1—ALTERNATIVE D CODE DEFINITIONS TO ACCOMMODATE CELLULOSIC DIESEL

D value	Meaning under RFS1	Meaning under RFS2
1	Cellulosic biomass ethanol	Cellulosic biofuel.
2	Any renewable fuel that is not cellulosic biomass ethanol.	Biomass-based diesel.
3	Not applicable	Cellulosic biofuel or biomass-based diesel.
4	Not applicable	Advanced biofuel.
5	Not applicable	Renewable fuel.

Under this alternative, producers of cellulosic diesel would assign a D code of 3 to their product rather than being given a choice of whether to assign a D code of 1 or 2. Any obligated party that acquired a RIN with a D code of 3 could apply that RIN to either its cellulosic biofuel or biomass-based diesel obligation, but not both. The advantage of this alternative approach is that it reflects the full compliance value for the product, and hence its potential value to an obligated party. The obligated party is then given the ability to make a choice about how to treat cellulosic diesel based on the market price and availability of RINs with D codes of 1 and 2. We request comment on this alternative approach to the designation of D codes for cellulosic diesel.

b. Foreign Producers

Under RFS1, foreign producers have the option of generating RINs for the renewable fuel that they export to the U.S. if they want to designate their fuel as cellulosic biomass ethanol or waste-derived ethanol, and thereby take advantage of the additional 1.5 credit value afforded by the 2.5 Equivalence Value for such products. In order to ensure that EPA has the ability to enforce the regulations relating to the generation of RINs from such foreign ethanol producers, the RFS1 regulations require them to post a bond and submit to third-party engineering reviews of their production process. If a foreign producer does not generate RINs for the renewable fuel that it exports to the U.S., the U.S. importer is responsible for generating the RINs associated with the imported renewable fuel.

EISA creates unique challenges in the implementation and enforcement of the renewable fuel standards for imported renewable fuel. Unlike our other fuels programs, EPA cannot determine whether a particular shipment of renewable fuel is eligible to generate RINs under the new program by testing the fuel itself. Instead, information regarding the feedstock that was used to produce renewable fuel and the process by which it was produced is vital to determining the proper renewable fuel category and RIN type for the imported fuel. It is for these reasons that we required foreign producers of cellulosic biomass ethanol or waste-derived ethanol under RFS1 to take additional steps to ensure the validity of the RINs they generate.

For RFS2 we are proposing a similar approach to that taken under RFS1, but with a number of modifications to account for the changes that EISA makes to the definition of renewable fuel. Thus, we propose that foreign producers would have the option of generating RINs for any renewable fuel (not just the cellulosic biofuel category) that they export to the U.S. If the foreign producer did not generate RINs, the importer would be required to generate RINs for the imported renewable fuel. Our proposed importer provisions are covered in more detail in Section III.D.2.c below.

In general, we propose that foreign producers of renewable fuel who intend to export their fuel to the U.S. would use the same process as domestic producers to generate RINs, namely the lookup table to identify the appropriate D code as a function of fuel type, production process, and feedstock. They would be required to be registered with the EPA as a producer under the RFS2 program and would be subject to the same recordkeeping, reporting, and attest engagement requirements as domestic producers, including those provisions associated with ensuring that the feedstocks they use meet the definition of renewable biomass. They would also be required to submit to third-party engineering reviews of their production process and use of feedstocks, just as domestic producers are. As under the RFS1 program, the foreign producer would also be required to comply with additional requirements designed to ensure that enforcement of the regulations at the foreign production facility would not be compromised. For instance, foreign producers would be required to designate renewable fuel intended for export to the U.S. as such and segregate the volume until it reaches the U.S. in order to ensure that RINs are only generated for volumes imported into the U.S. Foreign producers would also be required to post a bond to ensure that penalties can be assessed in the event of a violation. Moreover, as a regulated party under the RFS2 program, foreign producers must allow for potential visits by EPA enforcement personnel to review the completeness and accuracy of records and registration information. Non-compliance with any of these requirements could be grounds for refusing to allow renewable fuel from such a foreign producer to be imported into the U.S.

For RFS2, we are proposing a number of additional provisions to address foreign companies that produce renewable fuel for export to the United States, but that do not generate their own RINs for that renewable fuel. These provisions are intended to account for the greater difficulties in verifying the validity of RINs for imported renewable fuel when the importer is generating the RINs, given that the importer would generally not have direct knowledge of the feedstocks used to produce the renewable fuel, the land used to grow those feedstocks, or the fuel production process. We believe that these additional provisions would be necessary to ensure that RINs representing imported renewable fuel and used by obligated parties have been generated appropriately.

As described more fully in Section III.D.2.c below, importers would only be allowed to import renewable fuel from registered foreign producers and would be required to generate RINs for all imported renewable fuel that has not been assigned RINs by the foreign producer. Like domestic and foreign producers who generate RINs, the importer must be able to determine if the renewable biomass definition has been met before generating RINs. The importer must also have enough information about the production process and feedstock to be able to use the lookup table to identify the appropriate D code to include in the RINs he generates. Since the foreign producer is the only party who can provide this information, we believe that it would be appropriate to require the foreign producer of any renewable fuel exported to the U.S. to provide this information to the U.S. importer before the renewable fuel enters U.S. commerce even if the foreign producer is not generating RINs himself. Moreover, the foreign producer should be liable for the accuracy of this information just as if he were the party generating RINs. Therefore, in order to ensure that RINs are valid regardless of who generates them, we propose that all the provisions described above that would be applicable to a foreign producer who generates RINs would also apply to a foreign producer who does not generate RINs but still exports renewable fuel to the U.S. This would include registration with the EPA under the RFS2 program, being subject to all the recordkeeping, reporting, and attest engagement requirements, and posting a bond. The only exception would be that the foreign producer would not be required to segregate a specific volume between the foreign producer's facility and the import facility if the foreign producer is not generating RINs, since the importer would be the primary party responsible for measuring the volume before generating RINs.

Although we are proposing that RINs for imported renewable fuel could be generated by either the importer or the foreign producer, it is possible that this could result in difficulty in verifying that only one set of RINs has been generated for a given volume of renewable fuel. One possible solution would be to require a foreign producer to make a decision regarding RIN generation that would apply for an entire calendar year. Under this approach, a foreign producer would be required to either generate RINs for all the renewable fuel that he exports to the U.S within a calendar year, or to generate no RINs for the renewable fuel that he exports to the U.S within a calendar year. While we are not proposing this approach it today's action, we request comment on it.

As described in Section III.B.4.b.ii, we are proposing that domestic producers could only introduce renewable fuel into commerce without generating RINs if they demonstrate that feedstocks used to produce the fuel did not meet the definition of renewable biomass. Thus it would not be sufficient for a domestic producer to simply fail to make a demonstration that the renewable biomass definition had been met, and thereby avoid generation of RINs. We propose that a similar approach would be applied to imported renewable fuel. As a result, all renewable fuel that would be imported into the U.S. would be required to come with documentation regarding the status of the feedstock's compliance with the renewable biomass definition. In the case of documentation indicating that the renewable biomass definition had been met, the importer would be required to generate RINs. In the case of documentation indicating that the renewable biomass definition had not been met, the importer would be prohibited from generating RINs but could still import the renewable fuel into the U.S. Renewable fuel that was not accompanied by any documentation regarding the status of the feedstock's compliance with the renewable biomass definition could not be imported into the U.S.

Our proposed approach to foreign producers is consistent with the approach we propose taking for domestic producers, in that the producer is responsible for ensuring that RINs generated for renewable fuel used in the U.S. are valid and categorized appropriately. While our proposed approach to foreign producers of renewable fuel under RFS2 would require additional actions in comparison to their general requirements under RFS1, we believe these provisions would be necessary to ensure that the volume mandates shown in Table II.A.1–1 are met, given the new definitions for renewable fuel and renewable biomass in EISA. We request comment on our proposed approach to foreign producers.

c. Importers

Under RFS1, importers who import more than 10,000 gallons in a calendar year must generate RINs for all imported renewable fuel based on its type, except for cases in which the foreign producer generated RINs for cellulosic biomass ethanol or waste-derived ethanol. Due to the new definitions of renewable fuel and renewable biomass in EISA, importers could no longer generate RINs under RFS2 on the basis of fuel type alone. Instead, they must be able to determine whether or not the renewable biomass definition has been met for the renewable fuel they intend to import, and they must also have sufficient information about the feedstock and process used to make the renewable fuel to allow them to identify the appropriate D code from the lookup table for use in the RINs they generate. As described in Section III.D.2.b above, we are proposing that in order for an importer to import renewable fuel into the U.S., the foreign producer would have to provide this information to the importer.

Under today's proposal, importers would be able to import renewable fuels only under one of the following scenarios:

1. The importer receives RINs generated by the registered foreign producer when he imports a volume of renewable fuel.

2. The imported renewable fuel is not accompanied by RINs generated by the registered foreign producer, and the foreign producer provides the importer with:

—A demonstration that the renewable biomass definition has been met for the volume of renewable fuel being imported.
—Information about the feedstock and production process used to produce the renewable fuel.

In this case, the importer would be required to generate RINs for the imported renewable fuel before introducing it into commerce in the contiguous 48 states or Hawaii.

3. The imported renewable fuel is not accompanied by RINs generated by the registered foreign producer, and the foreign producer provides the importer with a demonstration that the renewable biomass definition has not been met for the volume of renewable fuel being imported. See further discussion of this issue in Section III.B.4.b.ii. The importer would be prohibited from generating RINs for the imported volume, but could still introduce the renewable fuel into commerce.

If none of these scenarios applied, the importer would be prohibited from importing renewable fuel. Our proposed approach to imported fuels would apply to both neat renewable fuel and renewable fuels blended into gasoline or diesel.

As described in Section III.B.4.e, we also seek comment on an alternative approach to imported renewable fuel in which foreign renewable fuel producers would have the option of not participating in RFS2 but still export renewable fuel to the U.S. Under this alternative approach, foreign producers would have to meet requirements for segregating their fuel from renewable fuel for which RINs were generated, and the importer of their fuel would be required to track it to ensure that the fuel remains segregated in the U.S. and is not used by a domestic company for illegal RIN generation.

While it is important that all RINs be based on accurate information about the feedstocks and production process used to produce the renewable fuel, it may not be necessary to place the burden upon importers for acquiring this information before they generate RINs. Instead, an alternative approach would prohibit importers from generating any RINs, and instead require foreign producers to generate RINs for all renewable fuel that they export to the U.S. We recognize that this would be a significant change from RFS1, and thus we are not proposing it. However, since it would place the same responsibilities on foreign producers as domestic producers, we request comment on it.

3. Facilities With Multiple Applicable Pathways

If a given facility's operations can be fully represented by a single pathway, then a single D code taken from the lookup table will be applicable to all RINs generated at or imported into that facility. However, we recognize that this will not always be the case. Some facilities use multiple feedstocks at the same time, or switch between different feedstocks over the course of a year. A facility may be modified to produce the same fuel but with a different process, or may be modified to produce a different type of fuel. Any of these situations could result in multiple pathways being applicable to a facility, and thus there may be more than one D code used for various RINs generated at the facility.

If more than one pathway applies to a facility within a compliance period, no special steps would need to be taken if the D codes were the same for all the applicable pathways. In this case, all RINs generated at the facility would have the same D code. As for all other producers, the producer with multiple applicable pathways would describe its feedstock(s), fuel type(s), and production process(es) in its annual report to the Agency so that we could verify that the D code used was appropriate.

However, if more than one pathway applies to a facility within a compliance period and these pathways have been assigned different D codes, then the producer must determine which D codes to use when generating RINs. There are a number of different ways that this could occur, and our proposed approach to designating D codes for RINs in these cases is described in Table III.D.3–1.

TABLE III.D.3–1—PROPOSED APPROACH TO ASSIGNING MULTIPLE D CODES FOR MULTIPLE APPLICABLE PATHWAYS

Case	Description	Proposed approach
1	The pathway applicable to a facility changes on a specific date, such that one single pathway applies before the date and another single pathway applies on and after the date.	The applicable D code used in generating RINs must change on the date that the fuel produced changes pathways.
2	One facility produces two or more different types of renewable fuel at the same time.	The volumes of the different types of renewable fuel should be measured separately, with different D codes applied to the separate volumes.
3	One facility uses two or more different feedstocks at the same time to produce a single type of renewable fuel.	For any given batch of renewable fuel, the producer should assign the applicable D codes using a ratio (explained below) defined by the amount of each type of feedstock used.

In general, we are not aware of a scenario in which a facility uses two different processes in parallel to convert a single type of feedstock into a single type of renewable fuel. Therefore, we have not created a case in Table III.D.3–1 to address it. However, we know that some corn-ethanol facilities may dry only a portion of their distiller's grains and leave the remainder wet. Using the lifecycle with an assumed 100 year timeframe and 2% discount rate for GHG emission impacts, the treatment of the distiller's grains could impact the determination of whether the 20% GHG threshold for renewable fuel has been met, a corn-ethanol facility that dries some portion of its distiller's grains would need to implement additional technologies in order to qualify to generate RINs for all the ethanol it produces (if the facility has not been grandfathered). The lifecycle analyses conducted for this proposal only examined cases in which a corn-ethanol facility dried 100% of its distiller's grains or left 100% of its distiller's grains wet. As a result, a corn-ethanol facility that dried only a portion of its distiller's grain would be treated as if it dried 100% of its grains, and would thus need to implement additional GHG-reducing technologies as described in the lookup table in order to qualify to generate RINs. This is reflected in the list of required production technologies in the lookup table at § 80.1426(d) for facilities that dry any portion of their distiller's grains. In practice, depending on the selection of other technologies, it may be possible for a facility using some combination of dry and wet distiller's grains to meet the 20% GHG threshold. Therefore we request comment on whether a selection of pathways should be included in the lookup table that represent corn-ethanol facilities that dry only a portion of their distiller's grains. We also request comment on whether RINs could be assigned to only a portion of the facility's ethanol in cases wherein only a portion of the distiller's grains are dried.

We propose that the cases listed in Table III.D.3–1 be treated as hierarchical, with Case 2 only being used to address a facility's circumstances if Case 1 is not applicable, and Case 3 only being used to address a facility's circumstances if Case 2 is not applicable. We believe that this approach covers all likely cases in which multiple applicable pathways may apply to a renewable fuel producer. Some examples in which Case 2 or 3 would apply are provided in Table III.D.3–2.

TABLE III.D.3–2—EXAMPLES OF FACILITIES WITH MULTIPLE PATHWAYS

Example	Applicable case	Reasoning
Facility makes both diesel and naphtha (a gasoline blendstock) from gasified biomass in a Fischer-Tropsch process.	2	The production of two types of renewable fuel from the same feedstock and process makes it highly likely that the two pathways would be assigned the same D code. If LCA determined that this was not the case, the volumes of diesel and naphtha can be measured separately and assigned separate batch-RINs with different D codes.
Facility produces ethanol from corn starch and corn cobs/husks	3	There is only one fuel produced, so Case 2 cannot apply.
Facility makes both ethanol and butanol through two different processes using corn starch.	2	Case 2 is the default since there are two separate fuels produced. However, Case 3 would not apply regardless because there is only one feedstock.
Facility makes ethanol through an enzymatic hydrolysis process using both switchgrass and corn stover.	3	There is only one fuel produced, so Case 2 cannot apply.

A facility where two or more different types of feedstock were used to produce a single fuel (such as Case 3 in Table III.D.3–1) would be required to generate two or more separate batch-RINs [26] for a single volume of renewable fuel, and these separate batch-RINs would have different D codes. The D codes would be chosen on the basis of the different pathways as defined in the lookup table in § 80.1426(d). The number of gallon-RINs that would be included in each of the batch-RINs would depend on the relative amount of the different types of feedstocks used by the facility. We propose to use the useable energy content of the feedstocks to determine how many gallon-RINs should be assigned to each D code. Our proposed calculations are given in the regulations at § 80.1126(d)(5).

In determining the useable energy content of the feedstocks, we propose to take into account several elements to ensure that the number of gallon-RINs associated with each D code is appropriate. For instance, we propose

[26] Batch-RINs and gallon-RINs are defined in the RFS1 regulations at 40 CFR 80.1101(o).

that only that portion of a feedstock which is expected to be converted into renewable fuel by the facility should be counted in the calculation. For example, a biochemical cellulosic ethanol conversion process that could not convert the lignin into ethanol would not include the lignin portion of the biomass in the calculation. This approach would also take into account the conversion efficiency of the facility. We propose that the producer of the renewable fuel would be required to designate this fraction for the feedstocks processed by his facility and to include this information as part of its reporting requirements.

We are also proposing to use the energy content of the feedstocks instead of their mass since we believe that their relative energy contents are more closely related than their mass to the energy in the renewable fuel. Producers would be required to designate the energy content (in Btu/lb) of the portion of each of their feedstocks which is converted into fuel. We request comment on whether producers would determine these values independently for their own feedstocks, or whether a standard set of such values should be developed and incorporated into the regulations for use by all renewable fuel producers. If we did specify a standard set of energy content values, we request comment on what those values should be and/or the most appropriate sources for determining those values.

Some components in the calculation of the useable energy content of feedstocks are unlikely to vary significantly for a particular type of feedstock. This would include that portion of a feedstock which is expected to be converted into renewable fuel by the facility, and the relative amount of energy in the two feedstocks. For these factors, we propose that one set of values be determined by the producer and applied to all renewable fuel production within a calendar year. The values could be reassessed annually and adjusted as necessary.

Although we are proposing annual determinations of the portion of a feedstock which is expected to be converted into renewable fuel by the facility and the relative amount of energy in the two feedstocks, we are proposing daily determinations of the total mass of each type of feedstocks used by the facility. This approach would take into account the fact that the relative amount of the different feedstocks used could vary frequently, and thus the determination of the total useable energy content of the feedstocks would be unique to the renewable fuel produced each day. We believe that renewable fuel producers would have ready access to information about total feedstock mass used each day, such that the timely generation of RINs should not be unduly affected. We request comment on the effort and time involved in collecting information on feedstock mass and translating this information on a daily basis into RINs assigned to volumes of renewable fuel.

In order to generate RINs when the processing of two or more different feedstocks in the same facility results in two or more different applicable D codes but a single renewable fuel, the producer would continue to determine the total number of gallon-RINs that must be generated for and assigned to a given volume of renewable fuel using the process established under RFS1. In short, the total volume of the renewable fuel would be multiplied by its Equivalence Value. However, the feedstock's useable energy content would be used to divide the resulting number of gallon-RINs into two or more groups, each corresponding to a different D code. Two, three, or more separate batch-RINs could then be generated and assigned to the single volume of renewable fuel. The sum of all gallon-RINs from the different batch-RINs would be equal to the total number of gallon-RINs that must be generated to represent the volume of renewable fuel.

As described in Section III.J, we propose that in their reports, producers of renewable fuel be required to submit information on the feedstocks they used, their production processes, and the type of fuel(s) they produced during the compliance period. This would apply to both domestic producers and foreign producers who export any renewable fuel to the U.S. We would use this information to verify that the D codes used in generating RINs were appropriate.

4. Facilities That Co-Process Renewable Biomass and Fossil Fuels

We expect situations to arise in which a producer uses a renewable feedstock simultaneously with a fossil fuel feedstock, producing a single fuel that is only partially renewable. For instance, biomass might be cofired with coal in a coal-to-liquids (CTL) process that uses Fischer-Tropsch chemistry to make diesel fuel, biomass and waste plastics might be fed simultaneously into a catalytic or gasification process to make diesel fuel, or vegetable oils could be fed to a hydrotreater along with petroleum to produce a diesel fuel. In these cases, the diesel fuel would be only partially renewable. We propose that RINs must be generated in such cases, but in such a way that the number of gallon-RINs corresponds only to the renewable portion of the fuel.

Under RFS1, we created a provision to address the co-processing of ''renewable crudes'' along with petroleum feedstocks to produce a gasoline or diesel fuel that is partially renewable. *See* 40 CFR 80.1126(d)(6). However, this provision would not apply in cases where either the renewable feedstock or the fossil fuel feedstock is a gas (e.g., biogas, natural gas) or a solid (e.g. biomass, coal). Therefore, we propose to eliminate the existing provision applicable only to liquid feedstocks and replace it with a more comprehensive approach that could apply to liquid, solid, or gaseous feedstocks and any type of conversion process. Our proposed approach would be similar to the treatment of renewable fuels with multiple D codes as described in Section III.D.3 above. Thus, the producer would determine the renewable fuel volume that would be assigned RINs based on the amount of energy in the renewable feedstock relative to the amount of energy in the fossil feedstock. Just as two different batch-RINs would be generated for a single volume of renewable fuel produced from two different renewable feedstocks, only one batch-RIN would be generated for a single volume of renewable fuel produced from both a renewable feedstock and a fossil feedstock, and this one batch-RIN would be based on the contribution that the renewable feedstock makes to the volume of renewable fuel. See § 80.1426(d)(6) for our proposed calculations under these circumstances.

For facilities that co-process renewable biomass and fossil fuels to produce a single fuel that is partially renewable, we propose to use the relative energy in the feedstocks to determine the number of gallon-RINs that should be generated. As shown in the regulations at § 80.1426(d)(6), the calculation of the relative energy contents would include factors that take into account the conversion efficiency of the plant, and as a result, potentially different reaction rates and byproduct formation for the various feedstocks would be accounted for. The relative energy content of the feedstocks would be used to adjust the basic calculation of the number of gallon-RINs downward from that calculated on the basis of fuel volume alone. The D code that would be assigned to the RINs would be drawn from the lookup table in the regulations as if the feedstock was entirely renewable biomass. Thus, for instance, a coal-to-liquids plant that co-processes some cellulosic biomass to make diesel fuel would be treated as a plant that produces only cellulosic diesel for purposes of identifying the appropriate D code.

One drawback of our proposed approach is that it does nothing to address lifecycle GHG emissions associated with the portion of the fuel that comes from the fossil fuel feedstock. While the lifecycle GHG thresholds under RFS2 are specific to fuels made from renewable biomass, allowing a fuel producer to generate RINs for the co-processing of renewable biomass with fossil fuels might provide a greater incentive for production of transportation fuels from processes that have high lifecycle GHGs. In such cases, the GHG benefits of the renewable fuel may be overwhelmed by the GHG increases of the fossil fuel. This is of particular concern for CTL processes which generally produce higher lifecycle GHG emissions per unit of transportation fuel produced than traditional refinery processes that use petroleum. Under our proposed approach to the treatment of co-processing of renewable biomass and fossil fuels, incentives would be provided for renewable fuels with lower lifecycle GHG emissions, but there will be little disincentive for production of high GHG-emitting fuels made from fossil fuels.

As an alternative to our proposed approach, we could treat fuels produced through co-processing of renewable biomass and fossil fuel feedstocks in an aggregate fashion rather than focusing only on the renewable portion of those fuels. In this approach, we would require the whole fuel produced at co-processing facilities to meet the lifecycle GHG thresholds under RFS2. If, for instance, a diesel fuel produced from co-processing renewable biomass and coal in a Fischer-Tropsch process were determined to not meet the 20% GHG threshold, no RINs could be generated even though the renewable portion of the diesel fuel might meet the 20% GHG threshold. However, this alternative approach would require a lifecycle analysis that is specific to the relative amounts of renewable biomass and fossil fuel feedstock being used at a particular facility, which would in turn require a facility-specific lifecycle GHG model. As described in Section II.A.3, this is beyond the capabilities of our current modeling tools. Moreover, this alternative approach could have undesirable effects on facilities that produce renewable fuel from multiple renewable feedstocks. For instance, if a facility produced ethanol from both corn starch and corn stover and the lifecycle GHG assessment was conducted for this specific facility as a whole, it might not meet the 60% GHG threshold for cellulosic biofuel. As a result, the portion of the ethanol produced from corn stover could not be counted as cellulosic biofuel but would instead count only as renewable fuel, even though our lifecycle analyses have determined that ethanol from corn stover does meet the 60% GHG threshold. Nevertheless, we seek comment on this alternative approach.

As another alternative to using the relative energy in the feedstocks to determine the number of gallon-RINs that should be generated, we could allow renewable fuel producers to use an accepted test method to directly measure the fraction of the fuel which originates with biomass rather than a fossil fuel feedstock. For instance, ASTM test method D–6866 can be used to determine the renewable content of gasoline. However, such a test method could not distinguish between fuel made from feedstocks that meet the definition of renewable biomass, and other biomass feedstocks which do not meet the definition of renewable biomass. We request comment on the use of ASTM D–6866 or equivalent test methods to determine the number of RINs generated when multiple feedstocks are used simultaneously to make a fuel.

5. Treatment of Fuels Without an Applicable D Code

Among all fuels covered by our proposed RFS2 program, we have identified a number of specific ''pathways'' of fuels, defined by fuel type, feedstock, and various production process characteristics. This list includes fuels that either already exist in the marketplace or are expected to exist sometime during the next decade, and for which we had sufficient information to conduct a lifecycle analysis of the GHG emissions. As described in III.D.2, we have assigned each pathway a D code corresponding to the four categories of renewable fuel defined in EISA.

Despite our efforts to explicitly address the existing or possible pathways in our proposed program, it is expected that a fuel, process, or feedstock will arise that is a renewable fuel meeting the RFS definitions, and yet is not among the fuels we explicitly identified in the regulations as a RIN-generating fuel. This could occur for an entirely new fuel type, a known fuel produced from a new feedstock, or a known fuel produced through a unique production process. In such cases, the fuel may meet our definition of renewable fuel covered under our program, but would not have been assigned the appropriate D code in the regulations. To address some of these fuel pathways, we are proposing the use of default D codes.[27]

Under our proposed approach, the producer would be required to register under the RFS program and provide information about their facility as described in Section III.C. The producer will also be required to provide any information necessary for EPA to perform a proper lifecycle analysis. Additionally, the company would need to register their renewable fuel under title 40 CFR part 79 as a motor vehicle fuel. If EPA determines, based on the company's registration, that they are not producing renewable fuel, the company will not be able to generate RINs.

In order to generate RINs, the producer of renewable fuel would apply through our registration system to use the D code that best represents his combination of fuel type, feedstock, and production process. If the producer's combination of fuel type and feedstock, but not production process, is represented in an already defined pathway combination of fuels, processes, or feedstocks, the producer would use the highest numerical D code applicable to the fuel and feedstock combination. For example, if a fuel and feedstock spans the D Codes 3 and 4 then the producer would use 4 until the regulations were updated. The producer then would generate RINs using the D code 4, until EPA could perform a lifecycle analysis and issue a change to the regulations to reflect the new pathway. If the producer is making a new fuel or using a new feedstock that producer will still need to apply, but would be unable to generate RINs until the regulations were updated with the new pathway.

Since certain combinations of fuel, production process, and feedstock have been determined through our lifecycle analysis to not meet the minimum 20% GHG threshold, they would be ineligible to generate RINs and EPA would not allow producers using those processes to generate RINs using a default D code. To effectuate this, we propose to provide a statement in the regulations of pathways that are prohibited from using a default D code. For example, if a producer is producing ethanol from cornstarch in a process that uses coal or natural gas for process heat, then regardless of other elements of the production process the producer may not use a default D code, but must register and provide information

[27] Additional default requirements applicable to importers of renewable fuels are discussed in Section III.D.2.c.

necessary to conduct a lifecycle analysis.

EPA will not conduct a rulemaking every year to adjust the regulations for new fuels, processes, or feedstocks. EPA will periodically update the regulations as necessary under CAA section 211(o)(4) and may take the opportunity to update the list of fuel pathways. Companies are encouraged to work with EPA early to provide information about fuels, processes, or feedstocks not in the regulations so that we can do a proper lifecycle analysis before these fuels, processes, or feedstocks are commercially viable. EPA is proposing that if the regulations are not updated with in 5 years of receipt of the application and the application is not rejected in that time then the producer will no longer be able to generate RINs using a default D code until the regulations are updated.

6. Carbon Capture and Storage (CCS)

One element of the production process that may enable renewable fuel producers to greatly improve their GHG emissions is carbon capture and storage (CCS). CCS involves the process of capturing CO_2 from an industrial or energy-related source, transporting it to a suitable storage site, and isolating it from the atmosphere for long periods of time. While we are not proposing a specific pathway in today's NPRM that would allow a renewable fuel producer to use CCS to demonstrate compliance with the GHG thresholds, we believe that CCS could be an effective method for significantly reducing the GHG emissions associated with renewable fuel production.

Although there are several possible approaches for long-term storage of CO_2, this section will only address geologic storage as a means to reduce CO_2 emissions from renewable fuel production facilities. This method entails injecting CO_2 deep underground and monitoring to ensure long-term isolation from the atmosphere. The remainder of this section describes the efforts to establish regulatory requirements for CCS, and the further work that needs to be done before allowing the use of CCS as an element in pathways eligible for generating RINs under the RFS2 program.

Although there is limited experience with integrated CCS systems in the US, where CO_2 is captured, transported and injected for long-term storage, there are commercial CCS projects operating today and several DOE pilot projects underway to further demonstrate CCS in a variety of industrial sectors and geological settings. The EPA has been working closely with DOE to collectively ensure that governmental research programs address the range of potential environmental risks associated with CCS and that appropriate regulatory frameworks are in place to manage risks.[28]

The EPA has experience regulating underground injection of various fluids and believes that well selected, designed, and managed sites can sequester CO_2 for long periods of time. The Safe Drinking Water Act's (SDWA) Underground Injection Control (UIC) Program has been successfully regulating tens of thousands of injection wells for over 35 years. The UIC program's siting, well construction, and monitoring and testing requirements are keys to ensuring that injected fluids remain in the geologic rock formations specifically targeted for injection.

In March 2007, the EPA issued UIC permitting guidelines for pilot geologic sequestration projects in order to ensure that these projects could move forward under an appropriate regulatory framework. Subsequently, on July 25, 2008, EPA issued a proposed rulemaking that would address commercial-scale projects and establish the regulatory requirements for underground injection of CO_2 for the purpose of geologic storage (73 FR 43492). These proposed regulations include permitting requirements, criteria for establishing and maintaining the mechanical integrity of wells, minimum criteria for siting, injection well construction and operating requirements, recordkeeping and reporting requirements, etc. While these regulations cover many operational aspects of underground injection and monitoring geologic sequestration sites, their purpose is to protect underground sources of drinking water. The SDWA does not provide authority to develop regulations for all areas related to CCS, including capture and transport of CO_2 and accounting or certification for GHG emissions reductions. The UIC requirements will not replace or supersede other statutory or regulatory requirements for protection of human health and the environment. Thus, parties that implemented CCS would still need to obtain all necessary permits from appropriate State and Federal authorities under the Clean Air Act or any other applicable statutes and regulations.

Specific areas that would need to be addressed before allowing the renewable fuel producers to benefit from CCS in meeting GHG thresholds include: the means through which the CO_2 would be captured from the renewable fuel production facility, the minimum fraction that must be captured, appropriate means for transporting to the injection site, and appropriate monitoring procedures to ensure long-term storage of CO_2. We believe the CO_2 that would be most readily available for capture in an ethanol production facility would be that which is produced during the fermentation process, not CO_2 that is generated during the combustion of fossil fuels for process energy, since CO_2 from the fermentation process provides a more concentrated stream that is more amenable to capture. However, we request comment on the efficacy of capturing CO_2 from the combustion of fossil fuels for process heat.

A mechanism for accounting for potential leakage of captured CO_2 during transport to the storage site or after injection has occurred would also be required. The renewable fuel producer would be responsible for tracking any leaks that occur after CO_2 capture. We request comment on the type and level of surface and/or subsurface monitoring that would be required to demonstrate long-term storage of CO_2. We also request comment on whether additional monitoring and reporting requirements would be appropriate. For example, whether there should be a requirement for the monitoring and reporting of CO_2 volumes captured, transported, injected and stored, as well as any fugitive emissions released. We seek comment on the appropriateness of establishing a performance standard for CO_2 leakage during transport, injection, and/or geologic storage, and any data that might be available to help develop such a performance standard.

Finally, in order to generate RINs, the renewable fuel producer would have to, at minimum, demonstrate that a sufficient amount of CO_2 was sequestered to reach the appropriate lifecycle GHG threshold. We expect that the regulations would need to specify the minimum fraction of CO_2 emitted that must be captured and stored in order for a renewable fuel producer to qualify for generating RINs. We request comment on whether this approach is appropriate.

E. Applicable Standards

CAA section 211(o)(3) describes how the applicable standards are to be calculated. The only changes made to this provision by EISA are substituting ''transportation fuel'' for gasoline, and reflecting the expanded number of years

[28] More information on the EPA's UIC Program and ongoing research into CCS issues is available at: *http://www.epa.gov/safewater/uic/wells_sequestration.html.*

and additional renewable fuel categories added by Congress in CAA 211(o)(2). In general the form of the standard will not change under RFS2. The renewable fuel standards will continue to be expressed as a volume percentage, and will be used by each refiner, blender or importer to determine their renewable volume obligations. The applicable percentages are set so that if each regulated party meets the percentages, then the amount of renewable fuel, cellulosic biofuel, biomass-based diesel, and advanced biofuel used will meet the volumes specified in Table II.A.1–1.[29]

The new renewable fuel standards would be based on both gasoline and diesel volumes as opposed to only gasoline. Under CAA section 211(o)(3), EPA must determine the refiners, blenders and importers who are subject to the standard. We propose that the standard would apply to refiners, blenders and importers of diesel in addition to gasoline, for both highway and nonroad uses. As described more fully in Section III.F.3, we are proposing at this time that other producers of transportation fuel, such as producers of natural gas, propane, and electricity from fossil fuels, would not be subject to the standard. Since the standard would apply to refiners, blenders and importers of gasoline and diesel, these are also the transportation fuels that would be used to determine the annual volume obligation of the refiner, blender or importer.

The projected volumes of gasoline and diesel used to calculate the standards would continue to be provided by EIA's Short-Term Energy Outlook (STEO). The standards applicable to a given calendar year would be published by November 30 of the previous year. The renewable fuel standards would also continue to take into account various adjustments. For instance, gasoline and diesel volumes would be adjusted to account for the required renewable fuel volumes, and gasoline and diesel volumes produced by small refineries and small refiners would continue to be exempt through 2010.

While the calculation methodology for determination of standards would not change, there would be four separate standards under the new RFS2 program, corresponding to the four separate volume requirements shown in Table II.A.1–1. The specific formulas we propose using to calculate the renewable fuel standards are described below in Section III.E.1.

In order for an obligated party to demonstrate compliance, the percentage standards would 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 would continue to be referred to as its Renewable Volume Obligation (RVO). Since there would be four separate standards under the RFS2 program, there would likewise be four separate RVOs applicable to each refiner, importer, or other obligated party. However, all RVOs would be determined in the same way as described in the current regulations at § 80.1107, with the exception that each standard would apply to the sum of all gasoline and diesel produced or imported as opposed to just the gasoline volume. The formulas we propose using to calculate the RVOs under the RFS2 program are described in Section III.G.1.

1. Calculation of Standards

a. How Would the Standards Be Calculated?

Table II.A.1–1 shows the required overall volumes of four types of renewable fuel specified in EISA. The four separate renewable fuel standards would be based primarily on (1) the 49-state[30] gasoline and diesel consumption volumes projected by EIA, and (2) the total volume of renewable fuels required by EISA for the coming year. Each renewable fuel standard will be expressed as a volume percentage of combined gasoline and diesel sold or introduced into commerce in the U.S., and will be used by each obligated party to determine its renewable volume obligation.

While we are proposing that the standards be based on the sum of all gasoline and diesel, an alternative would split the standards between those that would be specific to gasoline and those that would be specific to diesel. To accomplish this, it would be necessary to project the fraction of the volumes shown in Table II.A.1–1 for cellulosic biofuel, advanced biofuel, and total renewable fuel that would represent gasoline-displacing renewable fuel, and apply this portion of the required volumes to gasoline (by definition the biomass-based diesel standard would have no component relevant to gasoline). The remaining portion would apply to diesel. The result would be seven standards instead of four. This approach to setting standards would more readily align the RFS obligations with the relative amounts of gasoline and diesel produced or imported by each obligated party. For instance, a refiner that produced only diesel fuel would have no obligations under the RFS program for renewable fuels that are used to displace gasoline. However, this alternative approach relies on projections of the relative amounts of gasoline-displacing and diesel-displacing renewable fuels that would need to be updated every year. While such projections would be available through our proposed Production Outlook Reports (see Section III.K), we nevertheless believe that such an approach would unnecessarily complicate the program, and thus we are not proposing it. However, we request comment on it.

In determining the applicable percentages for a calendar year, EISA requires EPA to adjust the standard to prevent the imposition of redundant obligations on any person and to account for renewable fuel use 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 standards will in fact result in the volumes shown in Table II.A.1–1, we must make several adjustments to what otherwise would be a simple calculation.

As stated, the renewable fuel standards for a given year are basically the ratio of the amount of each type of renewable fuel specified in EISA for that year to the projected 49-state non-renewable combined gasoline and diesel volume for that year. While the required amount of total renewable fuel for a given year is provided by EISA, the Act requires EPA to use an EIA estimate of the amount of gasoline and diesel that will be sold or introduced into commerce for that year to determine the percentage standards. The levels of the percentage standards would be reduced if Alaska or a U.S. territory chooses to participate in the RFS2 program, as gasoline and diesel produced in or imported into that state or territory would then be subject to the standard.

As mentioned above, we are proposing that EIA's STEO continue to be the source for projected gasoline, and now diesel, consumption estimates. These volumes include renewable fuel use. In order to achieve the volumes of renewable fuels specified in EISA, the gasoline and diesel volumes used to

[29] Actual volumes can vary from the amounts required in the statute. For instance, lower volumes may result if the statutorily required volumes are adjusted downward according to the waiver provisions in CAA 211(o)(7)(D). Also, higher or lower volumes may result depending on the actual consumption of gasoline and diesel in comparison to the projected volumes used to set the standards.

[30] Hawaii opted-in to the original RFS program; that opt-in is carried forward to the proposed new program.

determine the standard must be the non-renewable portion of the gasoline and diesel pools. In order to get total non-renewable gasoline and diesel volumes, we must subtract the total renewable fuel volume from the total gasoline and diesel volume. As with RFS1, 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 STEO.

CAA section 211(o) exempts small refineries [31] from the RFS requirements until the 2011 compliance period. In RFS1, we extended this exemption to the few remaining small refiners not already exempted.[32] Since EPA proposes that small refineries and small refiners continue to be exempt from the program until 2011 under the new RFS2 regulations, EPA will exclude their gasoline and diesel volumes from the overall non-renewable gasoline and diesel volumes used to determine the applicable percentages until 2011. EPA believes this is appropriate because the percentage standards need to be based on the gasoline and diesel subject to the renewable volume obligations, to achieve the overall required volumes of renewable fuel. Because the total small refinery and small refiner gasoline production volume is expected to be fairly constant compared to total U.S. transportation fuel production, we are proposing to estimate small refinery and small refiner gasoline and diesel volumes using a constant percentage of national consumption, as we did in RFS1. Using information from gasoline batch reports submitted to EPA for 2006, EIA data, and input from the California Air Resources Board regarding California small refiners, we estimate that small refinery volumes constitute 11.9% of the gasoline pool, and 15.2% of the diesel pool.

CAA section 211(o) 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 RFS2 program. Accounting for this volume of renewable fuel would reduce the total volume of renewable fuel use required of others, and thus directionally would reduce the percentage standard. However, as we discussed in RFS1, the amount of renewable fuel that would qualify, i.e., that was used by exempt small refineries and small refiners but not used as part of the RFS program, is expected to be very small. In fact, these volumes would not significantly change the resulting percentage standards. Whatever renewable fuels small refineries and small refiners blend will be reflected as RINs available in the market; thus there is no need for a separate accounting of their renewable fuel use in the equations used to determine the standards. We thus are proposing, as for RFS1, that this value be zero.

Just as with their corresponding gasoline and diesel volumes, renewable fuels used in Alaska or U.S. territories are not included in the renewable fuel volumes that are subtracted from the total gasoline and diesel volume estimates. Section 211(o) of the Clean Air Act requires that the renewable fuel be consumed in the contiguous 48 states, and any other state or territory that opts in to the program (Hawaii has subsequently opted in). However, because renewable fuel produced in Alaska or a U.S. territory is unlikely to be transported to the contiguous 48 states or to Hawaii, including their renewable fuel volumes in the calculation of the standard would not serve the purpose intended by section 211(o) of the Clean Air Act of ensuring that the statutorily required renewable fuel volumes are consumed in the 48 contiguous states and any state or territory that opts in.

In summary, we are proposing that the total projected non-renewable gasoline and diesel volumes from which the annual standards are calculated be based on EIA projections of gasoline and diesel consumption in the contiguous 48 states and Hawaii, adjusted by constant percentages of 11.9% and 15.2% in 2010 to account for small refinery/refiner gasoline and diesel volumes, respectively, and with built-in correction factors to be used when and if Alaska or a territory opt-in to the program. If actual gasoline and diesel consumption were to exceed the EIA projections, the result would be that renewable fuel volumes would exceed the statutory volumes. Conversely, if actual gasoline and diesel consumption was less than the EIA projection for a given year, actual renewable fuel volumes could be lower than the statutory volumes depending on market conditions. Additional special considerations in establishing the annual cellulosic biofuel standard are discussed below in Section III.E.1.c.

The following formulas will be used to calculate the percentage standards:

$$\mathrm{Std}_{\mathrm{CB,\,i}} = 100\% \times \frac{\mathrm{RFV}_{\mathrm{CB,\,i}}}{(G_i - RG_i) + (GS_i - RGS_i) - GE_i + (D_i - RD_i) + (DS_i - RDS_i) - DE_i}$$

$$\mathrm{Std}_{\mathrm{BBD,\,i}} = 100\% \times \frac{\mathrm{RFV}_{\mathrm{BBD,\,i}}}{(G_i - RG_i) + (GS_i - RGS_i) - GE_i + (D_i - RD_i) + (DS_i - RDS_i) - DE_i}$$

$$\mathrm{Std}_{\mathrm{AB,\,i}} = 100\% \times \frac{\mathrm{RFV}_{\mathrm{AB,\,i}}}{(G_i - RG_i) + (GS_i - RGS_i) - GE_i + (D_i - RD_i) + (DS_i - RDS_i) - DE_i}$$

$$\mathrm{Std}_{\mathrm{RF,\,i}} = 100\% \times \frac{\mathrm{RFV}_{\mathrm{RF,\,i}}}{(G_i - RG_i) + (GS_i - RGS_i) - GE_i + (D_i - RD_i) + (DS_i - RDS_i) - DE_i}$$

[31] Under section 211(o) of the Clean Air Act, small refineries are those with 75,000 bbl/day or less average aggregate daily crude oil throughput.

[32] *See* Section IV.B.2.

Where

$Std_{CB,i}$ = The cellulosic biofuel standard for year i, in percent

$Std_{BBD,i}$ = The biomass-based diesel standard for year i, in percent

$Std_{AB,i}$ = The advanced biofuel standard for year i, in percent

$Std_{RF,i}$ = The renewable fuel standard for year i, in percent

$RFV_{CB,i}$ = Annual volume of cellulosic biofuel required by section 211(o)(2)(B) of the Clean Air Act for year i, in gallons

$RFV_{BBD,i}$ = Annual volume of biomass-based diesel required by section 211(o)(2)(B) of the Clean Air Act for year i, in gallons

$RFV_{AB,i}$ = Annual volume of advanced biofuel required by section 211(o)(2)(B) of the Clean Air Act for year i, in gallons

$RFV_{RF,i}$ = Annual volume of renewable fuel required by section 211(o)(2)(B) of the Clean Air Act for year i, in gallons

G_i = Amount of gasoline projected to be used in the 48 contiguous states and Hawaii, in year i, in gallons*

D_i = Amount of diesel projected to be used in the 48 contiguous states and Hawaii, in year i, in gallons

RG_i = Amount of renewable fuel blended into gasoline that is projected to be consumed in the 48 contiguous states and Hawaii, in year i, in gallons

RD_i = Amount of renewable fuel blended into diesel that is projected to be consumed in the 48 contiguous states and Hawaii, in year i, in gallons

GS_i = Amount of gasoline projected to be used in Alaska or a U.S. territory in year i if the state or territory opts in, in gallons*

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

DS_i = Amount of diesel projected to be used in Alaska or a U.S. territory in year i if the state or territory opts in, in gallons*

RDS_i = Amount of renewable fuel blended into diesel that is projected to be consumed in Alaska or a U.S. territory in year i if the state or territory opts in, in gallons

GE_i = The amount of gasoline projected to be produced by exempt small refineries and small refiners in year i, in gallons, in any year they are exempt per §§ 80.1441 and 80.1442, respectively. Equivalent to $0.119 * (G_i - RG_i)$.

DE_i = The amount of diesel projected to be produced by exempt small refineries and small refiners in year i, in gallons, in any year they are exempt per §§ 80.1441 and 80.1442, respectively. Equivalent to $0.152 * (D_i - RD_i)$.

* Note that these terms for projected volumes of gasoline and diesel use include gasoline and diesel that has been blended with renewable fuel.

b. Proposed Standards for 2010

In today's NPRM we are proposing the specific standards that would apply to all obligated parties in calendar year 2010. We will consider comments received on these standards as part of the comment period associated with today's NPRM, and we intend to issue a **Federal Register** notice by November 30, 2009 setting the applicable standards for 2010. While we are not proposing standards for 2011 and beyond, we present our current projections of these standards in the next section.

Under CAA section 211(o)(7)(D)(i), EPA is required to make a determination each year regarding whether the required volumes of cellulosic biofuel for the following year can be produced. For any calendar year for which the projected volume of cellulosic biofuel production is less than the minimum required volume, the projected volume becomes the basis for the cellulosic biofuel standard. In such a case, the statute also indicates that EPA may also lower the required volumes for advanced biofuel and total renewable fuel.

Based on information available to date, we believe that there are sufficient plans underway to build plants capable of producing 0.1 billion gallons of cellulosic biofuel in 2010, the minimum volume of cellulosic biofuel required by EISA for 2010. Our April 2009 industry assessment concludes that there could be seven small commercial-scale plants online in 2010 (as well as a series of pilot and demonstration plants) capable of producing just over 100 million gallons of cellulosic biofuel. And since the majority of this production (73%) is projected to be cellulosic diesel, the ethanol-equivalent complaince volume could be closer to 145 million gallons. While it is possible that some of these plants could be delayed or a portion of the projected production may not meet the definition of ''cellulosic biofuel'' (due to mixed feedstocks), it is also possible that other plans could proceed ahead of their current schedules. For more on the 2010 cellulosic biofuel production assessment, refer to Section 1.5.3.4 of the DRIA

On the basis of this information, we are not proposing that any portion of the cellulosic biofuel requirement for 2010 be waived. Therefore, we are proposing that the volumes shown in Table II.A.1–1 be used as the basis for the applicable standards for 2010. As described more fully in Section III.E.2 below, we are also proposing that the 2010 standard for biomass-based diesel be based on the combined required volumes for 2009 and 2010, or a total of 1.15 billion gallons. The proposed standards for 2010 are shown in Table III.E.1.b–1.

TABLE III.E.1.b–1—PROPOSED STANDARDS FOR 2010

[Percent]

Cellulosic biofuel	0.06
Biomass-based diesel	0.71
Advanced biofuel	0.59
Renewable fuel	8.01

As described more fully in Section III.E.1.d below, we are proposing that the RFS2 program take effect on January 1, 2010, but we are also taking comment on an effective date later than January 1, 2010, including January 1, 2011 and a mid-2010 effective date. If the RFS2 program became effective mid-2010, the RFS1 program would apply during the first part of 2010 and the RFS2 program would apply for the remainder of the year. We request comment on whether the four proposed standards shown in Table III.E.1.b–1 would apply only to gasoline and diesel produced or imported after the RFS2 effective date or should apply to all gasoline and diesel produced in 2010. We also request comment on whether a single standard for total renewable fuel should apply under RFS1 regulations for the first part of 2010.

c. Projected Standards for Other Years

As discussed above, we intend to set the percentage standards for each upcoming year based on the most recent EIA projections, and using the other sources of information as noted above. We would publish the standard in the **Federal Register** by November 30 of the preceding year. The standards would be used to determine the renewable volume obligations based on an obligated party's total gasoline and diesel production or import volume in a calendar year, January 1 through December 31. An obligated party will calculate its Renewable Volume Obligations (discussed in Section III.G.1) using the annual standards.

For illustrative purposes, we have estimated the standards for 2011 and later based on current information using the formulas discussed above, and assuming no modifications to the annual volumes required.[33] These values are listed below in Table III.E.1.c-1. The required renewable fuel volumes specified in EISA are shown in Table II.A.1–1. The projected gasoline, diesel and renewable fuels volumes were determined from EIA's energy projections. Variables related to Alaska or territory opt-ins were set to zero since we do not have any information related

[33] ''Calculation of the Renewable Fuel Standard for Gasoline and Diesel,'' memo to the docket from Christine Brunner, ASD, OTAQ, EPA, April 2009.

to their participation at this time. No adjustment was made for small refiner or small refinery volumes since their exemption is assumed to end at the end of the 2010 compliance period.

TABLE III.E.1.c–1—PROJECTED STANDARDS UNDER RFS2
[percent]

	Cellulosic biofuel	Biomass-based diesel	Advanced biofuel	Renewable fuel
2011	0.15	0.49	0.83	8.60
2012	0.31	0.61	1.22	9.31
2013	0.61	0.61[a]	1.68	10.09
2014	1.07	0.61[a]	2.28	11.05
2015	1.83	0.61[a]	3.35	12.48
2016	2.58	0.61[a]	4.40	13.49
2017	3.34	0.61[a]	5.46	14.56
2018	4.25	0.61[a]	6.68	15.80
2019	5.19	0.61[a]	7.95	17.11
2020	6.47	0.62[a]	9.25	18.50
2021	8.40	0.62[a]	11.21	20.54
2022	10.07	0.63[a]	13.21	22.65

[a] These projected standards represent the minimum volume of 1.0 billion gallons required by EISA. The actual volume used to set the standard would be determined by EPA through a future rulemaking.

d. Alternative Effective Date

Although we are proposing that the RFS2 regulatory program begin on January 1, 2010 which, depending on timing for the final rule, would allow approximately two months from the anticipated issuance of the rule to its implementation, we seek comment on whether an effective date later than January 1, 2010 would be necessary. If the RFS2 program was not made effective on January 1, 2010, the most straightforward alternative start date would be January 1, 2011. Delaying to 2011 would provide regulated parties additional lead time and would allow all the new requirements and standards to go into effect at the beginning of an annual compliance period. However, delaying to 2011 would also mean that demonstrating compliance with the separate requirements for biomass-based diesel, cellulosic biofuel, and advanced biofuel mandates would not go into effect until 2011. The total renewable fuel mandate in EISA may be able to be implemented with the RFS1 regulations until such time as the RFS2 regulations become effective. However, under the RFS1 regulations, this entire standard would be for conventional biofuels and would be applied to gasoline producers and importers only. There would be no obligation with respect to diesel fuel producers and importers, resulting in a numerically larger standard that would apply to gasoline producers only and which could compel them to market a larger proportion of ethanol as E85 to acquire sufficient RINs for compliance. One possible way to address this issue would be to reduce the 2010 total renewable fuel standard proportionately to reflect the application of the standard only to gasoline producers. However, it does not appear that EPA has statutory authority, or discretion under the RFS1 regulations, to modify the total renewable fuel mandate in this manner. As discussed below in Section III.E.2, any delay beyond January 1, 2010 also has implications for our proposed treatment of the biomass-based diesel volumes required for 2009. EPA invites comment on whether RFS2 implementation should be delayed to January 1, 2011 and, if so, the manner in which the EISA-mandated RFS program should be implemented prior to that date.

Another alternative would be to delay the effective date of the RFS2 program to some time after January 1, 2010 but before January 1, 2011. This alternative would raise the same issues described above (regarding the option of a delay until January 1, 2011) for that portion of 2010 during which RFS2 was not effective. It would also raise additional transition and implementation issues. For instance, we would need to determine whether diesel fuel producers and importers carry a total renewable fuel obligation calculated on the basis of their production for all of 2010 or just the production period in 2010 during which the RFS2 regulations are effective. We would also need to determine whether the 2010 cellulosic biofuel, biomass-based diesel, and advanced biofuel standards applicable under RFS2 should apply to production of gasoline and diesel for all of 2010 or just the production that occurred after the RFS2 regulations were effective If the latter, EPA would need to determine the extent to which RFS1 RINs generated in the first part of 2010 could be used to satisfy RFS2 obligations, given that some 2010 RINs would be generated under the RFS1 requirements while other 2010 RINs would be generated under RFS2 requirements. To accomplish this, RINs generated under the RFS2 requirements would need to be distinguished from RINs generated under RFS1 requirements through the RINs' D codes. Section III.A provides a more detailed description of this alternative approach to the assignment of D codes under the RFS2 program. For additional discussion of how RFS1 RINs would be treated in the transition to the RFS2 program, see our proposed transition approach described in Section III.G.3.

We are requesting comment on all issues related to the option of an RFS2 start date sometime after January 1, 2010, including the need for such a delayed start, the level of the standards, treatment of diesel producers and importers, whether the standards for advanced biofuel, cellulosic biofuel and biomass-based diesel should apply to the entire 2010 production or just the production that would occur after the RFS2 effective date, treatment of the 2009 and/or 2010 biomass-based diesel standard, and the extent to which RFS1 RINs should be valid to show compliance with RFS2 standards.

2. Treatment of Biomass-Based Diesel in 2009 and 2010

We are proposing to make the RFS2 program required through EISA effective on January 1, 2010. The RFS2 program would include an expansion to four separate standards, changes to the RIN system, changes to renewable fuel definitions, the introduction of lifecycle GHG reduction thresholds, and the expansion of obligated parties to include producers and importers of diesel and nonroad fuel. However, EISA requires promulgation of the final RFS2 regulations within one year of enactment and presumes full implementation by January 1, 2009. Moreover, EISA specifies new volume requirements for biomass-based diesel, advanced biofuel, and total renewable fuel for 2009. As described in Section II.A.5, it is not possible to have the full RFS2 program implemented by January 1, 2009. As a result, we must consider how to treat these separate volume requirements for 2009.

a. Proposed Shift in Biomass-Based Diesel Requirement From 2009 to 2010

The statutory language in EISA does not indicate that the existing RFS1 regulations cease to apply on January 1, 2009. Rather, it directs us to ''revise the regulations'' to ensure that the required volumes of renewable fuel are contained in transportation fuel. As a result, until the RFS1 regulations are changed through a notice and comment rulemaking process, they will remain in effect. If the full RFS2 program goes into effect on January 1, 2010, then the existing RFS1 regulations will continue to apply in 2009.

Under RFS1, we set the applicable standard each November for the following compliance period using the required volume of renewable fuel specified in the Clean Air Act, gasoline volume projections from EIA, and the formula provided in the regulations at § 80.1105(d). Since final RFS2 regulations will not be promulgated by the end of 2008, this RFS1 standard-setting process will apply to the 2009 compliance period as well. However, EISA modifies the Clean Air Act to increase the required volume of total renewable fuel for 2009 from 6.1 to 11.1 billion gallons, and thus the applicable standard for 2009, published in November of 2008,[34] reflects this higher volume. This will ensure that the total renewable fuel requirement under EISA for 2009 is implemented.

While the total renewable fuel volume of 11.1 billion gallons will be required in 2009, the existing RFS1 regulations do not provide a mechanism for requiring the 0.5 billion gallons of biomass-based diesel or the 0.6 billion gallons of advanced biofuel required by EISA for 2009. Below we describe our proposed approach for biomass-based diesel. With regard to advanced biofuel, we believe that it is not necessary to implement a separate requirement for the 0.6 billion gallons. Due to the nested nature of the volume requirements, the 0.5 billion gallon requirement for biomass-based diesel would count towards meeting the advanced biofuel requirement, leaving just 0.1 billion gallons that we believe will be supplied through imports of sugar-based ethanol even without a specific mandate for advanced biofuel.

We believe that the deficit carryover provision provides a conceptual mechanism for ensuring that the volume of biomass-based diesel that is required by EISA for 2009 is actually consumed. As described in the RFS1 final rule, the statute permits obligated parties to carry a deficit of any size from one compliance period to the next, so long as a deficit is not carried over two years in a row.[35] In theory this would allow any and all obligated parties to defer compliance with any or all of the 2009 standards until 2010. Based on the precedent set by this statutory provision, we propose that the compliance demonstration for the 2009 biomass-based diesel requirement be extended to 2010. We believe this approach would provide a reasonable transition for biomass-based diesel, given our inability to issue regulations before the beginning of the 2009 calendar year. Our proposed approach would implement the 2009 and 2010 biomass-based diesel volume requirements in a way that ensures that these two years worth of biomass-based diesel would be used, while providing reasonable lead time for obligated parties. It would avoid a transition that fails to have any requirements related to the 2009 biomass-based diesel volume, and instead would require the use of the 2009 volume but would achieve this by extending the compliance period by one year. We believe this is a reasonable exercise of our authority under section 211(o)(2) to issue regulations that ensure that the volumes for 2009 are ultimately used, even though we are unable to issue final regulations prior to the 2009 compliance year. In addition, it is a practical approach that provides obligated parties with appropriate lead time.

To implement our proposed approach, the 2009 requirement of 0.5 billion gallons of biomass-based diesel would be combined with the 2010 requirement of 0.65 billion gallons for a total adjusted 2010 requirement of 1.15 billion gallons of biomass-based diesel. The net effect is that obligated parties can demonstrate compliance with both the 2009 and 2010 biomass-based diesel requirements in 2010, consistent with what the deficit carryover provision would have allowed had we been able to implement the full RFS2 program by January 1, 2009.

Furthermore, we propose to allow all 2009 biodiesel and renewable diesel RINs, identifiable through an RR code of 15 or 17 respectively, to be valid for showing compliance with the adjusted 2010 biomass-based diesel standard of 1.15 billion gallons. This use of previous year RINs for current year compliance would be consistent with our approach to any other standard for any other year and consistent with the flexibility available to any obligated party that carried a deficit from one year to the next. Moreover, it allows an obligated party to acquire sufficient biodiesel and renewable diesel RINs during 2009 to comply with the 0.5 billion gallons requirement, even though their compliance demonstration would not occur until the 2010 compliance period.

While we recognize that RINs generated in 2009 under RFS1 regulations will differ from those generated in 2010 under RFS2 regulations in terms of the purpose of the D code and the other criteria for establishing the eligibility of renewable fuel, we believe that the use of 2009 RINs for compliance with the 2010 adjusted standard is appropriate. It is also consistent with CAA section 211(o)(5), which provides that validly generated credits may be used to show compliance for 12 months. The program transition issue of RINs generated under RFS1 but used to meet standards under RFS2 is discussed in more detail in Section III.G.3 below.

Rather than reducing the 2009 volume requirement for total renewable fuel by 0.5 billion gallons of biomass-based diesel and increasing the 2010 volume requirements for advanced biofuel and total renewable fuel by the same amount, we are proposing that the only standard that would be adjusted would be that for biomass-based diesel in 2010. This approach would minimize the changes to the annual RFS volume requirements and thus would more directly implement the requirements of the statute. However, this approach would also require that we allow 2009 biodiesel and renewable diesel RINs to be used for compliance purposes for both the 2009 total renewable fuel standard as well as the 2010 adjusted biomass-based diesel standard, but not for the 2010 advanced biofuel or total renewable fuel standards. We have

[34] *See* 73 FR 70643.

[35] *See* 72 FR 23935.

identified two possible options for accomplishing this.

i. First Option for Treatment of 2009 Biodiesel and Renewable Diesel RINs

In the first option, an obligated party would add up the 2009 biodiesel and renewable diesel RINs that he used for 2009 compliance with the RFS1 standard for renewable fuel, and reduce his 2010 biomass-based diesel obligation by this amount. Any remaining 2010 biomass-based diesel obligation would need to be covered with either 2009 biodiesel and renewable diesel RINs that were not used for compliance with the renewable fuel standard in 2009, or 2010 biomass-based diesel RINs. This is the option we are proposing in today's notice.

The primary drawback of our proposed option is that 2009 biodiesel and renewable diesel RINs used to demonstrate compliance with the 2009 renewable fuel standard could not be traded to any other party for use in complying with the 2010 biomass-based diesel standard. Thus, for instance, if a refiner acquired many 2009 biodiesel and renewable diesel RINs and used them for compliance with the 2009 renewable fuel standard, and if the number of these 2009 RINs was more than he needed to comply with his 2010 biomass-based diesel obligation, he could not trade the excess to another party. These excess RINs could never be applied to the adjusted 2010 biomass-based diesel standard by any party, and as a result the actual demand for biomass-based diesel could exceed 1.15 bill gal. We believe that obligated parties could avoid this outcome by planning ahead to use no more 2009 biodiesel and renewable diesel RINs for 2009 compliance with the renewable fuel standard than they would need for 2010 compliance with the adjusted biomass-based diesel standard. Moreover, this option could provide obligated parties with sufficient incentive to collect 0.5 billion gallons worth of biodiesel and renewable diesel RINs in 2009 without significant changes to the program's requirements.

ii. Second Option for Treatment of 2009 Biodiesel and Renewable Diesel RINs

Under the second option, biodiesel and renewable diesel RINs generated in 2009 would be allowed to be used for compliance purposes in both 2009 and 2010. To enable this option, for the specific and limited case of biodiesel and renewable diesel RINs generated in 2009, we would modify the regulatory prohibition at § 80.1127(a)(3) limiting the use of RINs for compliance demonstrations to a single compliance year to allow 2009 biodiesel and renewable diesel RINs to be used for compliance purposes in two different years. This change would allow all 2009 biodiesel and renewable diesel RINs to be used to meet the adjusted biomass-based diesel standard in 2010 regardless of whether they were also used to meet the total renewable fuel standard in 2009. We would also need to lift the 20% rollover cap that would otherwise limit the use of 2009 RINs in 2010, and instead allow any number of 2009 biodiesel and renewable diesel RINs to be used to meet the 2010 biomass-based diesel standard.

This option would also require that we implement additional RIN tracking procedures. Under the current RFS1 regulations, RINs used for compliance demonstrations are removed from the RIN market, while under this alternative approach biodiesel and renewable diesel RINs could continue to be valid for compliance purposes vis a vis the adjusted 2010 biomass-based diesel standard even if they were already used for compliance with the renewable fuel standard in 2009. The regulations would need to be changed to allow this, and both EPA's and industry's IT systems would need to be modified to allow for this temporary change.

Due to the additional complexities associated with this option, we are not proposing it. Nevertheless, we request comment on it, as it would more explicitly reflect two separate obligations for calendar year 2009: An RFS1 obligation for total renewable fuel, and an obligation for biomass-based diesel that starts during 2009 with compliance required by the end of 2010 for a volume that covers both 2009 and 2010. We also request comment on whether under this option we should allow 2009 biodiesel and renewable diesel RINs to continue to be bought and sold after 2009 if they are used to demonstrate compliance with the 2009 total renewable fuel standard.

b. Proposed Treatment of Deficit Carryovers and Valid RIN Life For Adjusted 2010 Biomass-Based Diesel Requirement

Although our proposed transition approach is conceptually similar to the statutory deficit carryover provision, the regulatory requirements would not explicitly treat the movement of the 0.5 billion gallons biomass-based diesel requirement from 2009 to 2010 as a deficit carryover. In the absence of any modifications to the deficit carryover provisions, then, an obligated party that did not fully comply with the 2010 biomass-based diesel requirement of 1.15 billion gallons could carry a deficit of any amount into 2011.

If we had been able to implement the 2009 biomass-based diesel volume requirement of 0.5 billion gallons in calendar year 2009, the 2010 biomass-based diesel standard would have been based on 0.65 billion gallons. In this case, the maximum volume of biomass-based diesel that could have been carried into 2011 as a deficit would have been 0.65 billion gallons. In the context of our proposed approach to the treatment of biomass-based diesel in 2009 and 2010, we believe that it would be inappropriate to allow the full 1.15 billion gallons to be carried into 2011 as a deficit. Therefore, we are proposing that obligated parties be prohibited from carrying over a deficit into 2011 larger than 0.65 bill gal. In practice, this would mean that deficit carryovers from 2010 into 2011 for biomass-based diesel could not exceed 57% of an obligated party's 2010 RVO.

Similarly, the combination of the 0.5 billion gallons biomass-based diesel requirement from 2009 with the 2010 volume raises the question of whether 2008 biodiesel or renewable diesel RINs could be used for compliance in 2010 with the adjusted biomass-based diesel standard. Without a change to the regulations, this practice would not be allowed because RINs are only valid for compliances purposes for the year generated or the year after. However, if we had been able to implement the full RFS2 program for the 2009 compliance year, 2008 biodiesel and renewable diesel RINs would be valid for compliance with the 0.5 billion gallons biomass-based diesel requirement. Therefore, we are proposing to modify the regulations to allow excess 2008 biodiesel and renewable diesel RINs to be used for compliance purposes in 2009 or 2010. We request comment on this proposal.

We also propose that the 20% rollover cap would continue to apply in all years as described in more detail in Section IV.D. However, we are proposing an additional constraint in the application of this cap to the biomass-based diesel obligation in the 2010 compliance year. If the 2009 biomass-based diesel volume requirement of 0.5 billion gallons could have been required in 2009, the use of excess 2008 biodiesel and renewable diesel RINs would have been limited to 20% of the 2009 requirement, or a maximum of 0.1 billion gallons. Since we are proposing to require that the 2009 and 2010 biomass-based diesel requirements be combined for a total of 1.15 billion gallons, we propose that the maximum allowable portion that could be derived from 2008 biomass-based diesel RINs would be 0.1 billion gallons. This would represent 8.7% of the 2010 obligation ($^{0.1}/_{1.15}$). In addition to this limit on the use of 2008 RINs for 2010 compliance that is unique to this option, the 20% rollover cap would continue to apply to the use of all previous-year RINs used for compliance purposes in 2010. Thus, the total number of all 2008 and 2009 RINs that could be used to meet the 2010 biomass-based diesel obligation would continue to be capped at 20%. We request comment on this approach.

Finally, we are proposing to allow 2009 RINs that are retired because they are ultimately used for nonroad or home heating oil purposes to be valid for compliance with the 2010 RFS standard. Currently, under RFS1, RINs associated with renewable fuel that is not ultimately used as motor vehicle fuel must be retired. In contrast, under EISA, renewable fuel used for nonroad purposes, except for use in industrial boilers or ocean-going vessels, is considered transportation fuel, and is eligible for the RFS program. We are proposing that 2009 RINs generated for renewable fuel that is ultimately used for nonroad or home heating oil purposes continue to be retired by the appropriate party pursuant to 80.1129(e). However, we are proposing that those retired 2009 nonroad or home heating oil RINs be eligible for reinstatement by the retiring party in 2010. These reinstated RINs may be used by that party to demonstrate compliance with a 2010 RVO, or for sale to other parties who would then use the RINs for compliance purposes. While we anticipate that this proposed provision would be utilized largely for biodiesel RINs that were retired by parties that sold them for use as nonroad fuel or home heating oil, we propose that the provision apply to all RINs. We request comment on this proposed approach.

c. Alternative Approach to Treatment of Biomass-Based Diesel in 2009 and 2010

Under our proposed approach, the 0.5 billion gallon requirement for biomass-based diesel in 2009 would be added to the 0.65 billion gallon requirement for 2010, and the total volume of 1.15 billion gallons would be used as the basis of a single adjusted standard applicable to obligated parties in 2010. The compliance demonstration for this single standard would need to be made by February 28, 2011. As an alternative, we could establish two separate biomass-based diesel standards for which compliance must be demonstrated by February 28, 2011. One of these standards would be based on 0.65 billion gallons and would represent the applicable biomass-based diesel standard for 2010. The other standard would be based on 0.5 billion gallons and would represent the applicable biomass-based diesel standard for 2009. In essence, the standard based on 0.5 billion gallons would be for the 2009 calendar year even though we would extend its compliance demonstration until February 28, 2011.

In this alternative, only excess 2008 or 2009 biodiesel and renewable diesel RINs could be used to comply with the standard based on 0.5 billion gallons. Excess 2009 biodiesel or renewable diesel RINs and 2010 biomass-based diesel RINs could be used to comply with the standard based on 0.65 billion gallons. The 20% rollover cap would apply to both standards. As a result, this alternative approach would effectively implement the 2009 biomass-based diesel standard in calendar year 2009, and thus it may come closer to the statute's requirements than our proposed approach. Moreover, the existing provisions for the valid life of RINs and deficit carryover would not need modification as they would under our proposed approach.

However, this alternative would arguably provide less than appropriate lead time for meeting the 0.5 billion gallon obligation, as it would require obligated parties to begin acquiring sufficient 2008 and 2009 biodiesel and renewable diesel RINs starting in January of 2009 even though our final rulemaking is not expected to be issued until the fall of 2009. There are two reasons that this lead time might nevertheless be considered appropriate. First, obligated parties could wait until the final rule is published to begin acquiring 2008 and 2009 biodiesel and renewable diesel RINs. Moreover, they would not need to demonstrate compliance with the 0.5 billion gallons standard until February 28, 2011, providing ample time to locate and acquire sufficient RINs. Second, the deficit carryover provisions would allow obligated parties to treat the separate 0.5 and 0.65 billion gallon requirements as a single requirement that must be met in total by February 28, 2011. In this sense, this alternative is similar to our proposed approach. We request comment on this alternative approach.

d. Treatment of Biomass-Based Diesel Under an RFS2 Effective Date Other Than January 1, 2010

The above discussion assumes that the RFS2 program is effective on January 1, 2010. If the program effective date is delayed, similar issues arise regarding whether EISA volume mandates for fuel categories with no mandates under RFS1 are lost, or should be recaptured through a delayed compliance demonstration in the first year of the RFS2 program. For a delay beyond January 1, 2010, the issues relate to cellulosic biofuel and advanced biofuel in addition to biomass-based diesel.

For instance, our proposed approach to biomass-based diesel effectively makes the one-year deficit carryover a necessary element of compliance for 2010, and maintains the two-year valid life of RINs. However, if the effective date of RFS2 were delayed to January 1, 2011, we could not take the same approach. By requiring compliance demonstrations to be made in 2011 for the required biomass-based diesel volumes mandated for 2009, 2010, and 2011, we would be effectively requiring a 2-year deficit carryover and a three-year valid life of RINs, contrary to the statutory limitations. As an alternative, one possible approach would be to only sum the required biomass-based diesel volumes for 2010 and 2011 and require compliance demonstrations at the end of 2011.

If the RFS2 program became effective in mid-2010, we would also need to determine the appropriate level of the biomass-based diesel standard, and whether it would apply to gasoline and diesel volumes produced only after the RFS2 effective date, or all gasoline and diesel volumes produced in 2010.

EPA invites comment on whether and how it should recapture these volume mandates under different start-date scenarios.

F. Fuels That Are Subject to the Standards

Under RFS1, producers and importers of gasoline are obligated parties subject to the standards. Any party that produces or imports only diesel fuel is not subject to the standards. EISA changes this provision by expanding the RFS program in general to include transportation fuel. As discussed above, however, section 211(o)(3) continues to require EPA to determine which refiners, blenders, and importers are treated as subject to the standard. As described further in Section III.G below, we are proposing that the sum of all highway and nonroad gasoline and diesel fuel produced or imported within a calendar year be the basis on which the RVOs are calculated. This section provides our proposed definition of gasoline and diesel for the purposes of the RFS program.

1. Gasoline

As with the RFS1 program, the volume of gasoline used in calculating the RVO under RFS2 would continue to include all finished gasoline (reformulated gasoline (RFG) and conventional gasoline (CG)) produced or imported for use in the contiguous United States or Hawaii, as well as all unfinished gasoline that becomes finished gasoline upon the addition of oxygenate blended downstream from the refinery or importer. This would include both unfinished reformulated gasoline, called ''reformulated gasoline blendstock for oxygenate blending,'' or ''RBOB,'' and unfinished conventional gasoline designed for downstream oxygenate blending (e.g., sub-octane conventional gasoline), called ''CBOB.'' The volume of any other unfinished gasoline or blendstock, such as butane or naphtha produced in a refinery, would not be included in the obligated volume, except where the blendstock is combined with other blendstock or gasoline to produce finished gasoline, RBOB, or CBOB. Where a blendstock is blended with other blendstock to produce finished gasoline, RBOB, or CBOB, the total volume of the gasoline blend would be included in the volume used to determine the blender's renewable fuels obligation. 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. For purposes of this preamble, the various gasoline products described above that we are proposing to include in a party's obligated volume would collectively be called ''gasoline.''

Also consistent with the RFS1 program, we propose to continue to exclude any volume of renewable fuel contained in gasoline from the volume of gasoline used to determine the renewable fuels obligations. 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 location. Thus, for example, any ethanol added to RBOB or CBOB at a refinery's rack or terminal downstream from the refinery or importer would be excluded from the volume of gasoline used by the refiner or importer to determine the obligation. This is consistent with how the standard itself is calculated—EPA determines the applicable percentage by comparing the overall projected volume of gasoline used to the overall renewable fuel volume that is specified in EPAct, and EPA excludes ethanol and other renewable fuels that blended into the gasoline in determining the overall projected volume of gasoline. When an obligated party determines their RVO by applying the applicable percentage to the amount of gasoline they produce or import, it is consistent to also exclude ethanol and other renewable fuel blends from the calculation of the volume of gasoline produced.

As with the RFS1 program, we are proposing that Gasoline Treated as Blendstock (GTAB) would continue to be treated as a blendstock under the RFS2 program, and thus would not count towards a party's renewable fuel obligation. Where the GTAB is blended with other blendstock (other than renewable fuel) to produce gasoline, the total volume of the gasoline blend, including the GTAB, would be included in the volume of gasoline used to determine the renewable fuel obligation. Where GTAB is blended with renewable fuel to produce gasoline, only the GTAB volume would be included in the volume of gasoline used to determine the renewable fuel obligation. Where the GTAB is blended with finished gasoline, only the GTAB volume would be included in the volume of gasoline used to determine the renewable fuel obligation.

2. Diesel

As discussed above in Section II.A.4, EISA expanded the RFS program to include transportation fuels other than gasoline, and we are proposing that both highway and nonroad diesel be used in calculating a party's RVO. We are proposing that any party that produces or imports petroleum-based diesel fuel that is designated as motor vehicle, nonroad, locomotive, and marine diesel fuel (MVNRLM) (or any subcategory of MVNRLM) would be required to include the volume of that diesel fuel in the determination of its RVO under the RFS2 rule. We are proposing that diesel fuel would include any distillate fuel that meets the definition of MVNRLM diesel fuel as it has already been defined in the regulations at § 80.2(qqq), including any subcategories such as MV (motor vehicle diesel produced for use in highway diesel engines and vehicles), NRLM (diesel produced for use in nonroad, locomotive, and marine diesel engines and equipment/vessels), NR (diesel produced for use in nonroad engines and equipment), and LM (diesel produced for use in locomotives and marine diesel engines and vessels).[36]

We are proposing that transportation fuels meeting the definition of MVNRLM would be used to calculate the RVOs, and refiners, blenders, or importers of MVNRLM would be treated as obligated parties. As such, diesel fuel that is designated as heating oil, jet fuel, or any designation other than MVNRLM or a subcategory of MVNRLM, would not be subject to the applicable percentage standard and would not be used to calculate the RVOs.[37]

We are also requesting comment on the idea that any diesel fuel not meeting these requirements, such as distillate or residual fuel intended solely for use in ocean-going vessels, would not be used to calculate the RVOs. As discussed above in Section II.A.4, EISA specifies that ''transportation fuels'' do not include fuels for use in ocean-going vessels. We are interpreting the term ''ocean-going vessel'' to mean those vessels that are powered by Category 3 (C3) marine engines and that use residual fuel or operate internationally; we request comment on this interpretation. As such, we are requesting comment on the concept that fuel intended solely for use in ocean-going vessels, or that an obligated party can verify as having been used in an ocean-going vessel, would be excluded from the renewable fuel standards. Further, we are also requesting comment on whether fuel used on such vessels with C2 engines should also be excluded from the renewable fuel standards, and how such an exemption should be phrased.

3. Other Transportation Fuels

As discussed further in Section III.J.3, below, we propose that transportation fuels other than gasoline or MVNRLM diesel fuel (natural gas, propane, and electricity) would not be used to calculate the RVOs of any obligated party. We believe this is a reasonable way to implement the obligations of 211(o)(3) because the volumes are small and the producers cannot readily differentiate the small transport portion from the large non-transport portion (in fact, the producer may have no knowledge of its use in transport); we will reconsider this approach if and when these volumes grow. At the same time, it is clear that other fuels can meet the definition of ''transportation fuel,'' and we are proposing that under certain

[36] EPA's diesel fuel regulations use the term ''nonroad'' to designate one large category of land-based off-highway engines and vehicles, recognizing that locomotive and marine engines and vessels are also nonroad engines and vehicles under EPAct's definition of nonroad. Except where noted, the discussion of nonroad in reference to transportation fuel includes the entire category covered by EPAct's definition of nonroad.

[37] *See* 40 CFR 80.598(a) for the kinds of fuel types used by refiners or importers in designating their diesel fuel.

circumstances, producers or generators of such other transportation fuels may generate RINs as a producer or importer of a renewable fuel. See Section III.B.1.a for further discussion of other RIN-generating fuels.

G. Renewable Volume Obligations (RVOs)

Under the current RFS program, each obligated party must determine its RVO based on the applicable percentage standard and its annual gasoline volume. The RVO represents the volume of renewable fuel that the obligated party must ensure is used in the U.S. in a given calendar year. Obligated parties must meet their RVO through the accumulation of RINs which represent the amount of renewable fuel used as motor vehicle fuel that is sold or introduced into commerce within the U.S. Each gallon-RIN would count as one gallon of renewable fuel for compliance purposes.

We propose to maintain this approach to compliance under the RFS2 program. One primary difference between the current and new RFS programs in terms of demonstrating compliance would be that each obligated party would now have four RVOs instead of one (through 2012) or two (starting in 2013) under the RFS1 program. Also, as discussed above, RVOs would be calculated based on production or importation of both gasoline and diesel fuels, rather than gasoline alone.

By acquiring RINs and applying them to their RVOs, obligated parties are effectively causing the renewable fuel represented by the RINs to be consumed as transportation fuel in highway or nonroad vehicles or engines. Obligated parties would not be required to physically blend the renewable fuel into gasoline or diesel fuel themselves. The accumulation of RINs would continue to be the means through which each obligated party shows compliance with its RVOs and thus with the renewable fuel standards.

If an obligated party acquires more RINs than it needs to meet its RVOs, then in general it could retain the excess RINs for use in complying with its RVOs in the following year or transfer the excess RINs to another party. If, alternatively, an obligated party has not acquired sufficient RINs to meet its RVOs, then under certain conditions it could carry a deficit into the next year.

This section describes our proposed approach to the calculation of RVOs under RFS2 and the RINs that would be valid for demonstrating compliance with those RVOs. This includes a description of the special treatment that must be applied to 2009 RINs used for compliance purposes in 2010, since RINs generated in 2009 under RFS1 would not be exactly the same as those generated in 2010 under RFS2. We also describe an alternative approach to the identification of obligated parties that would place the obligations under RFS2 on only finished gasoline and diesel rather than on certain blendstocks and unfinished fuels as well. The implication of this would be that the final blender of the gasoline or diesel would be the obligated parties rather than producers of blendstocks and unfinished fuels.

1. Determination of RVOs Corresponding to the Four Standards

In order for an obligated party to demonstrate compliance, the percentage standards described in Section III.E.1 which are applicable to all obligated parties must be converted into the volumes of renewable fuel each obligated party is required to satisfy. These volumes of renewable fuel are the volumes for which the obligated party is responsible under the RFS program, and are referred to here as its RVO. Under RFS2, each obligated party would need to acquire sufficient RINs each year to meet each of the four RVOs corresponding to the four renewable fuel standards.

The calculation of the RVOs under RFS2 would follow the same format as the existing formulas in the regulations at § 80.1107(a), with one modification. The standards for a particular compliance year would be multiplied by the sum of the gasoline and diesel volume produced or imported by an obligated party in that year rather than only the gasoline volume as under the current program.[38] To the degree that an obligated party did not demonstrate full compliance with its RVOs for the previous year, the shortfall would be included as a deficit carryover in the calculation. CAA section 211(o)(5) 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 for any of the four standards. They could, however, occur as frequently as every other year for a given obligated party.

Note that a party that produces only diesel fuel would have an obligation for all four standards even though he would not have the opportunity to blend ethanol into his own gasoline. Likewise, a party that produces only gasoline will have an obligation for all four standards even though he would not have an opportunity to blend biomass-based diesel into his own diesel fuel. Although these circumstances might imply that the four standards should be further subdivided into gasoline-specific and diesel-specific standards, we do not believe that this would be appropriate as described in Section III.E.1. Instead, since the obligations are met through the use of RINs, compliance with the standards does not require an obligated party to blend renewable fuel into their own or anyone else's gasoline or diesel fuel.

2. RINs Eligible To Meet Each RVO

Under RFS1, all RINs had the same compliance value and thus it did not matter what the RR or D code was for a given RIN when using that RIN to meet the total renewable fuel standard. In contrast, under RFS2 only RINs with specified D codes could be used to meet each of the four standards.

As described in Section II.A.1, the volume requirements in EISA are generally nested within one another, so that the advanced biofuel requirement includes fuel that meets either the cellulosic biofuel or the biomass-based diesel requirements, and the total renewable fuel requirement includes fuel that meets the advanced biofuel requirement. As a result, the RINs that can be used to meet the four standards are likewise nested. Using the proposed D codes defined in Table III.A–1, the RINs that could be used to meet each of the four standards are shown in Table III.G.2–1.

TABLE III.G.2–1—RINS THAT CAN BE USED TO MEET EACH STANDARD

Standard	Obligation	Allowable D codes
Cellulosic biofuel	RVO_{CB}	1.

[38] As discussed above, the diesel fuel that is used to calculate the RVO is any diesel designated as MVNRLM or a subcategory of MVNRLM.

TABLE III.G.2–1—RINS THAT CAN BE USED TO MEET EACH STANDARD—Continued

Standard	Obligation	Allowable D codes
Biomass-based diesel	RVO_{BBD}	2.
Advanced biofuel	RVO_{AB}	1, 2, and 3.
Renewable fuel	RVO_{RF}	1, 2, 3, and 4.

The nested nature of the four standards also means that we must allow the same RIN to be used to meet more than one standard in the same year. Thus, for instance, a RIN with a D code of 1 could be used to meet three of the four standards, while a RIN with a D code of 3 could be used to meet both the advanced biofuel and total renewable fuel standards. However, we propose continuing to prohibit the use of a single RIN for compliance purposes in more than one year or by more than one party.[39]

3. Treatment of RFS1 RINs Under RFS2

As described in Section II.A, we are proposing a number of changes to the RFS program as a result of the requirements in EISA. These changes would go into effect on January 1, 2010 and, among other things, would affect the conditions under which RINs are generated and their applicability to each of the four standards. As a result, RINs generated in 2010 under RFS2 will not be exactly the same as RINs generated in 2009 under RFS1. Given the valid RIN life that allows a RIN to be used in the year generated or the year after, we must address circumstances in which excess 2009 RINs are used for compliance purposes in 2010. We must also address deficit carryovers from 2009 to 2010, since the total renewable fuel standards in these two years will be defined differently.

a. Use of 2009 RINs in 2010

In 2009, the RFS1 regulations will continue to apply and thus producers will not be required to demonstrate that their renewable fuel is made from renewable biomass as defined by EISA, nor that their combination of fuel type, feedstock, and process meets the GHG thresholds specified in EISA. Moreover, there is no practical way to determine after the fact if RINs generated in 2009 meet any of these criteria. However, we believe that the vast majority of RINs generated in 2009 would in fact meet the RFS2 requirements. First, while ethanol made from corn must meet a 20% GHG threshold under RFS2 if produced by a facility that commenced construction after December 19, 2007, facilities that were already built or had commenced construction as of December 19, 2007 are exempt from this requirement. Essentially all ethanol produced in 2009 will meet the prerequisites for this exemption. Second, it is unlikely that renewable fuels produced in 2009 will have been made from feedstocks grown on agricultural land that had not been cleared or cultivated prior to December 19, 2007. In the intervening time period, it is much more likely that the additional feedstocks needed for renewable fuel production would come from existing cropland or cropland that has lain fallow for some time. Finally, the text of section 211(o)(5) states that a ''credit generated under this paragraph shall be valid to show compliance for the 12 months as of the date of generation,'' and EISA did not change this provision and did not specify any particular transition protocol to follow. A straightforward interpretation of this provision is to allow 2009 RINs to be valid to show compliance for 2010 obligations.

Since there will be separate standards for cellulosic biofuel and biomass-based diesel in 2010, RINs generated in 2009 that could be used to meet either of these two 2010 standards should meet the GHG thresholds of 60% and 50%, respectively. While we will not have a mechanism in place to determine if these thresholds have been met for RINs generated in 2009, and there are indications from our assessment of lifecycle GHG performance that at least some renewable fuels produced in 2009 would not meet these thresholds, nevertheless any shortfall in GHG performance for this one transition year is unlikely to have a significant impact on long-term GHG benefits of the program. Based on our belief that it is critical to the smooth operation of the program that excess 2009 RINs be allowed to be used for compliance purposes in 2010, we are proposing that RINs generated in 2009 to represent cellulosic biomass ethanol whose GHG performance has not been verified would still be valid for use for 2010 compliance purposes for the cellulosic biofuel standard. Likewise, we are proposing that RINs generated in 2009 to represent biodiesel and renewable diesel whose GHG performance has not been verified would still be valid for use for 2010 compliance purposes for the biomass-based diesel standard. We request comment on this approach.

We propose to use information contained in the RR and D codes of RFS1 RINs to determine how those RINs should be treated under RFS2. The RR code is used to identify the Equivalence Value of each renewable fuel, and under RFS1 these Equivalence Values are unique to specific types of renewable fuel. For instance, biodiesel (mono alkyl ester) has an Equivalence Value of 1.5, and non-ester renewable diesel has an Equivalence Value of 1.7, and both of these fuels may be valid for meeting the biomass-based diesel standard under RFS2. Likewise, RINs generated for cellulosic biomass ethanol in 2009 must be identified with a D code of 1, and these fuels may be valid for meeting the cellulosic biofuel standard under RFS2. Our proposed treatment of 2009 RINs in 2010 is shown in Table III.G.3.a–1.

TABLE III.G.3.a–1—PROPOSED TREATMENT OF EXCESS 2009 RINS IN 2010

Excess 2009 RINs	Treatment in 2010
RFS1 RINs with RR code of 15 or 17.	Equivalent to RFS2 RINs with D code of 2.
RFS1 RINs with D code of 1.	Equivalent to RFS2 RINs with D code of 1.
All other RFS1 RINs	Equivalent to RFS2 RINs with D code of 4.

Although we have discussed the issue of RFS1 RINs being used for RFS2 purposes in the context of our proposal that the RFS2 program be effective on January 1, 2010, we would expect a similar treatment of RFS1 RINs for RFS2 compliance purposes if the RFS2 effective date is delayed. In that case RFS1 RINs generated in 2010 would be available to show compliance for both the 2010 and 2011 compliance years, in a manner similar to that described above.

[39] Note that we are proposing an exception to this general prohibition for the specific and limited case of excess 2008 and 2009 biodiesel and renewable diesel RINs used to demonstrate compliance with both the 2009 total renewable fuel standard and the 2010 biomass-based diesel standard. *See* Section III.E.2.a.

b. Deficit Carryovers From the RFS1 Program to RFS2

If the RFS2 program goes into effect on January 1, 2010, the calculation of RVOs in 2009 under the existing regulations will be somewhat different than the calculation of RVOs in 2010 under RFS2. In particular, 2009 RVOs will be based upon gasoline production only, while 2010 RVOs would be based on volumes of gasoline and diesel. As a result, 2010 compliance demonstrations that include a deficit carried over from 2009 will combine obligations calculated on two different bases.

We do not believe that deficits carried over from 2009 to 2010 would undermine the goals of the program in requiring specific volumes of renewable fuel to be used each year. Although RVOs in 2009 and 2010 would be calculated differently, obligated parties must acquire sufficient RINs in 2010 to cover any deficit carried over from 2009 in addition to that portion of their 2010 obligation which is based on their 2010 gasoline and diesel production. As a result, the 2009 nationwide volume requirement of 11.1 billion gallons of renewable fuel will be consumed over the two year period concluding at the end of 2010. Thus, we are not proposing special treatment for deficits carried over from 2009 to 2010.

We propose that a deficit carried over from 2009 to 2010 would only affect a party's total renewable fuel obligation in 2010 ($RVO_{RF,i}$ as discussed in Section III.G.1), as the 2009 obligation is for total renewable fuel use, not a subcategory. The RVOs for cellulosic biofuel, biomass-based diesel, or advanced biofuel would not be affected, as they do not have parallel obligations in 2009 under RFS1.

If the RFS2 start date is delayed to be later than January 1, 2010, we expect that the same principles described above would apply for any deficit calculated under the RFS1 program and carried forward to RFS2.

4. Alternative Approach to Designation of Obligated Parties

Under RFS1, obligated parties who are subject to the standard are those that produce or import finished gasoline (RFG and conventional) or unfinished gasoline that becomes finished gasoline upon the addition of an oxygenate blended downstream from the refinery or importer. Unfinished gasoline includes reformulated gasoline blendstock for oxygenate blending (RBOB), and conventional gasoline blendstock designed for downstream oxygenate blending (CBOB) which is generally sub-octane conventional gasoline. The volume of any other unfinished gasoline or blendstock, such as butane, is not included in the volume used to determine the RVO, except where the blendstock is combined with other blendstock or finished gasoline to produce finished gasoline, RBOB, or CBOB. Thus, parties downstream of a refinery or importer are only obligated parties to the degree that they use non-renewable blendstocks to make finished gasoline, RBOB, or CBOB.

The approach we took for RFS1 was based on our expectation at that time that there would be an excess of RINs at low cost, and our belief that the ability of RINs to be traded freely between any parties once separated from renewable fuel would provide ample opportunity for parties who were in need of RINs to acquire them from parties who had excess. We also pointed out that the designation of ethanol blenders as obligated parties would have greatly expanded the number of regulated parties and increased the complexity of the RFS program beyond that which was necessary to carry out the renewable fuels mandate under CAA section 211(o).

Following the new requirements under EISA, the required volumes of renewable fuel will be increasing significantly above the levels required under RFS1. These higher volumes are already resulting in changes in the demand for RINs and operation of the RIN market. First, obligated parties who have excess RINs are increasingly opting to retain rather than sell them to ensure they have a sufficient number for the next year's compliance. Second, since all gasoline is expected to contain ethanol by 2013, few blenders would be able to avoid taking ownership of RINs by that time under the existing definition of obligated party. As a result, by 2013 essentially every blender would be a regulated party who is subject to recordkeeping and reporting requirements, and thus the additional burden of demonstrating compliance with the standard could be small. Third, major integrated refiners who operate gasoline marketing operations have direct access to RINs for ethanol blended into their gasoline, while refiners whose operations are focused primarily on producing refined products do not have such direct access to RINs. The result is that in some cases there are significant disparities between obligated parties in terms of opportunities to acquire RINs. If those that have excess RINs are reluctant to sell them, those who are seeking RINs may be forced to market a disproportionate share of E85 in order to gain access to the RINs they need for compliance. If obligated parties seeking RINs cannot acquire a sufficient number, they can only carry a deficit into the following year, after which they would be in noncompliance if they could not acquire sufficient RINs. The result might be a much higher price for RINs (and fuel) in the marketplace than would be expected under a more liquid market.

Given the change in circumstances brought about through EISA, it may be appropriate to consider a change in the way that obligated parties are defined to more evenly align a party's access to RINs with that party's obligations under the RFS2 program. The most straightforward approach would be to eliminate RBOB and CBOB from the list of fuels that are subject to the standard, such that a party's RVO would be based only on the non-renewable volume of finished gasoline or diesel that he produces or imports. Parties that blend ethanol into RBOB and CBOB to make finished gasoline would thus be obligated parties, and their RVOs would be based upon the volume of RBOB and CBOB prior to ethanol blending. Traditional refiners that convert crude oil into transportation fuels would only have an RVO to the degree that they produced finished gasoline or diesel, with all RBOB and CBOB sold to another party being excluded from the calculation of their RVO.

Since essentially all gasoline is expected to be E10 within the next few years (*see* discussion in Section V.D.2 below), this approach would effectively shift the obligation for all gasoline from refiners and importers to ethanol blenders (who in many cases are still the refiners). However, this approach by itself would maintain the obligation for diesel on refiners and importers. Thus, a variation of this approach would be to move the obligations for all gasoline and diesel downstream to parties who supply finished transportation fuels to retail outlets or to wholesale purchaser-consumer facilities. This variation would have the additional effect of more closely aligning obligations and access to RINs for parties that blend biodiesel and renewable diesel into petroleum-based diesel.

We are not proposing to eliminate RBOB and CBOB from the list of fuels that are subject to the standard in today's notice since it would result in a significant change in the number of obligated parties and the movement of RINs. Many parties that are not obligated under the current RFS program would become obligated, and would be forced to implement new systems for determining and reporting compliance. Nevertheless, it would have certain advantages. Currently, blenders that are not obligated parties are profiting from the sale of RINs they acquire through splash blending of ethanol. By eliminating RBOB and CBOB from the list of obligated fuels, these blenders would become directly responsible for ensuring that the volume requirements of the RFS program are met, and the cost of meeting the standard would be more evenly distributed among parties that blend renewable fuel into gasoline. With obligations placed more closely to the points in the distribution system where RINs are made available, the overall market prices for RINs may be lowered and consequently the cost of the program to consumers may be reduced.

While eliminating the categories of RBOB and CBOB from the list of obligated fuels would result in a significant change in the distribution of obligations among transportation fuel producers, it could help to ensure that the RIN market functions as we originally intended. As a result, RINs would more directly be made available to the parties that need them for compliance. This is similar to the goal of the direct transfer approach to RIN distribution as described in the proposed rulemaking for the RFS1 program and presented again in Section III.H.4 below. We request comment on the degree to which access to RINs is a concern among current obligated parties. Since either the elimination of RBOB and CBOB from the list of obligated fuels or the direct transfer approach to RIN distribution could both accomplish the same goal, we request comment on which one would be more appropriate, if any.

We have also considered a number of alternative approaches that could be used to help ensure that obligated parties can demonstrate compliance. For instance, one alternative approach would leave our proposed definitions for obligated parties in place, but would add a regulatory requirement that any party who blends ethanol into RBOB or CBOB must transfer the RINs associated with the ethanol to the original producer of the RBOB or CBOB. However, we believe that such an approach would be both inappropriate and difficult to implement. RBOB and CBOB is often transferred between multiple parties prior to ethanol blending. As a result, a regulatory requirement for RIN transfers back to the original producer would necessitate an additional tracking requirement for RBOB and CBOB so that the blender would know the identity of the original producer. It would also be difficult to ensure that RINs representing the specific category of renewable fuel blended were transferred to the producer of the RBOB or CBOB, given the fungible nature of RINs assigned to batches of renewable fuel. For these reasons, we do not believe that this alternative approach would be appropriate.

In another alternative approach, some RINs that expire without being used for compliance by an obligated party could be used to reduce the nationwide volume of renewable fuel required in the following year. We would only reduce the required volume of renewable fuel to the degree that sufficient RINs had been generated to permit all obligated parties to demonstrate compliance, but some obligated parties nevertheless could not acquire a sufficient number of RINs. Moreover, only RINs that were expiring would be used to reduce the nationwide volume for the next year. This alternative approach would ensure that the volumes required in the statute would actually be produced and would prevent the hoarding of RINs from driving up demand for renewable fuel. However, it would also reduce the impact of the valid life limit for RINs.

We could lower the 20% rollover cap applicable to the use of previous-year RINs to a lower value, such as 10%. This approach would provide a greater incentive for obligated parties with excess RINs to sell them but would further restrict a potentially useful means of managing an obligated party's risk. As described in Section IV.D, we are not proposing any changes in the 20% rollover cap in today's notice. However, we request comment on it.

Finally, another change to the program that would not change the definition of obligated parties, but could help address the disparity of access to RINs among obligated parties, would be to remove the requirement developed under RFS1 that RINs be transferred with renewable fuel volume by the renewable fuel producers and importers. This alternative is discussed further in Section III.H.4 below.

H. Separation of RINs

We propose that most of the RFS1 provisions regarding the separation of RINs from volumes of renewable fuel be retained for RFS2. However, the modifications in EISA will require a number of changes, primarily to the treatment of RINs associated with nonroad renewable fuel and renewable fuels used in heating oil and jet fuel. Our approach to the separation of RINs by exporters must also be modified to account for the fact that there would be four categories of renewable fuel under RFS2.

1. Nonroad

Under RFS1, RINs associated with renewable fuels used in nonroad vehicles and engines downstream of the renewable fuel producer are required to be retired by the party who owns the renewable fuel at the time of blending. This provision derived from the EPAct definition of renewable fuel which was limited to fuel used to replace fossil fuel used in a motor vehicle. EISA however expands the definition of renewable fuel, and ties it to the definition of transportation fuel, which is defined as any ''fuel for use in motor vehicles, motor vehicle engines, nonroad vehicles, or nonroad engines (except for ocean-going vessels). To implement these changes, the proposed RFS2 program eliminates the RFS1 RIN retirement requirement for renewable fuels used in nonroad applications, with the exception of RINs associated with renewable fuels used in ocean-going vessels.

2. Heating Oil and Jet Fuel

EISA defined 'additional renewable fuel' as ''fuel that is produced from renewable biomass and that is used to replace or reduce the quantity of fossil fuel present in home heating oil or jet fuel.'' [40] While we are proposing that fossil-based heating oil and jet fuel would not be included in the fuel used by a refiner or importer to calculate their RVO, we are proposing that renewable fuels used as or in heating oil and jet fuel may generate RINs for credit purposes. Thus, the RINs of a renewable fuel, such as biodiesel, that is blended into heating oil continue to be valid. See also discussion in Section III.B.1.e.

3. Exporters

Under RFS1, exporters are assigned an RVO representing the volume of renewable fuel that has been exported, and they are required to separate all RINs that have been assigned to fuel that is exported. Since there is only one standard, there is only one possible RVO applicable to exporters.

Under RFS2, there are four possible RVOs corresponding to the four categories of renewable fuel (cellulosic biofuel, biomass-based diesel, advanced biofuel, total renewable fuel). However, given the fungible nature of the RIN system and the fact that an assigned RIN transferred with a volume of renewable fuel may not be the same RIN that was originally generated to represent that volume, there is no way for an exporter to determine from an assigned RIN which of the four categories applies to

[40] EISA, Title II, Subtitle A–Renewable Fuel Standard, Section 201.

an exported volume. In order to determine its RVOs, the only information available to the exporter is the type of renewable fuel that he is exporting.

For RFS2, we are proposing that exporters use the fuel type and its associated volume to determine his applicable RVO. To accomplish this, an exporter must know which of the four renewable fuel categories applies to a given type of renewable fuel. We are proposing that all biodiesel (mono alkyl esters) and renewable diesel would be categorized as biomass-based diesel (D code of 4), and that exported volumes of these two fuels would be used to determine the exporter's RVO for biomass-based diesel. For all other types of renewable fuel, the most likely category for most of the phase-in period of the RFS2 program is general renewable fuel, and as a result we propose that all other types of renewable fuel be used to determine the exporter's RVO for total renewable fuel. Our proposed approach is provided at § 80.1430. We recognize that by 2022 the required volume of cellulosic biofuel will exceed the required volume of general renewable fuel that is in excess of the advanced biofuel requirements. Thus we request comment on requiring all or some portion of renewable fuels other than biodiesel and renewable diesel to be categorized as cellulosic biofuel in 2022 and beyond.

An alternative approach could be required that would more closely estimate the amount of exported renewable fuels that fall into the four categories defined by EISA. In this alternative, the total nationwide volumes required in each year (*see* Table II.A.1–1) would be used to apportion specific types of renewable fuel into each of the four categories. For example, exported ethanol may have originally been produced from cellulose to meet the cellulosic biofuel requirement, from corn to meet the total renewable fuel requirement, or may have been imported as advanced biofuel. If ethanol were exported, we could divide the exported volume into three RVOs for cellulosic biofuel, advanced biofuel, and total renewable fuel using the same proportions represented by the national volume requirements for that year. However, we believe that this alternative approach would add considerable complexity to the compliance determinations for exporters without necessarily adding more precision. Given the expected small volumes of exported renewable fuel, this added complexity does not seem warranted at this time. Nevertheless, we request comment on it.

4. Alternative Approaches to RIN Transfers

In the NPRM for the RFS1 rulemaking, we presented a variety of approaches to the transfer of RINs, ultimately requiring that RINs generated by renewable fuel producers and importers must be assigned to batches of renewable fuel and transfered along with those batches. However, given the higher volumes required under RFS2 and the resulting expansion in the number of regulated parties, we believe that two of the alternative approaches to RIN transfers should be considered for RFS2. Our proposal for an EPA-moderated RIN trading system (EMTS) may also support the implementation of one of these approaches.

In one of the alternative approaches, we would entirely remove the restriction established under the RFS1 rule requiring that RINs be assigned to batches of renewable fuel and transferred with those batches. Instead, renewable fuel producers could sell RINs (with a K code of 2 rather than 1) separately from volumes of renewable fuel to any party. This approach could significantly streamline the tracking and trading of RINs. For instance, there would no longer be a need for K-codes and restrictions on separation of RINs, there would only be a single RIN market rather than two (one for RINs assigned to volume and another for separated RINs), there would be no need for volume/RIN balance calculations at the end of each quarter, and there would be no need for restrictions on the number of RINs that can be transfered with each gallon of renewable fuel. As described more fully in Section III.B.4.b.ii, this approach could also provide a greater incentive for producers to demonstrate that the renewable biomass definition has been met for their feedstocks. As discussed in Section III.G.4, this approch could help level the playing field among obligated parties for access to RINs regardless of whether they market a substantial volume of gasoline or not. However, as discussed in the RFS1 rulemaking, this approach could also place obligated parties at greater risk of market manipulation by renewable fuel producers.

In order to address some of the concerns raised about allowing producers and importers to separate RINs from their volume, in the NPRM for the RFS1 rulemaking we also presented an alternative concept for RIN distribution in which producers and importers of renewable fuels would be required to transfer the RIN, but only to an obligated party (see 71 FR 55591). This ''direct transfer'' approach would require renewable fuel producers to transfer RINs with renewable fuel for all transactions with obligated parties, and sell all other RINs directly to obligated parties on a quarterly basis for any renewable fuel volumes that were not sold directly to obligated parties. Only renewable fuel producers, importers, and obligated parties would be allowed to own RINs, and only obligated parties could take ownership of RINs from producers and importers. This approach would spare marketers and distributors of renewable fuel from the burdens associated with transferring RINs with batches, and thus would eliminate the tracking, recordkeeping and reporting requirements that would continue to be applicable to them if RINs are transferred through the distribution system as required under the RFS1 program.

Under the direct transfer alternative, the renewable fuel producer or importer would be required to transfer the RINs associated with his renewable fuel to an obligated party who purchases the renewable fuel. The RINs associated with any renewable fuel that is not directly transferred to an obligated party would not be transferred with the fuel as required under the RFS1 program. Instead, the renewable fuel producer or importer would be required to sell the RINs directly to an obligated party. Any RINs not sold in this way would be required to be offered for sale to all obligated parties through a public auction. This could be through an EPA moderated trading system, an existing internet auction web site, or through another auction mechanism implemented by a renewable fuel producer.

Although we believe that the direct transfer approach has merit, many of the concerns laid out in the RFS1 NPRM remain valid today. In particular, the auctions would need to be regulated in some way to ensure that RIN generators could not withhold RINs from the market by such means as failing to adequately advertise the time and location of an auction, by setting the selling price too high, by specifying a minimum number of bids before selling, by conducting auctions infrequently, by having unduly short bidding windows, etc. We seek comment on how we could regulate such auctions to ensure that obligated parties could acquire sufficient RINs for compliance purposes in a timely manner.

Our proposed EPA-moderated RIN trading system (see Section IV.E) could help to make the direct transfer approach feasible. By creating accounts in a centralized system within which all RIN transfers between parties would be made, it may be more straightforward for obligated parties to identify available RINs owned by producers and importers, and to bid on those RINs. Therefore, while we are not proposing the direct transfer approach in today's action, we nevertheless request comment on it.

5. Neat Renewable Fuel and Renewable Fuel Blends Designated as Transportation Fuel, Home Heating Oil, or Jet Fuel

Under RFS1, RINs must, with limited exceptions, be separated by an obligated party taking ownership of the renewable fuel, or by a party that blends renewable fuel with gasoline or diesel. In addition, a party that designates neat renewable fuel as motor vehicle fuel may separate RINs associated with that fuel if the fuel is in fact used in that manner without further blending. For purposes of the RFS program, ''neat renewable fuel'' is defined in 80.1101(p) as ''a renewable fuel to which only de minimis amounts of conventional gasoline or diesel have been added.'' One exception to these provisions is that biodiesel blends in which diesel constitutes less than 20 volume percent are ineligible for RIN separation by a blender. As noted in the preamble to the final RFS1 regulations, EPA understands that in the vast majority of cases, biodiesel is blended with diesel in concentrations of 80 volume percent or less.

However, in order to account for situations in which biodiesel blends of 81 percent or greater may be used as motor vehicle fuel without ever having been owned by an obligated party, EPA is proposing to change the applicability of the RIN separation provisions for RFS2. EPA is proposing that 80.1429(b)(4) allow for separation of RINs for neat renewable fuel or blends of renewable fuel and or diesel fuel that the party designates as transportation fuel, home heating oil, or jet fuel, provided the neat renewable fuel or blend is used in the designated form, without further blending, as transportation fuel, home heating oil, or jet fuel. As in RFS1, those parties that blend renewable fuel with gasoline or diesel fuel (in a blend containing less than 80 percent biodiesel would in all cases be required to separate RINs pursuant 80.1429(b)(2).

Thus, for example, under these proposed regulations, if a party intends to separate RINs from a volume of B85, the party must designate the blend for use as transportation fuel, home heating oil, or jet fuel and the blend must be used in its designated form without further blending. The party would also be required maintain records of this designation pursuant to 80.1451(b)(5). Finally, the party would be required to comply with the proposed PTD requirements in 80.1453(a)(5)(iv), which serve to notify downstream parties that the volume of fuel has been designated for use as transportation fuel, home heating oil, or jet fuel, and must be used in that designated form without further blending. Parties could separate RINs at the time they complied with the designation and PTD requirements, and would not need to physically track ultimate fuel use.

EPA requests comment on this proposed approach to RIN separation. Additionally, EPA requests comment on an alternative approach to modifying the current program for separation of RINs. Under this second approach, 80.1429(b)(2) and (b)(5)would be eliminated as redundant, and 80.1429(b)(4) would be broadened to require separation of RINs for all neat renewable fuels and all blends of renewable fuels with either gasoline or diesel, when a party designates such fuel as transportation fuel, home heating oil or jet fuel, and the fuel is in fact used in accordance with that designation without further blending. The party would be required to maintain records that verify the ultimate use of the fuel as transportation, home heating, or jet fuel. Additionally, there would be a PTD requirement to inform downstream parties that the fuel has been designated as transportation, home heating, or jet fuel and may not be further blended. This proposed approach would eliminate the need for parties to distinguish for purposes of separating RINs between fuels that are neat or blended or, for biodiesel, between blends of E80 and below or E81 and above.

I. Treatment of Cellulosic Biofuel

1. Cellulosic Biofuel Standard

EISA requires in section 202(e) that the Administrator set the cellulosic biofuel standard each November for the next year based on the lesser of the volume specified in the Act or the projected volume of cellulosic biofuel production for that year. In the event that the projected volume is less than the amount required in the Act, EPA may also reduce the applicable volume of the advanced biofuels requirement by the same or a lesser volume. We intend to examine EIA's projected volumes and other available data including the production outlook reports proposed in Section III.K to be submitted to the EPA to decide the appropriate standard for the following year. The outlook reports from all renewable fuel producers would assist EPA in determining what the cellulosic biofuel standard should be and if the advanced biofuel standard should be adjusted. For years where EPA determines that the projected volume of cellulosic biofuels is not sufficient to meet the levels in EISA we will consider the availability of other advanced biofuels in deciding whether to lower the advanced biofuel standard as well.

2. EPA Cellulosic Allowances for Cellulosic Biofuel

Whenever EPA sets the cellulosic biofuel standard at a level lower than that required in EISA, EPA is required to provide a number of cellulosic credits for sale that is no more than the volume used to set the standard. Congress also specified the price for such credits: adjusted for inflation, they must be offered at the price of the higher of 25 cents per gallon or the amount by which $3.00 per gallon exceeds the average wholesale price of a gallon of gasoline in the United States. The inflation adjustment will be for years after 2008. We propose that the inflation adjustment would be based on the Consumer Price Index for All Urban Consumers (CPI–U) for All Items expenditure category as provided by the Bureau of Labor Statistics.[41]

Congress afforded the Agency considerable flexibility in implementing the system of cellulosic biofuel credits. EISA states EPA; ''shall include such provisions, including limiting the credits' uses and useful life, as the Administrator deems appropriate to assist market liquidity and transparency, to provide appropriate certainty for regulated entities and renewable fuel producers, and to limit any potential misuse of cellulosic biofuel credits to reduce the use of other renewable fuels, and for such other purposes as the Administrator determines will help achieve the goals of this subsection.''

Though EISA gives EPA broad flexibility, we believe the best way to accomplish the goals of providing certainty to both the cellulosic biofuel industry and the obligated parties is to propose credits with few degrees of freedom. We believe this would prevent speculation in the market and provide certainty for investments in real cellulosic biofuels.

Specifically, we propose that the credits would be called allowances so

[41] *See* U.S. Department of Labor, Bureau of Labor Statistics (BLS), Consumer Price Index Web site at: *http://www.bls.gov/cpi/*.

that there is no confusion with RINs, such allowances would only be available for the current compliance year for which we have waived some portion of the cellulosic biofuel standard, they would only be available to obligated parties, and they would be nontransferable and nonrefundable. Further, we propose that obligated parties would only be able to purchase allowances up to the level of their cellulosic biofuel RVO less the number of cellulosic biofuel RINs that they own. This would help ensure that every party that needs to meet the cellulosic biofuel standard will have equal access to the allowances. A company would also then only use an allowance to meet its total renewable and advanced biofuel standards if it used the allowance for the cellulosic biofuel standard. We believe that if a company can only purchase as many allowances as it needs to meet its cellulosic biofuel obligation, it can not hinder another obligated party from meeting the standard and therefore every company that needs to meet the standard will have equal access to the allowances in the event that they do not acquire sufficient cellulosic biofuel RINs. If we were to allow a company to purchase more allowances than they needed, another company may not be able to meet the standard which we believe was not the intent of Congress.

We also propose that these allowances would be offered in a generic format rather than a serialized format, like RINs. Allowances would be purchased from the EPA at the time that an obligated party submits its annual compliance demonstration to the EPA and establishes that it owns insufficient cellulosic biofuel RINs to meet its cellulosic biofuel RVO. A company owning cellulosic biofuel RINs and cellulosic allowances may use both types of credits if desired to meet their RVOs, but unlike RINs they would not be able to carry allowances over to the next calendar year.

Congress refers to allowances as ''cellulosic biofuel credits,'' with no indication that the ''credits'' should be given any less role in meeting a party's obligations under the CAA section 211(o) than would the purchase and use of a cellulosic biofuel RIN that reflects actual production and use of cellulosic biofuel. Because cellulosic biofuel RINs can be used to meet the advanced biofuel and total renewable fuel standards in addition to the cellulosic biofuel standard, we propose that cellulosic biofuel allowances also be available for use in meeting those three standards.

We propose that the wholesale price of gasoline will be based on the average monthly bulk (refinery gate) price of gasoline using data from the most recent twelve months of data from EIA's annual cellulosic ethanol forecast each October.[42] Thus we will set the allowance price for the following year each November along with the cellulosic biofuel standard for the following year. We seek comment on using the average monthly rack (terminal) price for the same period and changing the allowance price as often as quarterly. Though EISA allows EPA to change the price as often as quarterly we believe this will lead to speculation which may introduce more uncertainty for the obligated parties and the cellulosic biofuel industry.

3. Potential Adverse Impacts of Allowances

While the credit provisions of section 202(e) of EISA ensure that there is a predictable upper limit to the price that cellulosic biofuel producers can charge for a gallon of cellulosic biofuel and its assigned RIN, there may be circumstances in which this provision has other unintended impacts. For instance, if we made all cellulosic allowances available to any obligated party, one obligated party could purchase more allowances than he needs to meet his cellulosic biofuel RVO and then sell the remaining allowances at an inflated price to other obligated parties. Thus, we are proposing that each obligated party could only purchase allowances from the EPA up to the level of their cellulosic biofuel RVO. However, even with this restriction an obligated party could still purchase both cellulosic biofuel volume with its assigned RINs sufficient to meet its cellulosic biofuel RVO, and also purchase allowances from the EPA. In this case, the obligated party would effectively be using allowances as a replacement for corn ethanol rather than cellulosic biofuel. To prevent this, we are proposing an additional restriction: an obligated party could only purchase allowances from the EPA to the degree that it establishes it owns insufficient cellulosic biofuel RINs to meet its cellulosic biofuel RVO. This approach forces obligated parties to apply all their cellulosic biofuel RINs to their cellulosic biofuel RVO before appying any allowances to their cellulosic biofuel RVO.

[42] More information on wholesale gasoline prices can be found on the Department of Energy's (DOE), Energy Information Administration's (EIA) Web site at: *http://tonto.eia.doe.gov/dnav/pet/pet_pri_allmg_d_nus_PBS_cpgal_m.htm*.

However, even with these proposed restrictions on the purchase and application of allowances, the statutory provision may not operate as intended. For instance, if the combination of cellulosic biofuel volume price and RIN price is low compared to that for corn-ethanol, a small number of obligated parties could purchase more cellulosic biofuel than they need to meet their cellulosic biofuel RVOs and could use the additional cellulosic biofuel RINs to meet their advanced biofuel and total renewable fuel RVOs. Other obligated parties would then have no access to cellulosic biofuel volume nor cellulosic biofuel RINs, and would be forced to purchase allowances from the EPA. This situation would have the net effect of allowances replacing imported sugarcane ethanol and/or corn-ethanol rather than cellulosic biofuel.

Moreover, under certain conditions it may be possible for the market price of corn-ethanol RINs to be significantly higher than the market price of cellulosic biofuel RINs, as the latter is limited in the market by the price of EPA-generated allowances according to the statutory formula described in Section III.I.2 above. Under some conditions, this could result in a competitive disadvantage for cellulosic biofuel in comparison to corn ethanol. For instance, if gasoline prices at the pump are significantly higher than ethanol production costs, while at the same time corn-ethanol production costs are lower than cellulosic ethanol production costs, profit margins for corn-ethanol producers would be larger than for cellulosic ethanol producers. Under these conditions, while obligated parties may still purchase cellulosic ethanol volume and its associated RIN rather than allowances, cellulosic ethanol producers would realize lower profits than corn-ethanol producers due to the upper limit placed on the price of cellulosic biofuel RINs through the pricing formula for allowances. For a newly forming and growing cellulosic biofuel industry, this competitive disadvantage could make it more difficult for investors to secure funding for new projects, threatening the ability of the industry to reach the statutorily mandated volumes.

We have not established the likelihood that these circumstances would arise in practice, and we request comment on the specific market conditions that could lead to them. Nevertheless, we have explored a variety of ways that we could modify the RFS program structure to mitigate these potential negative outcomes. For instance, as mentioned in Section III.I.2 above, we are proposing that each cellulosic allowance could be used to meet an obligated party's RVOs for cellulosic biofuel, advanced biofuel, and total renewable fuel. However, we could restrict the applicability of allowances to only the cellulosic biofuel RVO. This approach could help ensure that demand for imported sugarcane ethanol and corn ethanol does not fall in the event that a small number of obligated parties purchase all available cellulosic biofuel volume, compelling the remaining obligated parties to purchase allowances. However, this approach could also have the effect of making the advanced biofuel and total renewable fuel standards more stringent. This could occur as obligated parties are forced to buy additional imported sugarcane ethanol and corn ethanol to make up for the fact that the allowances they purchase from the EPA would not apply to the advanced biofuel and total renewable fuel standards.

As a variation to this approach, while still restricting the applicability of allowances to only the cellulosic biofuel RVO, we could similarly make cellulosic biofuel RINs applicable to only the cellulosic biofuel RVO. This approach would ensure that the compliance value of both cellulosic biofuel RINs and allowances is the same, but would necessarily result in an increase in the effective stringency of the advanced biofuel and total renewable fuel standards.

Finally, we could institute a ''dual RIN'' approach to cellulosic biofuel that has the potential to address some of the shortcomings of the previous approaches. In this approach, both cellulosic biofuel RINs (with a D code of 1) and allowances could only be applied to an obligated party's cellulosic biofuel RVO, but producers of cellulosic biofuel would also generate an additional RIN representing advanced biofuel (with a D code of 3). The producer would only be required to transfer the advanced biofuel RIN with a batch of cellulosic biofuel, and could retain the cellulosic biofuel RIN for separate sale to any party.[43] The cellulosic biofuel and its attached advanced biofuel RIN would then compete directly with other advanced biofuel and its attached advanced biofuel RIN, while the separate cellulosic biofuel RIN would have an independent market value that would be effectively limited by the pricing formula for allowances as described in Section III.I.2. However, this approach would be a more significant deviation from the RIN generation and transfer program structure that was developed cooperatively with stakeholders during RFS1. It would provide cellulosic biofuel producers with significantly more control over the sale and price of cellulosic biofuel RINs, which was one of the primary concerns of obligated parties during the development of RFS1.

Due to the drawbacks of each of these potential changes to the RFS program structure, we are not proposing any of them in today's NPRM. However, we request comment on whether any of them, or alternatives, could address the adverse situations described above. We also request comment on the degree to which the adverse situations are likely to occur, and the degree of severity of the negative impacts that could result.

J. Changes to Recordkeeping and Reporting Requirements

1. Recordkeeping

As with the existing renewable fuel standard program, recordkeeping under this proposed program will support the enforcement of the use of RINs for compliance purposes. As with the existing renewable fuels program, we are proposing that parties be afforded significant freedom with regard to the form that product transfer documents (PTDs) take. We propose to permit the use of product codes as long as they are understood by all parties. We propose that product codes may not be used for transfers to truck carriers or to retailers or wholesale purchaser-consumers. We propose that parties must keep copies of all PTDs they generate and receive, as well as copies of all reports submitted to EPA and all records related to the sale, purchase, brokering or transfer or RINs, for five (5) years. We also propose that parties must also keep copies of records that relate to flexibilities, as described in Section IV.A. through C. of this preamble. Such flexibilities are related to attest engagements, the upward delegation of RIN-separating responsibilities, and various small business oriented provisions. Upon request, parties would be responsible for providing their records to the Administrator or the Administrator's authorized representative. We would reserve the right to request to receive documents in a format that we can read and use.

In Section IV.E. of this preamble, we propose an EPA-Moderated Trading System for RINs. If adopted, the new system would allow for real-time reporting of RIN generation (i.e., batch reports by producers and importers) and RIN transactions.

2. Reporting

Under the existing renewable fuels program, obligated parties, exporters of renewable fuel, producers and importers of renewable fuels, and any party who owns RINs must report appropriate information to EPA on a quarterly and/or annual basis. We are proposing a change in the schedule for submission of producers' and importers' batch reports, and for the submission of RIN transaction reports. This proposed change in schedule, which is discussed in great detail in Section IV.E. of this preamble, is effective for 2010 only. We are proposing that, for 2010, these reports (which were submitted quarterly under RFS1) be submitted monthly rather than quarterly. The reason for proposing monthly reporting for 2010 is to minimize difficulties associated with invalid RINs, while the EPA-Moderated Trading System is still under development. As described in detail in IV.E. we intend to have an EPA-Moderated Trading System fully operational by 2011. At the time that system becomes fully operational, all batch and RIN transactional reporting would be submitted in real time. The following deadlines would apply to ''real time,' monthly, quarterly, and annual reports.

''Real time'' reports within the EPA-Moderating Trading System would be submitted within three (3) business days of a reportable event (e.g. generation of a RIN, a transaction occurring involving a RIN). Real time reporting would apply to batch reports submitted by producers and importers who generate RINs and to to RIN transaction reports submitted in 2011 and future years.

Monthly reports would be submitted according to the following schedule:

TABLE III.J.2–1—MONTHLY REPORTING SCHEDULE

Month covered by report	Due date for report
January	February 28.
February	March 31.
March	April 30.
April	May 31.
May	June 30.
June	July 31.
July	August 31.
August	September 30.
September	October 31.
October	November 30.
November	December 31.
December	January 31.

The monthly reporting schedule would apply to batch reports submitted by producers and importers who generate RINs and to RIN transaction reports submitted for 2010 only.

[43] The cellulosic biofuel RIN would be a separated RIN with a K code of 2 immediately upon generation.

Quarterly reports would be submitted on the following schedule:

TABLE III.J.–2—QUARTERLY REPORTING SCHEDULE

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

Quarterly reports include summary reports related to RIN activities.

Annual reports (covering January through December) would continue to be due on February 28. Annual reports include compliance demonstrations by obligated parties.

Under this proposed rule, the universe of reporting parties would grow, but we propose similar reporting to existing reporting. We believe that the proposed EPA-Moderating Trading System will make reporting easier for most parties. Existing reporting forms and instructions are posted at *http://www.epa.gov/otaq/regs/fuels/rfsforms.htm*. You may wish to refer to these existing forms in preparing your comments on this proposal.

Simplified, secure reporting is currently available through our Central Data Exchange (CDX). CDX permits us to accept reports that are electronically signed and certified by the submitter in a secure and robustly encrypted fashion. Using CDX eliminates the need for wet ink signatures and reduces the reporting burden on regulated parties. It is our intention to continue to encourage the use of CDX for reporting under this proposed program as well.

Due to the criteria that renewable fuel producers and importers must meet in order to generate RINs under RFS2, and due to the fact that renewable fuel producers and importers must have documentation about whether their feedstock(s) meets the definition of ''renewable biomass,'' we propose several changes to the RFS1 RIN generation report. We propose to make the report a more general report on renewable fuel production in order to capture information on all batches of renewable fuel, whether or not RINs are generated for them. All renewable fuel producers and importers above 10,000 gallons per year would report to EPA on each batch of their fuel and indicate whether or not RINs are generated for the batch. If RINs are generated, the producer or importer would be required to certify that his feedstock meets the definition of ''renewable biomass.'' If RINs are not generated, the producer or importer would be required to state the reason for not generating RINs, such as they have documentation that states that their feedstock did not meet the definition of ''renewable biomass,'' or the fuel pathway used to produce the fuel was such that the fuel did not qualify for any D code (see Section III.B.4.b for a discussion about demonstrating whether or not feedstock meets the definition of ''renewable biomass''). For each batch of renewable fuel produced, we also propose to require information about the types and volumes of feedstock used and the types and volumes of co-products produced, as well as information about the process or processes used. This information is necessary to confirm that the producer or importer assigned the appropriate D code to their fuel and that the D code was consistent with their registration information.

Two minor additions are being incorporated into the RIN transaction report. First, for reports of RINs assigned to a volume of renewable fuel, we are asking that the volume of renewable fuel be reported. Additionally, we propose that RIN price information be submitted for transactions involving both separated RINs and RINs assigned to a renewable volume. This information is not collected under RFS1, but we believe this information has great programmatic value to EPA because it may help us to anticipate and appropriately react to market disruptions and other compliance challenges, will be beneficial when setting future renewable standards, and will provide additional insight into the market when assessing potential waivers. We anticipate that having current market information such as total number of RINs produced and RINs available in the separated market is incomplete. Missing is our ability to assess the general health and direction of the market and overall liquidity of RINs. Tracking price trend information will allow us to identify market inefficiencies and perceptions of RIN supply. When price information is combined with information from the production outlook reports, we will be better able to judge realistic expectations of renewable production and be in a better position when setting and justifying future renewable standards or pursuing relief through waiver provisions. Also, we believe the addition of price information will be highly beneficial to regulated parties. With price information being noted on transaction reports, buyers and sellers will have an additional and immediate reference when confirming transactions. Additionally, we believe that highly summarized price information (e.g., the average price of RINs traded) should be available to regulated parties, as well, and may help them to anticipate and avoid market disruptions.

We also propose to make minor changes to compliance reports related to the identification of types of RINs. Please refer to Section III.B. of this preamble for a discussion of types of renewable fuels. Also, please refer to Section III.A. for a discussion of proposed changes to RINs.

Under our proposed EPA-Moderated Trading System described in Section IV.E. of this preamble, then there would be a change in reporting burden on regulated parties that affects the frequency of reporting and the number of reports. Instead of quarterly and/or annual contact with EPA, there would be real time contact—i.e., as batches of renewable fuel are generated or as RINs are transacted. However, we believe that any burden is offset by the advantage of having a simplified system for RIN management that will promote the integrity of RINs and will remove ''guesswork'' now associated with RIN management. As things are now, a regulated party may experience frustration and incur expense in trying to track down and correct errors. Once an error is made, it propagates throughout the distribution system with each transfer from party to party. By having EPA moderate RIN management, we believe that errors would be minimized and regulated parties would be freed of the greater burden to attempt to track down and correct errors they may have made. Implementation of the EPA-Moderated Trading System would correspond to real-time reporting of the type of information contained in the following two quarterly reports: The Renewable Fuel Production Report, known as the RIN Generation Report or ''batch report'' under RFS1 (Report Form Template RFS0400), and the RIN Transaction Report (Report Form Template RFS0200), starting in 2011. For 2010, we are proposing that the type of information contained in these two forms be submitted monthly. These and other reports and instructions related to the existing renewable fuel standard program (RFS1) are posted at *http://www.epa.gov/otaq/regs/fuels/rfsforms.htm*.

3. Additional Requirements for Producers of Renewable Natural Gas, Electricity, and Propane

In addition to the general reporting requirement listed above, we are proposing an additional item of reporting for producers of renewable natural gas, electricity, and propane who choose to generate and assign RINs. While producers of renewable natural gas, electricity, and propane who generate and assign RINs would be responsible for filing the same reports as other producers of RIN-generating renewable fuels, we propose that additional reporting for these producers be required to support the actual use of their products in the transportation sector. We believe that one simple way to achieve this may be to add a requirement that producers of renewable natural gas, electricity, and propane add the name of the purchaser (e.g., the name of the wholesale purchaser-consumer (WPC) or fleet) to their quarterly RIN generation reports and then maintain appropriate records that further identify the purchaser and the details of the transaction. We are not proposing that a purchaser who is either a WPC or an end user would have to register under this scenario, unless that party engages in other activities requiring registration under this program.

K. Production Outlook Reports

We are also proposing additional reporting—annual production outlook reports that would be required of all domestic renewable fuel producers, foreign renewable fuel producers who register to generate RINs, and importers of covered renewable fuels starting in 2010. These production outlook reports would be similar to the pre-compliance reports required under the Highway and Nonroad Diesel programs. These reports would contain information about existing and planned production capacity, long-range plans, and feedstocks and production processes to be used at each production facility. For expanded production capacity that is planned or underway at each existing facility, or new production facilities that are planned or underway, the progress reports would require information on: (1) Strategic planning; (2) Planning and front-end engineering; (3) Detailed engineering and permitting; (4) Procurement and Construction; and (5) Commissioning and startup. These five project phases are described in EPA's June 2002 Highway Diesel Progress Review report (EPA document number EPA420–R–02–016, located at: *www.epa.gov/otaq/regs/hd2007/420r02016.pdf*).

The full list of requirements for the proposed production outlook reports is provided in the proposed regulations at § 80.1449. The information submitted in the reports would be used to evaluate the progress that the industry is making towards the renewable fuels volume goals mandated by EISA and to set the annual cellulosic biofuel, advanced biofuel, biomass-based diesel, and total renewable fuel standards (*see* Section II.A.7 of this preamble). We are proposing that the annual production outlook reports be due annually by February 28, beginning in 2010 and continuing through 2022, and we are proposing that each annual report must provide projected information through calendar year 2022.

EPA currently receives data on projected flexible-fuel vehicle (FFV) sales and conversions from vehicle manufacturers; however, we do not have information on renewable fuels in the distribution system. Thus, EPA is also considering whether to require the annual submission of data to facilitate our evaluation of the ability of the distribution system to deliver the projected volumes of biofuels to petroleum terminals that are needed to meet the RFS2 standards. We request comment on the extent to which such information is already publicly available or can be purchased from a proprietary source. We further request comment on the extent to which such publicly available or purchasable data would be sufficient for EPA to make its determination. To the extent that additional data might be needed, we request comment on the parties that should be required to report to EPA and what data should be required. For example, would it be appropriate to require terminal operators to report to EPA annually on their ability to receive, store, and blend biofuels into petroleum-based fuels? We believe that publicly available information on E85 refueling facilities is sufficient for us to make a determination about the adequacy of such facilities to support the projected volumes of E85 that would be used to satisfy the RFS2 standards.

We request comment on the proposed requirement of annual production outlook reports, and all other aspects mentioned above (e.g., reporting requirements, reporting dates, etc.).

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

The prohibition and liability provisions applicable to the proposed RFS2 program would be similar to those of the RFS1 program and other gasoline programs. The proposed rule identifies certain prohibited acts, such as a failure to acquire sufficient RINs to meet a party's RVOs, producing or importing a renewable fuel that is not assigned a proper RIN category (or D Code), improperly assigning RINs to renewable fuel that was not produced with renewable biomass, failing to assign RINs to qualifying fuel, or creating or transferring invalid RINs. 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 qualifying 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 this 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 (PTD) 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.

EPAct 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). Accordingly, under the proposed rule, any person who violates any prohibition or requirement of the RFS2 program may be subject to civil penalties of $32,500 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, the regulations would prohibit any party from creating or transferring invalid RINs. These invalid RIN provisions apply regardless of the good faith belief of a party that the RINs are valid. These enforcement provisions are necessary to ensure the RFS2 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 obligated party that used the invalid RINs would be required to deduct any invalid RINs from its compliance calculations. Obligated parties 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 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.

We request comment on the need for additional prohibition and liability provisions specific to the proposed RFS 2 program.

IV. What Other Program Changes Have We Considered?

In addition to the regulatory changes we are proposing today in response to EISA that are designed to implement the provisions of RFS2, there are a number of other changes to the RFS program that we are considering. These changes would be designed to increase flexibility, simplify compliance, or address RIN transfer issues that have arisen since the start of the RFS1 program. We have also investigated impacts on small businesses and are proposing approaches designed to address the impacts of the program on them.

A. Attest Engagements

The purpose of an attest engagement is to receive third party verification of information reported to EPA. An attest engagement, which is similar to a financial audit, is conducted by a Certified Public Accountant (CPA) or Certified Independent Auditor (CIA) following agreed-upon procedures. Under the RFS1 program, an attest engagement must be conducted annually. We propose to apply the same provision to this proposed RFS2 rule. However, we seek comment on whether there should be any flexibility provisions for those who own a small number of RINs and what level of flexibility might be appropriate (e.g., allowing those who own a small number of RINs to submit an attest engagement every two years, rather than every year).

B. Small Refinery and Small Refiner Flexibilities

1. Small Refinery Temporary Exemption

CAA section 211(o)(8), enacted as part of EPAct, provides a temporary exemption to small refineries (those refineries with a crude throughput of no more than 75,000 barrels of crude per day, as defined in section 211(o)(1)(K)) through December 31, 2010.[44] Accordingly, the RFS1 program regulations exempt gasoline produced by small refineries from the renewable fuels standard (unless the exemption was waived), see 40 CFR 80.1141. EISA did not alter the small refinery exemption in any way. Therefore, we intend to retain this small refinery temporary exemption in the RFS2 program without change. Further, as discussed below in Section IV.B.2.c, we are proposing to continue one of the hardship provisions for small refineries provided at 40 CFR 80.1141(e).

2. Small Refiner Flexibilities

As mentioned above, EPAct granted a temporary exemption from the RFS program to small refineries through December 31, 2010. In the RFS1 final rule, we exercised our discretion under section 211(o)(3)(B) and extended this temporary exemption to the few remaining small refiners that met the Small Business Administration's (SBA) definition of a small business (1,500 employees or less company-wide) but did not meet the Congressional small refinery definition as noted above.

As explained in the discussion of our compliance with the Regulatory Flexibility Act below in Section XII.C and in the Initial Regulatory Flexibility Analysis in Chapter 7 of the draft RIA, we considered the impacts of today's proposed regulations on small businesses. Most of our analysis of small business impacts was performed as a part of the work of the Small Business Advocacy Review Panel (SBAR Panel, or "the Panel") convened by EPA, pursuant to the Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA). The Final Report of the Panel is available in the docket for this proposed rule. For the SBREFA process, we conducted outreach, fact-finding, and analysis of the potential impacts of our regulations on small businesses.

During the SBREFA process, small refiners informed us that they would need to rely heavily on RINs and/or make capital improvements to comply with the RFS2 requirements. These refiners raised concerns about the RIN program itself, uncertainty (with the required renewable fuel volumes, RIN availability, and cost), and the desire for a RIN system review access to RINs, and the difficulty in raising capital and competing for engineering resources to make capital improvements.

During the Panel process, EPA raised a concern regarding provisions for small refiners in the RFS2 rule; and this rule presents a very different issue than the small refinery versus small refiner concept from RFS1. This issue deals with whether or not EPA has the authority to provide a subset of small refineries (those that are operated by small refiners) with an extension of time that would be different from, and more than, the temporary exemption specified by Congress in section 211(o)(9) for small refineries (temporary exemption through December 31, 2010, with the potential for extensions of the exemption beyond this date if certain criteria are met.). In other words, the temporary exemption specified by Congress provided relief for those small refiners that are covered by the small refinery provision; EPA believes that providing these refiners with an additional exemption different from that provided by section 211(o)(9) may be inconsistent with the intent of Congress. Congress spoke directly to the relief that EPA may provide for small refineries, including those small refineries operated by small refiners, and limited it to a blanket exemption through December 31, 2010, with additional extensions if the criteria specified by Congress were met.

The Panel recommended that EPA consider the issues raised by the SERs and discussions had by the Panel itself, and that EPA should consider comments on flexibility alternatives that would help to mitigate negative impacts on small businesses to the extent allowable by the Clean Air Act. A summary of further recommendations of the Panel are discussed in Section XII.C of this preamble, and a full discussion of the regulatory alternatives discussed and recommended by the Panel can be found in the SBREFA Final Panel Report.

[44] Small refineries are also allowed to waive this exemption.

a. Extension of Existing RFS1 Temporary Exemption

As previously stated, the RFS1 program regulations provide small refiners who operate small refineries, as well as those small refiners who do not operate small refineries, with a temporary exemption from the standards through December 31, 2010. Small refiner SERs suggested that an additional temporary exemption for the RFS2 program would be beneficial to them in meeting the RFS2 standards; and the Panel recommended that EPA propose a delay in the effective date of the standards until 2014 for small entities, to the maximum extent allowed by the statute.

We have evaluated an additional temporary exemption for small refiners for the required RFS2 standards, and we have also evaluated such an exemption with respect to our concerns about our authority to provide an extension of the temporary exemption for small refineries that is different from that provided in CAA section 211(o)(9). As a result, we believe that the limitations of the statute do not necessarily allow us the discretion to provide an exemption for small refiners only (i.e., small refiners but not small refineries) beyond that provided in section 211(o)(9). However, it is important to recognize that the 211(o)(9) small refinery provision does allow for extensions beyond December 31, 2010, with two separate provisions addressing extensions beyond 2010. These provisions are discussed below in Section IV.B.2.c.

Therefore, we are proposing to continue the temporary exemption finalized in RFS1—through December 31, 2010—for small refineries and all qualified small refiners. We also request comment on the interpretation of our authority under the CAA and the appropriateness of providing an extension to small refiners only beyond that authorized by section 211(o)(9).

b. Program Review

During the SBREFA process, the small refiner SERs also requested that EPA perform an annual program review, to begin one year before small refiners are required to comply with the program. We have slight concerns that such a review could lead to some redundancy since EPA is required to publish a notice of the applicable RFS standards in the Federal Register annually, and this annual process will inevitably include an evaluation of the projected availability of renewable fuels. Nevertheless, some Panel members commented that they believe a program review could be beneficial to small entities in providing them some insight to the RFS program's progress and alleviate some uncertainty regarding the RIN system. As we will be publishing a Federal Register notice annually, the Panel recommended that we include an update of RIN system progress (e.g., RIN trading, publicly-available information RIN availability, etc.) in this annual notice.

We propose to include elements of RIN system progress—such as RIN trading and availability—in the annual Federal Register RFS2 standards notice. We also invite comment on additional elements to include in this review.

c. Extensions of the Temporary Exemption Based on Disproportionate Economic Hardship

As noted above, there are two provisions in section 211(o)(9) that allow for an extension of the temporary exemption beyond December 31, 2010. One involves a study by the Department of Energy (DOE) concerning whether compliance with the renewable fuel requirements would impose disproportionate economic hardship on small refineries, and would grant an extension of at least two years for a small refinery that DOE determines would be subject to such disproportionate hardship. Another provision authorizes EPA to grant an extension for a small refinery based upon disproportionate economic hardship, on a case-by-case basis.

We believe that these avenues of relief can and should be fully explored by small refiners who are covered by the small refinery provision. In addition, we believe that it is appropriate to consider allowing petitions to EPA for an extension of the temporary exemption based on disproportionate economic hardship for those small refiners who are not covered by the small refinery provision (again, per our discretion under section 211(o)(3)(B)); this would ensure that all small refiners have the same relief available to them as small refineries do. Thus, we are proposing a hardship provision for small refineries in the RFS2 program, that any small refinery may apply for a case-by-case hardship at any time on the basis of disproportionate economic hardship per CAA section 211(o)(9)(B). While EISA stated (per section 211(o)(9)(A)(ii)(I)) that the small refinery temporary exemption shall be extended for at least two years for any small refinery that the DOE small refinery study determines would face disproportionate economic hardship in meeting the requirements of the RFS2 program, we are not proposing this hardship provision given the outcome of the DOE small refinery study (as discussed below).

In the small refinery study, ''EPACT 2005 Section 1501 Small Refineries Exemption Study'', DOE's finding was that there is no reason to believe that any small refinery would be disproportionately harmed by inclusion in the proposed RFS2 program. This finding was based on the fact that there appeared to be no shortage of RINs available under RFS1, and EISA has provided flexibility through waiver authority (per section 211(o)(7)). Further, in the case of the cellulosic biofuel standard, cellulosic biofuel allowances can be provided from EPA at prices established in EISA (see proposed regulation section 80.1455). DOE thus determined that no small refinery would be subject to disproportionate economic hardship under the proposed RFS2 program, and that the small refinery exemption should not be extended beyond December 31, 2010. DOE noted in the study that, if circumstances were to change and/or the RIN market were to become non-competitive or illiquid, individual small refineries have the ability to petition EPA for an extension of their small refinery exemption (as proposed at draft regulation section 80.1441). We note that the findings of DOE's small refinery study, and a consideration of EPA's ongoing review of the functioning of the RIN market, could factor into the basis for approval of such a hardship request.

We are also proposing a case-by-case hardship provision for those small refiners that do not operate small refineries, at draft regulation section 80.1442(h), using our discretion under CAA section 211(o)(3)(B). This proposed provision would allow those small refiners that do not operate small refineries to apply for the same kind of extension as a small refinery. In evaluating applications for this proposed hardship provision, it was recommended by the SBAR Panel that EPA take into consideration information gathered from annual reports and RIN system progress updates.

d. Phase-in

The small refiner SERs suggested that a phase-in of the obligations applicable to small refiners would be beneficial for compliance, such that small refiners would comply by gradually meeting the standards on an incremental basis over a period of time, after which point they would comply fully with the RFS2 standards, however we have concerns about our authority under the statute to allow for such a phase-in of the standards. CAA section 211(o)(3)(B) states that the renewable fuel obligation shall ''consist of a single applicable percentage that applies to all categories of persons specified'' as obligated parties. This kind of phase-in approach would result in different applicable percentages being applied to different obligated parties. Further, as discussed above, such a phase-in approach would provide more relief to small refineries operated by small refiners than that provided under the small refinery provision. We do not believe that we can use our discretion under the statute to allow for such a provision; however we invite comment on the concept of a phase-in provision for all small refiners.

e. RIN-Related Flexibilities

The small refiner SERs requested that the proposed rule contain provisions for small refiners related to the RIN system, such as flexibilities in the RIN rollover cap percentage and allowing all small refiners to use RINs interchangeably. Currently in the RFS program, up to 20% of a previous year's RINs may be ''rolled over'' and used for compliance in the following year. A provision to allow for flexibilities in the rollover cap could include a higher RIN rollover cap for small refiners for some period of time or for at least some of the four standards. While the rollover cap is the means through which we are implementing the limited credit lifetime provisions in section 211(o) of the CAA, and therefore cannot simply be eliminated, the magnitude of the cap can be modified to some extent. Thus, there could be an opportunity to provide appropriate flexibility in this area. However, given the results of the DOE small refinery study, we do not believe it would be appropriate to propose a change to the RIN rollover cap for small refiners today. However, we request comment on the concept of increasing the RIN rollover cap percentage for small refiners. We also request comment on an appropriate level of that percentage. For example, would a rollover cap of 50% for small refiners be appropriate? Or, would an intermediate value between 20% and 50%, such as 35%, be more appropriate?

The Panel recommended that we take comment on allowing RINs to be used interchangeably for small refiners, but not propose this concept because under this approach small refiners would arguably be subject to a different applicable percentage than other obligated parties. However, this concept fails to require the four different standards mandated by Congress (e.g., conventional biofuel could not be used instead of cellulosic biofuel or biomass-based diesel), and is not consistent with section 211(o) of the Clean Air Act. Thus, we are not proposing this provision in this action, however we invite comment on such an approach for small refiners.

C. Other Flexibilities

1. Upward Delegation of RIN-Separating Responsibilities

Since the start of the RFS1 program on September 1, 2007, there have been a number of instances in which a party who receives RINs with a volume of renewable fuel is required to either separate or retire those RINs, but views the recordkeeping and reporting requirements under the RFS program as an unnecessary burden. Such circumstances typically might involve a renewable fuel blender, a party that uses renewable fuel in its neat form, or a party that uses renewable fuel in a non-highway application and is therefore required to retire the RINs (under RFS1) associated with the volume. In some of these cases, the affected party may purchase and/or use only small volumes of renewable fuel and, absent the RFS program, would be subject to few if any other EPA regulations governing fuels.

This situation will become more prevalent with the RFS2 program, as EISA added diesel fuel to the RFS program. With the RFS1 rule, small blenders (generally farmers and other parties that use nonroad diesel fuel) blending small amounts of biodiesel were not covered under the rule as EPAct mandated renewable fuel blending for highway use only. EISA mandates certain amounts of renewable fuels to be blended into transportation fuels—which includes nonroad diesel fuel. Thus, parties that were not regulated under the RFS1 rule who only blend a small amount of renewable fuel (and, as mentioned above, are generally not subject to many of the EPA fuels regulations) would now be regulated by the program.

Consequently, we believe it may be appropriate, and thus we are proposing today, to permit blenders who only blend a small amount of renewable fuel to allow the party directly upstream to separate RINs on their behalf. Such a provision would be consistent with the fact that the RFS1 program already allows marketers of renewable fuels to assign more RINs to some of their sold product and no RINs to the rest of their sold product. We believe that this provision would eliminate undue burden on small parties who would otherwise not be regulated by this program. We are proposing that this provision apply to small blenders who blend and trade less than 125,000 total gallons of renewable fuel per year. We also request comment on whether or not this threshold is appropriate.

We envision that such a provision would be available to any blender who must separate RINs from a volume of renewable fuel under § 80.1429(b)(2). We also request comment on appropriate documentation to authorize this upward delegation. This could be something such as a document given to the supplier identifying the RIN separation that the supplier would perform. The document could include sufficient information to precisely identify the conditions of the authorization, such as the volume of renewable fuel in question and the number of RINs assigned to that volume. By necessity the document would need to be signed by both parties, and copies retained as records by both parties, since the supplier would then be responsible for these actions. The supplier would then be allowed to retain ownership of RINs assigned to a volume of renewable fuel when that volume is transferred, under the condition that the RINs be separated or retired concurrently with the transfer of the volume. We are proposing an annual authorization that would apply to all volumes of renewable fuel transferred between two parties for a given year (i.e., the two parties would enter into a contract stating that the supplier has RIN-separation responsibilities for all transferred volumes).

We are proposing this provision solely for the case of blenders who blend and trade less than 125,000 total gallons of renewable fuel per year. A company that blends 100,000 gallons and trades 100,000 gallons would not be able to use this provision. However, we request comment on whether authorization to delegate RIN-separation responsibilities should also be allowed for other parties as well.

2. Small Producer Exemption

Under the RFS1 program, parties who produce or import less than 10,000 gallons of renewable fuel in a year are not required to generate RINs for that volume, and are not required to register with the EPA if they do not take ownership of RINs generated by other parties. We propose to maintain this exemption under the RFS2 rule. However, we request comment on whether the 10,000 gallon threshold should be higher given that the total volume of renewable fuel mandated by EISA is considerably higher than that required by the RFS1 program, or conversely whether it should be lower given that the biomass-based diesel standard is considerably lower than the mandated volume for total renewable fuel.

D. 20% Rollover Cap

EISA does not change the language in CAA section 211(o)(5) stating that renewable fuel credits must be valid for showing compliance for 12 months as of the date of generation. As discussed in the RFS1 final rulemaking, we interpreted the statute such that credits would represent renewable fuel volumes in excess of what an obligated party needs to meet their annual compliance obligation. Given that the renewable fuel standard is an annual standard, obligated parties determine compliance shortly after the end of the year, and credits would be identified at that time. In the context of our RIN-based program, we have accomplished the statute's objective by allowing RINs to be used to show compliance for the year in which the renewable fuel was produced and its associated RIN first generated, or for the following year. RINs not used for compliance purposes in the year in which they were generated will by definition be in excess of the RINs needed by obligated parties in that year, making excess RINs equivalent to the credits referred to in section 211(o)(5). Excess RINs are valid for compliance purposes in the year following the one in which they initially came into existence. RINs not used within their valid life will thereafter cease to be valid for compliance purposes.

In the RFS1 final rulemaking, we also discussed the potential ''rollover'' of excess RINs over multiple years. This can occur in situations wherein the total number of RINs generated each year for a number of years in a row exceeds the number of RINs required under the RFS program for those years. The excess RINs generated in one year could be used to show compliance in the next year, leading to the generation of new excess RINs in the next year, causing the total number of excess RINs in the market to accumulate over multiple years despite the limit on RIN life. The rollover issue could in some circumstances undermine the ability of a limit on credit life to guarantee an ongoing market for renewable fuels.

To implement the Act's restriction on the life of credits and address the rollover issue, the RFS1 final rulemaking implemented a 20% cap on the amount of an obligated party's RVO that can be met using previous-year RINs. Thus each obligated party is required to use current-year RINs to meet at least 80% of its RVO, with a maximum of 20% being derived from previous-year RINs. Any previous-year RINs that an obligated party may have that are in excess of the 20% cap can be traded to other obligated parties that need them. If the previous-year RINs in excess of the 20% cap are not used by any obligated party for compliance, they will thereafter cease to be valid for compliance purposes.

EISA does not modify the statutory provisions regarding credit life, and the volume changes by EISA also do not change at least the possibility of large rollovers of RINs for individual obligated parties. Therefore, we propose to maintain the regulatory requirement for a 20% rollover cap under the new RFS2 program. However, under RFS2 obligated parties will have four RVOs instead of one. As a result, we are proposing that the 20% rollover cap would apply separately to all four RVOs. We do not believe it would be appropriate to apply the rollover cap to only the RVO representing total renewable fuel, leaving the other three RVOs with no rollover cap. Doing so would allow all previous-year RINs used for compliance to be those with a D code of 4, and this in turn would allow an obligated party to meet one of the nested standards, such as that for biomass-based diesel, using more than 20% previous-year RINs. This could result in significant rollover of RINs with a D code of 2, representing biomass-based diesel, and the valid life of these RINs would have no meaning in this case.

Some obligated parties have suggested that the rollover cap should be raised to a value higher than 20%, citing the need for greater flexibility in the face of significantly higher volume requirements. However, we believe that a higher value could create disruptions in the RIN market as parties with excess RINs would have a greater incentive to hold onto them rather than sell them. This would especially be a concern in years where the volume of renewable fuel available in the market is very close to the RFS requirements. Nevertheless, we request comment on whether the 20% rollover cap should be raised to a higher value.

As described in Section III.G.4, some parties have also suggested that the rollover cap should be lowered to a value lower than 20%, such as 10%. In the event of concerns about the availability of RINs, a lower rollover cap would provide a greater incentive for parties with excess RINs to sell them rather than hold onto them. However, a lower rollover cap would also reduce flexibility for many obligated parties. While we are not proposing it in today's notice, we request comment on it.

E. Concept for EPA Moderated Transaction System

1. The Need for an EPA Moderated Transaction System

In implementing RFS1, we found that the 38-digit standardized RINs have proven confusing to many parties in the distribution chain. Parties have made various errors in generating and using RINs. For example, we have seen errors wherein parties have transposed digits within the RIN. We have seen parties creating alphanumeric RINs, despite the fact that RINs are supposed to consist of all numbers. We have also seen incorrect numbering of volume start and end codes.

Once an error is made within a RIN, the error propagates throughout the distribution system. Correcting an error can require significant time and resources and involve many steps. Not only must reports to EPA be corrected, underlying records and reports reflecting RIN transactions must also be located and corrected to reflect discovery of an error. Because reporting related to RIN transactions under RFS1 is only on a quarterly basis, a RIN error may exist for several months before being discovered.

Incorrect RINs are invalid RINs. If parties in the distribution system cannot track down and correct the error made by one of them in a timely manner, then all downstream parties that trade the invalid RIN will be in violation. Because RINs are the basic unit of compliance for the RFS1 program, it is important that parties have confidence when generating and using them.

All parties in the RFS1 and the proposed RFS2 regulated community use RINs. These parties include producers of renewable fuels, obligated parties, exporters, and other owners of RINS, typically marketers of renewable fuels and blenders. (Anyone can own RINs, but those who do would be subject to registration, recordkeeping, reporting, and attest engagement requirements described in this preamble.). Currently under RFS1, all RINs are used to comply with a single standard, and in 2013 an additional cellulosic standard would have been added. Under this proposed rule, there are four standards, and RINs must be generated to identify four types of renewable fuels: cellulosic biofuel, biomass-based diesel, other advanced biofuels, and other renewable fuels (e.g., corn ethanol). (For a more detailed discussion of RINs, see Section III.A of this preamble.) In the proposed EPA Moderated Transaction System (EMTS), the four types of RINs will be managed through four types of account.

Based upon problems we observed with the use of RINs under RFS1, and considering that we will now have a more complex system including four standards instead of just one, we believe that the best way to screen RINs and conduct RIN-based transactions is through EMTS.

This section describes the proposed EMTS and options for implementing it. By implementing EMTS, we believe that we would be able to greatly reduce RIN-related errors and efficiently and accurately manage the universe of RINs. There are two aspects to our proposal for EMTS. The first aspect focuses upon creating four, generic types of RIN account. The second aspect focuses upon actually developing a ''real time'' environment for handling RIN trades.

2. How EMTS Would Work

EMTS would be a closed, EPA-managed system that provides a mechanism for screening RINs as well as a structured environment for conducting RIN transactions. ''Screening'' RINs will mean that parties would have much greater confidence that the RINs they handle are genuine. Although screening cannot remove all human error, we believe it can remove most of it.

We propose that screening and assignment of RINs be made at the logical point, i.e., the point when RINs are generated through production or importation of renewable fuel. A renewable producer would electronically submit, in ''real time,'' a batch report for the volume of renewable fuel produced or imported, as well as a list of the RINs generated and assigned. EMTS would automatically screen each batch and either reject the RINs or permit them to pass into the transaction system, into the RIN generator's account, as one of the four types of RINs. Note that under RFS1, RIN generation (batch) and RIN transaction reports are submitted quarterly. Batch reports are submitted by producers and importers quarterly and reflect how they generated and assigned RINS to batches. RIN transaction reports are submitted by all parties who engage in RIN transactions, including buying or selling RINs. Under this proposed approach for RFS2, these batch reports and RIN transaction reports would be submitted monthly for calendar year 2010. However, once EMTS is implemented in calendar year 2011, these separate periodic reports may no longer be necessary. Instead the information would be submitted as RINs are generated and assigned within EMTS.

Under RFS1, the producer or importer list RINs they generate and assign via the batch report. EPA, in turn, uses the batch report data to verify RINs generated and transacted. The report is submitted quarterly. Under RFS1, the purpose of the RIN transaction report is to document RIN transactions and to document that RINs have been sold or transferred from party to party in the distribution system. This report is also submitted quarterly. The RIN transaction report includes the following information in this report: its name, its EPA company registration number, and in some cases (where compliance is on a facility basis), its EPA facility identification number. For the quarterly reporting period, the reporting party indicates the transaction type (RIN purchase, RIN sale, expired RIN, or retired RIN), and the date of the transaction. For a RIN purchase or sale, the transaction report includes the trading partner's name and the trading partner's EPA company registration number. There is also information that may have to be submitted in the event a reporting party must report a RIN that has been retired (e.g., when a RIN has become invalid due to the spillage of the associated volume of renewable fuel). As discussed above, the shortcoming of these reports is that they are only submitted quarterly. RIN errors that affect compliance may not be discovered for many months because of the relative infrequency of reporting transactions to EPA. EMTS will assume the functionality of batch reporting and transaction reporting used by regulated parties, allowing EPA to better screen RINs and reduce or eliminate generation and transaction errors.

Under the RFS2 program, we are proposing that batch reports submitted by producers and importers and RIN transaction reports be submitted monthly rather than quarterly in the first year of the program (i.e., calendar year 2010). During 2010, we will be finishing development and testing of the EMTS. In order to minimize the hardship that undiscovered, invalid RINs may cause, we propose and seek comment on increasing the frequency of reporting and our own review of reports in order to assist the regulated community with compliance. As we develop EMTS through calendar year 2010, we intend to invite and encourage interested reporting parties to ''opt in'' to EMTS. This will serve a two-fold purpose: regulated parties may opt to gain familiarity EMTS before it becomes fully operational and we may have actual customers with which to test EMTS prior to it becoming fully operational. We believe that permitting interested parties to ''opt in'' will result in a better EMTS for all.

In the second year of the program (i.e., calendar year 2011 and forward), we anticipate fully implementing the proposed EMTS and receiving the data contained in batch and RIN transaction reports in relatively ''real time'' (i.e., as transactions occur). We propose that ''real time'' be construed as within three (3) business days of a reportable event (e.g., generation and assignment of RINs, transfer of RINs).

Parties who use EMTS would have to register with EPA in accordance with the proposed RFS2 registration program described in Section III.C of this preamble. They would also have to create an account (i.e., register) via EPA's Central Data Exchange (CDX), as we envision managing EMTS via CDX. CDX is a secure and central portal through which parties may submit compliance reports. We propose that parties must establish an account with EMTS by October 1, 2010 or 60 days prior to engaging in any transaction involving RINs, whichever is later. As discussed above, the actual items of information covered by reporting under RFS2 are nearly identical to those reported under RFS1.

Once registration occurs with EMTS, individual RIN accounts would be established and the system would manage the accounts for each individual party. The RIN accounts would correspond to the four broad types of renewable fuel. RIN accounts would be established for cellulosic biofuel, biomass-based diesel, other advanced biofuels, and other renewable fuels (including corn ethanol). One big advantage of RIN accounts is that the system would make available generic accounts for transactions involving RINs of similar type. The unique identification of the RIN would exist within EMTS, but parties engaging in RIN transactions would no longer have to worry about incorrectly recording or using 38-digit RIN numbers. As with RFS1, there is no ''good faith'' provision to RIN ownership. An underlying principle of RIN ownership is still one of ''buyer beware'' and RINs may be prohibited from use at any time if they are found to be invalid. Because of the ''buyer beware'' aspect, we intend to offer the option for a buyer to accept or reject RINs from specific RIN generators or from classes of RIN generators. Also, we propose to collect information about the price associated with RINs traded. This information is not collected under RFS1, but we believe this information has great programmatic value to EPA because it may help us to anticipate and appropriately react to market disruptions and other compliance challenges, assess and develop responses to potential waivers, and assist in setting future renewable standards. We believe that highly summarized price information (e.g., the average price of RINs traded nationwide) may be valuable to regulated parties, as well, and may help them to anticipate and avoid market disruptions.

The following is an example of how a RIN transaction might occur in the proposed EMTS model:

1. Seller logs into EMTS and posts his sale of 10,000 RINs to Buyer. For this example, assume the RINs were generated in 2008 and were assigned to 10,000 gallons of ''other renewable fuel'' (corn ethanol). Seller's RIN account for ''other renewable fuel'' is automatically reduced by 10,000 with the posting of his sale to Buyer. Buyer receives automatic notification of the pending transaction.

2. Buyer logs into EMTS. She sees the sale transaction pending. Assuming it is correct, she accepts it. Upon her acceptance, her RIN account for ''other renewable fuel'' (corn ethanol) is automatically increased by 10,000 2008 assigned RINs.

3. After Seller has posted his sale and Buyer has accepted it, EMTS automatically notifies both Buyer and Seller that the transaction has been fully completed.

Under EMTS as we are proposing it, the seller would always have to initiate any transaction. The seller's account is reduced when he posts his sale. The buyer must acknowledge the sale in order to have the RINs transferred to her account. Transactions would always be limited to available RINs. Notification would automatically be sent to both the buyer and the seller upon completion of the transaction. EPA proposes to consider any sale or transfer as complete upon acknowledgement by the buyer.

We propose that RINs and the parameters of RIN generation (e.g., year) be considered public information. We also propose that summary RIN price information, such as average price of all RINs in a broad geographic area (such as a state, region, or nationwide) be considered public information. This summary price information would be aggregated from transactions conducted within EMTS, but would not be identified with individual companies or particular transactions that have occurred. Because we believe information about RIN pricing in general will be useful to regulated parties, we are proposing to make this information available to them. We propose that the actual transactions between parties and that individual company account information may be claimed as confidential business information (CBI) by the parties to that transaction. EPA would treat any information submitted that is covered by a CBI claim in accordance with the procedures at 40 CFR Part 2 and applicable Agency policies and guidelines for the handling of claimed CBI.

3. Implementation of EMTS

We anticipate that implementing EMTS will take until January 1, 2011, although we are proposing that the RFS2 program be effective on January 1, 2010. We anticipate that development of EMTS will require significant time and effort and that a delayed effective date may permit better pre-testing with interested regulated parties. We propose to permit regulated parties who are willing to participate in EMTS early to voluntarily opt-in to the system before January 1, 2011. The actual date for these parties' opt-in will depend upon the actual timeline for development of EMTS. We encourage comments from interested parties as to how we might best make use of the development period and the proposed opportunity for willing and interested parties to ''opt in'' early.

Under our proposed scenario, for the 2010 compliance year, recordkeeping and reporting would be analogous to RFS1, although registration would be enhanced in accordance with the discussion in Section III.C of this preamble and recordkeeping and reporting would reflect the four types of RIN described above. In order to avoid propagation of RIN-related errors and to prevent errors from going too long without being detected, we believe it is necessary to increase the frequency of batch reporting and RIN transaction reporting to monthly rather than quarterly during 2010.

EPA will implement the EMTS during the first year of the RFS2 program. RINs generated under the RFS1 regulations will continue to be traded and reported using the current processes. RINs would still have unique identifying information, but EMTS will allow transactions to take place on a generic basis having the system track the specific unique identifiers. We believe that EMTS will virtually eliminate errors related to tracking and using individual RINs. Parties will be required to submit RIN transactions by specifying RIN year, RIN assignment, RIN fuel type, and any other reporting requirement specified by the administrator.

Implementation of EMTS should save considerable time and resources for both industry and EPA. This is most evident considering that the proposed system virtually eliminates multiple sources of administrative errors, resulting in a reduction in costs and effort expended to correct and regenerate product transfer documents, documentation and recordkeeping, and resubmitting reports to EPA. We anticipate that a fully functioning EMTS will result in fewer reports and easier reporting for industry, and fewer reports requiring processing by EPA. Industry will need to spend less time and effort verifying the validity of the RINs they procure and allowing them to procure them on the open market with confidence. EPA will need to spend less time tracking down the responsible parties for invalid RINs. This is possible because EMTS will remove management of the 38-digit RIN from the hands of the reporting community. At the same time, EPA and the reporting community will be working with a standardized system, reducing stresses and development costs on IT systems.

In summary, the advantage to implementing EMTS is that parties may engage in RIN transactions with a high degree of confidence. Errors would be virtually eliminated. Everyone engaging in RIN transactions would have a simplified environment in which to work which should minimize the level of resources needed for implementation. However, the one unavoidable disadvantage that we foresee is that parties would have to switch to a new and different reporting system in the second year of the RFS2 program. Some errors may still occur in by parties who continue to generate and use the 38-digit RINs during 2010. As discussed above, we propose to increase the frequency of batch and RIN transaction reporting to monthly for 2010, in order that we may help parties discover errors and correct them before they become violations. We also propose to permit parties to voluntarily ''opt in'' to using EMTS while it is still in development in order to ease the transition. We invite comment from all interested parties as to how we may best assist regulated parties in transitioning from the ''old'' RFS1 method of handing RINs to the ''new,'' proposed RFS2 EMTS method on January 1, 2011.

We also invite comment on whether, in the event the RFS2 start date is delayed, EPA should nevertheless allow a one-year period during which use of EMTS is optional, or if EPA should begin the program at the inception of the delayed RFS2 program if EMTS is fully operational at that time.

F. Retail Dispenser Labelling for Gasoline With Greater Than 10 Percent Ethanol

Fuel retailers expressed concern that the magnitude of the price discount for E85 relative to E10 that would be necessary to facilitate sufficient use of E85 would encourage widespread misfueling of non-flex fuel vehicles. Today's proposal contains labeling requirements for pumps that dispense blends that contain greater than 10% ethanol which state that the use in non-flex fuel vehicles is prohibited and may cause damage to the vehicle.[45] We anticipate that the industry would also conduct public information activities to alert customers who may not have yet become accustomed to seeing E85 at retail to avoid using E85 in their non-flex-fuel vehicles. Uniquely colored/labeled nozzle handles may also be useful in helping to prevent accidental cases of misfueling. We believe that in most cases the warnings that the use of E85 in non-flex fuel vehicles is illegal, can damage the vehicle, and can void vehicle manufacturer warranties may be a sufficient disincentive to prevent intentional misfueling. In cases where intentional misfueling may occasionally take place, the party is likely to experience drivability problems and thus would not repeat the act.

Today's proposal does not contain requirements that E85 refueling hardware be configured to prevent the introduction of E85 into non-flex-fuel vehicles. It is unclear how such an approach could be implemented to allow the approximately 6 million flex-fuel vehicles on the road today to continue to be fueled with E85 without modification to their filler neck hardware.[46] In any event, we do not believe that unique E85 nozzles are necessary.

We request comment on whether the proposed labeling requirements and voluntary measures such as those described above would provide sufficient warning to fuel retail customers not to refuel non-flex-fuel vehicles with E85. To the extent that other measures to prevent misfueling are thought to be necessary, comment is requested on the specific nature of such measures and the associated potential costs and benefits. One additional potential measure to prevent misfueling would be for cards to be issued to flex fuel vehicle owners and for all E85 dispensers to be equipped with card readers that would allow E85 to be dispensed only to card holders.

V. Assessment of Renewable Fuel Production Capacity and Use

To assess the impacts of this rule, there must be a clear understanding of the kind of renewable fuels that could be used, the types and locations of their feedstocks, the fuel volumes that could be produced by a given feedstock, and any challenges associated with their use. This section provides this assessment of the potential feedstocks and renewable fuels that may be used to meet the Energy Independence and Security Act (EISA) and the rationale behind our projections of various fuel types to represent the control case for analysis purposes. Definitional issues regarding the four types of renewable fuel required under EISA are discussed in Section III.B of this preamble.

A. Summary of Projected Volumes

EISA mandates the use of increasing volumes of renewable fuel. To assess the impacts of this increase in renewable fuel volume from business-as-usual (what is likely to have occurred without EISA), we have established a reference and control case from which subsequent analyses are based. The reference case is essentially a projection of renewable fuel volumes without the enactment of EISA. The control case is a projection of the volumes and types of renewable fuel that might be used to comply with the EISA volume mandates. Both the reference and control cases are discussed in further detail below.

1. Reference Case

Our reference case renewable fuel volumes are based on the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2007 reference case projections. The AEO 2007 presents long-term projections of energy supply, demand, and prices through 2030 based on results from EIA's National Energy Modeling System (NEMS). EIA's analysis focuses primarily on a reference case (which we use as our reference case), lower and higher economic growth cases, and lower and higher energy price cases. AEO 2007 projections generally are based on Federal, State, and local laws and regulations in effect on or before October 31, 2006.[47] The potential impacts of pending or proposed legislation, regulations, and standards are not reflected in the projections. While AEO 2007 is not as up-to-date as AEO 2008 (or the recently released AEO 2009), we chose to use AEO 2007 because AEO 2008 already includes the impact of increased renewable fuel volumes under EISA as well as fuel economy improvements under CAFE, whereas AEO 2007 did not. Table V.A.1–1 summarizes the fuel types and volumes for the years 2009–2022 as taken from AEO 2007. For our air quality analysis we also considered a reference case assuming the mandated renewable fuel volumes under the Renewable Fuel Standard Program from the Energy Policy Act of 2005 (EPAct). Refer to Section VII for further details.

TABLE V.A.1–1—AEO 2007 REFERENCE CASE PROJECTED RENEWABLE FUEL VOLUMES

[billion gallons]

Year	Advanced biofuel			Non-advanced biofuel	Total renewable fuel
	Cellulosic biofuel	Biomass-based diesel[a]	Other advanced biofuel		
	Cellulosic ethanol	FAME biodiesel[b]	Imported ethanol	Corn ethanol	
2009	0.07	0.32	0.50	9.44	10.33
2010	0.12	0.32	0.29	10.49	11.22
2011	0.19	0.33	0.16	10.69	11.37
2012	0.25	0.33	0.18	10.81	11.57

[45] *See* section 80.1469 in the proposed regulatory text.

[46] An E85 nozzle design and corresponding flex-fuel vehicle filler design that would prevent the introduction of E85 into non-flex-fuel vehicles while allowing flex fuel vehicles to be fueled with E10 as well as E85 would also prevent the introduction of E85 into current flex-fuel vehicles since there is currently no difference in nozzle/filler neck hardware between flex-fuel and non-flex-fuel vehicles.

[47] EIA. Annual Energy Outlook 2007 with Projections to 2030. *http://www.eia.doe.gov/oiaf/archive/aeo07/index.html*. Accessed February 2008.

TABLE V.A.1–1—AEO 2007 REFERENCE CASE PROJECTED RENEWABLE FUEL VOLUMES—Continued

[billion gallons]

Year	Advanced biofuel			Non-advanced biofuel	Total renewable fuel
	Cellulosic biofuel	Biomass-based diesel[a]	Other advanced biofuel		
	Cellulosic ethanol	FAME biodiesel[b]	Imported ethanol	Corn ethanol	
2013	0.25	0.33	0.19	10.93	11.70
2014	0.25	0.23	0.20	11.01	11.69
2015	0.25	0.25	0.39	11.10	11.99
2016	0.25	0.35	0.51	11.16	12.27
2017	0.25	0.36	0.53	11.30	12.44
2018	0.25	0.36	0.54	11.49	12.64
2019	0.25	0.37	0.58	11.69	12.89
2020	0.25	0.37	0.60	11.83	13.05
2021	0.25	0.38	0.63	12.07	13.33
2022	0.25	0.38	0.64	12.29	13.56

[a] Biomass-Based Diesel includes FAME biodiesel, cellulosic diesel, and non-co-processed renewable diesel. AEO 2007 only projects FAME biodiesel volumes.
[b] Fatty acid methyl ester (FAME) biodiesel.

2. Control Case for Analyses

Our assessment of the renewable fuel volumes required to meet EISA necessitates establishing a primary set of fuel types and volumes on which to base our assessment of the impacts of the new standards. EISA contains four broad categories: cellulosic biofuel, biomass-based diesel, total advanced biofuel, and total renewable fuel. As these categories could be met with a wide variety of fuel choices, in order to assess the impacts of the rule, we projected a set of reasonable renewable fuel volumes based on our interpretation at the time we began our analysis of likely fuels that could come to market.

Although actual volumes and feedstocks may be different, we believe the projections made for our control case are within the range of reasonable predictions and allow for an assessment of the potential impacts of the RFS2 standards. Table V.A.2–1 summarizes the fuel types used for the control case and their corresponding volumes for the years 2009–2022.

TABLE V.A. 2–1—CONTROL CASE PROJECTED RENEWABLE FUEL VOLUMES

[billion gallons]

Year	Advanced biofuel					Non-Advanced Biofuel	Total renewable fuel
	Cellulosic biofuel	Biomass-based diesel[a]		Other advanced biofuel			
	Cellulosic ethanol	FAME[b] biodiesel	Non-co-processed renewable diesel	Co-processed renewable diesel	Imported ethanol	Corn ethanol	
2009	0.00	0.50	0.00	0.00	0.50	9.85	10.85
2010	0.10	0.64	0.01	0.01	0.29	11.55	12.60
2011	0.25	0.77	0.03	0.03	0.16	12.29	13.53
2012	0.50	0.96	0.04	0.04	0.18	12.94	14.66
2013	1.00	0.94	0.06	0.06	0.19	13.75	16.00
2014	1.75	0.93	0.07	0.07	0.36	14.40	17.58
2015	3.00	0.91	0.09	0.09	0.83	15.00	19.92
2016	4.25	0.90	0.10	0.10	1.31	15.00	21.66
2017	5.50	0.88	0.12	0.12	1.78	15.00	23.40
2018	7.00	0.87	0.13	0.13	2.25	15.00	25.38
2019	8.50	0.85	0.15	0.15	2.72	15.00	27.37
2020	10.50	0.84	0.16	0.16	2.70	15.00	29.36
2021	13.50	0.83	0.17	0.17	2.67	15.00	32.34
2022	16.00	0.81	0.19	0.19	3.14	15.00	35.33

[a] Biomass-Based Diesel includes FAME biodiesel, cellulosic diesel, and non-co-processed renewable diesel.
[b] Fatty acid methyl ester (FAME) biodiesel.

We needed to make this projection soon after EISA was signed to allow sufficient time to conduct our long lead-time analyses. As a result, we used the same ethanol-equivalence basis for these projections as was used in the RFS1 rulemaking. However, as described in Section III.D.1, we are also co-proposing that volumes of renewable fuel be counted on a straight gallon-for-gallon basis under RFS2, such that all Equivalence Values would be 1.0. The net effect of these two approaches to Equivalence Values on projected volumes is very small; instead of 36 billion gallons of renewable fuel in 2022, our control case includes 35.3 billion gallons. We do not believe that this difference will substantively affect the analyses that are based on our projected control case volumes.

The following subsections detail our rationale for projecting the amount and type of fuels needed to meet EISA as shown in Table V.A.2–1. For cellulosic biofuel we have assumed that the entire volume will be domestically produced cellulosic ethanol. Biomass-based diesel is assumed to be comprised of a majority of fatty-acid methyl ester (FAME) biodiesel and a smaller portion of non-co-processed renewable diesel. The portion of the advanced biofuel category not met from cellulosic biofuel and biomass-based diesel is assumed to come mainly from imported (sugarcane) ethanol with a smaller amount from co-processed renewable diesel. The total renewable fuel volume not required to be comprised of advanced biofuels is assumed to be met with corn ethanol.

In addition, the following subsections also describe other fuels that have the potential to contribute to meeting EISA, but because of their uncertainty of use, or because their use likely might be negligible we have chosen to not assume any use for our analysis. Examples of these types of renewable fuels or blendstocks include bio-butanol, biogas, cellulosic diesel, cellulosic gasoline, biofuel from algae, jatropha, or palm, imported cellulosic ethanol, other biomass-to-liquids (BTL), and other alcohols or ethers. We intend to revisit these assumptions for the final rule and invite comment on whether these renewable fuels or other potential fuels which have not been included in our analyses should be included.

a. Cellulosic Biofuel

As defined in EISA, cellulosic biofuel means renewable fuel produced from any cellulose, hemicellulose, or lignin that is derived from renewable biomass and that has lifecycle greenhouse gas emissions, as determined by the Administrator, that are at least 60% less than the baseline lifecycle greenhouse gas emissions.

When many people think of cellulosic biofuel, they immediately think of cellulosic ethanol. However, cellulosic biofuel could be comprised of other alcohols, synthetic gasoline, synthetic diesel fuel, and synthetic jet fuel, propane, and biogas. Whether cellulosic biofuel is ethanol will depend on a number of factors, including production costs, the form of tax subsidies, credit programs, and issues associated with blending the biofuel into the fuel pool. It will also depend on the relative demand for gasoline and diesel fuel. For instance, European refineries are undersupplying the European market with diesel fuel and oversupplying it with gasoline, and based on the recent high diesel fuel price margins over gasoline, it seems that the U.S. is falling in line with Europe. Therefore, if the U.S. trend is toward being relatively oversupplied with gasoline, there could be a price advantage towards producing renewable fuels that displace diesel fuel rather than a gasoline fuel replacement like ethanol.

Current efforts in converting cellulosic feedstocks into fuels focus on biochemical and thermochemical conversion processes. Biochemical processes use live bacteria or isolated enzymes, or acids, to break cellulose down into fermentable sugars. The advantage of using live bacteria or enzymes is that simple carbon steel could be used which helps to control the capital costs. However, bacteria and enzymes that break down cellulose are generally specific to certain types of cellulose, thus, the cellulosic biofuel facility may have difficulty processing different types of feedstocks.[48] If live bacteria are used, the bacteria could be susceptible to contamination that could force a plant shutdown. An example of a company using enzymes to process cellulose into ethanol is Iogen, which has a demonstration plant in Canada.

On the other hand, biochemical processes which rely on strong acids will likely be less susceptible to contamination issues, and could more easily process mixed feedstocks. Thus, strong acid biochemical cellulosic ethanol plants could process MSW or a variety of feedstocks which may be available in areas where no single feedstock dominates. The strong acids, however, would likely require more expensive metallurgy. A company which is planning to use strong acids to hydrolyze the cellulose is Blue Fire Ethanol. Blue Fire is planning on building a MSW plant in Southern California. Once cellulose is reduced to simple sugars, either strong acid or enzymatic cellulosic ethanol plants operate in a manner similar to a corn ethanol plant. This consists of fermenting sugars into ethanol and then separating the ethanol from the water that facilitated the fermentation step.

The thermochemical conversion process is very different from the biochemical process right from the beginning. For the thermochemical process, feedstocks are partially burned with oxygen at a very high temperature and converted into a synthesis gas comprised of carbon monoxide and hydrogen. The principal advantage of the thermochemical process is that virtually any hydrocarbon material could be processed as feedstock, as they would all be converted to the synthesis gas, even if they produce different relative concentrations of carbon monoxide and hydrogen. The synthesis gas is typically converted to ethanol or diesel by one of several different processes.

Examples of companies currently pursuing the thermochemical route to selectively produce ethanol include Range Ethanol and Coskata. Range Ethanol is using a specially formulated catalyst that will primarily produce ethanol, but it will produce other higher molecular weight alcohols as well which would be recycled and mostly converted to ethanol. Coskata, which is being supported by General Motors, is planning on using bacteria to convert the synthesis gas to ethanol.

Another thermochemical plant could employ a very similar gasification reactor, but instead of producing ethanol from syngas, a Fischer Tropsch (F–T) reactor would be used to produce a primarily diesel product, i.e., cellulosic diesel. The F–T reactor would use a specially designed iron or cobalt catalyst to convert the syngas to straight chain hydrocarbon compounds of varying lengths and molecular weights. The heavier of these hydrocarbon compounds are then hydrocracked to produce a very high percentage of valuable diesel fuel and naphtha (gasoline type compounds). The F–T diesel fuel produced from the F–T process is very high in quality due to its high cetane and essentially zero sulfur level. While the naphtha produced from the F–T process also contains essentially zero sulfur, it is very low in octane and thus is a poor gasoline blendstock (although it could still be desirable as a gasoline blendstock because of all the high octane ethanol being blended into gasoline). Cellulosic naphtha is also valuable as a cracking feedstock for producing various petrochemical compounds. Since the F–T diesel is of better quality than the naphtha, the heavier hydrocarbon compounds are selectively hydrocracked to produce more diesel over naphtha.

No commercial cellulosic diesel plants currently exist in the U.S., nor elsewhere in the world. Currently, there is a cellulosic diesel pilot plant operated by Choren in Germany and a commercial sized plant in the planning stages by Choren also in Germany. Choren is planning to employ woody materials and agricultural residue as feedstocks. Choren specially developed a three-stage gasification process for dealing with the complexities of

[48] This is currently an area of intense research.

biomass and has partnered with Shell which has commercialized a F–T reaction process. The Choren commercial cellulosic diesel plant in Germany is expected to begin operating in 2010. Although coal-to-liquids (CTL) plants rely on coal as their feedstock, they are very similar to cellulosic diesel plants in design and help to demonstrate the feasibility of the cellulosic diesel process. There are CTL pilot plants which are operating today, as well as a number of commercial CTL plants operating today or in the planning stages. Some of these plants have experimented with or are being planned for co-feeding biomass along with the coal. A current list of proposed cellulosic diesel and CTL plants is provided in Chapter 1 of the DRIA.

In terms of production costs, at least for the current state of technology, neither the biochemical nor thermochemical platforms (comparing enzymatic biochemical processing to ethanol and thermochemical processing to cellulosic diesel) appear to have clear advantages in capital costs or operating costs.[49] Other processing techniques, for example, the syngas-to-ethanol process used by Coskata, claim to be capable of producing at even lower production costs, but without any commercial facilities operating today, it is hard to predict how these other processing techniques differ from our estimates of what the production costs for cellulosic biofuel facilities will be in the future and which technology pathways will be most economic. As such, both enzymatic biochemical and thermochemical technologies could be key processing pathways for the production of cellulosic biofuel.

The economic competitiveness of cellulosic biofuels will also depend on the extent of financial support from the government. Under the Farm Bill of 2008, both cellulosic ethanol and cellulosic diesel receive the same tax subsidies ($1.01 per gallon each). The tax subsidy, however, gives ethanol producers a considerable advantage over those producing cellulosic diesel due to the feedstock quantity needed per gallon produced (i.e., typically the higher the energy content of the product, the more feedstock that is required). On an energy basis, cellulosic ethanol would receive approximately $13/mmBtu while cellulosic diesel would receive approximately $8/mmBtu. In a similar manner, if we were to finalize an approach to the Equivalence Values for generating RINs in which volume rather than energy content is the basis, there would be an advantage for the production of cellulosic ethanol over cellulosic diesel.

One large advantage that cellulosic diesel has over ethanol is the ability for the fuel to be blended easily into the current distribution infrastructure at sizeable volumes. There are currently factors tending to limit the amount of ethanol that can be blended into the fuel pool (see Section V.D. for more discussion). Thus, the production of cellulosic diesel instead of cellulosic ethanol could help increase consumption of renewable fuels.

Thus, there is uncertainty as to which mix of cellulosic biofuels will be produced to fulfill the 16 Bgal mandate by 2022. The latest release of AEO 2009, for example, estimates a mixture of cellulosic diesel and ethanol produced for cellulosic biofuel. For assessing the impacts of the RFS2 standards, we made the simplifying assumption that cellulosic biofuel would only consist of ethanol, though market realities may also result in cellulosic diesel and other products. We are requesting comment on the types of cellulosic biofuel that should be accounted for in our analyses and whether certain fuels are more likely to come to fruition than others.

Cellulosic biofuel could also be produced internationally. One example of internationally produced cellulosic biofuel is ethanol produced from bagasse or straw from sugarcane processing in Brazil. Currently, Brazil burns bagasse to produce steam and generate bioelectricity. However, improving efficiencies over the coming decade may allow an increasing portion of bagasse to be allocated to other uses, including cellulosic biofuel, as the demand for bagasse for steam and bioelectricity could remain relatively constant.

One recent study assessed the biomass feedstock potential for selected countries outside the United States and projected supply available for export or for biofuel production.[50 51] For the study's baseline projection in 2017, it was estimated that approximately 21 billion ethanol-equivalent gallons could be produced from cellulosic feedstocks at $36/dry tonne or less. The majority (~80%) projected is from bagasse, with the rest from forest products. Brazil was projected to have the most potential for cellulosic feedstock production from both bagasse and forest products. Other countries include India, China, and those belonging to the Caribbean Basin Initiative (CBI), though much smaller feedstock supplies are projected as compared to Brazil. Although international production of cellulosic biofuel is possible, it is uncertain whether this supply would be available primarily to the U.S. or whether other nations would consume the fuel domestically. Therefore, for our analyses we have chosen to assume that all the cellulosic biofuel used to comply with RFS2 would be produced domestically.

b. Biomass-Based Diesel

Biomass-based diesel as defined in EISA means renewable fuel that is biodiesel as defined in section 312(f) of the Energy Policy Act of 1992 with lifecycle greenhouse gas emissions, as determined by the Administrator, that are at least 50% less than the baseline lifecycle greenhouse gas emissions. Biomass-based diesel can include fatty acid methyl ester (FAME) biodiesel, renewable diesel (RD) that has not been co-processed with a petroleum feedstock, as well as cellulosic diesel. Although cellulosic diesel produced through the Fischer-Tropsch (F–T) process could potentially contribute to the biomass-based diesel category, we have assumed for our analyses that the fuel and its corresponding feedstocks (cellulosic biomass) are already accounted for in the cellulosic biofuel category discussed previously in Section V.A.2.a.

FAME and RD processes can make acceptable quality fuel from vegetable oils, fats, and greases, and thus will generally compete for the same feedstock pool. For our analyses, we have assumed that the volume contribution from FAME biodiesel and RD will be a function of the available feedstock types. In our analysis we assumed that virgin plant oils would be preferentially processed by biodiesel plants, while the majority of fats and greases would be routed to RD production.[52 53] This is because the RD process involves hydrotreating (or thermal depolymerization), which is more severe and uses multiple chemical mechanisms to reform the fat molecules into diesel range material. The FAME

[49] Wright, M. and Brown, R, ''Comparative Economics of Biorefineries Based on the Biochemical and Thermochemical Platforms,'' *Biofuels, Bioprod. Bioref.* 1:49–56, 2007.

[50] Countries evaluated include Argentina, Brazil, Canada, China, Colombia, India, Mexico, and CBI.

[51] Kline, K. *et al.,* ''Biofuel Feedstock Assessment for Selected Countries,'' Oak Ridge National Laboratory, February 2008.

[52] Recent changes to federal tax subsidies and market shifts may warrant changes to this assumption. We will reevaluate the relative production volumes of biodiesel and renewable diesel for the FRM.

[53] This analysis was conducted prior to the completion of our lifecycle analysis discussed in Section VI, and assumes the fuels will meet the required GHG threshold.

process, by contrast, relies on more specific chemical mechanisms and requires pre-treatment if the feedstocks contain more than trace amounts of free fatty acids or other contaminates which are typical of recycled fats and greases. In terms of volume availability of feedstocks, supplies of fats and greases are more limited than virgin vegetable oils. As a result, our control case assumes the majority of biomass-based diesel volume is met using biodiesel facilities processing vegetable oils, with RD making up a smaller portion and using solely fats and greases.

The RD production volume must be further classified as co-processed or non-co-processed, depending on whether the renewable material was mixed with petroleum during the hydrotreating operations (more details on this definition are in Section III.B.1). EISA specifically forbids co-processed RD from being counted as biomass-based diesel, but it can still count toward the total advanced biofuel requirement. What fraction of RD will ultimately be co-processed is uncertain at this time, since little or no commercial production of RD is currently underway, and little public information is available about the comparative economics and feasibility of the two methods. We assumed in our control case that half the material will be non-co-processed and thus qualify as biomass-based diesel. We invite comment on whether RD production will favor co-processing or non-co-processing with a petroleum feedstock in the future.

Perhaps the feedstock with the greatest potential for providing large volumes of oil for the production of biomass-based diesel is microalgae. Algae grown on land in photo-bioreactors or in open ponds could potentially yield 15 to 50 times more oil per acre than traditional oil crops such as soy, rapeseed, or oil palm. Additionally it can be cultivated on marginal land with low nutrient inputs, and thus does not suffer from the sheer resource constraints that make other biofuel feedstocks problematic at large scale. However, several technical hurdles do still exist. Specifically, more efficient harvesting, dewatering and lipid extraction methods are needed to lower costs to a level competitive with other biodiesel feedstocks (20–30% of current costs). Until these hurdles are overcome, it is unlikely that algae-based biodiesel can be commercially competitive with other biodiesel fuels. Thus, for our control case we have chosen not to include oil from algae as a feedstock. Although the majority of algae to biofuel companies are focusing on producing algae oil for traditional biodiesel production, several companies are alternatively using algae for producing ethanol or crude oil for gasoline or diesel which could also help contribute to the advanced biofuel mandate.[54] For more detail on algae as a feedstock refer to Section 1.1 of the DRIA.

Jatropha curcas, a shrub native to Central America, is yet another possible biofuel feedstock. The perennial yields oil-rich seeds yearly, with oil yields per acre up to 4 times that of soy and twice that of rapeseed under optimal conditions. It can grow on low-nutrient lands, and is tolerant of drought. However, jatropha yields under these marginal conditions are hard to predict because of insufficient commercial experience; it is possible that jatropha will have low yields in the sub-optimal conditions where its cultivation would be most advantageous. Furthermore, jatropha seed harvesting is very labor intensive, and little is known about the crop's sustainability impacts, its long-term yield, or the feasibility of cultivation as a monoculture. It is unlikely that jatropha can be cultivated in the United States economically or sustainably, and the possibility of importing jatropha oil or biodiesel from producing countries is very uncertain because overseas cultivation efforts are still underdeveloped and initial volumes will likely be used domestically. As a result, we have not projected the use of jatropha as a feedstock under our control case. For more detail on the potential use of jatropha refer to Section 1.1 of the DRIA.

c. Other Advanced Biofuel

As defined in EISA, advanced biofuel means renewable fuel, other than ethanol derived from corn starch, that has lifecycle greenhouse gas emissions, as determined by the Administrator, that are at least 50% less than baseline lifecycle greenhouse gas emissions. As described more fully in Section VI.D, we are proposing that the GHG threshold for advanced biofuels be adjusted to 44% or potentially as low as 40% depending on the results from the analyses that will be conducted for the final rule. As defined in EISA, advanced biofuel includes the cellulosic biofuel, biomass-based diesel, and co-processed renewable diesel categories that were mentioned in Sections V.A.2.a and V.A.2.b above. However, EISA requires greater volumes of advanced biofuel than just the volumes required of these fuels; see Table V.A.2–1. It is entirely possible that greater volumes of cellulosic biofuel, biomass-based diesel, and co-processed renewable diesel than required by EISA could be produced in the future. Our control case, however, does not assume that cellulosic biofuel and biomass-based diesel volumes will exceed those required under EISA.[55] As a result, to meet the total advanced biofuel volume required under EISA, advanced biofuel types are needed other than cellulosic biofuel, biomass-based diesel, and co-processed renewable diesel through 2022.

We have assumed for our control case that the most likely source of advanced fuel other than cellulosic biofuel, biomass-based diesel, and co-processed renewable diesel would be from imported sugarcane ethanol.[56] Our assessment of international fuel ethanol production and demand indicate that anywhere from 3.8–4.2 Bgal of sugarcane ethanol from Brazil could be available for export by 2020/2022. If this volume were to be made available to the U.S., then there would be sufficient volume to meet the advanced biofuel standard. To calculate the amount of imported ethanol needed to meet the EISA standards, we took the difference between the total advanced biofuel category and cellulosic biofuel, biomass-based diesel, and co-processed renewable diesel categories. The amount of imported ethanol required by 2022 is approximately 3.2 Bgal. We solicit comment on our estimate of 3.2 Bgal and whether or not it is reasonable to assume that Brazil (or any other country) could satisfy this demand.

Recent news indicates that there are also plans for sugarcane ethanol to be produced in the U.S in places where the sugar subsidy does not apply. For instance, sugarcane has been grown in California's Imperial Valley specifically for the purpose of making ethanol and using the cane's biomass to generate electricity to power the ethanol distillery as well as export excess electricity to the electric grid.[57] There are at least two projects being developed at this time that could result in several

[54] Algenol and Sapphire Energy, *see http://www.algenolbiofuels.com/* and *http://www.sapphireenergy.com/.*

[55] While cellulosic biofuel will not be limited by feedstock availability, it likely will be limited by the very aggressive ramp up in production volume for an industry which is still being demonstrated on the pilot scale and therefore is not yet commercially viable. On the other hand, biomass-based diesel derived from agricultural oils and animal fats are faced with relatively high feedstock costs which limit feedstock supply.

[56] This analysis was conducted prior to the completion of our lifecycle analysis discussed in Section VI, and assumes the fuel will meet the required GHG threshold.

[57] Personal communication with Nathalie Hoffman, Managing Member of California Renewable Energies, LLC, August 27, 2008.

hundred million gallons of ethanol produced. The sugarcane is being grown on marginal and existing cropland that is unsuitable for food crops and will replace forage crops like alfalfa, Bermuda grass, Klein grass, etc. Harvesting is expected to be fully mechanized. Thus, there is potential for these projects and perhaps others to help contribute to the EISA biofuels mandate. This could lower the volume needed to be imported from Brazil.

Butanol is another potential motor vehicle fuel which could be produced from biomass and used in lieu of ethanol to comply with the RFS2 standard. Production of butanol is being pursued by a number of companies including a partnership between BP and Dupont. Other companies which have expressed the intent to produce biobutanol are Baer Biofuels and Gevo. The near term technology being pursued for producing butanol involves fermentation of starch compounds, although it can also be produced from cellulose. Butanol has several inherent advantages compared to ethanol. First, it has higher energy density than ethanol which would improve fuel economy (mpg). Second, butanol is much less water soluble which may allow the butanol to be blended in at the refinery and the resulting butanol-gasoline blend then more easily shipped through pipelines. This would reduce distribution costs associated with ethanol's need to be shipped separately from its gasoline blendstock and also save on the blending costs incurred at the terminal. Third, butanol can be blended in higher concentrations than 10% which would likely allow butanol to be blended with gasoline at high enough concentrations to avoid the need for most or all of high concentration ethanol-gasoline blends, such as E85, that require the use of fuel flexible vehicles. For example, because of butanol's lower oxygen content, it can be blended at 16% (by volume) to match the oxygen concentration of ethanol blended at 10% (by volume).[58] Because of butanol's higher energy density, when blending butanol at 16% by volume, it is the renewable fuels equivalent to blending ethanol at about 20 percent. Thus, butanol would enable achieving most of the RFS2 standard by blending a lower concentration of renewable fuel than having to resort to a sizable volume of E85 as in the case of ethanol. As pointed out in Section V.D., the need to blend ethanol as E85 provides some difficult challenges. The use of butanol may be one means of avoiding these blending difficulties.

At the same time, butanol has a couple of less desirable aspects relative to ethanol. First, butanol is lower in octane compared to ethanol—ethanol has a very high blending octane of around 115, while butanol's octane ranges from 87 octane numbers for normal butanol and 94 octane numbers for isobutanol. Potential butanol producers are likely to pursue producing isobutanol over normal butanol because of isobutanol's higher octane content. Higher octane is a valuable attribute of any gasoline blendstock because it helps to reduce refining costs. A second negative property of butanol is that it has a much higher viscosity compared to either gasoline or ethanol. High viscosity makes a fuel harder to pump, and more difficult to atomize in the combustion chamber in an internal combustion engine. The third downside to butanol is that it is more expensive to produce than ethanol, although the higher production cost is partially offset by its higher energy density.

Another potential source of renewable transportation fuel is biomethane refined from biogas. Biogas is a term meaning a combustible mixture of methane and other light gases derived from biogenic sources. It can be combusted directly in some applications, but for use in highway vehicles it is typically purified to closely resemble fossil natural gas for which the vehicles are typically designed. The definition of biogas as given in EISA is sufficiently broad to cover combustible gases produced by biological decomposition of organic matter, as in a landfill or wastewater treatment facility, as well as those produced via thermochemical decomposition of biomass.

Currently, the largest source of biogas is landfill gas collection, where the majority of fuel is combusted to generate electricity, with a small portion being upgraded to methane suitable for use in heavy duty vehicle fleets. Current literature suggests approximately 16 billion gasoline gallons equivalent of biogas (referring to energy content) could potentially be produced in the long term, with about two thirds coming from biomass gasification and about one third coming from waste streams such as landfills and human and animal sewage digestion.[59 60]

Because the majority of the biogas volume estimates assume biomass as a feedstock, we have chosen not to include this fuel in our analyses since we are projecting most available biomass will be used for cellulosic liquid biofuel production in the long term. The remaining biogas potentially available from waste-related sources would come from a large number of small streams requiring purification and connection to storage and/or distribution facilities, which would involve significant economic hurdles. An additional and important source of uncertainty is whether there would be a sufficient number of vehicles configured to consume these volumes of biogas. Thus, we expect future biogas fuel streams to continue to find non-transportation uses such as electrical power generation or facility heating.

d. Other Renewable Fuel

The remaining portion of total renewable fuel not met with advanced biofuel is assumed to come from corn-based ethanol. EISA effectively sets a limit for participation in the RFS program of 15 Bgal of corn ethanol by 2022. It should be noted, however, that there is no specific ''corn-ethanol'' mandated volume, and that any advanced biofuel produced above and beyond what is required for the advanced biofuel requirements could reduce the amount of corn ethanol needed to meet the total renewable fuel standard. This occurs in our projections during the earlier years (2009–2014) in which we project that some fuels could compete favorably with corn ethanol (e.g. biodiesel and imported ethanol). Beginning around 2015, fuels qualifying as advanced biofuels likely will be devoted to meeting the increasingly stringent volume mandates for advanced biofuel. It is also worth noting that more than 15 Bgal of corn ethanol could be produced and RINs generated for that volume under our proposed RFS2 regulations. However, obligated parties would not be required to purchase more than 15 Bgal worth of corn ethanol RINs.

We are assuming for our analysis that sufficient corn ethanol will be produced to meet the 15 Bgal limit. However, this assumes that in the future corn ethanol production is not limited due to environmental constraints, such as water quantity issues (see Section 6.10 of the DRIA). This also assumes that in

[58] To obtain EPA approval for butanol blends as high as 16% by volume would require that the butanol be blended with an approved corrosion inhibitor.

[59] National Renewable Energy Laboratory estimate based on biomass portion available at $45–$55/dry ton. Using POLYSYS Policy Analysis System, Agricultural Policy Analysis Center, University of Tennessee. *http://www.agpolicy.org/polysys.html.* Accessed May 2008.

[60] Milbrandt, A., ''Geographic Perspective on the Current Biomass Resource Availability in the United States.'' 70 pp., NREL Report No. TP–560–39181, 2005.

the future either corn ethanol plants are constructed or modified to meet the 20% GHG threshold, or that sufficient corn ethanol production exists that is grandfathered and not required to meet the 20% threshold. Our current projection is that up to 15 Bgal could be grandfathered, but actual volumes will be determined at the time of facility registration. Refer to Section 1.5.1.4 of the DRIA for more information. Since our current lifecycle analysis estimates that much of the current corn ethanol would not meet the 20% GHG reduction threshold required of non-grandfathered facilities without facility upgrades, then if actual grandfathered corn volumes are less than 15 Bgal it may be necessary to meet the volume mandate with other renewable fuels or through the use of advanced technologies that could improve the corn ethanol lifecycle GHG estimates.

B. Renewable Fuel Production

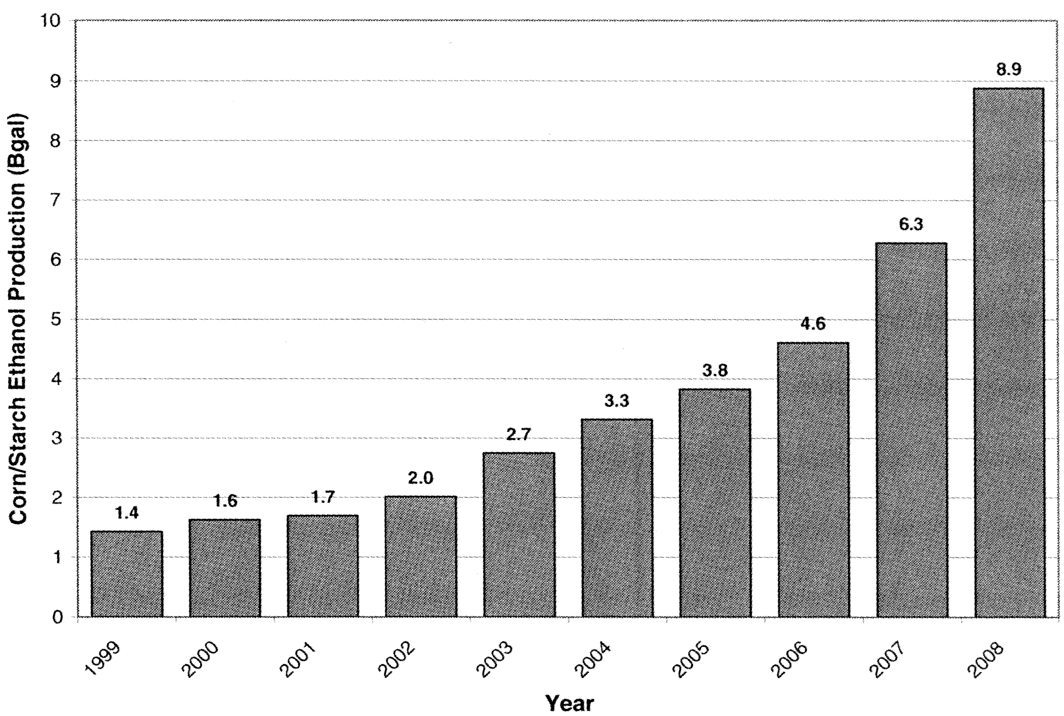
1. Corn/Starch Ethanol

The majority of domestic biofuel production currently comes from plants processing corn and other similarly-processed grains in the Midwest. However, there are a handful of plants located outside the Corn Belt and a few plants processing simple sugars from food or beverage waste. In this section, we will summarize the present state of the corn/starch ethanol industry and discuss how we expect things to change in the future under the proposed RFS2 program.

a. Historic/Current Production

The United States is currently the largest ethanol producer in the world. In 2008, the U.S. produced almost nine billion gallons of fuel ethanol for domestic consumption, the majority of which came from locally-grown corn.[61] Although the U.S. ethanol industry has been in existence since the 1970s, it has rapidly expanded over the past few years due to the phase-out of methyl tertiary butyl ether (MTBE),[62] elevated crude oil prices, state mandates and tax incentives, the introduction of the Federal Volume Ethanol Excise Tax Credit (VEETC),[63] and the implementation of the existing RFS1 program.[64] As shown in Figure V.B.1–1, U.S. ethanol production has grown exponentially over the past decade.

Figure V.B.1-1.
Historical Growth in U.S. Corn/Starch Ethanol Production[65]



[61] Based on total transportation ethanol reported in EIA's March 2009 Monthly Energy Review (Table 10.2) less imports (*http://tonto.eia.doe.gov/dnav/pet/hist/mfeimus1a.htm*).

[62] For more information on how the phase-out of MTBE helped spur ethanol production/consumption, refer to Section V.D.1.

[63] On October 22, 2004, President Bush signed into law H.R. 4520, the American Jobs Creation Act of 2004 (JOBS Bill), which created the Volumetric Ethanol Excise Tax Credit (VEETC). The $0.51/gal VEETC for ethanol blender replaced the former fuel excise tax exemption, blender's credit, and pure ethanol fuel credit. However, the recently-enacted 2008 Farm Bill modifies the alcohol credit so that corn ethanol gets a reduced credit of $0.45/gal and cellulosic biofuel a credit of $1.01/gal effective January 1, 2009.

[64] On May 1, 2007, EPA published a final rule (72 FR 23900) implementing the Renewable Fuel Standard (RFS) required by EPAct. The RFS requires that 4.0 billion gallons of renewable fuel be blended into gasoline/diesel by 2006, growing to 7.5 billion gallons by 2012.

[65] Based on total transportation ethanol reported in EIA's March 2009 Monthly Energy Review (Table 10.2) less imports (*http://tonto.eia.doe.gov/dnav/pet/hist/mfeimus1a.htm*).

As of April 1, 2009, there were 169 corn/starch ethanol plants operating in the U.S. with a combined estimated production capacity of 10.5 billion gallons per year.[66] This does not include a number of ethanol plants that are currently idled.[67] The majority of today's ethanol (over 91% by volume) is produced exclusively from corn. Another 8% comes from a blend of corn and/or similarly processed grains (milo, wheat, or barley) and less than half a percent is produced from cheese whey, waste beverages, and sugars/starches combined. A summary of U.S. ethanol production by feedstock is presented in Table V.B.1–1.

TABLE V.B.1–1—CURRENT CORN/STARCH ETHANOL PRODUCTION CAPACITY BY FEEDSTOCK

Plant feedstock (Primary listed first)	Capacity MGY	Percent of capacity	Number of plants	Percent of plants
Corn [a]	9,605	91.2	144	85.2
Corn, Milo [b]	717	6.8	14	8.3
Corn, Wheat	130	1.2	1	0.6
Milo	3	0.0	1	0.6
Wheat, Milo	50	0.5	1	0.6
Cheese Whey	5	0.0	1	0.6
Waste Beverages [c]	19	0.2	5	3.0
Waste Sugars & Starches [d]	7	0.1	2	1.2
Total	10,535	100	169	100

[a] Includes one facility processing seed corn, two facilities also operating pilot-level cellulosic ethanol plants at these locations, and four facilities planning on incorporating cellulosic feedstocks in the future.
[b] Includes one facility processing a small amount of molasses in addition to corn and milo.
[c] Includes two facilities processing brewery waste.
[d] Includes one facility processing potato waste that intends to add corn in the future.

As shown in Table V.B.1–1, of the 169 operating plants, 161 process corn and/or other similarly processed grains. Of these facilities, 150 utilize dry-milling technologies and the remaining 11 plants rely on wet-milling processes. Dry mill ethanol plants grind the entire kernel and generally 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. However, there are a growing number of dry mill ethanol plants pursuing front-end fractionation or back-end extraction to produce fuel-grade corn oil for the biodiesel industry. There are also additional plants pursuing cold starch fermentation and other energy-saving processing technologies. For more on the dry-milling and wet-milling processes as well as emerging advanced technologies, refer to Section 1.4 of the DRIA.

In contrast to dry mill plants, wet mill facilities separate the kernel prior to processing into its component parts (germ, fiber, protein, and starch) and in turn produce other co-products (usually gluten feed, gluten meal, and food-grade corn oil) in addition to DGS. Wet mill plants are generally more costly to build but are larger in size on average.[68] As such, 11.5% of the current grain ethanol production comes from the 11 previously-mentioned wet mill facilities. The remaining eight plants which process cheese whey, waste beverages or sugars/starches, operate differently than their grain-based counterparts. These small production facilities do not require milling and operate a simpler enzymatic fermentation process.

Ethanol production is a relatively resource-intensive process that requires the use of water, electricity, and steam.[69] Steam needed to heat the process is generally produced on-site or by other dedicated boilers.[70] The ethanol industry relies primarily on natural gas. Of today's 169 ethanol production facilities, 142 burn natural gas [71] (exclusively), three burn a combination of natural gas and biomass, one recently started burning a combination of natural gas, landfill biogas and wood, and two burn a combination of natural gas and syrup from the process. In addition, 20 plants burn coal as their primary fuel and one burns a combination of coal and biomass. Our research suggests that 25 plants currently utilize cogeneration or combined heat and power (CHP) technology, although others may exist. CHP is a mechanism for improving overall plant efficiency. Whether owned by the ethanol facility, their local utility, or a third party, CHP facilities produce their own electricity and use the waste heat from power production for process steam, reducing the energy intensity of ethanol production.[72] A summary of the energy sources and CHP technology utilized by today's ethanol plants is found in Table V.B.1–2.

[66] Our April 2009 corn/starch ethanol industry characterization was based on a variety of sources including: Renewable Fuels Association (RFA) Ethanol Biorefinery Locations (updated March 31, 2009); Ethanol Producer Magazine (EPM) Producing plant list (last modified on April 7, 2009), and ethanol producer Web sites. The baseline does not include ethanol plants whose primary business is industrial or food-grade ethanol production nor does it include plants that might be located in the Virgin Islands or U.S. territories. Where applicable, current/historic production levels have been used in lieu of nameplate capacities to estimate production capacity. The April 2009 information presented in this section reflects our most recent knowledge of the corn/starch ethanol industry. However, for various NPRM impact analyses, an earlier May 2008 industry assessment was used. For more on this assessment, refer to Section 1.5.1.5 of the DRIA.

[67] In addition to idled plants, the assessment does not include idled production capacity at facilities that are currently operating at 50% or less than their nameplate capacity.

[68] According to our April 2009 corn ethanol plant assessment, the average wet mill plant capacity was 111 million gallons per year—almost twice that of the average dry mill plant capacity (62 million gallons per year). For more on average plant sizes, refer to Section 1.5.1.1 of the DRIA.

[69] For more information on plant energy requirements, refer to Section 1.5.1.3 of the DRIA.

[70] We are also aware of a couple plants that pull steam directly from a nearby utility.

[71] Facilities were assumed to burn natural gas if the plant boiler fuel was unspecified or unavailable on the public domain.

[72] For more on CHP technology, refer to Section 1.4.1.3 of the DRIA.

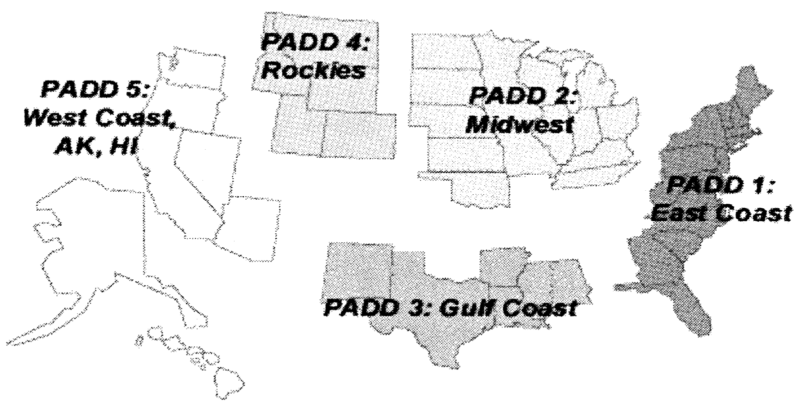
TABLE V.B.1–2—CURRENT CORN/STARCH ETHANOL PRODUCTION CAPACITY BY ENERGY SOURCE

Plant energy source (primary listed first)	Capacity MGY	Percent of capacity	Number of plants	Percent of plants	CHP tech.
Coal [a]	1,868	17.7	20	11.8	9
Coal, Biomass	50	0.5	1	0.6	0
Natural Gas [b]	8,294	78.7	142	84.0	15
Natural Gas, Biomass [c]	113	1.1	3	1.8	1
Natural Gas, Landfill Biogas, Wood	110	1.0	1	0.6	0
Natural Gas, Syrup	101	1.0	2	1.2	0
Total	10,535	100.0	169	100.0	25

[a] Includes four plants that are permitted to burn biomass, tires, petroleum coke, and wood waste in addition to coal and one facility that intends to transition to biomas in the future.
[b] Includes one facility that intends to switch to biomass, one facility that intends to burn thin stillage biogas, and two facilities that might switch to coal in the future.
[c] Includes one facility processing bran in addition to natural gas.

Since the majority of ethanol is made from corn, it is no surprise that most of the plants are located in the Midwest near the Corn Belt. Of today's 169 ethanol production facilities, 151 are located in the 15 states comprising PADD 2. For a map of the Petroleum Administration for Defense Districts or PADDs, refer to Figure V.B.1–2.

Figure V.B.1-2
Petroleum Administration for Defense Districts



As a region, PADD 2 accounts for 94% (or almost 10 billion gallons) of today's estimated ethanol production capacity, as shown in Table V.B.1–3. For more information on today's ethanol plants and a detailed map of their locations, refer to Section 1.5 of the DRIA.

TABLE V.B.1–3—CURRENT CORN/STARCH ETHANOL PRODUCTION CAPACITY BY PADD

PADD	Capacity MGY	Percent of capacity	Number of plants	Percent of plants
PADD 1	150	1.4	3	1.8
PADD 2	9,900	94.0	151	89.3
PADD 3	194	1.8	3	1.8
PADD 4	160	1.5	7	4.1
PADD 5	131	1.2	5	3.0
Total	10,535	100.0	169	100.0

The U.S. ethanol industry is currently comprised of a mixture of company-owned plants and locally-owned farmer cooperatives (co-ops). The majority of today's ethanol production facilities are company-owned, and on average these plants are larger in size than farmer-owned co-ops. Accordingly, company-owned plants account for more than 79% of today's ethanol production capacity.[73] Furthermore, 30% of the total domestic product comes from 38 plants owned by just three different companies—POET Biorefining, Archer Daniels Midland (ADM), and Valero Renewables.[74]

[73] Farmer-owned plant status derived from Renewable Fuels Association (RFA), Ethanol Biorefinery Locations (updated March 31, 2009). For more on average plant sizes, refer to Section 1.5.1 of the DRIA.

[74] Valero recently entered into the renewable fuels business by acquiring five idled corn ethanol plants and one construction site formerly owned by VeraSun Energy Corporation. Valero has since

Continued

b. Forecasted Production Under RFS2

As highlighted above, 10.5 billion gallons of corn/starch ethanol plant capacity was online as of April 1, 2009. So even if no additional capacity was added, U.S. ethanol production would grow from 2008 to 2009, provided facilities continue to operate at or above today's production levels. And despite today's temporary unfavorable market conditions (i.e., low ethanol market values), we expect the ethanol industry will continue to expand in the future under RFS2. Although there is not a set corn ethanol standard, EISA allows for 15 billion gallons of the 36-billion gallon renewable fuel standard to be met by conventional biofuels. And we expect that corn and other sugar or starch-based ethanol will fulfill this requirement. Furthermore, we project that all new corn/starch ethanol plant capacity brought online under RFS2 would either meet the conventional biofuel GHG threshold requirement [75] or meet the grandfathering requirement (for more information, refer to Section 1.5.1.4 of the DRIA).

In addition to the 169 corn/starch ethanol plants that are currently online today, 36 plants are presently idled. Some of these constructed facilities (namely smaller ethanol plants) have been idled for quite some time, whereas other plants have just recently been put into ''hot idle'' mode. A number of ethanol producers (e.g., VeraSun) are idling operations, putting projects on hold, selling off plants, and even filing for Chapter 11 bankruptcy. In addition, we are aware of two facilities that are currently operating at 50% or less than their nameplate capacity. As crude oil and gasoline prices rise again in the future, corn ethanol production will become more viable again and we expect that these plants will resume operations. At the time of our April 2009 ethanol industry assessment, there were also 19 new ethanol plants under construction in the U.S, and two plant expansion projects underway. While many of these projects are also on hold due to the current economic conditions, we expect these facilities will eventually come online under the RFS2 program. A summary of the projected industry growth is found in Table V.B.1–4.[76]

TABLE V.B.1–4—POTENTIAL INDUSTRY EXPANSION UNDER RFS2

	Growth in ethanol production				
	Plants currently online	Idled plants/ capacity [a]	New construction projects	Expansion projects	Total
Plant Capacity (MGY)	10,535	2,471	1,955	80	15,042
Total No. of Plants	169	36	19	2	226

[a] Includes the idled plant capacity of the two facilities that are currently operating at 50% or less than nameplate capacity.

While theoretically it only takes 12 to 18 months to build an ethanol plant,[77] the rate at which new plant capacity comes online will be dictated by market conditions, which will in part be influenced by the RFS2 requirements. As mentioned above, today's proposed program will create a growing demand for corn ethanol reaching 15 billion gallons by 2015. However, it is possible that market conditions could drive demand even higher. Whether the nation will overcomply with the corn ethanol standard is uncertain and will be determined by feedstock availability/ pricing, crude oil pricing, and the relative ethanol/gasoline price relationship. To measure the impacts of the proposed RFS2 program, we assumed that corn ethanol production would not exceed 15 billion gallons. We also assumed that all growth would come from new plants or plant expansion projects (in addition to idled plants being brought back online).[78] However, it is possible that some of the growth could come from minor process improvements (e.g., debottlenecking) at existing facilities.

Once all the aforementioned projects are complete, we project that there would be 226 corn/starch ethanol plants operating in the U.S. with a combined production capacity of around 15 billion gallons per year. Much like today's ethanol industry, the overwhelming majority of new production capacity (93% by volume) is expected to come from corn-fed plants. Another 7% is forecasted to come from plants processing a blend of corn and other grains, and a very small increase is projected to come from idled cheese whey and waste beverage plants coming back online. A summary of the forecasted ethanol production by feedstock under the RFS2 program is found in Table V.B.1–5.

TABLE V.B.1–5—PROJECTED RFS2 CORN/STARCH ETHANOL PRODUCTION CAPACITY BY FEEDSTOCK

Plant feedstock (primary listed first)	Additional production		Total RFS2 estimate	
	Capacity MGY	Number of plants	Capacity MGY	Number of plants
Corn [a]	4,197	49	13,802	193
Corn, Milo [b]	185	3	902	17
Corn, Wheat	8	1	138	2
Corn, Wheat, Milo	110	2	110	2
Milo	0	0	3	1
Wheat, Milo	0	0	50	1

purchased two more idled VeraSun plants, but they have not been brought back online yet.

[75] The lifecycle assessment values which assume a 2% discount rate over a 100-year timeframe.

[76] Idled plants and construction projects based on Renewable Fuels Association (RFA) Ethanol Biorefinery Locations (updated March 31, 2009); Ethanol Producer Magazine (EPM) Not Producing and Under Construction plant lists (last modified on April 7, 2009), ethanol producer Web sites, and follow-up correspondence with ethanol producers. It is worth noting that for our industry assessment, ''under construction'' implies that more than just a ground breaking ceremony has taken place.

[77] For more information on plant build rates, refer to Section 1.2.5 of the RIA.

[78] For our NPRM impact analyses, we relied on an earlier May 2008 industry assessment. For more information, refer to Section 1.5.1.5 of the DRIA.

TABLE V.B.1–5—PROJECTED RFS2 CORN/STARCH ETHANOL PRODUCTION CAPACITY BY FEEDSTOCK—Continued

Plant feedstock (primary listed first)	Additional production		Total RFS2 estimate	
	Capacity MGY	Number of plants	Capacity MGY	Number of plants
Cheese Whey	3	1	8	2
Waste Beverages [c]	4	1	23	6
Waste Sugars & Starches [d]	0	0	7	2
Total	4,507	57	15,042	226

[a] Includes one facility processing seed corn, another facility processing small amounts of whey, two facilities also operating pilot-level cellulosic ethanol plants at these locations, and four facilities planning on incorporating cellulosic feedstocks in the future.
[b] Includes one facility processing a small amount of molasses in addition to corn and milo.
[c] Includes two facilities processing brewery waste.
[d] Includes one facility processing potato waste that intends to add corn in the future.

Based on current industry plans, the majority of additional corn/grain ethanol production capacity (almost 84% by volume) is predicted to come from new or expanded plants burning natural gas.[79] Additionally, we are forecasting one new plant and a reopening of another plant relying on manure biogas. We are also predicting expansions at three coal-fired ethanol plants.[80] Of the 55 new ethanol plants, our research indicates that five would utilize cogeneration, bringing the total number of CHP facilities to 30. A summary of the projected near-term ethanol plant energy sources is found in Table V.B.1–6.

TABLE V.B.1–6—PROJECTED NEAR-TERM CORN/STARCH ETHANOL PRODUCTION CAPACITY BY ENERGY SOURCE

Plant energy source (primary listed first)	Additional production		Total RFS2 estimate		
	Capacity MGY	Number of plants	Capacity MGY	Number of plants	CHP tech.
Coal [a]	610	2	2,478	22	11
Coal, Biomass	0	0	50	1	0
Manure Biogas	134	2	134	2	0
Natural Gas [b]	3,763	53	12,056	195	18
Natural Gas, Biomass [c]	0	0	113	3	1
Natural Gas, Landfill Biogas, Wood	0	0	110	1	0
Natural Gas, Syrup	0	0	101	2	0
Total	4,507	57	15,042	226	30

[a] Includes six plants that are permitted to burn biomass, tires, petroleum coke, and wood waste in addition to coal and one facility that intends to transition to biomass in the future.
[b] Includes one facility that intends to switch to biomass, one facility that intends to burn thin stillage biogas, and six facilities that might switch to coal in the future.
[c] Includes one facility processing bran in addition to natural gas.

The information in Table V.B.1.6 is based on short-term industry production plans at the time of our April 1, 2009 plant assessment. However, we are anticipating growth in advanced ethanol production technologies under the proposed RFS2 program. We project that fuel prices will drive a large number of corn ethanol plants to transition from conventional boiler fuels to advanced biomass-based feedstocks. We also believe that fossil fuel/electricity prices will drive a number of ethanol producers to pursue CHP technology. For more on our projected 2022 utilization of these technologies under the RFS2 program, refer to Section 1.5.1.3 of the DRIA.

Under the proposed RFS2 program, the majority of new ethanol production is expected to originate from PADD 2, close to where most of the corn is grown. However, there are a number of ''destination'' ethanol plants being built outside the Midwest in response to production subsidies, E10/E85 retail pump incentives, and state mandates. A summary of the forecasted ethanol production by PADD under the RFS2 program can be found in Table V.B.1–7.

[79] Facilities were assumed to burn natural gas if the plant boiler fuel was unspecified or unavailable on the public domain.

[80] Two of the three coal-fired plant expansions appear as new plants in Table V.B.1–6. This is because two of the expansion projects consist of adding dry milling plant capacity to an existing wet mill plant. However, our interpretation is that these facilities will rely on the same (potentially expanded) coal-fired boilers for process steam. Since all the aforementioned coal-fired ethanol production facilities appear to have commenced construction prior to December 19, 2007, we project that the ethanol produced at these facilities will be grandfathered under the proposed RFS2 rule. For more on our grandfathered volume estimate, refer to Section 1.5.1.4 of the DRIA.

TABLE V.B.1–7—PROJECTED RFS2 CORN/STARCH ETHANOL PRODUCTION CAPACITY BY PADD

PADD	Additional production		Total RFS2 Estimate	
	Capacity MGY	Number of plants	Capacity MGY	Number of plants
PADD 1	178	3	328	6
PADD 2	3,566	43	13,466	194
PADD 3	350	4	544	7
PADD 4	50	1	210	8
PADD 5	363	6	494	11
Total	4,507	57	15,042	226

2. Cellulosic Biofuel

Ethanol currently dominates U.S. biofuel production, and more specifically, ethanol produced from corn and other grains. However, cellulosic feedstocks have the potential to greatly expand domestic ethanol production, both volumetrically and geographically. It is also possible to produce synthetic diesel fuel from cellulosic feedstocks (also known as ''cellulosic diesel'') through a Fischer-Tropsch gasification process or a thermal depolymerization process. We are also aware of one company using live bacteria to break down biomass and produce cellulosic diesel and other petroleum replacements. Before wide-scale commercialization of cellulosic biofuel can occur in today's marketplace, technical and logistical barriers must be overcome. In addition to today's RFS2 program which sets aggressive goals for all ethanol production, the Department of Energy (DOE) and other federal and state agencies are helping to spur industry growth.

a. Current Production/Plans

The cellulosic biofuel industry is essentially in its infancy. With the exception of a 20 million-gallon-per year cellulosic diesel plant recently opened by Cello Energy in Bay Minette, AL, the majority of facilities in operation today are small pilot- or demonstration-level plants. Most of these facilities operate intermittently and produce insignificant volumes of biofuel. Some researchers are focusing on processing corn residues, e.g., corn stover, cobs, and/or fiber. Some are focusing on other agricultural residues such as sugarcane bagasse, rice and wheat straw. Others are looking at waste products such as forestry residues, citrus residues, pulp or paper mill waste, municipal solid waste (MSW), and construction and demolition (C&D) debris. Dedicated energy crops including switchgrass and poplar trees are also being investigated.

Based on an April 2009 assessment of information available on the public domain, there are currently 25 pilot- and demonstration-level (or smaller) cellulosic ethanol plants operating in the United States. However, only 9 of these plants report measurable volumes of ethanol production. In addition, we are aware of one pilot-level cellulosic diesel plant in addition to the commercial-level Cello Energy plant.[81] A summary of these 11 facilities totaling just over 23 million gallons of annual production capacity is provided in Table V.B.2–1. The date listed in the table indicates when the facility first began operations. For more on the existing cellulosic ethanol and diesel plants, refer to Sections 1.5.3.1 and 1.5.3.3 of the DRIA.

TABLE V.B.2–1—EXISTING CELLULOSIC BIOFUEL PLANTS

Company or organization name	Location	Feedstocks	Prod cap (MGY)	Est. Op. date	Conv. tech.[a]
Cellulosic Ethanol					
Abengoa Bioenergy Corporation[b]	York, NE	Wheat straw, corn stover, energy crops	0.02	Sep-07	Bio.
Bioengineering Resources, Inc. (BRI)	Fayetteville, AR	MSW, wood waste, coal	0.04	1998	Therm.
BPI & Universal Entech	Phoenix, AZ	Paper waste (sorted MSW)	0.01	2004	Bio.
Gulf Coast Energy	Livingston, AL	Wood waste (sorted MSW)	0.20	Dec-08	Therm.
Mascoma Corporation	Rome, NY	Wood chips	0.20	Feb-09	Bio.
POET Project Bell[b]	Scotland, SD	Corn cobs & fiber	0.02	Jan-09	Bio.
Verenium	Jennings, LA	Sugarcane bagasse	0.05	2006	Bio.
Verenium	Jennings, LA	Sugarcane bagasse, wood, energy cane	1.50	Feb-09	Bio.
Western Biomass Energy LLC. (WBE)	Upton, WY	Wood waste (softwood)	1.50	2007	Bio.
Cellulosic Diesel					
Cello Energy	Bay Minette, AL	Wood chips, hay	20.00	Dec-08	CatDep.
Bell BioEnergy	Fort Stewart, GA	Wood chips	0.01	Dec-08	Bact.
Total Existing Production Capacity >23 MGY					

[a] Bio = biochemical pre-treatment, Therm = thermochemical conversion, CatDep = catalytic depolymerization, Bact = involves the use of live bacteria to break down biomass for cellulosic diesel production.
[b] Cellulosic pilot plant is collocated with a corn ethanol plant.

[81] Our April 2009 cellulosic ethanol industry characterization was based on researching DOE- and USDA-supported projects, plants referenced in HART's Ethanol & Biodiesel News (through the April 14, 2009 issue), plants included on the Cellulosic Ethanol Site (*http://www.thecesite.com/*), and plants referenced on other biofuel industry Web sites.

To date, the majority of cellulosic ethanol research has focused on biochemical pre-treatment technologies, i.e., the use of acids and/or enzymes to break down cellulosic materials into fermentable sugars. However, there are a growing number of companies investigating the thermochemical pathway which involves gasification of biomass into a synthesis gas or pyrolysis of biomass into a bio-crude oil for processing. Cellulosic diesel can also be made from thermochemical as well as other processes. Many companies are also researching the potential of co-firing biomass to produce plant energy in addition to biofuels. For more on cellulosic biofuel processing technologies, refer to Section 1.4.3 of the DRIA.

In addition to the existing facilities in Table V.B.2–1, our April 2009 industry assessment suggests that there are currently three cellulosic ethanol plants under construction in the United States. Like the existing plants, two are pilot-level facilities that are still working towards proving their conversion technologies. However, Range Fuels, a company that received $76 million from DOE and an $80 loan guarantee from USDA to build one of the first commercial-scale cellulosic ethanol plants in the U.S., is currently building a 40 million gallon per year plant in Soperton, GA.[82] At this time, the company is just working on the initial 10 million gallon per year phase. Bell Bioenergy, a company that received $7.5 million in funding from the Department of Defense to convert biomass into cellulosic diesel using live bacteria, also has six pilot plants under construction in various locations through the country. A summary of these nine cellulosic biofuel plants, totaling over 10 million gallons of annual production capacity, is presented in Table V.B.2–2.

As shown in Tables V.B.2–1 and V.B.2–2, unlike corn ethanol production, which is primarily located in the Midwest near the Corn Belt, cellulosic biofuel production is spread throughout the country. The geographic distribution of plants is due to the wide variety and availability of cellulosic feedstocks. Corn stover is found primarily in the Midwest, while the Pacific Northwest, the Northeast, and the Southeast all have forestry residues. Some southern states have access to sugarcane bagasse and citrus waste while MSW and C&D debris are available in highly populated areas throughout the country. For more information on cellulosic feedstock availability, refer to Section 1.1.2 of the DRIA.

TABLE V.B.2–2—CELLULOSIC BIOFUEL PLANTS CURRENTLY UNDER CONSTRUCTION

Company plant name	Location	Feedstocks	Prod cap (MGY)	Est. op. date.	Conv. tech. [a]
Cellulosic Ethanol					
Coskata	Madison, PA	MSW, natural gas, woodchips, bagasse, switchgrass.	0.04	Jul–09	Therm.
DuPont Dansico Cellulosic Ethanol (DDCE)	Vonore, TN	Corn cobs then switchgrass	0.25	Dec–09	Bio.
Range Fuels [b]	Soperton, GA	Wood waste, switchgrass	10.00	Dec–09	Therm.
Cellulosic Diesel					
Bell Bio-Energy	Fort Lewis, WA	Cellulose	0.01	2009	Bact.
Bell Bio-Energy	Fort Drum, NY	Cellulose	0.01	2009	Bact.
Bell Bio-Energy	Fort AP Hill, VA	Cellulose	0.01	2009	Bact.
Bell Bio-Energy	Fort Bragg, NC	Cellulose	0.01	2009	Bact.
Bell Bio-Energy	Fort Benning, GA	Cellulose	0.01	2009	Bact.
Bell Bio-Energy	San Pedro, CA	Cellulose	0.01	2009	Bact.
Total Under Construction Production Capacity >10 MGY					

[a] Bio = biochemical pre-treatment, Therm = thermochemical conversion, Bact = involves the use of live bacteria to break down biomass for cellulosic diesel production.

[b] The first 10 MGY phase is currently under construction in Soperton, GA. Once this second 30 MGY phase is added, the plant will be capable of producing 40 MGY of cellulosic ethanol.

Increased public interest, government support, technological advancement, and the recently-enacted EISA have helped spur many plans for new cellulosic biofuel plants. Although more and more plants are being announced, most are limited in size and contingent upon technology breakthroughs and efficiency improvements at the pilot or demonstration level. Additionally, because cellulosic biofuel production has not yet been proven on the commercial level, financing of these projects has primarily been through venture capital and similar funding mechanisms, as opposed to conventional bank loans.

Consequently, recently-announced Federal grant and loan guarantee programs may serve as a significant asset to the cellulosic biofuel industry in this area. In February 2007, DOE announced that it would invest up to $385 million in six commercial-scale ethanol projects over the next four years. Since the announcement, two of the companies have forfeited their funding. Iogen has decided to locate its first commercial-scale plant in Canada and Alico has discontinued plans to produce ethanol all together. The four remaining ‘‘pioneer’’ plants (including Range Fuels) hold promise and could very well be some of the first plants to demonstrate the commercial-scale viability of cellulosic ethanol production. However, there is still more to be learned at the pilot level. Although technologies needed to convert

[82] Range Fuels' ultimate goal is to expand the Soperton, GA facility to produce 100 million gallons of cellulosic ethanol per year.

cellulosic feedstocks into ethanol (and diesel) are becoming more and more understood, there are still a number of efficiency improvements that need to occur before cellulosic biofuels can compete in today's marketplace.

In May 2007, DOE announced that it would provide up to $200 million to help fund small-scale cellulosic biorefineries experimenting with novel processing technologies that could later be expanded to commercial production facilities. Four recipients were announced in January 2008 and three more were announced in April 2008. Three months later, DOE announced that it would provide $40 million more to help fund two additional small-scale plants. Of the nine announced small-scale plants, seven were pursuing cellulosic ethanol production (including Verenium Corp.) and two are pursuing cellulosic diesel production. However, Lignol Innovations, recently suspended plans to build a 2.5 million gallon per year cellulosic ethanol plant in Grand Junction, CO due to market uncertainty.

The Department of Energy has also introduced a loan guarantee program to help reduce risk and spur investment in projects that employ new, clean energy technologies. In October 2007, DOE issued final regulations and invited 16 project sponsors who submitted pre-applications to submit full applications for loan guarantees. Of those who were invited to participate, five were pursuing cellulosic biofuel production. However, only three companies appear to still be eligible.[83] Of the three remaining companies, two are pursuing cellulosic ethanol production (and are also DOE grant recipients) and one is pursuing cellulosic diesel production. The U.S. Department of Agriculture is also providing an $80 million loan guarantee to Range Fuels to help support construction of its 40 million-gallon-per-year cellulosic ethanol plant in Soperton, GA. For more on information on Federal support for biofuel production, refer to Section 1.5.3 of the DRIA.

In addition to the companies receiving government funding, there are a growing number of privately-funded companies (including Cello Energy) with plans to build more cellulosic biofuel plants in the United States. These facilities range in size from pilot- and demonstration-level plants (similar to those currently operational or under construction), to small commercial plants (similar to the four commercial-scale plants receiving DOE funding), to large commercial plants (similar in size to an average corn ethanol plant). These projects are also at various stages of planning. According to our April 2009 industry assessment, 11 plants are currently at advanced stages of planning and likely to go online in the near future. Along with those plants currently operational or under construction, we believe that these facilities will enable the U.S. to meet the 100 million gallon cellulosic biofuel standard in 2010. For a summary of the plants and their respective projected contributions, refer to Table V.B.2–3 below. For a greater discussion on these and other cellulosic biofuel projects, refer to Section 1.5.3.1 of the DRIA.

TABLE V.B.2–3—PROJECTED CELLULOSIC BIOFUEL PRODUCTION IN 2010

Company or organization name	Location	Prod cap (MGY)	Est. op. date	Est. 2010 million gallons	Est 2010 ETOH-equiv. million gallons
Cellulosic Ethanol					
BPI & Universal Entech	Phoenix, AZ	0.01	Online	0.01	0.01
POET Project Bell	Scotland, SD	0.02	Online	0.02	0.02
Abengoa Bioenergy Corporation	York, NE	0.02	Online	0.02	0.02
Bioengineering Resources, Inc. (BRI)	Fayetteville, AK	0.04	Online	0.04	0.04
Verenium	Jennings, LA	0.05	Online	0.05	0.05
Gulf Coast Energy	Livingston, AL	0.20	Online	0.20	0.20
Mascoma Corporation	Rome, NY	0.20	Online	0.20	0.20
Verenium	Jennings, LA	1.50	Online	1.50	1.50
Western Biomass Energy, LLC. (WBE)	Upton, WY	1.50	Online	1.50	1.50
Coskata	Madison, PA	0.04	Jul-09	0.04	0.04
DuPont Dansico Cellulosic Ethanol (DDCE).	Vonore, TN	0.25	Dec-09	0.25	0.25
Range Fuels	Soperton, GA	10.0	Dec-09	10.0	10.0
Ecofin/Alltech	Springfield, KY	1.30	2010	0.65	0.65
Fulcrum Bioenergy	Storey County, NV	10.50	2010	5.25	5.25
ICM Inc.	St. Joseph, MO	1.50	2010	0.75	0.75
RSE Pulp & Chemical	Old Town, ME	2.20	2010	1.10	1.10
ZeaChem	Boardman, OR	1.50	2010	0.75	0.75
ClearFuels Technology	Kauai, HI	1.50	End of 2010	0.38	0.38
Southeast Renewable Fuels LLC	Clewiston, FL	20.00	End of 2010	5.00	5.00
Cellulosic Diesel					
Cello Energy	Bay Minette, AL	20.00	Online	20.00	32.00
Bell Bio-Energy	Fort Stewart, GA	0.01	2008	0.01	0.01
Bell Bio-Energy	Fort Lewis, WA	0.01	2009	0.01	0.01
Bell Bio-Energy	Fort Drum, NY	0.01	2009	0.01	0.01
Bell Bio-Energy	Fort AP Hill, VA	0.01	2009	0.01	0.01
Bell Bio-Energy	Fort Bragg, NC	0.01	2009	0.01	0.01
Bell Bio-Energy	Fort Benning, GA	0.01	2009	0.01	0.01
Bell Bio-Energy	San Pedro, CA	0.01	2009	0.01	0.01

[83] Iogen and Alico have also forfeited a potential loan guarantee from DOE.

TABLE V.B.2–3—PROJECTED CELLULOSIC BIOFUEL PRODUCTION IN 2010—Continued

Company or organization name	Location	Prod cap (MGY)	Est. op. date	Est. 2010 million gallons	Est 2010 ETOH-equiv. million gallons
Cello Energy	TBD (AL)	50.00	2010	16.67	26.67
Cello Energy	TBD (AL)	50.00	2010	16.67	26.67
Cello Energy	TBD (GA)	50.00	2010	16.67	26.67
Flambeau River Biofuels	Park Falls, WI	6.00	2010	3.00	4.80
Total 2010 Production Forecast				100.74	144.57

b. Federal/State Production Incentives

In addition to helping fund a series of small-scale cellulosic biofuel plants, the Department of Energy, along with the U.S. Department of Agriculture (USDA), is also helping to fund critical research to help make cellulosic biofuel production more commercially viable. In March 2007, DOE awarded $23 million in grants to four companies and one university to develop more efficient microbes for ethanol refining. In June 2007, DOE and USDA awarded $8.3 million to 10 universities, laboratories, and research centers to conduct genomics research on woody plant tissue for bioenergy. Later that same month, DOE announced plans to spend $375 million to build three bioenergy research centers dedicated to accelerating research and development of cellulosic ethanol and other biofuels. The centers, which will each focus on different feedstocks and biological research challenges, will be located in Oak Ridge, TN, Madison, WI, and Berkeley, CA. In December 2007, DOE awarded $7.7 million to one company, one university, and two research centers to demonstrate the thermochemical conversion process of turning grasses, stover, and other cellulosic materials into biofuel. In February 2008, DOE awarded another $33.8 million to three companies and one research center to support the development of commercially-viable enzymes to support cellulose hydrolysis, a critical step in the biochemical breakdown of cellulosic feedstocks. Finally, in March 2008, DOE and USDA awarded $18 million to 18 universities and research institutes to conduct research and development of biomass-based products, biofuels, bioenergy, and related processes. Since 2007, DOE has announced more than $1 billion and since 2006, USDA has invested almost $600 million for the research, development, and demonstration of new biofuel technology.

Numerous states are also offering grants, tax incentives, and loan guarantees to help encourage biofuel production. The majority of efforts are centered on expanding ethanol production, and more recently, cellulosic ethanol production.[84] According to a July 2008 assessment of DOE's Energy Efficiency and Renewable Energy (EERE) Web site,[85] 33 states currently offer some form of ethanol production incentive. The incentives range from support for ethanol producers to support for research and development companies to support for feedstock suppliers. Kansas, Maryland, and South Carolina each offer specific incentives towards cellulosic ethanol production. Kansas offers revenue bonds through the Kansas Development Finance Authority to help fund construction or expansion of a cellulosic ethanol plant. Additionally, these newly-built or expanded facilities are exempt from state property tax for 10 years. Maryland offers a credit towards state income tax for 10% of cellulosic ethanol research and development expenses. They also have a $0.20 per gallon production credit for cellulosic ethanol. South Carolina gives a $0.30 per gallon production credit to cellulosic ethanol producers that meet certain requirements.

In addition to individual state incentives, a group of states in the Midwest have joined together to pursue ethanol and other biofuel production and usage goals as part of the Midwest Energy Security and Climate Stewardship Platform.[86] As of June 2008, Indiana, Iowa, Kansas, Michigan, Minnesota, North Dakota, Ohio, South Dakota, and Wisconsin had all committed to these goals which emphasize energy independence through the growth of cellulosic ethanol production and availability of E85. The Platform goals are to produce cellulosic ethanol on a commercial level by 2012 and to have E85 offered at one-third of refueling stations by 2025. They also want to reduce the energy intensity of ethanol production and supply 50% of their transportation fuel needs by regionally produced biofuels by 2025.

Finally, the passage of the Food, Conservation, and Energy Act of 2008 (also known as the ''2008 Farm Bill'') is also helping to spur cellulosic ethanol production and use.[87] The 2008 Farm Bill modified the existing $0.51 per gallon alcohol blender credit to give preference to ethanol and other biofuels produced from cellulosic feedstocks. Corn ethanol now receives a reduced credit of $0.45/gal while cellulosic biofuel earns a credit of $1.01/gal.[88] The 2008 Farm Bill also has provisions that enable USDA to assist with the commercialization of second-generation biofuels. Section 9003 authorizes loan guarantees for the development, construction and retrofitting of commercial scale biorefineries. Section 9004 provides payments to biorefineries to replace fossil fuels with renewable biomass. Section 9005 provides payments to producers to support and ensure production of advanced biofuels. And finally, Section 9008 provides competitive grants, contracts and financial assistance to enable eligible entities to carry out research, development, and demonstration of biofuels and biomass-based based products. For more information on the Federal and state production incentives outlined in this subsection, refer to Section 1.5.3.2 of the DRIA.

c. Feedstock Availability

A wide variety of feedstocks can be used for cellulosic ethanol production, including: Agricultural residues,

[84] For more on state-level biodiesel production incentives, refer to Section 1.5.4 of the DRIA.

[85] The database of ethanol incentives and laws by state is available at: *http://www.eere.energy.gov/afdc/ethanol/incentives_laws.html*.

[86] Midwest Governors Association, ''Energy Security and Climate Stewardship Platform for the Midwest 2007'' (*http://www.midwesterngovernors.org/resolutions/Platform.pdf*)

[87] The Food, Conservation, and Energy Act of 2008 (*http://www.usda.gov/documents/Bill_6124.pdf*)

[88] Refer to Part II, Subparts A and B (Sections 15321 and 15331).

forestry biomass, municipal solid waste, construction and demolition waste, and energy crops. These feedstocks are much more difficult to convert into ethanol than traditional starch/corn crops or at least require new and different processes because of the more complex structure of cellulosic material.

One potential barrier to commercially viable cellulosic biofuel production is high feedstock cost. As such, fuel producers will seek to acquire inexpensive feedstocks in sufficient quantities to lower their production costs and the risk of feedstock supply shortages. At least initially, the focus will be on feedstocks that are readily available, already produced or collected for other reasons, and even waste biomass which currently incurs a disposal fee. Consequently, initial volumes of cellulosic biofuels may benefit from low-cost feedstocks. However, to reach 16 Bgal will likely require reliance on more expensive feedstock sources purposely grown and or harvested for conversion into cellulosic biofuel.

To determine the likely cellulosic feedstocks for production of 16 billion gallons cellulosic biofuel by 2022, we analyzed the data and results from various sources. Sources include agricultural modeling from the Forestry Agriculture Sector Optimization Model (FASOM) to establish the most economical agriculture residues and energy crops (see Section IX for more details on the FASOM), consultation with USDA–Forestry Sector experts for forestry biomass supply curves, and feedstock assessment estimates for urban waste.[89]

An important assumption in our analysis projecting which feedstocks will be used for producing cellulosic ethanol is that an excess of feedstock would have to be available for producing the biofuel. Banks are anticipated to require excess feedstock supply as a safety factor to ensure that the plant will have adequate feedstock available for the plant, despite any feedstock emergency, such as a fire, drought, infestation of pests etc. For our analysis we assumed that twice the feedstock of MSW, C&D waste, and forest residue would have to be available to justify the building of a cellulosic ethanol plant. For corn stover, we assumed 50% more feedstock than necessary. We used a lower safety factor for corn stover because it could be possible to remove a larger percentage of the corn stover in any given year (usually only 50% or less of corn stover is assumed to be sustainably removed in any one year).[90] As a result, our projected cellulosic facilities only consume a portion of the total supply of feedstock available. After a cellulosic facility is fully established and certain risks are reduced, it is entirely possible that the facility may choose to consume excess feedstock in order to expand production. In addition, more facilities could potentially be built if financial investors required less excess supply. Since we are assessing the impact of producing 16 Bgal of cellulosic biofuel by 2022, this analysis does not project the construction of more facilities or more feedstocks consumed than necessary.

Another assumption that we made is that if multiple feedstocks are available in an area, each would be used as feedstocks for a prospective cellulosic ethanol plant. For example, a particular area might comprise a small or medium sized city, some forest and some agricultural land. We would include the MSW and C&D wastes available from the city along with the corn stover and forest residue for projecting the feedstock that would be processed by the particular cellulosic ethanol plant.

The following subsections describe the availability of various cellulosic feedstocks and the estimated amounts from each feedstock needed to meet the EISA requirement of 16 Bgal of cellulosic biofuel by 2022. Refer to Section V.B.2.c.iv for the summarized results of the types and volumes of cellulosic feedstocks chosen based on our analyses.

i Urban Waste

Cellulosic feedstocks available at the lowest cost to the ethanol producer will likely be chosen first. This suggests that urban waste which is already being gathered today and which incurs a fee for its disposal may be among the first to be used. Urban wood wastes are used in a variety of ways. Most commonly, wastes are ground into mulch, dumped into land-fills, or incinerated with other municipal solid waste (MSW) or construction and demolition (C&D) debris. Urban wood wastes include a variety of wood resources such as wood-based municipal solid waste and wood debris from construction and demolition.

MSW consists of paper, glass, metals, plastics, wood, yard trimmings, food scraps, rubber, leather, textiles, etc. The portion of MSW containing cellulosic material and typically the focus for biofuel production is wood and yard trimmings. In addition, paper, which made up approximately 34% of the total MSW generated in 2006, could potentially be converted to cellulosic biofuel.[91] Food scraps could also be converted to cellulosic biofuel, however, it was noted by an industry group that this feedstock could be more difficult to convert to biofuel due to challenges with separation, storage, transport, and degradation of the materials. Although recycling/recovery rates are increasing over time, there appears to still be a large fraction of biogenic material that ends up unused and in land-fills. C&D debris is typically not available in wood waste assessments, although some have estimated this feedstock based on population. In 1996, this was estimated to be approximately 124 million metric tons of C&D debris.[92] Only a portion of this, however, would be made of woody material. Utilization of such feedstocks could help generate energy or biofuels for transportation. However, despite various assessments on urban waste resources, there is still a general lack of reliable data on delivered prices, issues of quality (potential for contamination), and lack of understanding of potential competition with other alternative uses (e.g. recycling, burning for electricity).

We estimated that 42 million dry tons of MSW (wood and yard trimmings & paper) and C&D wood waste could be available for producing biofuels after factoring in several assumptions (e.g. percent contamination, percent recovered or combusted for other uses, and percent moisture).[93] [94] We assumed that approximately 25 million dry tons (of the total 42 million dry tons) would be used. However, many areas of the U.S. (e.g. much of the Rocky Mountain States) have such sparse resources that a MSW and C&D cellulosic facility would not likely be justifiable. We did assume that in areas with other

[89] It is important to note that our plant siting analysis for cellulosic ethanol facilities used the most current version of outputs from FASOM at the time, which was from April 2008. Since then, FASOM has been updated to reflect better assumptions. Therefore, the version used for the NPRM in Section IX on economic impacts is slightly different than the one we used here. We do not believe that the differences between the two versions are enough to have a major impact on the plant siting analysis.

[90] The FASOM results do not take into consideration these feedstock safety margins. Safety margins were used, however, for the plant siting analysis described in Section V.B.2.c.v.

[91] EPA. Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Facts and Figures for 2006.

[92] Fehrs, J., ''Secondary Mill Residues and Urban Wood Waste Quantities in the United States—Final Report,'' Northeast Regional Biomass Program Washington, DC, December 1999.

[93] Wiltsee, G., ''Urban Wood Waste Resource Assessment,'' NREL/SR–570–25918, National Renewable Energy Laboratory, November 1998.

[94] Biocycle, ''The State of Garbage in America,'' Vol. 47, No. 4, 2006, p. 26.

cellulosic feedstocks (forest and agricultural residue), that the MSW would be used even if the MSW could not justify the installation of a plant on its own. Therefore, we have estimated that urban waste could help contribute to the production of approximately 2.2 billion gallons of ethanol.[95] A more detailed discussion on this analysis is included in the DRIA Chapter 1. Subsequent to initiating our analysis, however, we realized that the revised renewable biomass definition in the statute may preclude the use of most MSW. See Section III.B.4 for a discussion of renewable biomass. When the definition of renewable biomass is finalized, it could preclude the use of some of the lowest cost potential feedstocks, including waste paper and C&D waste, for use in producing cellulosic biofuel for use toward the RFS2 standard. If this is the case, then our FRM analysis will be adjusted to reflect this.

In addition to MSW and C&D waste generated from normal day-to-day activities, there is also potential for renewable biomass to be generated from natural disasters. This includes diseased trees, other woody debris, and C&D debris. For instance, Hurricane Katrina was estimated to have damaged approximately 320 million large trees.[96] Katrina also generated over 100 million tons of residential debris, not including the commercial sector. The material generated from these situations could potentially be used to generate cellulosic biofuel. While we acknowledge this material could provide a large source in the short-term, natural disasters are highly variable, making it hard to predict future volumes that could be generated. We seek comment on how to take into account such estimates to be included in future feedstock availability analyses.

ii. Agricultural and Forestry Residues

The next category of feedstocks chosen will likely be those that are readily produced but have not yet been commercially collected. This includes both agricultural and forestry residues.

Agricultural residues are expected to play an important role early on in the development of the cellulosic ethanol industry due to the fact that they are already being grown. Agricultural crop residues are biomass that remains in the field after the harvest of agricultural crops. The most common residue types include corn stover (the stalks, leaves, and/or cobs), straw from wheat, rice, barley, or oats, and bagasse from sugarcane. The eight leading U.S. crops produce more than 500 million tons of residues each year, although only a fraction can be used for fuel and/or energy production due to sustainability and conservation constraints.[97] Crop residues can be found all over the United States, but are primarily concentrated in the Midwest since corn stover accounts for half of all available agricultural residues.

Agricultural residues play an important role in maintaining and improving soil quality, protecting the soil surface from water and wind erosion, helping to maintain nutrient levels, and protecting water quality. Thus, collection and removal of agricultural residues must take into account concerns about the potential for increased erosion, reduced crop productivity, depletion of soil carbon and nutrients, and water pollution. Sustainable removal rates for agricultural residues have been estimated in various studies, many showing tremendous variability due to local differences in soil and erosion conditions, soil type, landscape (slope), tillage practices, crop rotation managements, and the use of cover crops. One of the most recent studies by top experts in the field showed that under current rotation and tillage practices, about 30% of stover (about 59 million metric tons) produced in the U.S. could be collected, taking into consideration erosion, soil moisture concerns, and nutrient replacement costs.[98] The same study showed that if farmers chose to convert to no-till corn management and total stover production did not change, then approximately 50% of stover (100 million metric tons) could be collected without causing erosion to exceed the tolerable soil loss. This study, however, did not consider possible soil carbon loss which other studies indicate may be a greater constraint to environmentally sustainable feedstock harvest than that needed to control water and wind erosion.[99] Experts agree that additional studies are needed to further evaluate how soil carbon and other factors affect sustainable removal rates. Despite unclear guidelines for sustainable removal rates due to the uncertainties explained above, our agricultural modeling analysis assumes that 0% of stover is removable for conventional tilled lands, 35% of stover is removable for conservation tilled lands, and 50% is removable for no-till lands. In general, these removal guidelines are appropriate only for the Midwest, where the majority of corn is currently grown.

As already noted, removal rates will vary within regions due to local differences. Given the current understanding of sustainable removal rates, we believe that such assumptions are reasonably justified. We invite comment on these assumptions. Based on our research we also note that residue maintenance requirements for the amount of biomass that must remain on the land to ensure soil quality is another approach for modeling sustainable residue collection quantities, therefore we also invite comment on this approach. This approach would likely be more accurate for all landscapes as site specific conditions such as soil type, topography, etc. could be taken into account. This would prevent site specific soil erosion and soil quality concerns that would inevitably exist when using average values for residue removal rates across all soils and landscapes. At the time of our analyses we had limited data on which to accurately apply this approach and therefore assumed the removal guidelines based on tillage practices. Refer to the Section 1.1 of the DRIA for more discussion on sustainable removal rates.

Some of the challenges of relying on agricultural residues to produce biofuels include the development of the technology and infrastructure for the harvesting of biomass crops. For example, it may be possible to reduce costs by harvesting the corn stover at the same time that the corn is harvested, in a single pass operation, as opposed to two separate harvests. In addition, because agricultural residues are usually harvested only one time per year, but cellulosic ethanol plants must receive the feedstock throughout the year, agricultural residues would likely need to be stored at a secondary storage facility. The transportation and storage issues and costs associated with this secondary storage will add additional costs to using agricultural residue as cellulosic plant feedstock. These significant transportation and storage issues need to be resolved and the infrastructure built before agricultural

[95] Assuming 90 gal/dry ton ethanol conversion yield for urban waste in 2022.

[96] Chambers, J., ''Hurricane Katrina's Carbon Footprint on U.S. Gulf Coast Forests'' *Science* Vol. 318, 2007.

[97] Elbehri, Aziz. USDA, ERS. ''An Evaluation of the Economics of Biomass Feedstocks: A Synthesis of the Literature. Prepared for the Biomass Research and Development Board,'' 2007; Since 2007, a final report has been released. Biomass Research and Development Board, ''The Economics of Biomass Feedstocks in the United States: A Review of the Literature,'' October 2008.

[98] Graham, R.L., ''Current and Potential U.S. Corn Stover Supplies,'' *American Society of Agronomy* 99:1–11, 2007.

[99] Wilhelm, W.W. *et. al.,* ''Corn Stover to Sustain Soil Organic Carbon Further Constrains Biomass Supply,'' *Agron. J.* 99:1665–1667, 2007.

residues can supply a steady stream of feedstock to the biorefinery. We discuss these harvesting and storage challenges in Section 1.3 of the DRIA.

Our agricultural modeling (FASOM) suggests that corn stover will make up the majority of agricultural residues used by 2022 to meet the EISA cellulosic biofuel standard (approximately 83 million dry tons used to produce 7.8 billion gallons of cellulosic ethanol).[100] Smaller contributions are expected to come from other crop residues, including bagasse (1.2 Bgal ethanol) and sweet sorghum pulp (0.1 Bgal ethanol).[101] At the time of this proposal, FASOM was able to model agricultural residues but not forestry biomass as potential feedstocks. As a result, we relied on USDA–Forest Service (FS) for information on the forestry sector.

The U.S. has vast amounts of forest resources that could potentially provide feedstock for the production of cellulosic biofuel. One of the major sources of woody biomass could come from logging residues. The U.S. timber industry harvests over 235 million dry tons annually and produces large volumes of non-merchantable wood and residues during the process.[102] Logging residues are produced in conventional harvest operations, forest management activities, and clearing operations. In 2004, these operations generated approximately 67 million dry tons/year of forest residues that were left uncollected at harvest sites.[103] Other feedstocks include those from other removal residues, thinnings from timberland, and primary mill residues.

Harvesting of forestry residue and other woody material can be conducted throughout the year. Thus, unlike agricultural residue which must be moved to secondary storage, forest material could be ''stored on the stump.'' Avoiding the need for secondary storage and the transportation costs for moving the feedstock there potentially provides a significant cost advantage for forest residue over agricultural residue. This could allow forest residue to be transported from further distances away from the cellulosic plant compared to agricultural residue at the same feedstock price. Section 1.1 of the DRIA further details some of challenges with using forestry biomass as a feedstock.

EISA does not allow forestry material from national forests and virgin forests that could be used to produce biofuels to count towards the renewable fuels requirement under EISA. Therefore, we required forestry residue estimates that excluded such material. Most recently, the USDA–FS provided forestry biomass supply curves for various sources (i.e., logging residues, other removal residues, thinnings from timberland, etc.). This information suggested that a total of 76 million dry tons of forest material could be available for producing biofuels (excluding forest biomass material contained in national forests as required under EISA). However, much of the forest material is in small pockets of forest which because of its regional low density, could not help to justify the establishment of a cellulosic ethanol plant. After conducting our feedstock availability analysis, we estimated that approximately 44 million dry tons of forest material could be used, which would make up approximately one fourth, or 3.8 billion gallons, of the 16 billion gallons of cellulosic biofuel required to meet EISA.

iii Dedicated Energy Crops

While urban waste, agricultural residues, and forest residues will likely be the first feedstocks used in the production of cellulosic biofuel, there may be limitations to their use due to land availability and sustainable removal rates. Energy crops which are not yet grown commercially but have the potential for high yields and a series of environmental benefits could help provide additional feedstocks in the future. Dedicated energy crops are plant species grown specifically as renewable fuel feedstocks. Various perennial plants have been researched as potential dedicated feedstocks. These include switchgrass, mixed prairie grasses, hybrid poplar, miscanthus, and willow trees.

Perennials have several benefits over many major agricultural crops (the majority of which are annual plants). First, energy crops based on perennial species are grown from roots or rhizomes that remain in the soil after harvests. This reduces annual field preparation and fertilization costs. Second, perennial crops in temperate zones may also have significantly higher total biomass yield per unit of land area compared to annual species because of higher rates of net photosynthetic CO_2 fixation into sugars. Third, lower fertilizer runoff, lower soil erosion, and increased habitat diversity are also attributes that make perennial crops more attractive than annual crops.[104] Finally, energy crops tend to store more carbon in the soil compared to agricultural crops such as corn.[105]

The introduction of dedicated energy crops could present some potential risks, however. Dedicated energy crops for cellulosic biofuels can be non-native to the region where their production is proposed.[106] As a result, these species may potentially escape cultivation and damage surrounding ecosystems.[107] In addition breeding and genetic engineering to increase environmental tolerance, increase harvestable biomass production, and enhance energy conversion may have unexpected ecological consequences. To minimize such risks, non-native species and non-wild-type native species (i.e. native species after genetic modification) should be introduced in a responsible manner and evaluated carefully in order to weigh the potential risks against the benefits.

Currently, an energy crop receiving much attention is switchgrass. Switchgrass has many qualities that make it a prime cellulosic feedstock option. However, switchgrass and other energy crops are not currently harvested on a large scale. Switchgrass would likely be grown on a 10-year crop rotation basis, with harvest beginning in year 1 or 2, depending on location. Because switchgrass and other dedicated energy crops would not be harvested annually, there will be some economic challenges in terms of price forecasting and contracts. Accordingly, 10- to 15-year arrangements may be needed to stabilize the market for energy crops.[108] Despite these challenges, dedicated energy crops are still projected to be needed in 2022 in order to meet the aggressive goal of 16 Bgal of

[100] Assuming 94 gal/dry ton ethanol conversion yield for corn stover in 2022.

[101] Bagasse is a byproduct of sugarcane crushing and not technically an agricultural residue. Sweet sorghum pulp is also a byproduct of sweet sorghum processing. We have included it under this heading for simplification due to sugarcane being an agricultural feedstock.

[102] Smith, W. Brad *et. al.,* ''Forest Resources of the United States, 2002 General Technical Report NC–241,'' St. Paul, MN: U.S. Dept. of Agriculture, Forest Service, North Central Research Station, 2004.

[103] USDA–Forest Service. ''Timber Products Output Mapmaker Version 1.0.'' 2004.

[104] DOE., ''Breaking the Biological Barriers to Cellulosic Ethanol: A Joint Research Agenda,'' 2006.

[105] Tolbert, V.R., *et al.,* ''Biomass Crop Production: Benefits for Soil Quality and Carbon Sequestration,'' March 1999.

[106] Lewandowski, I., J. M. O. Scurlock, E. Lindvall, and M. Chistou, ''The development and current status of perennial rhizomatous grasses as energy crops in the U.S. and Europe,'' *Biomass Bioenergy* 25:335–361, 2003.

[107] The Council for Agricultural Science and Technology (CAST), ''Biofuel Feedstocks: The Risk of Future Invasions,'' CAST Commentary QTA2007–1. November 2007. Accessed at: *http://pdf.cast-science.org/websiteUploads/publicationPDFs/Biofuels%20Commentary%20Web%20version%20with%20color%20%207927146.pdf*

[108] Zeman, N., ''Feedstock: Potential Players,'' *Ethanol Producer Magazine,* October 2006.

cellulosic biofuel by 2022 as outlined in EISA.

Since energy crops are not being grown today to make fuels, their production and use depends on the development of a successful strategy. One issue is that if they were to be grown on farmland currently used to grow crops, the growth of switchgrass would have an opportunity cost associated with the loss of agricultural production. For this reason, energy crops may instead be grown on more marginal farm land such as fallow farmland and farmland which has been converted over to prairie grass. A study by Stanford and the Carnegie Institution found that 58 million hectares (145 million acres) of abandoned farmland would potentially be available for growing energy crops here in the U.S.[109] However, they also concluded that this land is marginal in quality and thus the production per acre would be much lower compared to prime farm land. Additionally, a substantial amount of this abandoned farm land is a part of the Conservation Reserve Program (CRP). The CRP is the U.S. Department of Agriculture's voluntary program that was established by the Food Security Act of 1985 to provide farmers with a dependable source of income, reduce erosion on unused farmland, and serve to preserve wildlife and water quality.[110] A large portion of the 36 million acres in the CRP land is currently planted with switchgrass and mixed prairie grasses.[111] However, the 2008 Farm Bill capped the number of CRP acres at 32 million acres for 2010–2012, and we expect that some of the CRP acres that are not re-enrolled will go into crop production. While it may be possible to use some of the CRP acres to produce biofuels from switchgrass and prairie grass, the potential loss of the wildlife habitat and water quality benefits of CRP land would have to be weighed against the potential use for this land for growing energy crops. Also, a significant portion of the CRP land is wetlands and likely could not be used for growing energy crops without impacting water quality and wildlife.

In addition to estimating the extent that agricultural residues might contribute to cellulosic ethanol production, FASOM also estimated the contribution that energy crops might provide.[112] FASOM covers all cropland and pastureland in production in the 48 conterminous United States, however it does not contain all categories of grassland and rangeland captured in USDA's Major Land Use data sets. Therefore, it is possible there is land appropriate for growing dedicated energy crops that is not currently modeled in FASOM. Furthermore, we constrained FASOM to be consistent with the 2008 Farm Bill and assumed 32 million acres would stay in CRP.[113] These constraints on land availability may have contributed to the model choosing a substantial amount of agricultural residues mostly as corn stover and a relatively small portion of energy crops as being economically viable feedstocks. The use of other models, such as USDA's Regional Environment and Agriculture Programming (REAP) model and University of Tennessee's POLYSYS model, have shown that the use of energy crops in order to meet EISA may be more significant than our current FASOM modeling results.[114] As such, we plan to revisit these land availability assumptions in order to arrive at a more consistent basis for the FRM. We request comment on these assumptions, in addition to all the cellulosic yield assumptions that are contained in DRIA Chapter 1.

iv. Summary of Cellulosic Feedstocks for 2022

Table V.B.2–4 summarizes our internal estimate of cellulosic feedstocks and their corresponding volume contribution to 16 billion gallons cellulosic biofuel by 2022 for the purposes of our impacts assessment.

TABLE V.B.2–4—CELLULOSIC FEEDSTOCKS ASSUMED TO MEET EISA IN 2022

Feedstock	Volume (Bgal)
Agricultural Residues	9.1
Corn Stover	7.8
Sugarcane Bagasse	1.2
Sweet Sorghum Pulp	0.1
Forestry Biomass	3.8
Urban Waste	2.2
Dedicated Energy Crops (Switchgrass)	0.9
Total	16.0

v. Cellulosic Plant Siting

Future cellulosic biofuel plant siting was based on the types of feedstocks that would be most economical as shown in Table V.B.2–4, above. As cellulosic biofuel refineries will likely be located close to biomass resources in order to take advantage of lower transportation costs, we've assessed the potential areas in the U.S. that grow the various feedstocks chosen. To do this, we used data on harvested acres by county for crops that are currently grown today, such as corn stover and sugarcane (for bagasse).[115] In some cases, crops are not currently grown, but have the potential to replace other crops or pastureland (e.g. dedicated energy crops). We used the output from our economic modeling (FASOM) to help us determine which types of land are likely to be replaced by newly grown crops. For forestry biomass, USDA-Forestry Service provided supply curve data by county showing the available tons produced. Urban waste (MSW wood, paper, and C&D debris) was estimated to be located near large population centers.

Using feedstock availability data by county/city, we located potential cellulosic sites across the U.S. that could justify the construction of a cellulosic plant facility. For more details on this analysis, refer to Section 1.5 of the DRIA. Table V.B.2–5 shows the volume of cellulosic facilities by feedstock by state projected for 2022. The total volumes given in Table V.B.2–5 match the total volumes given in Table V.B.2–4 within a couple hundred million gallons. As these differences are relatively small, we believe the cellulosic facilities sited are a good estimate of potential locations.

[109] Campbell, J.E. *at al.,* ''The global potential of bioenergy on abandoned agriculture lands,'' *Environ. Sci. Technology,* 2008.

[110] Charles, Dan; ''The CRP: Paying Farmers not to Farm,'' National Public Radio, May 5, 2008.

[111] Farm Service Agency, ''Conservation Reserve Program, Summary and Enrollment Statistics FY2006,'' May 2007.

[112] Assuming 16 Bgal cellulosic biofuel total, 2.2 Bgal from Urban Waste, and 3.8 Bgal from Forestry Biomass; 10 Bgal of cellulosic biofuel for ag residues and/or energy crops would be needed.

[113] Beside the economic incentive of a farmer payment to keep land in CRP, local environmental interests may also fight to maintain CRP land for wildlife preservation. Also, we did not know what portion of the CRP is wetlands which likely could not support harvesting equipment.

[114] Biomass Research and Development Initiative (BR&DI), ''Increasing Feedstock Production for Biofuels: Economic Drivers, Environmental Implications, and the Role of Research,'' *http://www.brdisolutions.com* December 2008.

[115] NASS database. *http://www.nass.usda.gov/.*

TABLE V.B.2–5—PROJECTED CELLULOSIC ETHANOL VOLUMES BY STATE

[Million gallons in 2022]

State	Total volume	Agricultural residue volume	Energy crop volume	Urban waste volume	Forestry volume
Alabama	532	0	0	140	392
Arkansas	298	0	0	0	298
California	450	0	0	221	229
Colorado	28	0	0	28	0
Florida	421	390	0	31	0
Georgia	437	0	0	67	370
Illinois	1,525	1,270	0	198	58
Indiana	1,109	948	0	101	60
Iowa	1,697	1,635	0	32	30
Kansas	310	250	0	29	32
Kentucky	70	70	0	0	0
Louisiana	1,001	590	0	103	308
Maine	191	0	0	2	189
Michigan	505	283	0	171	51
Minnesota	876	750	0	50	76
Mississippi	214	0	0	22	192
Missouri	654	504	0	78	72
Montana	92	0	0	9	83
Nebraska	956	851	0	31	75
Nevada	17	0	0	17	0
New Hampshire	171	0	35	29	107
New York	72	0	0	72	0
North Carolina	315	0	0	98	217
Ohio	598	410	0	156	32
Oklahoma	793	0	777	0	16
Oregon	244	0	0	44	200
Pennsylvania	42	0	0	42	0
South Carolina	213	0	0	57	156
South Dakota	434	350	0	6	78
Tennessee	97	0	0	19	78
Texas	576	300	0	131	145
Virginia	197	0	0	95	102
Washington	175	0	0	17	158
West Virginia	149	0	101	0	48
Wisconsin	581	432	0	43	106
Total Volume	16,039	9,034	913	2,139	3,955

It is important to note, however, that there are many more factors other than feedstock availability to consider when eventually siting a plant. We have not taken into account, for example, water constraints, availability of permits, and sufficient personnel for specific locations. As many of the corn stover facilities are projected to be located close to corn starch facilities, there is the potential for competition for clean water supplies. Therefore, as more and more facilities draw on limited resources, it may become apparent that various locations are infeasible. Nevertheless, our plant siting analysis provides a reasonable approximation for analysis purposes since it is not intended to predict precisely where actual plants will be located. Other work is currently being done that will help address some of these issues, but at the time of this proposal, was not yet available.[116]

As we are projecting the location of cellulosic plants in 2022, it is important to keep in mind the various uncertainties in the analysis. For example, future analyses could determine better recommendations for sustainable removal rates. In the case where lower removal rates are recommended, agricultural residues may be more limited and could require more growth in dedicated energy crops. Also, the feedstocks could be processed in the field to a liquid by a pyrolysis process, facilitating the ability to ship the preprocessed biomass to plants located further away from the feedstock source. Given the information we have to date, we believe our projected locations for cellulosic facilities represent a reasonable forecast for estimating the impacts of this rule.

3. Imported Ethanol

a. Historic World Ethanol Production and Consumption

Although ethanol can be used for multiple purposes (fuel, industrial, and beverage), fuel ethanol is by far the largest market, accounting for about two-thirds of the total world ethanol consumed. According to forecasts, fuel ethanol might even exceed 80% of the market share by the end of the decade.[117] In 2008, the top three fuel ethanol producers were the U.S., Brazil, and the European Union (EU), producing 9.0, 6.5, and 0.7 billion gallons, respectively.[118] Other countries that have produced ethanol include

[116] USDA, WGA, Bioenergy Strategic Assessment project findings upcoming as noted in report WGA. Transportation Fuels for the Future Biofuels: Part I. 2008.

[117] F.O. Licht., ''World Ethanol Markets: The Outlook to 2015'', 2006, pg. 21.

[118] Renewable Fuels Association (RFA), ''2007 World Fuel Ethanol Production,'' *http://www.ethanolrfa.org/industry/statistics/#E*, March 31, 2009.

China, Canada, Thailand, Colombia, and India.

Consumption of fuel ethanol, like production, is also dominated by the United States and Brazil. The U.S. dominates world fuel ethanol consumption, with 9.6 billion gallons consumed in 2008 (domestic production plus imports).[119] Brazil is second in consumption, with about 4.9 billion gallons projected to be consumed in 2007/2008.[120] The EU is also a significant consumer of ethanol; however, consumption for the EU countries was only approximately 0.7 billion gallons in 2007.[121]

b. Historic/Current Domestic Imports

Ethanol imports have traditionally played a relatively small role in the U.S. transportation fuel market due to historically low crude prices and the tariff on imported ethanol. While low crude prices made it difficult for both domestic and imported ethanol to compete with gasoline, the addition of the federal excise tax credit made it possible for domestic ethanol to be economically competitive.

Between 2000 and 2003, the total volume of fuel ethanol imports into the United States remained relatively stable at 46–68 million gallons.[122] During this period of time, mostly Brazilian-based ethanol entered the U.S. primarily through the Caribbean Basin Initiative (CBI) countries where it could avoid the tariff. From 2004–2005, with rising crude oil prices, most estimates show U.S. fuel ethanol imports increased slightly to 135–164 million gallons, or about 4% of the total U.S. fuel ethanol consumption (3.5 to 4.0 billion gallons). The volume of imports rose dramatically in 2006 to 654–720 million gallons, or about 13% of the 2006 total ethanol consumption of 5.4 billion gallons. The largest volume of imports in 2006 was from direct Brazilian imports. This increase in ethanol imports was mainly due to the withdrawal of MTBE from the fuel pool which increased the price of ethanol. MTBE was used in gasoline to fulfill the oxygenate requirements set by Congress in the 1990 Clean Air Act Amendments. EPAct further accelerated the withdrawal of MTBE because gasoline marketers were no longer required to use an oxygenate and gasoline marketers did not receive the MTBE liability protection that they had petitioned for. Refiners responded by removing MTBE and replacing its use with ethanol. As a result, the demand for ethanol increased at unprecedented rates as most refiners replaced MTBE with ethanol. The dramatic increase in crude oil costs at this time also made ethanol more economical by comparison.

By the end of 2006, almost all MTBE was phased out of gasoline. However, crude oil prices remained high, allowing ethanol imports to the U.S. to remain economical in comparison to the past. Although not as high as the volume of ethanol imported in 2006, the U.S. continued to import ethanol in 2007 (425–450 million gallons). In 2008, the U.S. imported 519–556 million gallons.[123] As the data show, the volume of imported ethanol can fluctuate greatly. By looking at historical import data it is difficult to project the potential volume of future imports to the U.S. Rather, it is necessary to assess future import potential by analyzing the major players for foreign biofuels production and consumption.

c. Projected Domestic Imports

In our assessment of foreign ethanol production and consumption, we analyzed the following countries or group of countries: Brazil, the EU, Japan, India, and China. Our analyses indicate that Brazil would likely be the only nation able to supply any meaningful amount of ethanol to the U.S. in the future. Depending on whether the mandates and goals of the EU, Japan, India, and China are enacted or met in the future, it is likely that this group of countries would consume any growth in their own production and be net importers of ethanol, thus competing with the U.S. for Brazilian ethanol exports.

Brazil is expected to supply the majority of future ethanol demand and to expand their capacity for several reasons. First, Brazil has over 30 years experience in developing the research and technologies for producing sugarcane ethanol. As a result, Brazilians have been able to improve agricultural and conversion processes so that sugarcane ethanol is currently the least costly method for producing biofuels. See Section VIII for further discussion on the production costs for sugarcane ethanol.

Second, it is believed that domestic demand for ethanol in Brazil will begin to slow as most of the national fleet of vehicles will have transitioned to flex-fuel within the next few years.[124] Thus, as domestic demand begins to level off, some experts see a significant possibility that exports will become more relevant in market share terms.

Lastly, Brazil has large land areas for potential expansion for sugarcane. A study commissioned by the Brazilian government produced an analysis in which Brazil's arable land was evaluated for its suitability for cane.[125] Setting aside areas protected by environmental regulations and those with a slope greater than 12% (those not suitable for mechanized farming), tripling ethanol production (a goal set by the Brazilian government by 2020) would require only an additional 14 million acres. This additional acreage would only be about 2% of suitable land for sugarcane production. Refer to Section 1.5 of the DRIA for more details.

Although Brazil is in an excellent position to help meet the growing global demand for ethanol, several constraints could limit the expansion of ethanol production. As Brazil's government has adopted plans to meet global demand by tripling production by 2020,[126] this would mean a total capacity of about 12.7 billion gallons, to be achieved through a combination of efficiency gains, greenfield projects, and infrastructure expansions. Estimates for the investment required tend to range from $2 to $4 billion a year.[127] In addition, Brazil will need to improve its current ethanol infrastructure (i.e. improvements in power, transportation, storage, distribution logistics, and communications). It is estimated that Brazil will need to invest $1 billion each year for the next 15 years in infrastructure to keep pace with capacity expansion and export demand.[128] Refer to Section 1.5 of the DRIA for further details on the improvements needed for Brazil to increase ethanol production capacity.

Due to uncertainties in the future demand for ethanol domestically and internationally as well as uncertainties in the actual investments made in the Brazilian ethanol industry, there appears to be a wide range of Brazilian production and domestic consumption estimates. The most current and complete estimates indicate that total

[119] *Ibid.*

[120] UNICA, ''Sugarcane Industry in Brazil: Ethanol Sugar, Bioelectricity'' Brochure, 2008.

[121] European Bioethanol Fuel Association (eBio), ''The EU Market: Production and Consumption,'' *http://www.ebio.org/EUmarket.php*, March 31, 2009.

[122] Values given report USITC and RFA data, however, EIA reports slightly lower numbers prior to 2004.

[123] USITC and EIA import data reported.

[124] Agra FNP, ''Sugar and Ethanol in Brazil: A Study of the Brazilian Sugar Cane, Sugar and Ethanol Industries,'' 2007.

[125] CGEE, ABDI, Unicamp, and NIPE, Scaling Up the Ethanol Program in Brazil, n.d. as quoted in Rothkopf, Garten, ''A Blueprint for Green Energy in the Americas,'' 2006.

[126] Rothkopf, Garten, ''A Blueprint for Green Energy in the Americas,'' 2006.

[127] *Ibid.*

[128] *Ibid.*

Brazilian ethanol exports will likely reach 3.8–4.2 billion gallons by 2022.[129 130 131] As this volume of ethanol export is available to countries around the world, only a portion of this will be available exclusively to the United States. If the balance of the EISA advanced biofuel requirement not met with cellulosic biofuel and biomass-based diesel were to be met with imported sugarcane ethanol alone, it would require 3.2 billion gallons (*see* Table V.A.2–1), or approximately 80% of total Brazilian ethanol export estimates.

The amount of Brazilian ethanol available for shipment to the U.S. will be dependent on the biofuels mandates and goals set by other foreign countries (i.e., the EU, Japan, India, and China) in addition to U.S. policies to promote the use of renewable fuels. Our estimates show that there could be a potential demand for imported ethanol of 4.6–14.6 billion gallons by 2020/2022 from these countries. This is due to the fact that some countries are unable to produce large volumes of ethanol because of land constraints or low production capacity. As such, foreign countries may have limited domestic biofuel production capability and may therefore require importation of biofuels in order to meet their mandates and goals. Refer to Section 1.5 of the DRIA for further details. Therefore, if other foreign country mandates and goals are to be met, then Brazil may need to either increase production much more than its government projects or export less ethanol to the U.S. This suggests that the U.S. may be competing for Brazilian ethanol exports if supplies are limited in the future. For our analysis we assumed that the U.S. would consume the majority of Brazilian exports (i.e. 80% of export estimates in 2022). This is aggressive, yet within the bounds of reason, therefore, we have made this simplifying assumption for the purposes of further analysis. We seek comment on the legitimacy of this assumption given the ethanol export deals and commitments that Brazil has made or may potentially make with other nations in the future.

[129] EPE, ''Plano Nacional de Energia 2030,'' Presentation from Mauricio Tolmasquim, 2007.

[130] UNICA, ''Sugarcane Industry in Brazil: Ethanol, Sugar, Bioelectricity,'' 2008.

[131] USEPA International Visitors Program Meeting October 30, 2007, correspondence with Mr. Rodrigues, Technical Director from UNICA Sao Paulo Sugarcane Agro-industry Union, stated approximately 3.7 billion gallons probable by 2017/2020; Consistent with brochure ''Sugarcane Industry in Brazil: Ethanol Sugar, Bioelectricity'' from UNICA (3.25 Bgal export in 2015 and 4.15 Bgal export in 2020).

Generally speaking, Brazilian ethanol exporters will seek routes to countries with the lowest transportation costs, taxes, and tariffs. With respect to the U.S., the most likely route is through the Caribbean Basin Initiative (CBI).[132] Brazilian ethanol entering the U.S. through the CBI countries is not currently subject to the 54 cent imported ethanol tariff and yet receives the 45 cent ethanol blender tax subsidy. Due to the economic incentive of transporting ethanol through the CBI, we expect the majority of the tariff rate quota (TRQ) to be met or exceeded, perhaps 90% or more. The TRQ is set each year as 7% of the total domestic ethanol consumed in the prior year. If we assume that 90% of the TRQ is met and that total domestic ethanol (corn and cellulosic ethanol) consumed in the prior year was 28.5 Bgal, then approximately 1.8 Bgal of ethanol could enter the U.S. through CBI countries. The rest of the Brazilian ethanol exports not entering the CBI will compete on the open market with the rest of the world demanding some portion of direct Brazilian ethanol. We calculated the amount of direct Brazilian ethanol exports in 2022 to the U.S. as the total imported ethanol required (3.14 billion gallons) to meet the RFS2 volume requirements subtracted by imported ethanol from CBI countries (1.8 billion gallons), or equal to 1.34 billion gallons.

In the past, companies have also avoided the ethanol import tariff through a duty drawback.[133] The drawback is a loophole in the tax rules which allowed companies to import ethanol and then receive a rebate on taxes paid on the ethanol when jet fuel is sold for export within three years. The drawback considered ethanol and jet fuel as similar commodities (finished petroleum derivatives).[134 135] Most recently, however, Senate Representative Charles Grassley from Iowa included a provision into the Farm Bill of 2008 that ended such refunds. The provision states that ''any duty paid under subheading 9901.00.50 of the Harmonized Tariff Schedule of the United States on imports of ethyl alcohol or a mixture of ethyl alcohol may not be refunded if the exported article upon which a drawback claim is based does not contain ethyl alcohol or a mixture of ethyl alcohol.'' [136] The provision is effective on or after October 1, 2008 and companies have until October 1, 2010 to apply for a duty drawback on prior transactions. With the loophole closed, it is anticipated that there may be less ethanol directly exported from Brazil in the future.[137]

[132] Other preferential trade agreements include the North American Free Trade Agreement (NAFTA) which permits tariff-free ethanol imports from Canada and Mexico and the Andean Trade Promotion and Drug Eradication Act (ATPDEA) which allows the countries of Columbia, Ecuador, Bolivia, and Peru to import ethanol duty-free. Currently, these countries export or produce relatively small amounts of ethanol, and thus we have not assumed that the U.S. will receive any substantial amounts from these countries in the future for our analyses.

[133] Rapoza, Kenneth, ''UPDATE: Tax Loophole Helps US Import Ethanol 'Duty Free'—ED&F,'' *INO News, Dow Jones Newswires,* March 2008. *http://news.ino.com/*.

[134] Peter Rhode, ''Senate Finance May Take Up Drawback Loophole As Part of Energy Bill,'' *EnergyWashington Week,* April 18, 2007. As sited in Yacobucci, Brent, ''Ethanol Imports and the Caribbean Basin Initiative,'' CRS Report for Congress, Order Code RS21930, Updated March 18, 2008.

[135] Perkins, Jerry, ''BRAZIL: Loophole Hurt U.S. Ethanol Prices,'' *DesMoinesRegister.com,* October 18, 2007.

For our distribution and air quality analyses, we had to make a determination as to where the projected imported ethanol would likely enter the United States. To do so, we started by looking at 2006 ethanol import data and made assumptions as to which countries would likely contribute to the CBI ethanol volumes in Table V.B.3–1, and to what extent.[138] We estimated that, on average, in future years, 30% would come from Jamaica, 20% each would come from El Salvador and Costa Rica, and 15% each would originate from Trinidad & Tobago and the Virgin Islands. Even though to date there have not been a lot of ethanol imports from the Virgin Islands, we believe that they could become a comparable importer to Trinidad & Tobago in the future under the proposed RFS2 program.

From there, we looked at 2006–2007 import data and estimated the general destination of Brazilian ethanol and the five contributing CBI countries' domestic imports. Based on these countries' geographic locations and import histories, we estimated that in 2022 about 75% of the ethanol would be imported to the East and Gulf Coasts and the remainder would go to the West Coast and Hawaii. To estimate import locations, we considered coastal port cities that had received ethanol or finished gasoline imports in 2006 and distributed the ethanol accordingly based on ethanol demand. For more information on this analysis, refer to Section 1.5 of the DRIA.

[136] Public Law Version 6124 of the Farm Bill. 2008. *http://www.usda.gov/documents/Bill_6124.pdf*.

[137] Lundell, Drake, ''Brazilian Ethanol Export Surge to End; U.S. Customs Loophole Closed Oct. 1,'' Ethanol and Biodiesel News, Issue 45, November 4, 2008.

[138] Source: EIA data on company-level imports (*http://www.eia.doe.gov/oil_gas/petroleum/data_publications/company_level_imports/cli_historical.html*).

4. Biodiesel & Renewable Diesel

Biodiesel and renewable diesel are replacements for petroleum diesel that are made from plant or animal fats. Biodiesel consists of fatty acid methyl esters (FAME) and can be used in low-concentration blends in most types of diesel engines and other combustion equipment with no modifications. The term renewable diesel covers fuels made by hydrotreating plant or animal fats in processes similar to those used in refining petroleum. Renewable diesel is chemically analogous to blendstocks already used in petroleum diesel, thus its use can be transparent and its blend level essentially unlimited. The goal of both biodiesel and renewable diesel conversion processes is to change the properties of a variety of feedstocks to more closely match those of petroleum diesel (such as its density, viscosity, and energy content) for which the engines and distribution system have been designed. Both processes can produce suitable fuels from biogenic sources, though we believe some feedstocks lend themselves better to one process or the other. The definition of biodiesel given in applicable regulations is sufficiently broad to be inclusive of both fuels.[139] However, the EISA stipulates that renewable diesel that is co-processed with petroleum diesel cannot be counted as ''biomass-based diesel'' for purposes of complying with its volume mandates.[140]

In general, plant and animal oils are valuable commodities with many uses other than transportation fuel. Therefore we expect the primary limiting factor in the supply of both biodiesel and renewable diesel to be feedstock availability and price. Expansion of their market volumes is dependent on being able to compete on price with the petroleum diesel they are displacing, which will depend largely on continuation of current subsidies and other incentives.

Other biomass-based diesel fuel plants are either already built or being considered for construction. Cello Energy has already started up a 20 million gallon per year catalytic depolymerization plant that is producing diesel fuel from cellulose and other feedstocks, and Cello intends on building several 50 million gallon per year plants to be started up in 2010. Also, numerous other companies are planning on building biomass to liquids (BTL) plants that produce diesel fuel through the syngas and Fischer Tropsch pathway. However, for our analysis for this proposed rulemaking, we did not project that biomass-based diesel fuel would be produced from these processes.

a. Historic and Projected Production

i. Biodiesel

As of September 2008, the aggregate production capacity of biodiesel plants in the U.S. was estimated at 2.6 billion gallons per year across approximately 176 facilities.[141] Biodiesel plants exist in nearly all states, with the largest density of plants in the Midwest and Southeast where agricultural feedstocks are most plentiful.

Table V.B.4–1 gives U.S. biodiesel production capacity, sales, and capacity utilization in recent years. The figures suggest that the industry has grown out of proportion with actual biodiesel demand. Reasons for this include various state incentives to build plants, along with state and federal incentives to blend biodiesel, which have given rise to an optimistic industry outlook over the past several years. Since the cost of capital is relatively low for the biodiesel production process (typically four to six percent of the total per-gallon cost), this industry developed a more grassroots profile in comparison to the ethanol industry, and, with median size less than 10 million gallons/yr, consists of a large number of small plants.[142] These small plants, with relatively low operating costs other than feedstock, have generally been able to survive producing below their nameplate capacities.

TABLE V.B.4–1—U.S. BIODIESEL CAPACITY AND PRODUCTION VOLUMES

[Million gallons][143]

Year	Capacity	Production	Utilization (percent)
2003	150	21	14%
2004	245	36	15
2005	395	115	29
2006	792	241	30
2007	1,809	499	28
2008	2,610	700	27

Some of this industry capacity may not be dedicated specifically to fuel production, instead being used to make oleochemical feedstocks for further conversion into products such as surfactants, lubricants, and soaps. These products do not show up in renewable fuel sales figures.

In 2004–5, demand for biodiesel grew rapidly, but the trend of increasing capacity utilization was quickly overwhelmed by additional plant starts. Since then, high commodity prices followed by reduced demand for transportation fuel have caused additional economic strain beyond the overcapacity situation. According to a survey conducted by Biodiesel Magazine staff, more than 1 in 5 plants were already idle or defunct as of late 2007 (though this likely varies by

[139] *See* Section 1515 of the Energy Policy Act of 2005. More discussion of the definitions of biodiesel and renewable diesel are given in the preamble of the Renewable Fuel Standard rulemaking, Section III.B.2, as published in the **Federal Register** Vol. 72, No. 83, p. 23917.

[140] For more detailed discussion of the definition of coprocessing and its implications for compliance with EISA, see Section III.B.1 of this preamble.

[141] Figures here were taken from National Biodiesel Board fact sheet dated September 29, 2008 (*http://biodiesel.org/pdf_files/fuelfactsheets/Producers%20Map%20-%20existing.pdf*). This information was current at the time these analyses were being done. More recent data maintained by Biodiesel Magazine suggests that by April 2009 the industry had contracted to approximately 137 plants with aggregate capacity of 2.3 billion gal/yr (*see http://www.biodieselmagazine.com/plant-list.jsp*).

[142] Capital figures derived from USDA production cost models. A publication describing USDA modeling of biodiesel production costs can be found in Bioresource Technology 97(2006) 671–8.

[143] Capacity data taken from National Biodiesel Board. Production figures taken from F.O. Licht World Ethanol and Biofuels Report, vol. 6, no. 11, p S271, except 2008, which is an estimate taken from National Biodiesel Board (*http://www.biodiesel.org/pdf_files/fuelfactsheets/Production_graph_slide.pdf*).

region).[144] A significant portion of the 2007 and 2008 production was exported to Europe or Asia where fuel prices and additional tax subsidies on top of those provided in the U.S. help cover transportation overseas and offset high feedstock costs. The Energy Information Administration is beginning to collect data on biodiesel imports and exports, but reports are not expected until later in 2009. Therefore precise figures are not available on what fraction of production was consumed domestically, but sources familiar with the industry suggest exports may have been as much as 200 million gallons in 2007 and likely more in 2008.[145] We do not account for any biodiesel exports in our analysis, though there will be sufficient plant capacity to produce material beyond the volumes required in the EISA should an export market exist.

To perform our distribution and emission impacts analyses for this proposal, it was necessary to forecast the state of the biodiesel industry in the timeframe of the fully-phased-in RFS. In general, this consisted of reducing the over-capacity to be much closer to the amount demanded, which we assumed to be equal to the requirement under the EISA given uncertainties about feedstock prices and changes in tax incentives in the long term. This was accomplished by considering as screening factors the current production and sales incentives in each state as well as each plant's primary feedstock type and whether it was BQ–9000 certified.[146] Going forward producers will compete for feedstocks and markets will consolidate. During this period the number of operating plants is expected to shrink, with surviving plants adding feedstock segregation and pre-treatment capabilities, giving them flexibility to process any mix of feedstocks available in their area. By the end of this period we project a mix of large regional plants and some smaller plants taking advantage of local market niches, with an overall average capacity utilization around 80% for dedicated fuel plants. Table V.B.4–2 summarizes this forecast. See Section 1.5.4 of the DRIA for more details.

TABLE V.B.4–2—SUMMARY OF PROJECTED BIODIESEL INDUSTRY CHARACTERIZATION USED IN OUR ANALYSES[147]

	2008	2022
Total production capacity on-line (million gal/yr)	2,610	1,050
Number of operating plants	176	35
Median plant size (million gal/yr)	5	30
Total biodiesel production (million gal)	700	810
Average plant utilization	0.27	0.77

ii. Renewable Diesel

Renewable diesel is a fuel (or blendstock) produced from animal fats, vegetable oils, and waste greases using chemical processes similar to those employed in petroleum hydrotreating. These processes remove oxygen and saturate olefins, converting the triglycerides and fatty acids into paraffins. Renewable diesel typically has higher cetane, lower nitrogen, and lower aromatics than petroleum diesel fuel, while also meeting stringent sulfur standards.

In comparison to biodiesel, renewable diesel has improved storage, stability, and shipping properties as a result of the oxygen and olefins in the feedstock being removed. This allows renewable diesel fuel to be shipped in existing petroleum pipelines used for transporting fuels, thus avoiding one significant issue with distribution of biodiesel. For more on fuel distribution, refer to Section V.C.

Considering that this industry is still in development and that there are no long-term projections of production volume, we base our production estimates primarily on the potential volume of feedstocks for this process, in the context of recent industry project announcements involving proven technology. We project that approximately two-thirds of renewable diesel will be produced at existing petroleum refineries, and half will be co-processed with petroleum (thus prohibiting it from counting as ''biomass-based diesel'' under the EISA). Tables V.B.4–3 and V.B.4–4 summarize these volumes.

TABLE V.B.4–3—PROJECTED RENEWABLE DIESEL VOLUMES BY PRODUCTION CATEGORY

[Million gallons in 2022]

	Existing facility	New facility
Co-processed with petroleum	188	—
Not co-processed with petroleum	63	125

b. Feedstock Availability

The primary feedstock for domestic biodiesel production has historically been soybean oil, with other plant and animal fats as well as recycled greases making up a smaller but significant portion of the biodiesel pool. Agricultural commodity modeling we have done for this proposal (*see* Section IX.A) suggests that soybean oil production will stay relatively flat in the future, causing supplies to tighten and prices to rise as demand increases for biofuels and food uses worldwide. The output of these models suggests that domestic soy oil production could support about 550 million gallons per year in 2022. This material is most likely to be processed by biodiesel plants due to the large available capacity of these facilities and their proximity to soybean production. Compared to other feedstocks, virgin plant oils are more easily processed into biofuel via simple transesterification due to their homogeneity of composition and lack of contaminants.

Another source of feedstock which could provide increasing and significant volume is oil extracted from corn or its co-products in the dry mill ethanol production process. Sometimes referred to as corn fractionation or dry separation, these processes get additional products of value from the dry milling process. This idea is not

[144] Derived from figures published in Biodiesel Magazine, May 2008, p. 39.

[145] Staff-level communication with National Biodiesel Board (April 2008).

[146] Information on state incentives was taken from U.S. Department of Energy Web site, accessed July 30, 2008, at *http://www.eere.energy.gov/afdc/fuels/biodiesel_laws.html*. Information on feedstock and BQ–9000 status was taken from Biodiesel Board fact sheet, accessed July 30, 2008, at *http://biodiesel.org/pdf_files/fuelfactsheets/Producers%20Map%20-%20existing.pdf*.

[147] Industry data for 2008 taken from National Biodiesel Board fact sheets at *http://www.biodiesel.org/buyingbiodiesel/producers_marketers/Producers%20Map-Existing.pdf* and *http://www.biodiesel.org/pdf_files/fuelfactsheets/Production_graph_slide.pdf* (both accessed April 27, 2009).

new, as existing wet mill plants create several product streams from their corn input, including oil. Corn fractionation can be seen as a way to get some of this added value without incurring the larger capital costs and potentially lower ethanol yields associated with wet mill plants. More detailed discussion of these processes and how they affect the co-product stream(s) can be found in DRIA Section 1.4.1.3.

The corn oil process on which we have chosen to focus for cost and volume estimates in this proposal is one that extracts oil from the thin stillage after fermentation (the non-ethanol liquid material that typically becomes part of distillers' grains with solubles). We believe installation of this type of equipment will be attractive to industry because it can be added onto an existing dry mill plant and does not impact ethanol yields since it does not process the corn prior to fermentation. Depending on the configuration, such a system can extract 20–50% of the oil from the co-product streams, and produces a distressed corn oil (non-food-grade, with some free fatty acids and/or oxidation by-products) product stream which can be used as feedstock by biodiesel facilities. Since it offers another stream of revenue, we believe it is reasonable to expect about 40% of projected total ethanol production to implement some type of oil extraction process by 2022, generating approximately 150 million gallons per year of corn oil biofuel feedstock.[148] We expect this material to be processed in biodiesel plants.

Rendered animal fats and reclaimed cooking oils and greases are another potentially significant source of biodiesel feedstock. We estimate that just two to four percent of biodiesel in 2007 was produced from waste cooking oils and greases, though this number is likely higher more recently.[149] Tyson Foods, in joint efforts with ConocoPhilips and Syntroleum, announced construction plans in 2008 for renewable diesel production facilities to begin operating in 2010 and producing up to 175 million gallons annually (combined capacity). By the end of our projection period, as much as 30% of rendered fats and waste grease could be converted to biofuel while still supporting production of pet food, soaps and detergents, and other oleochemicals.[150] We request comment from members of these industries on any potential impacts of diversion of rendered materials to biofuel.

Under this assumption, this material could make approximately 500 million gallons of biofuel (though we have not chosen to allocate all of it in our analyses here). We estimate this type of material could be most economically made into renewable diesel in the long term, as that process does not have the same sensitivities to free fatty acids and other contaminates typically present in waste greases as the biodiesel process; however, some amount of this material may continue to be processed in biodiesel plants that have acid pretreatment capabilities where it makes economic sense. Recent market shifts and changes in tax subsidies enacted after analyses were done for this NPRM have affected the relative economics of using waste fats and greases for biodiesel versus renewable diesel. We will reevaluate our assumptions in the FRM.

Our analysis of the countries with the most potential to produce and consume biodiesel in the future suggests that supplies of finished biodiesel will be tight, and prices of its feedstocks will remain high. Supplies to the U.S. will be limited by biofuel mandates and targets of other countries, preferential shipment of biodiesel to European and Asian nations, and the speed at which non-traditional crops such as jatropha can be developed. Thus, we cannot at this time project more than negligible amounts of biodiesel or its feedstocks being available for import into the U.S. in the future. For more discussion of international movement of biodiesel and its feedstocks, refer to Section 1.1 of the DRIA.

Table V.B.4–4 shows the projected potential contribution of these sources we have chosen to quantify. Other potential, but less certain, sources for biodiesel feedstocks include conversion of some existing croplands used for soybeans to higher-yielding oilseed crops. Production of oil from algae farms is also being investigated by a number of companies and universities as a source of biofuel feedstock. For additional discussion of such sources, refer to Section 1.1 of the DRIA.

TABLE V.B.4–4—ESTIMATED POTENTIAL BIODIESEL AND RENEWABLE DIESEL VOLUMES IN 2022

[Million gallons of fuel]

	Biomass-based diesel		Other advanced biofuel
	Biodiesel	Renewable diesel	Renewable diesel
Virgin plant oils	660	—	—
Corn fractionation	150	—	—
Rendered fats and greases	—	188	188

C. Renewable Fuel Distribution

The following discussion pertains to the distribution of biofuels. A discussion of the distribution of biofuel feedstocks and co-products is contained in Section 1.3.3 and 5.1 of the DRIA respectively. In conducting our analysis of biofuel distribution, we took into account the projected size and location of biofuel production facilities and where we project biofuels would be used.[151]

The current motor fuel distribution infrastructure has been optimized to facilitate the movement of petroleum-based fuels. Consequently, there are very efficient pipeline-terminal networks that move large volumes of petroleum-based fuels from production/import centers on the Gulf Coast and the Northeast into the heartland of the

[148] *See* Table 3 in Mueller, Steffen. An analysis of the projected energy use of future dry mill corn ethanol plants (2010–2030). October 10, 2007. Available at *http://www.chpcentermw.org/pdfs/2007CornEthanolEnergySys.pdf.*

[149] Based on plant capacities reported by the National Biodiesel Board and data reported by F.O. Licht.

[150] Based on statements from the National Renderer's Association.

[151] The location of biofuel production facilities and where biofuels would be used is discussed in Sections 1.5 and 1.7 of the DRIA respectively and earlier in this Section V of the preamble.

country. In contrast, the majority of renewable fuel is expected to be produced in the heartland of the country and will need to be shipped to the coasts, flowing roughly in the opposite direction of petroleum-based fuels. This limits the ability of renewable fuels to utilize the existing fuel distribution infrastructure.

The modes of distributing renewable fuels to the end user vary depending on constraints arising from their physical/chemical nature and their point of origination. Some fuels are compatible with the existing fuel distribution system, while others currently require segregation from other fuels. The location of renewable fuel production plants is also often dictated by the need to be close to the source of the feedstocks used rather than to fuel demand centers or to take advantage of the existing petroleum product distribution system. Hence, the distribution of renewable fuels raises unique concerns and in many instances requires the addition of new transportation, storage, blending, and retail equipment.

Significant challenges must be faced in reconfiguring the distribution system to accommodate the large volumes of ethanol and to a lesser extent biodiesel that we project will be used. While some uncertainties remain, particularly with respect to the ability of the market to support the use of the volume of E85 needed, no technical barriers appear to be insurmountable. The response of the transportation system to date to the unprecedented increase in ethanol use is encouraging. A U.S. Department of Agriculture (USDA) report concluded that logistical concerns have not hampered the growth in ethanol production, but that concerns may arise about the adequacy of transportation infrastructure as the growth in ethanol production continues.[152]

Considerable efforts are underway by individual companies in the fuel distribution system, consortiums of such companies, industry associations, independent study groups, and inter-agency governmental organizations to evaluate what steps may be necessary to facilitate the necessary upgrades to the distribution system to support compliance with the RFS2 standards.[153] EPA will continue to participate/monitor these efforts as appropriate to keep abreast of potential problems in the biofuel distribution system which might interfere with the use of the volumes of biofuels that we project will be needed to comply with the RFS2 standards. The 2008 Farm Act (Title IX) requires USDA, DOE, DOT, and EPA to conduct a biofuels infrastructure study that will assess infrastructure needs, analyze alternative development approaches, and provide recommendations for specific infrastructure development actions to be taken.[154]

Considerations related to the distribution of ethanol, biodiesel, and renewable diesel are discussed in the following sections as well as the changes to each segment in the distribution system that would be needed to support the volumes of these biofuels that we project would be used to satisfy the RFS2 standards.[155] We request comments on the challenges that will be faced by the fuel distribution system under the RFS2 standards and on what steps will be necessary to facilitate making the necessary accommodations in a timely fashion.[156]

To the extent that biofuels other than ethanol and biodiesel are produced in response to the RFS2 standards, this might lessen the need for added segregation during distribution. Distillate fuel produced from cellulosic feedstocks might be treated as petroleum-based diesel fuel blendstocks or a finished distillate fuel in the distribution system. Likewise, bio-gasoline or bio-butanol could potentially be treated as petroleum-based gasoline blendstocks.[157] This also might open the possibility for additional transport by pipeline. However, the location of plants that produce such biofuels relative to petroleum pipeline origination points would continue to be an issue limiting the usefulness of existing pipelines for biofuel distribution.[158]

1. Overview of Ethanol Distribution

Pipelines are the preferred method of shipping large volumes of petroleum products over long distances because of the relative low cost and reliability. Ethanol is currently not commonly shipped by pipeline because it can cause stress corrosion cracking in pipeline walls and its affinity for water and solvency can result in product contamination concerns.[159] Shipping ethanol in pipelines that carry distillate fuels as well as gasoline also presents unique difficulties in coping with the volumes of a distillate-ethanol mixture which would typically result.[160] It is not possible to re-process this mixture in the way that diesel-gasoline mixtures resulting from pipeline shipment are currently handled.[161] Substantial testing and analysis is currently underway to resolve these concerns so that ethanol may be shipped by pipeline either in a batch mode or blended with petroleum-based fuel.[162] By the time of the publication of this proposal, results of these evaluations may be available regarding what actions are necessary by multi-product pipelines to overcome safety and product contamination concerns associated with shipping 10% ethanol blends. A short gasoline pipeline in Florida has begun shipping

[152] ''Ethanol Transportation Backgrounder, Expansion of U.S. Corn-based Ethanol from the Agricultural Transportation Perspective'', USDA, September 2007, *http://www.ams.usda.gov/tmd/TSB/EthanolTransportationBackgrounder09-17-07.pdf.*

[153] *For example:* (1) The Biomass Research and Development Board, a government study group, has formed a task group on biofuels distribution infrastructure that is composed of experts on biofuel distribution from a broad range of governmental agencies. (2) The National Commission on Energy Policy, an independent advisory group, has formed a task group of fuel distribution experts to make recommendations on the steps needed to facilitate the distribution of biofuels. (3) The Association of Oil Pipelines is conducting research to evaluate what steps are necessary to allow the distribution of ethanol blends by pipeline.

[154] *http://www.ers.usda.gov/FarmBill/2008/Titles/TitleIXEnergy.htm#infrastructure.*

[155] Additional discussion can be found in Section 1.6 of the DRIA.

[156] The costs associated with making the necessary changes to the fuel distribution infrastructure are discussed in Section VIII.B of today's preamble.

[157] Biogasoline might also potentially be treated as finished fuel.

[158] The projected location of biofuel plants would not be affected by the choice of whether they are designed to produce ethanol, distillate fuel, bio-gasoline, or butanol. Proximity to the feedstock would continue to be the predominate consideration. The use of pipelines is being considered for the shipment of bio-oils manufactured from cellulosic feedstocks to refineries where they could be converted into renewable diesel fuel or renewable gasoline. The distribution of biofuel feedstocks is discussed in Section 1.3 of the DRIA.

[159] Stress corrosion cracking could lead to a pipeline leak. The potential impacts on water from today's proposal are discussed in Section X of today's preamble.

[160] Different grades of gasoline and diesel fuel are typically shipped in multi-product pipelines in batches that abut each other. To the extent possible, products are sequenced in a way to allow the interface mixture between batches to be cut into one of the adjoining products. In cases where diesel fuel abuts gasoline in the pipeline, the resulting mixture must typically be reprocessed into its component parts by distillation for resale as gasoline and diesel fuel.

[161] Gasoline-ethanol mixtures can be blended into finished gasoline.

[162] *Association of Oil Pipelines: http://aopl.org/go/searchresults/888/?q=ethanol&sd=&ed=.* ''Hazardous Liquid Pipelines Transporting Ethanol, Ethanol Blends, and Other Biofuels'', Notice of policy statement and request for comment, Pipeline and Hazardous Materials Safety Administration, Department of Transportation, August 10, 2007, 72 FR 45002.

batches of ethanol.[163] Thus, existing petroleum pipelines in some areas of the country might play a role in the shipment of ethanol from the points of production/importation to petroleum terminals.

However, the location of ethanol plants in relation to existing pipeline origination points will limit the role of existing pipelines in the shipment of ethanol.[164] Current corn ethanol production facilities are primarily located in the Midwest far from the origination points of most existing product pipelines and the primary gasoline demand centers. We project that a substantial fraction of future cellulosic ethanol plants will also be located in the Midwest, although a greater proportion of cellulosic plants are expected to be dispersed throughout the country compared to corn ethanol plants. The projected locations for this subset of future cellulosic ethanol plants more closely coincide with the origination points of product pipelines in the Gulf Coast.[165] Imported ethanol could also be brought into ports near the origination point of product pipelines in the Gulf Coast and the Northeast. Nevertheless, the majority of ethanol will continue to be produced at locations distant from the origination points of product pipelines and gasoline demand centers. The gathering of ethanol from production facilities located in the Midwest and shipment by barge down the Mississippi for introduction to pipelines in the Gulf Coast is under consideration. However, the additional handling steps to bring the ethanol to the pipeline origin points in this manner could negate any potential benefit of shipment by existing petroleum pipelines compared to direct shipment by rail.

Evaluations are also currently underway regarding the feasibility of constructing a new dedicated ethanol pipeline from the Midwest to the East Coast.[166] Under such an approach, ethanol would be gathered from a number of Midwest production facilities to provide sufficient volume to justify pipeline operation. To the extent that ethanol production would be further concentrated in the Midwest due to the siting of cellulosic ethanol plants, this would tend to help justify the cost of installing a dedicated ethanol pipeline. Substantial issues would need to be addressed before construction on such a pipeline could proceed, including those associated with securing new rights-of-ways and establishing sufficient surety regarding the return on the several billion dollar investment.

Due to the uncertainties regarding the degree to which pipelines will be able to participate in the transportation of ethanol, we assumed that ethanol will continue to be transported by rail, barge, and truck to the terminal where it will be blended into gasoline. The distribution by these modes can be further optimized primarily through the increased shipment by unit train and installation of additional hub delivery terminals that can accept large volumes of ethanol for further distribution to satellite terminals. To the extent that pipelines do eventually play a role in the distribution of ethanol, this could tend to reduce distribution costs and improve reliability in supply.

USDA estimated that in 2005 approximately 60% of ethanol was transported by rail, 30% was transported by tank truck, and 10% was transported by barge.[167] Denatured ethanol is shipped from production/import facilities to petroleum terminals where it is blended with gasoline. When practicable, shipment by unit train is the preferred method of rail shipment rather than shipping on a manifest rail car basis. The use of unit trains, sometimes referred to as a virtual pipeline, substantially reduces shipping costs and improves reliability. Unit trains are composed entirely of 70–100 ethanol tank cars, and are dedicated to shuttle back and forth to large hub terminals.[168] Manifest rail car shipment refers to the shipment of ethanol in rail tank cars that are incorporated into trains which are composed of a variety of other commodities. Unit trains can be assembled at a single ethanol production plant or if a group of plants is not large enough to support such service individually, can be formed at a central facility which gathers ethanol from a number of producers. The Manly Terminal in Iowa, which is the first such ethanol gathering facility, accepts ethanol from a number of nearby ethanol production facilities for shipment by unit train. Regional (Class 2) railroad companies are an important link bringing ethanol to gathering facilities for assembly into unit trains for long-distance shipment by larger (Class 1) railroads. Ethanol is sometimes carried by multiple modes before finally arriving at the terminal where it is blended into gasoline. For example, some ethanol is currently shipped from the Midwest to a hub terminal on the East Coast by unit train where a portion is further shipped to satellite terminals by barge or tank truck.

Ethanol is blended into gasoline at either 10 or 85 volume percent at terminals (to produce E10 and E85) for delivery to retail and fleet facilities by tank truck. Special retail delivery hardware is needed for E85 which can be used in flexible fuel vehicles only.[169] The large volume of ethanol that we project will be used by 2022 means that more ethanol will need to be used than can be accommodated by blending to the current legal limit of 10% in all of the gasoline used in the country. This will require the installation of a substantial number of new E85 refueling facilities and the addition of a substantial number of flex-fuel vehicles to the fleet. Concerns have been raised regarding the inducements that would be necessary for retailers to install the needed E85 facilities and for consumers to purchase E85.[170] As discussed in Section V.D. of today's preamble, this is prompting many to evaluate whether a mid-level ethanol blend (e.g. E15) might be allowed for use in existing (non-flex-fuel) vehicles. Current refueling equipment (not designed for E85) is only certified for ethanol blends up to 10 volume percent (E10).[171] Hence, if a mid-level ethanol blend were to be introduced, fuel retail facilities would need to ensure that the equipment used to store/dispense mid-level ethanol

[163] Article on shipment of ethanol in Kinder Morgan pipeline: *http://www.ethanolproducer.com/article.jsp?article_id=5149.*

[164] Some small petroleum product refineries are currently limited in their ability to ship products by pipeline because their relatively low volumes were not sufficient to justify connection to the pipeline distribution system.

[165] A discussion of the projected location of cellulosic ethanol plants is contained in Section 1.5 of the DRIA.

[166] Magellan and Poet joint assessment of dedicated ethanol pipeline: *http://www.magellanlp.com/news/2009/20090316_5.htm.*

[167] ''Ethanol Transportation Backgrounder, Expansion of U.S. Corn-based Ethanol from the Agricultural Transportation Perspective'', USDA, September 2007, *http://www.ams.usda.gov/tmd/TSB/EthanolTransportationBackgrounder09-17-07.pdf.*

[168] Hub ethanol receipt terminals can be located at large petroleum terminals or at rail terminals.

[169] The cost of retail dispensing hardware which is tolerant to ethanol blends greater than E10 is discussed in Section VIII.B. of today's preamble and discussed in more detail in Section 4.2 of the DRIA.

[170] See Section V.D of today's preamble for a discussion of issues related to use of the projected volumes of ethanol that would be produced to comply with the RFS2 standards.

[171] Underwriters Laboratory certifies retail refueling equipment. UL stated that they have data which indicates that the use of fuel dispensers certified for up to E10 blends to dispense blends up to a maximum ethanol content of 15 volume percent would not result in critical safety concerns (*http://www.ul.com/newsroom/newsrel/nr021909.html*). Based on this, UL stated that it would support authorities having jurisdiction who decide to permit legacy equipment originally certified for up to E10 blends to be used to dispense up to 15 volume percent ethanol. The UL announcement did address the compatibility of underground storage tank systems with greater than E10 blends.

blends is compatible with the mid-level ethanol blend.[172] Underwriters Laboratories has one certification standard for fuel retail equipment that covers ethanol blends up to 10%, and a separate certification standard for equipment that dispenses ethanol blends above 10% (including E85).[173]

Should other biofuels be introduced that do not require differentiation from diesel fuel or gasoline in place of some of the volume of ethanol that we project would be used under the RFS2 standards, this may tend to reduce the need for changes at fuel retail facilities and the need for flex-fuel vehicles. Concerns about the difficulties/costs associated with expanding the ethanol distribution infrastructure and adding a sufficient number of vehicles capable of using 10% ethanol to fleet is generating increased industry interest in renewable diesel and gasoline which would be more transparent to the existing fuel distribution system.

2. Overview of Biodiesel Distribution

Biodiesel is currently transported from production plants by truck, manifest rail car, and by barge to petroleum terminals where it is blended with petroleum-based diesel fuel. Unblended biodiesel must be transported and stored in insulated/heated containers in colder climes to prevent gelling. Insulated/heated containers are not needed for biodiesel that has been blended with petroleum-based diesel fuel (i.e., B2, B5). Biodiesel plants are not as dependent on being located close to feedstock sources as are corn and cellulosic ethanol plants.[174] Biodiesel feedstocks are typically preprocessed to oil prior to shipment to biodiesel production facilities. This can substantially reduce the volume of feedstocks shipped to biodiesel plants relative to ethanol plants, and has allowed some biodiesel plants to be located adjacent to petroleum terminals. Biodiesel production facilities are more geographically dispersed than ethanol facilities and the production volumes also tend to be smaller than ethanol facilities.[175] These characteristics in combination with the smaller volumes of biodiesel that we project will be used under the RFS2 standards compared to ethanol allow relatively more biodiesel to be used within trucking distance of the production facility. However, we project that there will continue to be a strong and growing demand for biodiesel as a blending component in heating oil which could not be satisfied alone by local sources of production. It is likely that state biodiesel mandates will also need to be satisfied in part by out-of-state production. Fleets are also likely to continue to be a substantial biodiesel user, and these will not always be located close to biodiesel producers. Thus, we are assuming that a substantial fraction of biodiesel will continue to be shipped long distances to market. Downstream of the petroleum terminal, B2 and B5 can be distributed in the same manner as petroleum diesel.

Concerns remain regarding the shipment of biodiesel by pipeline (either by batch mode or in blends with diesel fuel) related to the contamination of other products (particularly jet fuel), the solvency of biodiesel, and compatibility with pipeline gaskets and seals.[176] The smaller anticipated volumes of biodiesel and the more dispersed and smaller production facilities relative to ethanol also make biodiesel a less attractive candidate for shipment by pipeline. Due to the uncertainties regarding the suitability of transporting biodiesel by pipeline, we assumed that biodiesel which needs to be transported over long distance will be carried by manifest rail car and to a lesser extent barge. Due to the relatively small plant size and dispersion of biodiesel plants, we anticipate the volumes of biodiesel that can be gathered at a single location will continue to be insufficient to justify shipment by unit train. To the extent that pipelines do eventually play a role in the distribution of biodiesel, this could tend to reduce distribution costs and improve reliability in supply.

3. Overview of Renewable Diesel Distribution

We believe that renewable diesel fuel will be confirmed to be sufficiently similar to petroleum-based diesel fuel blendstocks with respect to distribution system compatibility. Hence, renewable diesel fuel could be treated in the same manner as any petroleum-based diesel fuel blendstock with respect to transport in the existing petroleum distribution system. Approximately two-thirds of renewable diesel fuel is projected to be produced at petroleum refineries.[177] The transport of such renewable diesel fuel would not differ from petroleum-based diesel fuel since it would be blended to produce a finished diesel fuel before leaving the refinery. The other one-third of renewable diesel fuel is projected to be produced at stand-alone facilities located more closely to sources of feedstocks. We anticipate that such renewable diesel fuel would be shipped by tank truck to nearby petroleum terminals where it would be blended directly into diesel fuel storage tanks. Because of its high cetane and value, we anticipate that all renewable diesel fuel would likely be blended with petroleum based diesel fuel prior to use. Downstream of the terminal, renewable/petroleum diesel fuel mixtures would be distributed the same as petroleum diesel.

4. Changes in Freight Tonnage Movements

To evaluate the magnitude of the challenge to the distribution system up to the point of receipt at the terminal, we compared the growth in freight tonnage for all commodities from the AEO 2007 reference case to the growth in freight tonnage under the RFS2 standards in which ethanol increases, as does the feedstock (corn) and co-products (distillers grains). We did not include a consideration of the distribution of cellulosic ethanol feedstocks on freight tonnage for the proposal. We intend to evaluate this in the final rule. For purposes of this analysis, we focused on only the ethanol portion of the renewable fuel goals for ease of calculation and because ethanol represents the vast majority of the total volume of biofuel. The resulting calculations serve as an indicator of changes in freight tonnages associated with increases in renewable fuels. We calculated the freight tonnage for the total of all modes of transport as well as the individual cases of rail, truck, and barge.

[172] Although it has yet to be established, most underground steel storage tanks themselves would likely be compatible with ethanol blends greater than 10 percent. The compatibility of piping, submersed pumps, gaskets, and seals associated with these tanks with ethanol blends greater than 10% would also need to be evaluated. Some fiberglass tanks are incompatible and would need to be replaced. It is difficult and sometimes impossible to verify the suitability of underground storage tanks and tank-related equipment for E85 use. The State of California prohibits the conversion of underground storage tanks to E85 use. Significant changes to dispensers, including hoses, nozzles, and other miscellaneous fittings would be needed to ensure they are compatible with ethanol blends greater than 10 percent.

[173] Joint UL/DOE Legacy System Certification Clarification *http://www.ul.com/global/eng/documents/offerings/industries/chemicals/flammableandcombustiblefluids/development/UL_DOE_LegacySystemCertification.pdf.*

[174] Biodiesel feedstocks are typically preprocessed to oil prior to shipment to biodiesel production facilities. This can substantially reduce the volume of feedstocks shipped to biodiesel plants relative to ethanol plants.

[175] Section 1.2 contains a discussion of our projections regarding the location of biodiesel production facilities.

[176] Industry evaluations are currently underway to resolve these concerns.

[177] Either co-processed with crude oil or processed in separate units at the refinery for blending with other refinery diesel blendstocks.

In calculating the reference case percent growth rate in total freight tonnage, we used data compiled by the Federal Highway Administration to calculate the tonnages associated with these commodities.[178] We then calculated the growth in freight tonnage for 2022 under the RFS2 standards and compared the difference with the reference case. The comparisons indicate that across all transport modes, the incremental increase in freight tonnage of ethanol and accompanying feedstocks and co-products associated with the increased ethanol volume under the RFS2 standards are small. The percent increase for total freight across all modes (including pipeline) by 2022 is 0.9 percent. Because pipelines currently do not carry ethanol, and the increase in the volume of ethanol used in motor vehicles displaces a corresponding volume of gasoline, pipelines showed a decrease in the total tonnage carried due to a decrease in the volume of gasoline carried by pipeline. The displaced gasoline also resulted in some decrease in tonnage in other modes that slightly reduced the overall increases in tonnage reflected in the totals.

To further evaluate the magnitude of the increase in freight tonnage under the RFS2 standards, we calculated the portion of the total freight tonnage for rail, barge, and truck modes made up of ethanol-related freight for both the 2022 and control cases. The freight associated with ethanol constitutes only a very small portion of the total freight tonnage for all commodities. Specifically, ethanol freight represents approximately 0.5% and 2.5% of total freight for the reference case and RFS2 standards case, respectively. The results of this analysis suggest that it should be feasible for the distribution infrastructure upstream of the terminal to accommodate the additional freight associated with this RFS2 standards especially given the lead time available. Specific issues related to transportation by rail, barge, and tank truck are discussed in the following sections. We intend to incorporate the results of a recently completed study by Oak Ridge National Laboratory (ORNL) on the potential constraints in ethanol distribution into the analysis for the final rule.[179] The ORNL study concluded that the increase in ethanol transport would have minimal impacts on the overall transportation system. However, the ORNL study did identify localized areas where significant upgrades to the rail distribution system would likely be needed.

5. Necessary Rail System Accommodations

Many improvements to the freight rail system will be required in the next 15 years to keep pace with the large increase in the overall freight demand. Improvements to the freight railroad infrastructure will be driven largely by competition in the burgeoning inter-model transport sector. As inter-model freight represents the vast majority of all freight hauled by these railroads, the biofuels transport sector can be expected to benefit from the infrastructure build-out resulting from inter-model transport sector competition. As such, most of the needed upgrades to the rail freight system are not specific to the transport of renewable fuels and would be needed irrespective of today's proposed rule. We also expect that the excess rail capacity associated with inter-model build-out to be adequately large to absorb potential increases in truck transport associated with fuel cost increases. The modifications required to satisfy the increase in demand include upgrading tracks to allow the use of heavier trains at faster speeds, the modernization of train braking systems to allow for increased traffic on rail lines, the installation of rail sidings to facilitate train staging and passage through bottlenecks.

Some industry groups[180] and governmental agencies in discussions with EPA, and in testimony provided for the Surface Transportation Board (STB) expressed concerns about the ability of the rail system to keep pace with the large increase in demand even under the reference case (27% by 2022). For example, the electric power industry has had difficulty keeping sufficient stores of coal in inventory at power plants due to rail transport difficulties and has expressed concerns that this situation will be exacerbated if rail congestion worsens. One of the more sensitive bottleneck areas with respect to the movement of ethanol from the Midwest to the East coast is Chicago. The City of Chicago commissioned its own analysis of rail capacity and congestion, which found that the lack of rail capacity is ''no longer limited to a few choke points, hubs, and heavily utilized corridors.'' Instead, the report finds, the lack of rail capacity is ''nationwide, affecting almost all the nation's critically important trade gateways, rail hubs, and intercity freight corridors.''

Significant private and public resources are focused on making the modifications to the rail system to cope with the increase in demand. Rail carriers report that they typically invest $16 to $18 billion a year in infrastructure improvements.[181] Substantial government loans are also available to small rail companies to help make needed improvements by way of the Railroad Rehabilitation and Improvement Finance (RRIF) Program, administered by Federal Railroad Administration (FRA), as well as Section 45G Railroad Track Maintenance Credits, offered by the Internal Revenue Service (IRS). The American Association of State Highway Transportation Officials (AASHTO) estimates that between $175 billion and $195 billion must be invested over a 20-year period to upgrade the rail system to handle the anticipated growth in freight demand, according to the report's base-case scenario.[182] The report suggests that railroads should be able to provide up to $142 billion from revenue and borrowing, but that the remainder would have to come from other sources including, but not limited, to loans, tax credits, sale of assets, and other forms of public-sector participation. Given the reported historical investment in rail infrastructure, it may be reasonable to assume that rail carriers would be able to manage the $7.1 billion in annual investment from rail carriers that AASHTO projects would be needed to keep pace with the projected increase in freight demand.

However, the Government Accounting Office (GAO) found that it is not possible to independently confirm statements made by Class I rail carriers regarding future investment plans.[183] In

[178] *http://www.ops.fhwa.dot.gov/freight/freight_analysis/faf/index.htm.*

[179] ''Analysis of Fuel Ethanol Transportation Activity and Potential Distribution Constraints'', prepared for EPA by Oak Ridge National Laboratory, March 2009.

[180] Industry groups include the Alliance of Automobile Manufacturers, American Chemistry Council, and the National Industrial Transportation League; governmental agencies include the Federal Railroad Administration (FRA), the Government Accountability Office (GAO), and the American Association of State Highway Transportation Officials (AASHTO). Testimony for the STB public hearings includes Ex Parte No. 671, *Rail Capacity and Infrastructure Requirements and Ex Parte No. 672, Rail Transportation and Resources Critical to the Nation's Energy Supply.*

[181] ''The Importance of Adequate Rail Investment'', Association of American Railroads, *http://www.aar.org/GetFile.asp?File_ID=150.*

[182] AASHTO Freight-Rail Bottom-Line Report, 2003.

[183] The railroads interviewed by GAO were generally unwilling to discuss their future investment plans with the GAO. Therefore, GAO was unable to comment on how Class I freight rail companies are likely to choose among their competing investment priorities for the future, including those of the rail infrastructure, GAO

Continued

addition, questions persist regarding allocation of these investments, with the Alliance of Automobile Manufacturers, American Chemistry Council, National Industrial Transportation League, and others expressing concern that their infrastructural needs may be neglected by the Class I railroads in favor of more lucrative intermodal traffic. Moreover, the GAO has raised questions regarding the competitive nature and extent of Class I freight rail transport. This raises some concern that providing sufficient resources to facilitate the transport of increasing volumes of ethanol and biodiesel might not be a first priority for rail carriers. In response to GAO concerns, the Surface Transportation Board (STB) agreed to undertake a rigorous analysis of competition in the freight railroad industry.[184]

Given the broad importance to the U.S. economy of meeting the anticipated increase in freight rail demand, and the substantial resources that seem likely to be focused on this cause, we believe that overall freight rail capacity would not be a limiting factor to the successful implementation of the biofuel requirements to meet the RFS2 standards. Evidence from the recent ramp up of ethanol use has also shown that rail carriers are enthusiastically pursuing the shipment of ethanol. Class 2 railroads have been particularly active in gathering sufficient numbers of ethanol cars to allow Class 1 railroads to ship ethanol by unit train. Likewise, we believe that that Class 2 railroads and, to a lesser extent, the trucking industry, will play a key role in the transportation of DDGs and other byproducts from regions with concentrated ethanol production facilities to those with significant livestock operations. Based on this recent experience, we believe that ethanol will be able to compete successfully with other commodities in securing its share of freight rail service.

While many changes to the overall freight rail system are expected to occur irrespective of today's proposed rule, a number of ethanol-specific modifications will be needed. For instance, a number of additional rail terminals are likely to be configured for receipt of unit trains of ethanol for further distribution by tank truck or other means to petroleum terminals. The placement of ethanol unit train receipt facilities at rail terminals would be particularly useful in situations where petroleum terminals might find it difficult or impossible to install their own ethanol rail receipt capability. We anticipate that ethanol storage will typically be installed at rail terminal ethanol receipt hubs over the long run. We do not anticipate that the rail industry will experience substantial difficulty in installing such ethanol-specific facilities once a clear long term demand for ethanol in the target markets has been established to justify the investment. However, the need for long-term demand to be established prior to the construction of such facilities will likely mean that the needed facilities will, at best, come on-line on a just-in-time basis. This may lead to use of less efficient means of ethanol transport in the short term. The ability to rely on transloading while ethanol storage facilities at rail terminal ethanol receipt hub facilities are constructed will speed the optimization of the distribution of ethanol by rail by allowing the construction of ethanol storage at rail terminal hubs to be delayed.

We estimate that a total of 44,000 rail cars would be needed to distribute the volumes of ethanol and biodiesel that we project would be used in 2022 to satisfy the RFS2 requirements.[185] Our analysis of ethanol and biodiesel rail car production capacity indicates that access to these cars should not represent a serious impediment to meeting the requirements under the RFS2 standards. Ethanol tank car production has increased approximately 30% per year since 2003, with over 21,000 tank cars expected to be produced in 2007. The volume of these newly-produced tank cars, coupled with that of an existing tank car fleet already dedicated to ethanol and biodiesel transport, suggests that an adequate number of these tank cars will be in place to transport the proposed renewable fuel volume requirements in the time available.

We request comment on the extent to which the rail system will be able to deliver the additional volumes of ethanol and biodiesel that we anticipate would be used in response to the RFS2 standards in a timely and reliable fashion. A recently completed report by ORNL identifies specific segments of the rail system which would likely see the most significant increase in traffic due to increased shipments of ethanol under the EISA.[186]

6. Necessary Marine System Accommodations

The American Waterway's Association has expressed concerns about the need to upgrade the inland waterway system in order to keep pace with the anticipated increase in overall freight demand. The majority of these concerns have been focused on the need to upgrade the river lock system on the Mississippi River to accommodate longer barge tows and on dredging inland waterways to allow for movement of fully loaded vessels. We do not anticipate that a substantial fraction of renewable/alternative fuels will be transported via these arteries. Thus, we do not believe that the ability to ship ethanol/biodiesel by inland marine will represent a serious barrier to the implementation of implementation of the requirements under RFS2 standards. Substantial quantities of the corn ethanol co-product dried distiller grains (DDG) is expected to be exported from the Midwest via the Mississippi River as the U.S. demand for DDG becomes saturated. We anticipate that the volume of exported DDG would take the place of corn that would be shifted from export to domestic use in the production of ethanol. Thus, we do not expect the increase in DDG exports to result in a substantial increase in river freight traffic. We request comment on the extent to which marine transport may be used in the transport of cellulosic ethanol feedstocks.

7. Necessary Accommodations to the Road Transportation System

Concerns have been raised regarding the ability of the trucking industry to attract a sufficient number of drivers to handle the anticipated increase in truck freight.[187] The American Trucking Association projected the need for additional 54,000 drivers each year. We estimate that the growth in the use of biofuels through 2022 due to the RFS2 standards would result in the need for a total of approximately 3,000

testimony Before the Subcommittee on Surface Transportation and Merchant Marine, Senate Committee on Commerce, Science, and Transportation, U.S. Senate, *Freight Railroads Preliminary Observations on Rates, Competition, and Capacity Issues,* Statement of JayEtta Z. Hecker, Director, Physical Infrastructure Issues, GAO, GAO–06–898T (Washington, DC: June, 21, 2006).

[184] GAO, *Freight Railroads: Industry Health Has Improved, but Concerns about Competition and Capacity Should Be Addressed,* GAO–07–94 (Washington, DC: Oct. 6, 2006); GAO, *Freight Railroads: Updated Information on Rates and Other Industry Trends,* GAO–07–291R Freight Railroads (Washington, DC: Aug. 15, 2007). STB's final report, entitled *Report to the U.S. STB on Competition and Related Issues in the U.S. Freight Railroad Industry,* is expected to be completed November, 1, 2008.

[185] A discussion of how we arrived at the estimated number of tank cars needed is contained in Section 4.2 of the DRIA.

[186] ''Analysis of Fuel Ethanol Transportation Activity and Potential Distribution Constraints'', prepared for EPA by Oak Ridge National Laboratory, March 2009.

[187] ''The U.S. Truck Driver Shortage: Analysis and Forecasts'', Prepared by Global Insights for the American Trucking Association, May 2005. *http://www.truckline.com/NR/rdonlyres/E2E789CF–F308–463F–8831–0F7E283A0218/0/ATADriverShortageStudy05.pdf.*

additional trucks drivers. Given the relatively small number of new truck drivers needed to transport the volumes of biofuels needed to comply with the RFS2 standards through 2022 compared to the total expected increase in demand for drivers over the same time period (>750,000), we do not expect that the implementation of the RFS2 standards would substantially impact the potential for a shortage of truck drivers. However, specially certified drivers are required to transport ethanol and biodiesel because these fuels are classified as hazardous liquids. Thus, there may be a heightened level of concern about the ability to secure a sufficient number of such specially certified tank truck drivers to transport ethanol and biodiesel. The trucking industry is involved in efforts to streamline the certification of drivers for hazardous liquids transport and more generally to attract and retrain a sufficient number of new truck drivers.

Truck transport of biofuel feedstocks to production plants and finished biofuels and co-products from these plants is naturally concentrated on routes to and from these production plants. This may raise concerns about the potential impact on road congestion and road maintenance in areas in the proximity of these facilities. We do not expect that such potential concerns would represent a barrier to the implementation of the RFS2 standards. The potential impact on local road infrastructure and the ability of the road network to be upgraded to handle the increased traffic load is an inherent part in the placement of new biofuel production facilities. Consequently, we expect that any issues or concerns would be dealt with at the local level.

We request comment on the extent to which satisfying the requirements under the RFS2 standards might exacerbate the anticipated shortage of truck drivers or lead to localized road congestion and condition problems. Comment is further requested on the means to mitigate such potential difficulties to the extent they might exist.

8. Necessary Terminal Accommodations

Terminals will need to install additional storage capacity to accommodate the volume of ethanol/biodiesel that we anticipate will be used in response to the RFS2 standards. Questions have been raised about the ability of some terminals to install the needed storage capacity due to space constraints and difficulties in securing permits.[188] Overall demand for fuel used in spark ignition motor vehicles is expected to remain relatively constant through 2022. Thus, much of the demand for new ethanol and biodiesel storage could be accommodated by modifying storage tanks previously used for the gasoline and petroleum-based diesel fuels that would displaced by ethanol and biodiesel. The areas served by existing terminals also often overlap. In such cases, one terminal might be space constrained while another serving the same area may be able to install the additional capacity to meet the increase in demand. Terminals with limited ethanol storage (or no access to rail/barge ethanol shipments) could receive truck shipments of ethanol from terminals with more substantial ethanol storage (and rail/barge receipt) capacity. The trend towards locating ethanol receipt and storage capability at rail terminals located near petroleum terminals is likely to be an important factor in reducing the need for large volume ethanol receipt and storage facilities at petroleum terminals. In cases where it is impossible for existing terminals to expand their storage capacity due to a lack of adjacent available land or difficulties in securing the necessary permits, new satellite storage or new separate terminal facilities may be needed for additional ethanol and biodiesel storage. However, we believe that there would be few such situations.

Another question is whether the storage tank construction industry would be able to keep pace with the increased demand for new tanks that would result from today's proposal. The storage tank construction industry recently experienced a sharp increase in demand after years of relatively slack demand for new tankage. Much of this increase in demand was due to the unprecedented increase in the use of ethanol. Storage tank construction companies have been increasing their capabilities which had been pared back during lean times.[189] Given the projected gradual increase in the need for biofuel storage tanks, it seems reasonable to conclude that the storage tank construction industry would be able to keep pace with the projected demand.

The RFG and anti-dumping regulations currently require certified gasoline to be blended with denatured ethanol to produce E85. The gasoline must meet all applicable RFG and anti-dumping standards for the time and place where it is sold. We understand that some parties may be blending butanes and or pentanes into gasoline before it is blended with denatured ethanol in order to meet ASTM minimum volatility specifications for E85 that were set to ensure proper drivability, particularly in the winter.[190] If terminal operators add blendstocks to finished gasoline for use in manufacturing E85, the terminal operator would need to register as a refiner with EPA and meet all applicable standards for refiners.

Recent testing has shown that much of in-use E85 does not meet minimum ASTM volatility specifications.[191] However, it is unclear if noncompliance with these specifications has resulted in a commensurate adverse impact on drivability. This has prompted a re-evaluation of the fuel volatility requirements for in-use E85 vehicles and whether the ASTM E85 volatility specifications might be relaxed.[192] For the purpose of our analysis, we are assuming that certified gasoline currently on hand at terminals can be used to make up the non-ethanol portion of E85.[193]

We request comment on the extent that this will be the case in light of the projected outcome of the ASTM process. Comment is requested on the fraction of terminals that currently have butane/pentane blending capability and the logistical/cost implications of adding such capability including sourcing and transportation issues associated with supplying these blending components to the terminal for the purpose of blending E85 to ASTM specifications. We also seek comment on whether we should include a separate section in the RFS2 regulations to specify the requirements for producing E85, and whether we should provide E85 manufacturers who use blendstocks to produce E85 with any flexibilities in complying with the refiner requirements.[194]

[188] The Independent Fuel Terminal Operators Association represents terminals in the Northeast.

[189] It currently may take 4 to 8 months to begin construction of a storage tank after a contract is signed due to tightness in construction assets and steel supply.

[190] "Specification for Fuel Ethanol (Ed75–Ed85) for Spark-Ignition Engines", American Society for Testing and Materials standard ASTM D5798.

[191] Coordinating Research Council (CRC) report No. E–79–2, Summary of the Study of E85 Fuel in the USA Winter 2006–2007, May 2007. *http://www.crcao.org/reports/recentstudies2007/E–79–2/E–79–2%20E85%20Summary%20Report%202007.pdf.*

[192] CRC Cold Start and Warm-up E85 Driveability Program, *http://www.crcao.com/about/Annual%20Report/2007%20Annual%20Report/Perform/CM–133.htm.*

[193] This is different from the approach taken in the refinery modeling which assumed that special blendstocks would be used to blend E85. A discussion of the refinery modeling can be found in Section 4 of the DRIA.

[194] Certain accommodations for butane blenders into gasoline were provided in a direct final rule

Continued

A significant challenge facing terminals and one that is currently limiting the volume of ethanol that can be used is the ability to receive ethanol by rail. Only a small fraction of petroleum terminals currently have rail receipt capability and a number likely have space constraints or are located too far from the rail system which prevents the installation of such capability. The trend to locate ethanol unit train destinations at rail terminals will help to alleviate these concerns. Petroleum terminals within trucking distance of each other are also likely to cooperate so that only one would need to install rail receipt capability. Given the timeframe during which the projected volumes of ethanol ramp up, we believe that these means can be utilized to ensure that a sufficient number of terminals have access to ethanol shipped by rail although some will need to rely on secondary shipment by truck from large ethanol hub receipt facilities. We request comment on the current rail receipt capability at terminals and the extent to which petroleum terminals can be expected to install such capability. Comment is also requested on the extent to which the installation of ethanol receipt facilities at rail terminals can help to meet the need to bring ethanol by rail to petroleum terminals. Our current analysis estimated that half of the new ethanol rail receipt capability needed to support the use of the projected ethanol volumes under the EISA would be installed at petroleum terminals, and half would be installed at rail terminals. A recently completed study by ORNL estimated that all new ethanol rail receipt capability would be installed at existing rail terminals given the limited ability to install such capability at petroleum terminals.[195] We intend to review our estimates regarding the location of the additional ethanol rail receipt facilities for the final rule in light of the ORNL study.

9. Need for Additional E85 Retail Facilities

We estimate that an additional 24,250 E85 retail facilities would be needed to facilitate the consumption of the additional amount of ethanol that we project would be used by 2022 in response to the requirements under the RFS2 standards.[196] On average, this equates to approximately 1,960 new E85 facilities that would need to be added each year from 2009 through 2022 in order to satisfy this goal. This is a very ambitious timeline given that there are less than 2,000 E85 retail facilities in service today. Nevertheless, we believe the addition of these numbers of new E85 facilities may be possible for the industries that manufacture and install E85 retail equipment. Underwriters Laboratories recently finalized its certification requirements for E85 retail equipment.[197] Equipment manufactures are currently evaluating the changes that will be needed to meet these requirements.[198] However, we anticipate the needed changes will not substantially increase the difficulty in the manufacture of such equipment compared to equipment which is specifically manufactured for dispensing E85 today.

We estimate that the cost of installing E85 refueling equipment will average $122,000 per facility which equates to $3 billion by 2022.[199] These costs include the installation of an underground storage tank, piping, dispensers, leak detection, and other ancillary equipment that is compatible with E85.[200] Our E85 facility cost estimates are based on input from fuel retailers and other parties with familiarity in installing E85 compatible equipment. We understand that a certification has yet to be finalized by Underwriters Laboratories for a complete equipment package necessary to store/dispense E85 at a retail facility.[201] Thus, there is some uncertainty regarding the type of equipment that will be needed for compliance with the E85 equipment certification requirements, and the associated costs. Nevertheless, we believe that the E85 equipment that is eventually certified for use will not be substantially different from that on which our cost estimates are based.[202]

Petroleum retailers expressed concerns about their ability to bear the cost installing the needed E85 refueling equipment. Today's proposal does not contain a requirement for retailers to carry E85. We understand that retailers will only install E85 facilities if it is economically advantageous for them to do so and that they will price their E85 and E10 in a manner to recover these costs. While the $3 billion total cost for E85 refueling facilities is a substantial sum, it equates to just 1.5 cents per gallon of E85 throughput.[203] Therefore, we do not believe that the cost of installing E85 refueling equipment will represent an undue burden to retailers given the very large projected consumer demand for E85.

Petroleum retailers also expressed concern regarding their ability to discount the price of E85 sufficiently to persuade flexible fuel vehicle owners to choose E85 given the lower energy density of ethanol. This issue is discussed in Section V.D.2.e. of today's preamble.

D. Ethanol Consumption

1. Historic/Current Ethanol Consumption

Ethanol and ethanol-gasoline blends have a long history as automotive fuels. However, cheap gasoline/blendstocks kept ethanol from making a significant presence in the transportation sector until the end of the 20th century when environmental regulations and tax incentives helped to stimulate growth.

In 1978, the U.S. passed the Energy Tax Act which provided an excise tax exemption for ethanol blended into gasoline that would later be modified through subsequent regulations.[204] In the 1980s, EPA initiated a phase-out of leaded gasoline which created some interest in ethanol as a gasoline

published on December 15, 2005 entitled, ''Modifications to Standards and Requirements for Reformulated and Conventional Gasoline Including Butane Blenders and Attest Engagements'', 70 FR 74552.

[195] ''Analysis of Fuel Ethanol Transportation Activity and Potential Distribution Constraints'', prepared for EPA by Oak Ridge National Laboratory, March 2009.

[196] *See* Section 1.6 of the DRIA for a discussion of the projected number of E85 refueling facilities that would be needed. There would need to be a total of 28,750 E85 retail facilities, 4,500 of which are projected to have been placed in service absent the RFS2 standards.

[197] *See http://ulstandardsinfonet.ul.com/outscope/0087A.html.*

[198] All dispenser equipment except the hose used to dispense fuel to the vehicle has been evaluated by UL. Once suitable hoses have been evaluated, a complete E85 dispenser system can be certified by UL.

[199] See Section 4.2 of the DRIA for a discussion of E85 facility costs. These costs include the installation of 2 pumps with 4 E85 refueling positions at 40% of new facilities, and 1 pump with 2 refueling positions at 60% of new facilities. A sensitivity case was evaluated where it was assumed that all new E85 facilities would install 3 pumps with 6 refueling positions. The cost per facility under this sensitivity case is $166,000.

[200] 40 CFR 280.32 requires that underground storage tank systems must be made of or lined with materials that are compatible with the substance stored in the system.

[201] Underwriters Laboratories recently finalized their requirements for the certification of E85 compatible equipment. No certifications have been completed to date, because of the time needed to complete the application for certification including necessary testing.

[202] All retail dispenser components except the hose that connects the nozzle to the dispenser have been evaluated by UL. Once such hoses have been evaluated by UL, a certification for the complete fuel dispenser assembly may be finalized by UL.

[203] E85 facility costs were amortized over 15 years at 7% and the costs spread over the projected volume of E85 dispensed.

[204] Gasohol, a fuel containing at least 10% biomass-derived ethanol, received a partial exemption from the federal gasoline excise tax. This exemption was implemented in 1979 and a blender's tax credit and a pure alcohol fuel credit were added to the mix in 1980.

oxygenate. Upon passage of the 1990 CAA amendments, states implemented winter oxygenated fuel (''oxyfuel'') programs to monitor carbon monoxide emissions. EPA also established the reformulated gasoline (RFG) program to help reduce emissions of smog-forming and toxic pollutants. Both the oxyfuel and RFG programs called for oxygenated gasoline. However, petroleum-derived ethers, namely methyl tertiary butyl ether (MTBE), dominated oxygenate use until drinking water contamination concerns prompted a switch to ethanol. Additional support came in 2004 with the passage of the Volumetric Ethanol Excise Tax Credit (VEETC). The VEETC provided domestic ethanol blenders with a $0.51/gal tax credit, replacing the patchwork of existing subsidies.[205] The phase-out of MTBE and the introduction of the VEETC along with state mandates and tax incentives created a growing demand for ethanol that surpassed the traditional oxyfuel and RFG markets. By the end of 2004, not only was ethanol the lead oxygenate, it was found to be blended into a growing number of states' conventional gasoline.[206]

In the years that followed, rising crude oil prices and other favorable market conditions continued to drive ethanol usage. In May 2007, EPA promulgated a Renewable Fuel Standard (''RFS1'') in response to EPAct. The RFS1 program set a floor for renewable fuel use reaching 7.5 billion gallons by 2012, the majority of which was ethanol. The country is currently on track for exceeding the RFS1 requirements and meeting the introductory years of today's proposed RFS2 program. For a summary of the growth in U.S. ethanol usage over the past decade, refer to Table V.D.1.–1.

TABLE V.D.1–1—U.S. ETHANOL CONSUMPTION (INCLUDING IMPORTS)

Year	Total ethanol use [a]	
	Trillion BTU	Bgal
1999	120	1.4
2000	138	1.6
2001	144	1.7
2002	171	2.0
2003	233	2.8
2004	292	3.5
2005	334	4.0
2006	451	5.3
2007	566	6.7
2008	792	9.4

[a] EIA Monthly Energy Review March 2009 (Table 10.2).

Through the years, there have also been several policy initiatives to increase the number of flexible fuel vehicles (FFVs) capable of consuming up to 85 volume percent ethanol blends (E85). The Alternative Motor Vehicle Fuels Act of 1988 provided automakers with Corporate Average Fuel Economy (CAFE) credits for producing alternative-fuel vehicles, including FFVs as well as CNG and propane vehicles. Furthermore, the Energy Policy Act of 1992 required government fleets to begin purchasing alternative-fuel vehicles, and the majority of fleets chose FFVs.[207] As a result of these two policy measures, there are over 7 million FFVs on the road today.[208] These vehicles increase our nation's ethanol consumption potential beyond what is capable with conventional vehicles. However, most FFVs are currently refueling on conventional gasoline (E0 or E10) due to limited E85 availability and the fact that E85 is typically priced 20–30 cents per gallon higher than gasoline on an energy equivalent basis. As such, we are not currently tapping into the full ethanol consumption potential of our FFV fleet. However, we expect refueling patterns to change in the future under the RFS2 program.

2. Increased Ethanol Use under RFS2

To meet the RFS2 standards, ethanol consumption will need to be much higher than both today's levels and those projected to occur absent RFS2. The Energy Information Administration (EIA) projected that under business-as-usual conditions, ethanol usage would grow to just over 13 billion gallons by 2022.[209] This represents significant growth from today's usage, however, this volume of ethanol is capable of being consumed by today's vehicle fleet albeit with some fuel infrastructure improvements.[210] Although EIA projected a small percentage of ethanol to be blended as E85 in 2022, 13 billion gallons of ethanol could also be consumed by displacing about 90% of our country's forecasted gasoline energy demand with E10. The maximum amount of ethanol our country is capable of consuming as E10 compared to the projected RFS2 ethanol volumes is shown below in Figure V.D.2–1.[211]

[204] Gasohol, a fuel containing at least 10% biomass-derived ethanol, received a partial exemption from the federal gasoline excise tax. This exemption was implemented in 1979 and a blender's tax credit and a pure alcohol fuel credit were added to the mix in 1980.

[205] The 2008 Farm Bill, discussed in more detail in Section V.B.2.b, replaces the $0.51/gal ethanol blender credit with a $0.45/gal corn ethanol blender credit and also introduces a $1.01/gal cellulosic biofuel producer credit. Both credits are effective January 1, 2009.

[206] Based on 2004 Federal Highway Association (FHWA) State Gasohol Report less estimated RFG and oxyfuel ethanol usage based on EPA's 2004 RFG Fuel Survey results and knowledge of state oxyfuel programs and fuel oxygenates. For more on historical ethanol usage by state and fuel type, refer to Section 1.7.1.1 of the DRIA.

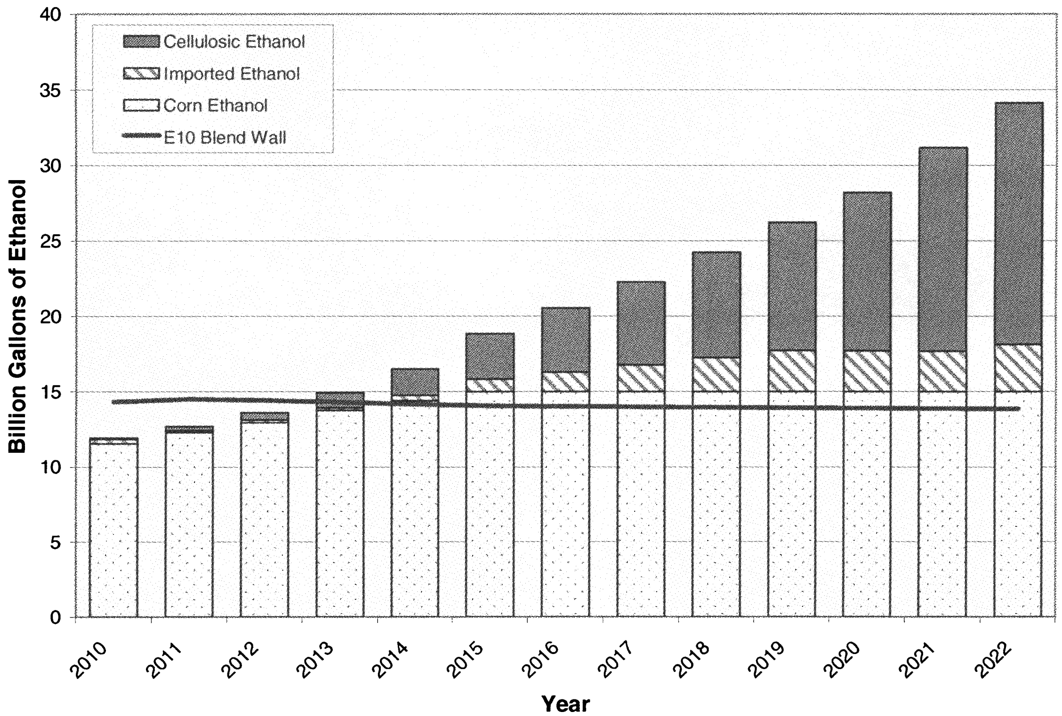
[207] *Source:* June 23, 2008 Federal Times, *Special Report: Fleet Management*.

[208] *Source:* DOE Energy Efficiency and Renewable Energy (worksheet available at *www.eere.energy.gov/afdc/data/index.html*.)

[209] Source: EIA Annual Energy Outlook 2007, Table 17.

[210] For more information on distribution accommodations, refer to Section V.C.

Figure V.D.2-1
Max E10 Ethanol Consumption Compared to RFS2 Requirements[212]



As shown in Figure V.D.2–1, under the proposed RFS2 program, we are projected to hit the E10 ''blend wall'' of about 14.5 billion gallons of ethanol by 2013. This volume corresponds to 100% E10 nationwide. However, if gasoline demand falls, or if E10 cannot get distributed nationwide, the nation could hit the blend wall sooner. Regardless, to get beyond the blend wall and consume more than 14–15 billion gallons of ethanol, we are going to need to see significant increases in the number FFVs on the road, the number of E85 retailers, and the FFV E85 refueling frequency. In the subsections that follow, we will highlight the variables that impact our nation's ethanol consumption potential and, more specifically, what measures the market may need to take in order to consume 34 billion gallons of ethanol by 2022 (assuming the cellulosic biofuel standard and the majority of the advanced biofuel standard are met with ethanol).

As explained in Section V.A.2, our primary RFS2 analysis focuses on ethanol as the main biofuel in the future.[213] In addition, from an ethanol consumption standpoint, we have focused on an E10/E85 world. While E0 is capable of co-existing with E10 and E85 for a while, we assumed that E10 would replace E0 as expeditiously as possible and that all subsequent ethanol growth would come from E85. Furthermore, for our primary analysis, we assumed that no ethanol consumption would come from the mid-level ethanol blends (i.e., E15 or E20) as they are not currently approved for use in non-FFVs. However, in Section V.D.3 below, we discuss the potential approval pathways for mid-level ethanol blends and the volume implications.

We acknowledge that, if approved, mid-level ethanol blends could help the nation meet the proposed RFS2 volume requirements. First, non-FFVs could consume more ethanol per gallon of ''gasoline''. This could result in greater ethanol consumption nationwide. In addition, mid-level blends could allow gasoline retailers to continue to price ethanol relative to gasoline (as it currently is for E10). For these reasons, it is possible that mid-level ethanol blends could help the nation get beyond the E10 blend wall. However, as explained in Section V.D.3.b, there are numerous actions that would need to be taken to bring mid-level ethanol blends to market. In addition, mid-level ethanol blends alone (even if made available nationwide) are not capable of fulfilling the RFS2 requirements in later years. We would essentially hit another blend wall 1–6 years later depending on the intermediate blend, how quickly it could be brought to market, and how widely mid-level ethanol blends were distributed at retail stations nationwide. Nevertheless, this time could be very valuable when it comes to expanding E85/FFV infrastructure and/or commercializing other non-ethanol cellulosic biofuels.

Regardless, our primary analysis focuses on an E10/E85 world because mid-level ethanol blends are not currently approved for use in conventional gasoline vehicles and nonroad equipment. Before usage could be legalized, as discussed more in Section V.D.3 below, EPA would need to grant a waiver declaring that mid-level blends are substantially similar or ''sub-sim'' to gasoline or perhaps even reinterpret the meaning of ''sub-sim''. While such a waiver has not yet been granted, several organizations/agencies are performing vehicle emission testing and investigating other impacts of mid-

[211] The maximum E10 volumes are a function of the gasoline energy demand reported in EIA's Annual Energy Outlook 2009, Table 2 adjusted with lower heating values.

[213] For consideration of other biofuels, refer to Section V.D.3.d.

level blends.[214] Therefore, as a sensitivity analysis, we have analyzed what might need to be done to bring mid-level ethanol blends to market (should a sub-sim waiver be approved) and the extent to which such blends could help our nation meet the RFS2 ethanol standards, at least in the near term. Finally we end our ethanol usage discussion by looking at other strategies for getting beyond the E10 blend wall.

a. Projected Gasoline Energy Demand

The maximum amount of ethanol our country is capable of consuming in any given year is a function of the total gasoline energy demanded by the transportation sector. Our nation's gasoline energy demand is dependent on the number of gasoline-powered vehicles on the road, their average fuel economy, vehicle miles traveled (VMT), and driving patterns. For analysis purposes, we relied on the gasoline energy projections reported by EIA in AEO 2008.[215] Unlike AEO 2007, AEO 2008 takes the fuel economy improvements set by EISA into consideration and also assumes a slight dieselization of the vehicle fleet. The result is a 15% reduction in the projected 2022 gasoline energy demand from AEO 2007 to AEO 2008.[216] EIA basically has gasoline energy demand (petroleum-based gasoline plus ethanol) flattening out, and even slightly decreasing, as we move into the future and implement the EISA vehicle standards.[217]

b. Projected Growth in Flexible Fuel Vehicles

According to DOE's Department of Energy Efficiency and Renewable Energy, there are currently over 7 million FFVs on the road today capable of consuming E85.[218] And that number is growing steadily. Automakers are incorporating more and more FFVs into their light-duty production plans. While the FFV system (i.e., fuel tank, sensor, delivery system, etc.) used to be an option on some vehicles, most FFV producers are moving in the direction of converting entire product lines over to E85-capable systems. Still, the number of FFVs that will be manufactured and purchased in future years is uncertain. For our cost analysis, we examined several different FFV production scenarios. But for our ethanol usage analysis, we focused on one primary FFV scenario, described in more detail below.[219]

In response to President Bush's ''20-in-10'' plan of reducing American gasoline usage by 20% in 10 years, domestic automakers responded with aggressive FFV production goals. General Motors, Ford and Chrysler (referred to hereafter as ''The Detroit 3'') announced plans to produce 50% FFVs by 2012.[220] And despite the current state of the economy and the auto industry, it appears U.S. automakers are still moving forward with their FFV production plans.[221] Assuming that The Detroit 3 continue to maintain 50% market share and that total vehicle sales remain around 16 million per year, at least 4 million FFVs will be produced by the 2012 model year. Based on 2008 offerings, we assumed that approximately 80% of The Detroit 3's FFV production commitment would be met by light-duty trucks and the remaining 20% would be cars.[222] [223] We also assumed that all the FFVs in existence today were produced by The Detroit 3 (and therefore share the same aforementioned car/truck ratio) and that production would ramp up linearly beginning in 2008 to reach the 2012 commitment.

Although non-domestic automakers have not made any official FFV production commitments, Nissan, Mercedes, Izuzu, and Mazda all included at least one flexible fuel vehicle in their 2008 model year offerings.[224] And we anticipate that additional FFVs (or FFV options) will be added in the future. Ultimately, we predict that non-domestic FFV production could be as high as 25%, or about 2 million FFVs per year. While we are not forecasting an official FFV production commitment from the non-domestic automakers, we believe that this represents an aggressive, yet reasonable FFV production estimate for analysis purposes. Furthermore, based on current offerings, we assumed that the majority of non-domestic FFV production would be trucks. With respect to timing, we expect that the non-domestic automakers would ramp up FFV production later than The Detroit 3. For analysis purposes, we assumed that non-domestic automakers would ramp up FFV production beginning in 2013, and like The Detroit 3, it would take about five years for them to reach their FFV production goals (or in this case, the assumed 25% production level)

Based on these FFV assumptions and forecasted vehicle phase-out, VMT, and fuel economy estimates provided by EPA's MOVES Model, we calculate that the maximum percentage of fuel (gasoline/ethanol mix) that could feasibly be consumed by FFVs in 2022 would be about 30%. For more information on our FFV analysis, refer to Section 1.7.1.2.2 of the DRIA.

c. Projected Growth in E85 Access

According to the National Ethanol Vehicle Coalition (NEVC), there are currently over 1,900 retailers offering E85 in 45 states plus the District of Columbia.[225] While this represents significant industry growth, it still only translates to about 1% of U.S. retail stations nationwide carrying the fuel.[226] As a result, most FFV owners clearly do not have reasonable access to E85. For our FFV/E85 analysis, we have defined ''reasonable access'' as one-in-four pumps offering E85 in a given area.[227] Accordingly, just over 4% of the nation currently has reasonable access to E85, up from 3% in 2007 (based on a mid-year NEVC E85 pump estimate).[228]

There are a number of states promoting E85 usage by offering FFV/E85 awareness programs and/or retail pump incentives. A growing number of states are also offering infrastructure grants to help expand E85 availability. Currently, nine Midwest states have adopted a progressive Energy Security and Climate Stewardship Platform.[229]

[214] For more information on mid-level ethanol blends testing, refer to Section V.D.3.b.

[215] For blend wall discussions, we rely on the most recent AEO 2009 projections. However for our detailed ethanol consumption analysis presented in this section (and in more detail in Section 1.7.1 of the DRIA), we relied on AEO 2008.

[216] EIA Annual Energy Outlook 2007 & 2008, Table 2.

[217] For more information on gasoline energy projections, refer to Section 1.7.1.2.1 of the DRIA.

[218] DOE Energy Efficiency and Renewable Energy August 2008 estimate (worksheet available at *www.eere.energy.gov/afdc/data/index.html*).

[219] For more on the FFV production scenarios we considered, refer to Section 1.7.1.2.2 of the DRIA.

[220] Ethanol Producer Magazine, ''View From the Hill.'' July 2007.

[221] Ethanol Producer Magazine, ''Automakers Maintain FFV Targets in Bailout Plans.'' February 2009.

[222] NEVC 2008 Purchasing Guide for Flexible Fuel Vehicles.

[223] Several of the FFV assumptions may need to be revised for the FRM in light of recent events.

[224] *Ibid.*

[225] NEVC FYI Newsletter: Volume 15, Issue 5: March 9, 2009.

[226] Based on National Petroleum News gasoline station estimate of 161,768 in 2008.

[227] For a more detailed discussion on how we derived our one-in-four reasonable access assumption, refer to Section 1.6 of the DRIA. For the distribution cost implications as well as the cost impacts of assuming reasonable access is greater than one-in-four pumps, refer to Section 4.2 of the DRIA.

[228] Computed as percent of stations with E85 (1,963/161,768 as of March 2009 or 1,251/164,292 as of July 2007) divided by 25% (one-in-four stations).

[229] The following states have adopted the plan: Indiana, Kansas, Michigan, Minnesota, Ohio, South Dakota, Wisconsin, Iowa, and most recently, North Dakota. For more information, visit: *http://*

Continued

The platform includes a Regional Biofuels Promotion Plan with a goal of making E85 available at one third of all stations by 2025. In addition, on July 31, 2008, Congresswoman Stephanie Herseth Sandlin (D–SD) and John Shimkus (R–IL) introduced The E85 and Biodiesel Access Act that would amend IRS tax code and increase the existing federal income tax credit from $30,000 or 30% of the total cost of improvements to $100,000 or 50% of the total cost of needed alternative fuel equipment and dispensing improvements.[230] While not signed into law, such a tax credit could provide a significant retail incentive to expand E85 infrastructure.

Given the growing number of state infrastructure incentives and the proposed Federal alternative fuel infrastructure subsidy, it is clear that E85 infrastructure will continue to expand in the future. However, the extent to which nationwide E85 access will grow is difficult to predict, let alone quantify. For analysis purposes, as a practical upper bound, we have selected 70% by 2022. This is roughly equivalent to all urban areas in the United States offering reasonable (one-in-four-station) access to E85.[231] We are not concluding that the percentage of the nation with reasonable access to E85 could not exceed 70% (as a sensitivity, we also modeled the cost impacts of nationwide access to E85) or that availability would necessarily be concentrated in urban areas. However, for analysis purposes, we believe that 70% is a good surrogate for a practical portion of the country that could have reasonable one-in-four access to E85 by 2022 under the proposed RFS2 program. On average, this translates to about 18% of retail stations nationwide offering E85. As discussed in Section V.C, we believe this is feasible based on our assessment of the distribution infrastructure capabilities. For more information on the projected growth in E85 access, refer to Section 1.7.1.2.3 of the DRIA.

d. Required Increase in E85 Refueling Rates

As mentioned above, there were approximately 7 million FFVs on the road in 2008. If all FFVs refueled on E85 100% of the time, this would translate to about 6.5 billion gallons of E85 use.[232] However, E85 usage was only around 12 million gallons in 2008.[233] This means that, on average, FFV owners were only tapping into about 0.2% of their vehicles' E85/ethanol usage potential last year. Assuming that only 4% of the nation had reasonable one-in-four access to E85 in 2008 (as discussed above), this equates to an estimated 5% E85 refueling frequency for those FFVs that had reasonable access to the fuel.

There are several reasons for today's low E85 refueling frequency. For starters, many FFV owners may not know they are driving a vehicle that is capable of handling E85. As mentioned earlier, more and more automakers are starting to produce FFVs by engine/product line, e.g., all 2008 Chevy Impalas are FFVs.[234] Consequently, consumers (especially brand loyal consumers) may inadvertently buy a flexible fuel vehicle without making a conscious decision to do so. And without effective consumer awareness programs in place, these FFV owners may never think to refuel on E85. In addition, FFV owners with reasonable access to E85 and knowledge of their vehicle's E85 capabilities may still not choose to refuel on E85. They may feel inconvenienced by the increased E85 refueling requirements. Based on its lower energy density, FFV owners will need to stop to refuel 21% more often when filling up on E85 over E10 (and likewise, 24% more often when refueling on E85 over conventional gasoline).[235] In addition, some FFV owners may be deterred from refueling on E85 out of fear of reduced vehicle performance or just plain unfamiliarity with the new motor vehicle fuel. However, as we move into the future, we believe the biggest determinant will be price—whether E85 is priced competitively with gasoline based on its reduced energy density and the fact that you need to stop more often, drive a little further to find an E85 station, and depending on the retail configuration, wait in longer lines to fill up on E85.

To comply with the proposed RFS2 program and consume 34 billion gallons of ethanol by 2022, not only would we need more FFVs and more E85 retailers, we would need to see a significant increase in the current FFV E85 refueling frequency. Based on the FFV and retail assumptions described above in subsections (b) and (c), our analysis suggests that FFV owners with reasonable access to E85 in 2022 would need to fill up on it 74% of the time, a significant increase from today's estimated 5% refueling frequency. Were there to be fewer FFVs in the fleet, the E85 refueling frequency would need to be even higher. Similarly, with more FFVs in the fleet, the E85 refueling frequency could be lower and still meet the proposed RFS2 requirements. However, even with an FFV mandate, our analysis suggests that we would need to see an increase from today's average FFV E85 refueling frequency. In order for this to be possible, there will need to be an improvement in the current E85/gasoline price relationship.

e. Market Pricing of E85 Versus Gasoline

According to a recent online fuel price survey, E85 is currently priced almost 30 cents per gallon higher than conventional gasoline on an energy-equivalent basis.[236] To increase our nation's E85 refueling frequency to the levels described above, E85 needs to be priced competitively with (if not lower than) conventional gasoline based on its reduced energy content, increased time spent at the pump, and limited availability. Our analysis, described in more detail in Section 1.7.1.2.5 of the DRIA, suggests that E85 would need to be priced about one-third lower than gasoline at retail (based on 2006 prices) in order for it to be cost-competitive. As expected, higher crude prices could make E85 look slightly more attractive while lower crude oil prices could make E85 look less attractive.

In Brazil, charts are posted at gas stations informing flex-fuel vehicle owners whether it makes sense to fill up on ''gasoline'' (containing 20–25% denatured anhydrous ethanol)[237] or ''alcohol'' (100% denatured hydrous ethanol) based on the price and relative energy density of each. However, in the U.S., FFV owners will likely be on their

www.midwesterngovernors.org/resolutions/Platform.pdf.

[230] A copy of House Rule 6734 can be accessed at: *http://www.e85fuel.com/news/2008/080108_shimkus_release/shimkus.pdf.*

[231] For this analysis, we've defined ''urban'' as the top 150 metropolitan statistical areas according to the U.S. census and/or counties with the highest VMT projections according the EPA MOVES model, all RFG areas, winter oxy-fuel areas, low-RVP areas, and other relatively populated cities in the Midwest.

[232] Based on the assumption that FFV owners travel approximately 12,000 miles per year and get about 18 miles per gallon on average under actual in-use driving conditions. For more information, refer to Section 1.7.1.2.4 of the DRIA.

[233] EIA Annual Energy Outlook 2009, Table 17.

[234] NEVC, ''2008 Purchasing Guide for Flexible Fuel Vehicles.'' Refers to all mass produced 3.5 and 3.9L Impalas. However, it is our understanding that consumers may still place special orders for non-FFVs.

[235] Based on our assumption that denatured ethanol has an average lower heating value of 77,930 BTU/gal and conventional gasoline (E0) has average lower heating value of 115,000 BTU/gal. For analysis purposes, E10 was assumed to contain 10 vol% ethanol and 90 vol% gasoline. Based on EIA's AEO 2008 report, E85 was assumed to contain 74 vol% ethanol and 26 vol% gasoline on average.

[236] Based on average E85 and regular unleaded gasoline prices reported at *http://www.fuelgaugereport.com/* on April 23, 2009.

[237] The government-mandated gasoline ethanol content was 25% as of July 2007. *Source:* F.O. Licht World Ethanol & Biofuels Report Vol. 5 No. 21 July 9, 2007.

own for figuring out which fuel is more economical.

Although in some areas of the country E85 is already priced significantly lower than gasoline, this is a far cry from a nationwide trend. And as we move into the future and incorporate cellulosic ethanol (a fuel that is currently more expensive to produce than corn ethanol), it may be even more difficult to produce ethanol for a price that the market would accept. However, a number of measures could be taken to help encourage FFV E85 refueling.

The first is increased consumer awareness. To maximize ethanol usage, it is important that FFV owners are aware of their vehicle's fueling capabilities, i.e., that their vehicle is capable of refueling on E85. It is equally important that FFV owners are aware of E85 refueling outlets that may be available to them. Automakers and/or car dealerships could notify FFV owners of E85 stations in their area. Together, increased automaker and retail awareness could help increase our nation's E85 throughput potential. However, in order for consumers to actually choose E85 over conventional gasoline on a regular basis, there needs to be a marked price incentive at the pump.

Current federal and most state tax code does not differentiate between ethanol sold as E10 and as E85. As of July 2008, state excise taxes were reported to account for more than $0.18 per gallon of gasoline (on average).[238] However, there are a number of states (e.g., Illinois, Indiana, North Dakota, and South Dakota) that currently waive or discount excise taxes on E85. This type of fuel tax structure helps contribute to a retail price relationship that favors E85 over conventional gasoline.[239] If states continue to waive/reduce E85 fuel taxes under RFS2, this could help increase the FFV E85 refueling frequency. As expected, this would have the greatest impact on ethanol consumption in the areas of the country with the most FFVs.

The E10/E85 price relationship could also be modified by the refining industry. Under the proposed program, gasoline refiners (as well as importers) would be required to purchase RINs to demonstrate that sufficient volumes of renewable/alternative fuels were used to meet their volume obligations. This could provide an incentive for these parties to take the steps necessary to ensure adequate ethanol use levels to facilitate compliance. One potential action that refiners might take to ensure a sufficient RIN supply would be to subsidize the price of the ethanol used to manufacture E85. Such a subsidy might be financed by an increase in their selling price of gasoline. In addition, refiners with marketing arms could adjust the retail price relationship of E10 in E85 in way that encourages E85 throughput while still maintaining the same average net profit. However, a relatively small proportion of refiners market their own gasoline and thus have the ability to make retail price adjustments. Consequently, relying solely on market mechanisms may create some competitive concerns. We request comment on viable and cooperative ways refiners and gasoline retailers could promote E85 throughput to meet the proposed RFS2 requirements.

3. Other Mechanisms for Getting Beyond the E10 Blend Wall

a. Mandate for FFV Production

One way to increase ethanol usage under RFS2 would be if there were more FFVs in the fleet. As described above, our primary analysis is based on the assumption that The Detroit 3 would follow through with their commitment to produce 50% FFVs by 2012 and the non-domestic automakers would ramp up FFV production beginning in 2013 and produce 25% FFVs by 2017. Based on the projected number of FFVs in the fleet (and our E85 infrastructure growth assumptions), FFV owners with reasonable one-in-four access to E85 would need to refuel on it 74% of the time. To achieve this optimistic refueling frequency, we believe there would need to be significant improvements to the E10/E85 price relationship.

One way to reduce the required FFV E85 refueling frequency (and in turn decrease some of the pressure off E85 prices) would be to further increase the number of FFVs in the fleet. While EPA does not have the authority to require automakers to produce FFVs, there are a number of bills in Congress that are set out to do just that. On July 22, 2008 Senator Sam Brownback (R–KS) on behalf of himself and Senators Susan Collins (R–ME), Joseph Lieberman (I–CT), Ken Salazar (D–CO), and John Thune (R–SD) introduced the Open Fuel Standard Act of 2008, a bill that calls for 50% of the U.S. vehicle fleet to be FFVs capable of using high blends of ethanol or methanol (in addition to gasoline) by 2012. This number would grow to 80% by 2015.[240] A similar FFV bill was introduced by Eliot Engel (D–NY) in the House on July 22, 2008.[241]

Since a future congressional mandate on FFV production in being discussed, we have modeled the impact that such a mandate could have on the RFS2 program. For our sensitivity analysis, we found that if automakers were required to make all light-duty vehicles E85-capable by 2015 (and our same E85 infrastructure growth assumptions applied), FFV owners with reasonable one-in-four access to E85 would only need to refuel on it 33% of the time. This represents a smaller increase from today's estimated 5% refueling rate. However, implementing such a FFV mandate would have significant cost implications on the auto industry and would still not provide certainty that FFV owners would fuel on E85. For more information on this analysis, as well as other FFV production scenarios we considered, refer to Section 1.7.1.2.2 of the DRIA.

b. Waiver of Mid-Level Ethanol Blends (E15/E20)

For our primary ethanol usage analysis, we considered that there would only be two fuels in the future, E10 and E85. And as explained in Section V.D.2, we believe it is feasible to consume 34 billion gallons of ethanol by 2022 given growth in FFV production and E85 availability and projected improvements in the current E10/E85 price relationship.

However, several organizations and government entities are interested in increasing the concentration of ethanol beyond the current 10% limit in the commercial gasoline pool. Section 211(f)(1) of the Clean Air Act prohibits the introduction into commerce, or increase in the concentration in use of, gasoline or gasoline additives for use in motor vehicles unless they are substantially similar to the gasoline or gasoline additives used in the certification of new motor vehicles or motor vehicle engines. EPA may grant a waiver of this prohibition under Section 211(f)(4) provided that the fuel or fuel additive ''will not cause or contribute to a failure of any emission control device or system (over the useful life of the motor vehicle, motor vehicle engine, nonroad engine or nonroad vehicle in which the device or system is used) to achieve compliance by the vehicle or engine with the emission standards to

[238] Source: The American Petroleum Institute July 2008 Gasoline Tax Report available at: *http://www.api.org/statistics/fueltaxes/upload/July_2008_gasoline_and_diesel_summary_pages.pdf.*

[239] Source: DOE Energy Efficiency and Renewable Energy Web site (*http://www.eere.energy.gov/*).

[240] Refer to Senate Bill 3303 which can be found at: *http://thomas.loc.gov/cgi-bin/query/z?c110:S.3303.*

[241] Refer to House Rule 6559 which can be found at: *http://thomas.loc.gov/cgi-bin/bdquery/z?d110:H.R.6559.*

which it has been certified.'' The most recent ''substantially similar'' interpretive rule for unleaded gasoline presently allows oxygen content up to 2.7% by weight for certain ethers and alcohols.[242] E10 contains approximately 3.5% oxygen by weight, which makes a gasoline-ethanol blend with ten% ethanol not ''substantially similar'' to certification fuel under the current interpretation.[243] Since any mid-level blend would have a greater than allowed oxygen content, any mid-level blend would need to have a waiver under Section 211(f)(4) of the CAA in order to be sold commercially.

Before EPA grants a 211(f)(4) waiver for a new fuel or fuel additive, an applicant must prove that the new fuel or fuel additive will meet the waiver requirements outlined in the statute. EPA has required that applicants provide vehicle/engine testing for tailpipe emissions, evaporative emissions, materials compatibility, and driveability. Testing needs to include emissions over the full useful life of vehicle and equipment. Several interested parties are investigating the impact that mid-level ethanol blends (e.g., E15 or E20) may have on these areas among others (i.e. catalyst, engine, and fuel system durability, and onboard diagnostics). In order to use the information collected for waiver application purposes, the mid-level ethanol blend testing will need to consider the different engines and fuel systems currently in service that could be exposed to mid-level ethanol blends and the long-term impact of using such blends.[244] After receiving a waiver application, EPA must give public notice and comment and has 270 days to grant or deny the waiver request.

The Department of Energy (DOE) has developed and initiated a comprehensive testing program to investigate the potential impacts of mid-level blends of ethanol. Initial testing was conducted on a limited number of high-volume vehicles and small non-road engines and a preliminary report was published in October, 2008.[245] In addition, DOE is in the process of leveraging existing EPA vehicle and small engine test programs (originally designed to test up to 10% ethanol) to add mid-level ethanol blends to the fuel matrix. DOE's comprehensive test program is intended to evaluate a wide range of emission, performance, and durability issues associated with mid-level ethanol blends (additional reports forthcoming).

DOE is not alone in pursuing mid-level blends. In 2005, the State of Minnesota, a large producer of corn ethanol, passed a law requiring that by 2015, 20% of gasoline (by volume) must be replaced by ethanol. While this level could be achieved with a high percentage of E85 usage by FFVs, the state has also expressed an interest in moving to 20% ethanol blends. Several other states and organizations have also expressed interest in increasing ethanol use by adopting E15 or E20. The Renewable Fuels Association (RFA) and the American Coalition for Ethanol (ACE) have been working with various government entities to investigate the impact of mid-level blends

On March 6, 2009, Growth Energy and 54 ethanol manufacturers submitted an application for a waiver of the prohibition of the introduction into commerce of certain fuels and fuel additives set forth in section 211(f) of the Act. This application seeks a waiver for ethanol-gasoline blends of up to 15 percent by volume ethanol. The statute directs the Administrator of EPA to grant or deny this application within 270 days of receipt by EPA, in this instance December 1, 2009. EPA recently issued a federal register notice announcing receipt of the Growth Energy waiver application and soliciting comment on all aspects of it. Refer to 74 FR 18228 (April 21, 2009).

While the current Growth Energy waiver application is still under review, as a sensitivity, we considered the implications that adding E15 or E20 to the marketplace could have on ethanol usage and the supporting fuel infrastructure should such blends be permitted. For each case, we assumed that E10 would need to continue to remain in existence to meet the demand of legacy vehicle and non-road engine owners. This would also provide consumer choice. Experience in past fuel programs has shown that many consumers will not be comfortable refueling on higher ethanol blends and will blame any problems that may occur on the new fuel (regardless of the actual cause of the vehicle problems) causing a backlash against the new fuel requirements. Therefore, we believe it is critical to continue to allow consumers the choice between mid-level ethanol blends and conventional gasoline (assumed to be E10 in the future).

For our optimistic mid-level ethanol blends scenario, we assumed that E15 or E20 could be available at all retail stations nationwide by the time the nation hits the E10 blend wall, or around 2013. This assumes a number of actions are taken to bring mid-level blends to market (explained in more detail below).[246] We assumed that E10 would be marketed as premium-grade gasoline, the mid-level ethanol blend (E15 or E20) would serve as regular, and like today, midgrade would be blended from the two fuels. Those vehicles and equipment which are unable to refuel on mid-level ethanol blends (or choose not to) could continue to fill up on E10. This mid-level ethanol blends scenario, described in more detail in Section 1.7.1.3 of the DRIA, concluded that if mid-level ethanol blends were to be distributed at all retail stations nationwide, they could help increase ethanol usage to over 19 billion gallons (with E15) and 25 billion gallons (with E20).

[242] 73 FR 22277 (April 25, 2008).

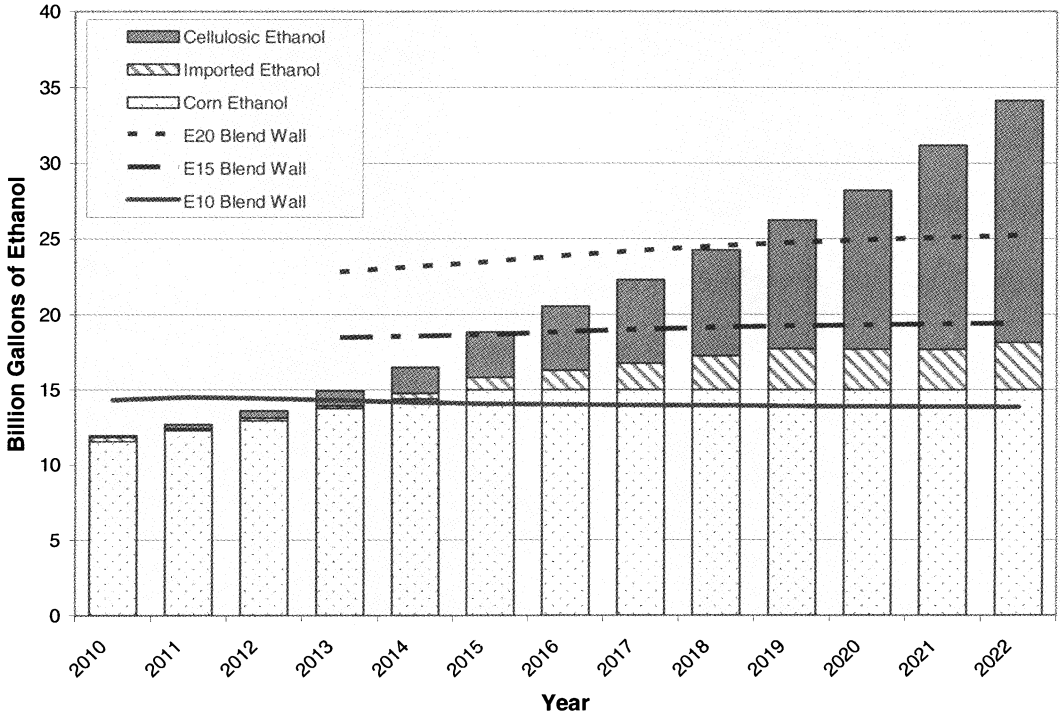
[243] Gas Plus, Inc. submitted an application for a 211(f)(4) waiver for E10 which was granted, see 44 FR 20777 (April 6, 1979).

[244] EPA has expressed what such a waiver testing program might look like, see Karl Simon, ''Mid Level Ethanol Blend Experimental Framework: Epa Staff Recommendations,'' June 2008, and Ed Nam ''Vehicle Selection & Sample Size Issues for Catalyst and Evap Durability Testing,'' November 2008, in the docket (EPA–HQ–OAR–2005–0161).

[245] Effects of Intermediate Ethanol Blends on Legacy Vehicles and Small Non-Road Engines, Report 1, Prepared by Oak Ridge National Laboratory for the Department of Energy, October 2008.

[246] Results for other cases are discussed in Section 1.7.1.3 of the DRIA.

Figure V.D.3-1
Max E15/E20 Ethanol Consumption Compared to RFS2 Requirements



As shown in Figure V.D.2–2, in this optimistic phase-in scenario, adding E15 could postpone the blend wall by about three years to 2016 and adding E20 could postpone it another three years to 2019. Although mid-level ethanol blends will fall short of meeting the RFS2 requirements, they could provide interim relief while the county ramps up E85/FFV infrastructure and/or finds other non-ethanol alternatives (e.g., cellulosic diesel or biobutanol) to reach the RFS2 volumes.

Our nation's whole system of gasoline fuel regulation, fuel production, fuel distribution, and fuel use is built around gasoline with ethanol concentrations limited to E10. As a result, while a waiver may legalize the use of mid-level ethanol blends under the CAA, there are a number of other actions that would have to occur to bring mid-level blends to retail. The time needed to take these actions could delay the penetration of mid-level ethanol blends into the market. The CAA only provides a 1 pound RVP waiver for ethanol blends of 10 volume percent or less. Lacking such an RVP waiver, a special low-RVP gasoline blendstock would be needed at terminals to allow the formulation of mid-level ethanol blends that are complaint with EPA RVP requirements. Providing such a separate gasoline blendstock would present significant logistical challenges and costs to the fuel distribution system.[247] A number of changes would be needed to EPA regulations including those pertaining to reformulated gasoline, anti-dumping, and gasoline deposit control additives to accommodate and mid-level ethanol blends. Such changes would need to be made through the notice and comment process similar to today's action. In addition, most states require that fuel comply with the applicable ASTM International (formally known as the American Standards for Testing and Materials) specification. The development of an ASTM International specification for mid-level ethanol blends through an industry consensus process is currently being initiated.

There are a number of requirements regarding the fire and leak protection safety of retail fuel dispensing and storage equipment. The Occupational Safety and Health Administration (OSHA) requires that retail fuel handling equipment be listed with an independent standards body such as Underwriters Laboratories (UL). No independent standards body has listed fuel handling equipment for mid-level ethanol blends. Furthermore, UL has stated that it would not expand listings for in-use fuel retail equipment originally listed for E10 blends to cover greater than E10 blends.[248] EPA's Office of Underground Storage Tanks (OUST) requires that UST systems must be compatible with the fuel stored in the system. These requirements pertain to all components of the system including the storage tank, connecting piping, pumps, seals and leak detection equipment.

States typically adopt fire safety codes from either the National Fire Protection Association (NFPA) or the International Code Council (ICC). These organizations currently do not have provisions that would allow the mid-level ethanol blends to be stored/dispensed from existing equipment at retail. Local safety officials (e.g. fire marshals) referred to as ''Authorities Having Jurisdiction'' (AHJ's) often require a UL certification for fuel retail storage/dispensing equipment although some will accept

[247] It may be possible for refiners to formulate a gasoline blendstock that would be suitable for manufacturing mid-level ethanol blends and E10 at the terminal. While this would avoid the logistical problems associated with maintaining separate blendstocks, there could be significant additional refining costs.

[248] UL stated that they have data which indicates that the use of fuel dispensers certified for up to E10 blends to dispense blends up to a maximum ethanol content of 15 volume percent would not result in critical safety concerns (*http://www.ul.com/newsroom/newsrel/nr021909.html*). Based on this, UL stated that it would support authorities having jurisdiction who decide to permit legacy equipment originally certified for up to E10 blends to be used to dispense up to 15 volume percent ethanol. The UL announcement did address the compatibility of underground storage tank systems with greater than E10 blends.

other substantiation of equipment safety such as a manufacture certification. Fuel retailers must also satisfy the requirements of the insurance company that they are insured through which may be more stringent than the legal requirements. Given the liability concerns associated with leaks from underground storage tanks, these issues have to be resolved in order to facilitate the widespread use of mid-level ethanol blends.

The Department of Energy and EPA are currently working with industry to evaluate what changes may be necessary to underground storage tank systems, fuel dispensers, and refueling vapor recovery equipment at fuel retail facilities to handle a mid-level ethanol blend. If existing equipment proves tolerant to a mid-level ethanol blend, this could substantially facilitate its introduction at retail. If the data supports the suitability of legacy retail equipment to store/dispense a mid-level blend, then the process of seeking acceptance by the standard bodies discussed above could commence. The normal processes used by these standards bodies can be lengthy. For example, the NFPA has a 3 year cycle for evaluating changes to its codes with proposals for the current cycle due this June. Thus, apart from the need to technically evaluate the suitability of legacy retail equipment to handle a mid-level ethanol blend, the need to secure recognition from standards bodies could delay the introduction of a mid-level ethanol blend at retail should a waiver be granted by EPA.

If some components of the above-ground existing retail hardware are found to be incompatible with a mid-level ethanol blend, it may be possible for them to be replaced through normal attrition. For example the ''hanging hardware'' which includes the nozzle and hose from the dispenser is typically replaced every 3 to 5 years. It is also possible that only minor changes might be needed to equipment that has a longer service life which might be accomplished without too much difficulty/cost. However, if extensive new equipment is needed and particularly if this involves the breaking of concrete, we believe that it is unlikely that fuel retailer would opt to install equipment specifically for a mid-level ethanol blend given the projected future need for retail equipment capable of handling E85.[249]

[249] As discussed previously, significant penetration of E85 is projected to be needed to facilitate the use of the volumes of ethanol we project would be needed to satisfy the requirements of the EISA.

Finally, all vehicles and nonroad equipment currently in use are only warranted for ethanol levels not exceeding E10 (except for FFVs), and the owner's manuals are written to reflect this. Before widespread acceptance of mid-level ethanol blends by consumers can occur, these warranty issues would need to be addressed.

c. Partial Waiver for Mid-Level Blends

CAA section 211(f)(4), the waiver provision, states that the Administrator may grant a fuel waiver if a fuel manufacturer can demonstrate that the fuel ''will not cause or contribute to a failure of any emission control device or system (over the useful life of the motor vehicle, motor vehicle engine, nonroad engine or nonroad vehicle in which such device or system is used) to achieve compliance by the vehicle or engine with the emission standards with respect to which it has been certified.'' For reasons discussed below, it may be possible that these criteria for a mid-level blend waiver may be met for a subset of gasoline vehicles or engines but not for all gasoline vehicles or engines. The waiver criteria are applied over the useful life of ''the motor vehicle, motor vehicle engine, nonroad engine or nonroad vehicle in which such device or system is used.'' Assuming the criteria is met for a certain subset of vehicles, and that adequate measures could be put in place to ensure that a waiver fuel were only used in that subset of vehicles or engines, one interpretation of this provision is that the waiver could apply only to that subset of vehicles or engines.

One potential outcome from a review of the entire body of scientific and technical information available may be an indication that mid-level ethanol blends could meet the criteria of a section 211(f)(4) waiver for some vehicles and engines but not for others. It may be that certain vehicles and engines operate as intended using mid-level blends but others may be more susceptible to emissions increases or durability problems. For example, vehicles or engines without newer technology that do not readily adjust for the higher oxygen level in the fuel may experience problems, while newer technology vehicles such as those meeting our Tier 2 standards may be able to adjust for such changes as a result of more advanced emissions and fuel control equipment. Nonroad engines, which are typically small, are likely to be most susceptible given the less sophisticated technology associated with such engines. Given this potential outcome, EPA requests comment on all aspects, both legal and technical, as to the possibility that a section 211(f)(4) waiver might be granted, in a partial way with conditions, such that the use of mid-level blends would be restricted to a subset of the gasoline vehicles or engines covered by the waiver provision, while those nonroad engines and vehicles not covered by the waiver would continue using fuels with blends no greater than E10.

Any waiver approval, either fully or partially, is likely to elicit a market response to add E15 blends to E10 and E0 blends in the marketplace, rather than replace them. Thus consumers would merely have an additional choice of fuel.

Experience in past fuel programs has shown that even with consumer education and fuel implementation efforts, there sometimes continues to be public concern for new fuel requirements. Several examples include the phasedown of the amount of lead allowed in gasoline in the 1980s and the introduction of reformulated gasoline (RFG) in 1995. Some segments of the public were convinced that the new fuels caused vehicle problems or decreases in fuel economy. Although substantial test data proved otherwise, these concerns lingered in some cases for several years. As a direct result of these experiences, EPA wants to be assured that prior to potentially granting a waiver for mid-level blends, sufficient testing has been conducted to demonstrate the compatibility of a waiver fuel with engine, fuel and emission control system components.

EPA has previously granted waivers with certain restrictions or conditions. Among other things, these restrictions have included requiring fuels to meet certain voluntary consensus-based gasoline standards such as those developed by the American Society of Testing and Materials (ASTM standards), requirements that precautions be taken to prevent using the waiver fuel as a base fuel for adding oxygenates, and that certain corrosion inhibitors be utilized when producing the waived fuel.[250] However, in those waivers, the conditions placed upon the fuel manufacturer were directly related to manufacturing the fuel itself. Here, the conditions placed upon the fuel manufacturer would be on the use of the fuel in certain vehicles or engines. In other words, the fuel manufacturer would have to ensure that the mid-level blend was only used in that particular subset of vehicles or engines to be able to legally manufacture and sell the fuel

[250] *See,* for example, 53 FR 3636, February 8, 1988, and 53 FR 33846, September 1, 1988.

under the terms of the waiver. Since it would become the fuel manufacturer's responsibility to prevent misfueling, the following discussion highlights some of the ideas that the fuel manufacturer could implement, based on particular subsets of vehicles,[251] to prevent misfueling.

If a partial waiver covered only newly manufactured vehicles, methods focused on the manufacturing of the vehicle could be utilized to inform the buyer that the vehicle was capable of operating on the waiver fuel. In this case, approaches such as the use of vehicle fueling inlet labels and owner's manuals could be utilized in tandem with retail station fuel dispenser labels. Such an approach depends on the attention of the vehicle operator to ensure compliance with the waiver. Additionally, retail station attendants could be trained to provide guidance to operators on which vehicles are covered under the waiver.

If only vehicles of certain model years were covered, owners would know if they could utilize the mid-level blends simply by knowing the model year (again, in tandem with pump labeling). Alternatively, if some portion of the existing fleet, not based upon model-year (such as vehicles meeting EPA Tier 2 emission standards), would also be covered, the approach would have to include some means by which the operator of such a vehicle would be made aware that the vehicle being fueled was covered or not covered by the waiver. Such an approach would likely involve notification of owners of covered vehicles, through direct contact or education campaigns, and would likely require the assistance of the vehicle manufacturers. This approach, as with other approaches, would require pump labeling.

Other approaches may bring about tighter control of misfueling situations but may present additional challenges. For example, one approach might be to provide owners of covered vehicles with a transaction card similar to a credit card that could be swiped at the dispenser to allow for the dispensing of a waived mid-level blend. Presumably, software and/or hardware at dispensing pumps may be able to be adjusted to accommodate such an approach. Some retail station chains have already utilized transponder mechanisms to record sales. Similar transponder systems could be utilized in place of transaction cards.

The above discussion is not meant to be an exhaustive list of possible approaches for ensuring compliance with a partial waiver, nor does it explore all the facets of any single approach. EPA recognizes that there may be legal and practical limitations on what a fuel manufacturer may be able to do to ensure compliance with the conditions of the partial waiver. EPA has not previously imposed this type of ''downstream'' condition on the fuel manufacturer as part of a section 211(f)(4) waiver. EPA does, however, have experience with compliance problems occurring when two types of gasoline have been available at service stations. Beginning in the mid-1970s with the introduction of unleaded gasoline and continuing into the 1980s as leaded gasoline was phased out, there was significant intentional misfueling by consumers. At the time most service stations had pumps dispensing both leaded and unleaded gasoline and a price differential as small as a few cents per gallon was enough to cause some consumers to misfuel. Higher price differentials could occur if, as expected, mid-level ethanol blends were to be marketed as the regular grade and E0 or E10 as the premium grade. The Agency seeks comment regarding whether this is a reasonable or practical condition for this type of waiver. EPA acknowledges that the issue of misfueling would be challenging in a situation where a partial waiver is granted. Therefore, EPA solicits comments on what measures a fuel manufacturer, EPA or others in the gasoline distribution network could take for ensuring compliance with a partial waiver.

While EPA has not analyzed the specific cost of a conditional waiver, such a waiver would likely carry a cost similar to the costs described above in Section V.D.3.b. Because existing equipment in retail stations is certified by Underwriters Laboratories only up to ten percent ethanol, existing equipment would need to be evaluated for its acceptability for use with mid-level blends (and deemed to be acceptable if possible) or it would have to be modified/replaced before any ethanol blend greater than ten percent could be effectuated in the marketplace.[252] If existing retail equipment is found not to be acceptable for storing/dispensing mid-level blends, the aforementioned infrastructure challenges would be present and additional costs would be associated with measures adopted for the prevention of releases due to material incompatibility, as well as those associated with misfueling. EPA therefore seeks comment on the compatibility of the existing retail fuel storage/dispensing equipment with mid-level ethanol blends. Further, adoption of such a waiver would mean that fewer vehicles/engines would be able to utilize mid-level blends and, therefore, the full impact of mid-level blends on the E10 blend wall under such a scenario would not be as significant as full unrestricted utilization of such blends.

d. Non-Ethanol Cellulosic Biofuel Production

While our analysis describes possible pathways by which the market could meet the RFS2 requirements with 34 billion gallons of ethanol as E10 and E85, our analysis of the required FFV and E85 infrastructure growth as well as the required changes to the E10/E85 price relationship suggests some inherent challenges. Furthermore, we conclude that the introduction of mid-level ethanol blends (contingent upon waiver approval) would by itself not allow the country to achieve the RFS2 standards. Another means of achieving the RFS2 volume requirements would be through the introduction of non-ethanol cellulosic biofuels. The growing spread in gasoline and diesel pricing implies that we are currently moving in the direction of being oversupplied with gasoline and undersupplied with diesel.[253] As such, it makes sense that the market might preferentially investigate diesel fuel replacements, e.g., cellulosic diesel via Fischer-Tropsch synthesis, pyrolysis, or catalytic depolymerization. These fuels would meet the definition of cellulosic biofuel (as well as advanced biofuel) under the proposed RFS2 program and help reduce the ethanol blend wall impacts associated with this rule. Although for our analysis we assumed that the cellulosic biofuel standard would be met with ethanol, the market could choose a significant volume of other non-ethanol renewable fuels. DOE and other agencies are currently providing grants to support critical

[251] Although it is not possible at this time to know the contours of a partial waiver with conditions, or even if one might be appropriate, the remainder of this discussion will refer only to vehicles covered by the waiver (and not engines) since newer vehicles are more likely to have more sophisticated emissions and fuel control equipment, while certain engines might be more affected for the reasons stated above.

[252] See previous discussion in Section V.D.3.b of this preamble regarding the issues that would need to be addressed to facilitate the introduction of mid-level ethanol blends at retail.

[253] According to EIA, gasoline and diesel prices were pretty similar on average for a decade from 1995–2004. However, over the past four years, diesel prices have begun to track consistently higher than gasoline prices. To date in 2008, diesel has been priced more than $0.50/gallon higher than gasoline on average. *Source: http://tonto.eia.doe.gov/oog/info/gdu/gasdiesel.asp.*

research into these second-generation cellulosic feedstock conversion technologies. DOE is also providing loan guarantees to help with the commercialization of such technologies. For more information on non-ethanol cellulosic biofuels, refer to Section V.A. or Section 1.4.3 of the DRIA.

e. Measurement Tolerance For E10

Some stakeholders have suggested that the implementation of a tolerance in the measurement of the ethanol content of gasoline could allow more ethanol to be used in existing vehicles without the need for a formal waiver and without the need for more FFVs. Such a tolerance could allow ethanol contents slightly higher than 10 volume percent while still treating such blends as meeting the 10 volume percent limitation on the ethanol content of gasoline.

Although there is no explicit written precedent for permitting ethanol contents higher than 10 vol%, some have speculated that current vehicles would not exhibit any noticeable change in performance, durability, or emissions if a small measurement tolerance for ethanol content of gasoline were allowed. The current specified test method for oxygen content ASTM D–5599–00 includes estimates of the measurement reproducibility that could be used to inform the determination of an appropriate tolerance for ethanol content in gasoline. For instance, based on the provided reproducibility, a measurement as high as 11 vol% ethanol in gasoline might be possible for gasoline that was blended to meet a 10 vol% ethanol requirement. Historically, however, EPA has always enforced the 10 vol% waiver at the 10 vol% level without any tolerance.

The 1978 gasohol waiver application requested a blend of 90% unleaded gasoline and 10% anhydrous ethanol. Although not specified in the application, the convention and the practical approach for blending ethanol into gasoline in 1978 was by volume, and it has continued to be by volume. Thus, the limit on ethanol in gasoline under the waiver is 10% by volume. This is approximately 3.5% oxygen by weight. The waiver request did not apply to a level of ethanol in gasoline beyond 10%, and since the application was approved by default after 180 days due to the fact that the Administrator did not make an explicit decision in this timeframe, there is no formal approval that could have indicated what measurement tolerances might have been acceptable. Thus it has historically been enforced at the 10 vol% limit without any enforcement tolerance.

However, parties who have raised this option have suggested that the Agency's previous treatment of the oxygenate content of gasoline may provide a precedent that would allow for a higher measurement tolerance for ethanol content.

Prior to and after 1981, several waivers issued by the Agency allowed the use of various alcohols and ethers in unleaded gasoline. In 1981, the ''substantially similar'' interpretive rule for unleaded gasoline allowed certain alcohols and ethers at up to 2.0% oxygen by weight. In 1991 the limit was increased to 2.7% oxygen by weight. For each of these waivers, the unleaded gasoline base to which the oxygenate was to be added was to be initially free of oxygenate. With the exception of ethanol, oxygenates, mostly MTBE, were blended at the refinery, with the refiner in control of the gasoline used for blending. This enabled the refiner to ensure that it was free of oxygenate prior to blending. Ethanol was primarily blended at terminals. In order to ensure that gasoline blended with ethanol at the terminal was free of other oxygenates, the ethanol blender first had to check for the presence of other oxygenates in the base gasoline. In the mid-1980's ethanol blenders informed EPA that they were having difficulty finding oxygenate-free gasoline. Much of gasoline had at least trace amounts of MTBE due to commingling of gasolines with different oxygenates in the fungible pipeline system. In order to continue to allow the blending of ethanol up to the 10 vol% limit, EPA issued a letter stating that it would not consider it to be a violation of the ethanol sub-sim waiver if up to 10% by volume ethanol were added to unleaded gasoline containing no more than 2% by volume MTBE. However, the MTBE must have been present only as a result of commingling during storage or transport and not purposefully added as an additional component to the ethanol blend.

Subsequently, two other statements by EPA provided guidance on the allowable oxygen content of oxygenated fuels. For instance, in a memorandum dated October 5, 1992, EPA provided interim guidance for states that allowed averaging programs.[254] This guidance allowed the oxygen content of ethanol to be as high as 3.8% by weight, but did not indicate that the ethanol concentration could be higher than 10 vol%. Also, in a 1995 RFG/Anti-dumping Q&A it was noted that the maximum oxygen range for the simple and complex models was 4.0% by weight. This range was implemented to once again continue to allow the blending of ethanol up to the 10 vol% limit in cases where an extremely low gasoline density might increase the calculated weight percent oxygen content for E10 above the more typical 3.5–3.7 wt% range.

Although we acknowledge that the currently specified test method ASTM D–5599–00 includes some variability, ethanol is different than many other fuel properties and components that are controlled in other fuel programs in one important respect. Fuel properties such as RVP, and components such as sulfur and benzene, are natural characteristics of gasoline as a result of the chemical nature of crude oil and the refining process. Their level or concentration in gasoline is unknown until measured, and then is dependent upon accuracy of the test method. In contrast, ethanol is intentionally added in known amounts using equipment designed to ensure a specific concentration within a small fraction of one percent. Parties that blend ethanol into gasoline therefore have precise control over the final concentration. Thus, a measurement tolerance for ethanol would be less appropriate than measurement tolerances for other fuel properties and components.

We request comment on whether a measurement tolerance should be allowed for the ethanol content of gasoline, the basis for such a tolerance, and what tolerance if any would be appropriate. We also request comment on whether such a tolerance would fit within the existing Underwriters Laboratories, Inc. (UL) approval for the safety of equipment at refueling stations, including underground storage tanks, pumps, piping, seals, etc.

f. Redefining ''Substantially Similar'' to Allow Mid-Level Ethanol Blends

Section 211(f)(1) prohibits the introduction into commerce, or increase in the concentration in use of, gasoline or gasoline additives for use in motor vehicles unless they are substantially similar to the gasoline or gasoline additives used in the certification of new motor vehicles or motor vehicle engines. EPA may grant a waiver of this prohibition under section 211(f)(4) of the Clean Air Act provided that the fuel or fuel additive ''will not cause or contribute to a failure of any emission control device or system (over the useful life of the motor vehicle, motor vehicle engine, nonroad engine or nonroad vehicle in which the device or system

[254] Memorandum from Mary T. Smith, Director of the Field Operations and Support Division, to State/Local Oxygenated Fuels Contacts, October 5, 1992. Subject: ''Testing Tolerance''.

is used) to achieve compliance by the vehicle or engine with the emission standards to which it has been certified.''

EPA first interpreted the term ''substantially similar'' for unleaded gasoline and its additives in 1978.[255] Recognizing that this interpretation was too limited, EPA updated it in 1980, and again in 1981.[256] EPA set the limits contained in the interpretation based on the physical and chemical similarities of the fuel or fuel additives to those used in the motor vehicle certification process. EPA also considered information available regarding the emission effects that such fuels and additives would exhibit relative to the emissions performance of the certification fuels and fuel additives. The 1981 interpretative rule identified the characteristics and specifications that EPA determined would make a fuel or fuel additive ''substantially similar'' to those used in certification. Under this rule, a fuel or fuel additive would be considered substantially similar if it satisfied certain limits on fuel and fuel additive composition, did not exceed a maximum allowable oxygen content of fuel at 2.0% by weight, and met certain ASTM specifications. Comments on this interpretative rule requested that EPA increase the maximum oxygen concentration up to 3.5% oxygen by weight, but EPA rejected this recommendation, stating that it would keep the limit at 2.0% because of concerns over emissions, material compatibility, and drivability from use of various alcohols at higher oxygen contents.

In 1991, EPA amended the interpretive rule by revising the oxygen content criteria to allow fuels containing aliphatic ethers and/or alcohols (excluding methanol) to contain up to 2.7% by weight oxygen.[257] EPA based this increase in the oxygen content on its review of information on a wide variety of alcohol and ether blends, leading it to determine that ''unleaded gasolines with such oxygen content are chemically and physically substantially similar to, and have been shown to have emissions properties substantially similar to, unleaded gasolines used in light-duty vehicle certification.'' [258] Finally, in 2008, EPA amended the interpretive rule to allow flexibility for the vapor/liquid ratio specification for fuel introduced into commerce in the state of Alaska to improve cold starting for vehicles during the winter months in Alaska.[259] Thus the ''substantially similar'' interpretive rule for unleaded gasoline presently allows oxygen content up to 2.7% by weight for certain ethers and alcohols.

A waiver of the substantially similar prohibition was provided by operation of law in 1979 under CAA section 211(f)(4), allowing a gasoline-alcohol fuel blend with up to 10% ethanol by volume (E10) (''E10 Waiver''). E10 has an oxygen content which typically ranges between 3.5 and 3.7% by weight, depending on the specific gravity of the gasoline. Any ethanol blends with greater than 10% ethanol by volume would have an oxygen content which exceeds the 2.7% by weight allowed under the current interpretation of ''substantially similar.'' Therefore, under the 1991 interpretive rule, mid-level ethanol blends would not be considered substantially similar and would require a CAA section 211(f)(4) waiver.

It has been suggested to EPA that we should update the interpretive rule such that mid-level ethanol blends would be considered substantially similar. As in the past, this would involve consideration of the physical and chemical similarities of such mid-level blends to fuels used in the certification process, as well as information about the expected emissions effects of such mid-level blends.[260] EPA invites comment on whether mid-level blends of ethanol are physically and chemically similar enough to the fuels used in the motor vehicle certification process such that they could be considered ''substantially similar'' to the certification fuels used by EPA. With respect to the emissions effects of mid-level blends on emissions performance, EPA recognizes that there may be different impacts depending on the kind of motor vehicle involved. For example, it has been suggested that older technology motor vehicles and engines may have emissions and durability impacts from ethanol blends higher than 10 percent, while Tier 2 and later technology vehicles—2004 and later model year vehicles—may have fewer such impacts.[261] These more recent technology vehicles represent an ever growing proportion of the in-use fleet. DOE is currently conducting various test programs to ascertain the impacts of higher level ethanol blends on vehicles and equipment.

EPA seeks comment on all of the issues involved with reconsidering its interpretation of the term ''substantially similar'' to include gasoline blended with ethanol to contain up to 4.5% oxygen by weight. If EPA revised the substantially similar interpretation in this manner, gasoline blended with up to 12% ethanol by volume (E12) would be considered ''substantially similar.'' [262] Given the possibility, based upon engineering judgment, of a varying impact of a mid-level ethanol blends on different technology vehicles, EPA invites comment on limiting such an interpretation to gasoline intended for use in Tier 2 and later motor vehicles. We estimate that defining E12 as ''substantially similar'' for Tier 2 and later motor vehicles could delay the saturation of the gasoline market with ethanol for up to a year, allowing for more comprehensive testing on higher blend levels to be carried out. However, before EPA could determine whether it was appropriate to revise the interpretation of ''substantially similar'' for gasoline to include gasoline-alcohol fuels blended with up to 12% ethanol, information would need to be provided to EPA that would allow for a robust assessment of the impact of E12 over the full useful life of Tier 2 and later motor vehicles addressing emissions (both tailpipe and evaporative emissions), materials compatibility, and drivability. Furthermore, E12 would still need to fulfill registration requirements (i.e. speciation and health effects testing found at 40 CFR 79.52 and 40 CFR 79.53).

EPA also seeks comments on additional regulatory and implementation issues that would arise as a result of changing the ''substantially similar'' definition to allow for E12. These issues as identified for mid-level blends in the discussion in Section V.D.3.b include, but are not necessarily limited to, the applicability of the 1.0 psi RVP waiver with regard to 10% ethanol blends found at 40 CFR

[255] 43 FR 11258 (March 17, 1978), 43 FR 24131 (June 2, 1978).

[256] 45 FR 67443 (October 10, 1980), 46 FR 38582 (July 28, 1981).

[257] 56 FR 5352 (February 11, 1991).

[258] 56 FR at 5353.

[259] 73 FR 22277 (April 25, 2008).

[260] One point to be clear on is that the substantially similar provision relates to fuels used in certification. It is not an issue of whether mid-level blends are substantially similar to a fuel that has received a waiver of this prohibition. See 46 FR 38582, 38583 (July 28, 1981). The fuels used in certification include the test fuels used for exhaust testing, test fuels for evaporative emissions testing, and the fuels used in the durability process.

[261] It has also been suggested that nonroad engines and equipment may experience greater emissions effects and durability problems when using mid-level blends.

[262] As mentioned earlier, EPA has typically used the oxygen weight percent convention when interpreting the ''substantially similar'' provision. A change in the ''substantially similar'' interpretation to allow for up to 4.5% oxygen by weight in the form of ethanol would essentially accommodate ethanol blends up to 12% by volume since the vast majority of gasolines blended at 12% by volume ethanol would not exceed this oxygen weight percent limit.

80.27(d), Clean Air Act section 211(h); the accommodation of ethanol blends in making calculations utilizing the complex model for reformulated and conventional gasoline at 40 CFR 80.45; and detergent certification requirements found at 40 CFR 80 (Subpart G). Emissions speciation and health effects testing is required for oxygenate-specific blends under 40 CFR 79 (Subpart F). Such testing is currently underway for 10% ethanol blends but not for ethanol levels higher than 10 percent. Additionally, if E12 was allowed under the ''substantially similar'' definition, presumably such a blend would have to meet one of the volatility classes of ASTM D4814–88, which is not now the case with some blends of 10% ethanol blended under the E10 Waiver. Any change in the allowable maximum ethanol level in motor fuels will impact these and, potentially, other motor fuel regulations.

Furthermore, there are also implications beyond EPA's motor fuel regulations. Existing equipment in retail stations is certified by Underwriters Laboratories only up to 10% ethanol. Thus, either existing equipment would need to be recertified for E12 (if possible) or it would have to be replaced before E12 could be effectuated in the marketplace. In addition, the substantially similar prohibition applies to the fuel manufacturer, and if the reinterpretation only applied to gasoline used with Tier 2 and later motor vehicles, then the manufacturer of a mid-level blend could not introduce it into commerce for use with any other motor vehicles. This means that the fuel distribution system would need to be structured in such a way that the fuel manufacturer could appropriately ensure that the fuel was only used in Tier 2 or later motor vehicles. Preventing the misfueling of mid-level blends into vehicles and engines not specified in the interpretive rule, and ensuring the availability of fuels for other vehicles and engines, poses a major problem with reinterpreting ''substantially similar'' to include mid-level blends with a restriction for use in Tier 2 and later motor vehicles. (For a more detailed discussion on this issue, see Section V.D.3.c above). We seek comment on these logistical and regulatory concerns as well.

VI. Impacts of the Program on Greenhouse Gas Emissions

A. Introduction

Lifecycle modeling, often referred to as fuel cycle or well-to-wheel analysis, assesses the net impacts of a fuel throughout each stage of its production and use including production/extraction of the feedstock, feedstock transportation, fuel production, fuel transportation and distribution, and tailpipe emissions.[263] This section describes and seeks comment on the methodology developed by EPA to determine the lifecycle greenhouse gas (GHG) emissions of biofuels fuels as required by EISA as well as the petroleum-based transportation fuels being replaced. While much of the discussion below focuses on those portions of lifecycle assessment particularly important to biofuel production, the basic methodology was the same for analyzing both petroleum-based fuels and biofuels. This methodology was utilized to determine which biofuels (both domestic and imported) qualify for the four different GHG reduction thresholds established in EISA. This threshold assessment compares the lifecycle emissions of a particular biofuel including its production pathway against the lifecycle emissions of the petroleum-based fuel it is replacing (e.g., ethanol replacing gasoline or biodiesel replacing diesel). This section also seeks comment on the Agency's proposal to utilize the discretion provided in EISA to adjust these thresholds downward should certain conditions be met. We also explain how feedstocks and fuel types not included in our analysis will be addressed and incorporated in the future. The overall GHG benefits of the RFS program, which are based on the same methodology presented here, are provided in Section VI.F.

As described in detail below, EPA has analyzed the lifecycle GHG impacts of the range of biofuels currently expected to contribute significantly to meeting the volume mandates of EISA through 2022. In these analyses we have used the best science available. Our analysis relies on peer reviewed models and the best estimate of important trends in agricultural practices and fuel production technologies as these may impact our prediction of individual biofuel GHG performance through 2022. We have identified and highlighted assumptions and model inputs that particularly influence our assessment and seek comment on these assumptions, the models we have used and our overall methodology so as to assure the most robust assessment of lifecycle GHG performance for the final rule.

[263] In this preamble, we are considering ''lifecycle analysis'' in the context of estimating GHG emissions, as required by EISA. More generally, the term ''lifecycle analysis'' or ''assessment'' has been defined as an evaluation of all the environmental impacts across the range of media/exposure pathways that are associated with a ''cradle to grave'' view of a product or set of policies. For more information on this broader context, please see the 2006 EPA publication ''Life Cycle Assessment: Principles and Practice (EPA/600/R–06/060).

EPA believes that compliance with the EISA mandate—determining the aggregate GHG emissions related to the full fuel lifecycle, including both direct emissions and significant indirect emissions such as land use changes—makes it necessary to assess those direct and indirect impacts that occur not just within the United States and also those that occur in other countries. This applies to determining the lifecycle emissions for petroleum-based fuels, to determine the baseline, as well as the lifecycle emissions for biofuels. For biofuels, this includes evaluating significant emissions from indirect land use changes that occur in other countries as a result of the increased production and importation of biofuels in the U.S. As detailed below, we have included the GHG emission impacts of international indirect land use changes. We recognize the significance of including international land use emissions impact and in our analysis presentation we have been transparent in breaking out the various sources of GHG emissions so that the reader can readily see the impact of including international land use impacts.

In addition to the many technical issues addressed in this proposal, this section also discusses the emissions decreases and increases associated with the different parts of the lifecycle emissions of various biofuels, and the timeframes in which these emissions changes occur. Determining a single lifecycle value that best represents this combination of emissions increases and decreases occurring over time led EPA to consider various alternative ways to analyze the timeframe of emissions related to biofuel production and use as well as options for adjusting or discounting these emissions to determine their net present value. Several variations of time period and discount rate are discussed. The analytical time horizon and the choice whether to discount GHG emissions and, if so, at what appropriate rate can have a significant impact on the final assessment of the lifecycle GHG emissions impacts of individual biofuels as well as the overall GHG impacts of these EISA provisions and this rule.

We believe that our lifecycle analysis is based on the best available science, and recognize that in some aspects it represents a cutting edge approach to addressing lifecycle GHG emissions. Because of this, varying degrees of uncertainty are in our analysis. For this proposal, we conducted a number of sensitivity analyses which focus on key parameters and demonstrate how our assessments might change under alternative assumptions. By focusing attention on these key parameters, the comments we receive as well as additional investigation and analysis by EPA will allow narrowing of uncertainty concerns for the final rule. In addition to this sensitivity analysis approach, we will also explore options for more formal uncertainty analyses for the final rule to the extent possible.

Because lifecycle analysis is a new part of the RFS program, in addition to the formal comment period on the proposed rule, EPA is making multiple efforts to solicit public and expert feedback on our proposed approach. As discussed in Section XI, EPA plans to hold a public workshop during the comment period focused specifically on our lifecycle analysis to help ensure full understanding of the analyses conducted, the issues addressed and options that should be considered. We expect that this workshop will help ensure that we receive the most thoughtful and useful comments to this proposal and that the best methodology and assumptions are used for calculating GHG emissions impacts of fuels for the final rule. Additionally we will conduct peer-reviews of key components of our analysis. As explained in more detail in the following sections, EPA is specifically seeking peer review of: Our use of satellite data to project future land use changes; the land conversion GHG emissions factors estimated by Winrock; our estimates of GHG emissions from foreign crop production; methods to account for the variable timing of GHG emissions; and how models are used together to provide overall lifecycle GHG estimates.

The regulatory purpose of the lifecycle greenhouse gas emissions analysis is to determine whether renewable fuels meet the GHG thresholds for the different categories of renewable fuel.

1. Definition of Lifecycle GHG Emissions

The GHG provisions in EISA are notable for the GHG thresholds mandated for each category of renewable fuel and also the mandated lifecycle approach to those thresholds. Renewable fuel must, unless ‘‘grandfathered’’ as discussed in Section II.B.3., achieve at least 20% reduction in lifecycle greenhouse gas emissions compared to the average lifecycle greenhouse gas emissions for gasoline or diesel sold or distributed as transportation fuel in 2005. Similarly, biomass-based diesel and advanced biofuels must achieve a 50% reduction, and cellulosic biofuels a 60% reduction, unless these thresholds are adjusted according to the provisions in EISA. To EPA's knowledge, the GHG reduction thresholds presented in EISA are the first lifecycle GHG performance requirements included in federal law. These thresholds, in combination with the renewable fuel volume mandates, are designed to ensure significant GHG emission reductions from the use of renewable fuels and encourage the use of GHG-reducing renewable fuels.

The definition of lifecycle greenhouse gas emissions established by Congress is also critical. Congress specified that:

> The term 'lifecycle greenhouse gas emissions' means the aggregate quantity of greenhouse gas emissions (including direct emissions and significant indirect emissions such as significant emissions from land use changes), as determined by the Administrator, related to the full fuel lifecycle, including all stages of fuel and feedstock production and distribution, from feedstock generation or extraction through the distribution and delivery and use of the finished fuel to the ultimate consumer, where the mass values for all greenhouse gases are adjusted to account for their relative global warming potential.[264]

This definition requires EPA to look broadly at lifecycle analyses and to develop a methodology that accounts for all the important factors that may significantly influence this assessment, including the secondary or indirect impacts of expanded biofuels use. EPA's analysis described below indicates that the assessment of lifecycle GHG emissions for biofuels is significantly affected by the secondary agricultural sector GHG impacts from increased biofuel feedstock production (e.g., changes in livestock emissions due to changes in agricultural commodity prices) and also by the international impact of land use change from increased biofuel feedstock production. Thus, these factors must be appropriately incorporated into EPA's lifecycle methodology to properly assess full lifecycle GHG performance of biofuels in accordance with the EISA definition.

2. History and Evolution of GHG Lifecycle Analysis

Traditionally, the GHG lifecycle analysis of fuels has involved calculating the emissions associated with each individual stage in the production and use of the fuel (e.g., growing or extracting the feedstock, moving the feedstock to the processing plant, processing the feedstock into fuel, moving the fuel to market, and combusting the fuel.) EPA used this approach for the lifecycle modeling conducted for the RFS1 program in 2005. However, it has become increasingly apparent that this type of first order or attributional lifecycle modeling has notable shortcomings, especially when evaluating the implications of biofuel policies.[265] In fact, the main criticism EPA received in reaction to our previous RFS1 lifecycle analysis was that we did not include important secondary, indirect, or consequential impacts of biofuel production and use.

Several studies and analyses conducted since the completion of RFS1 have contributed to our understanding of the lifecycle GHG emissions of biofuel production. These studies, and others, have highlighted the potential impacts of biofuel production on the agricultural sector and have specifically identified land use change impacts as an important consideration when determining GHG impacts of biofuels.[266] [267] In the meantime, the dramatic increase in U.S. production of biofuels has heightened the concern about the impacts biofuels might have on land use and has increased the importance of considering these indirect impacts in lifecycle analysis.

Based on the evolution of lifecycle analysis and the new requirements of EISA, we have developed a comprehensive methodology for estimating the lifecycle GHG emissions associated with renewable fuels. Through dozens of meetings with a wide range of experts and stakeholders, EPA has shared and sought input on this methodology. We also have relied on the expertise of the U.S. Department of Agriculture (USDA) and the Department of Energy (DOE) to help inform many of the key assumptions and modeling inputs for this analysis. Dialogue with the State of California and the European Union on their parallel, on-going efforts in GHG

[264] Clean Air Act Section 211(o)(1).

[265] *See* also, Conceptual and Methodological Issues in Lifecycle Analysis of Transportation Fuels, Mark A. Delucchi, Institute of Transportation Studies, University of California, Davis, 2004, UCD–ITS–RR–04–45 for a description of issues with traditional lifecycle analysis used to model GHG impacts of biofuels and biofuel policies.

[266] Fargione, J., J. Hill, D. Tilman, S. Polasky, and P. Hawthorne. 2008. Land clearing and the biofuel carbon debt. Science 319:1235–1238. *See http://www.sciencemag.org/cgi/reprint/319/5867/1235.pdf.*

[267] Searchinger, T., R. Heimlich, R.A. Houghton, F. Dong, A. Elobeid, J. Fabiosa, S. Tokgoz, D. Hayes, and T.-H. Yu. 2008. Use of U.S. croplands for biofuels increases greenhouse gases through emissions from land-use change. Science 319:1238–1240. *See http://www.sciencemag.org/cgi/reprint/319/5867/1238.pdf.*

lifecycle analysis has also helped inform EPA's methodology. As part of this discussion, we have identified several of the key drivers associated with these lifecycle GHG emissions estimates, including assumptions about international land use change and the timing of GHG emissions over time. The inputs we have received through these interactions are reflected throughout this section.

Specifically EPA has worked closely with the California Air Resources Board (CARB) regarding their development of transportation fuels lifecycle GHG impacts. California Executive Order S–1–07, the Low Carbon Fuel Standard (LCFS) (issued on January 18, 2007), calls for a reduction of at least 10 percent in the carbon intensity of California's transportation fuels by 2020. CARB has worked to develop lifecycle GHG impacts of different fuels for this Executive Order rulemaking. More information about this rulemaking and the lifecycle analysis conducted by California can be found at *http://www.arb.ca.gov/fuels/lcfs/lcfs.htm*. EPA will continue to coordinate with California on this rulemaking and the biofuels lifecycle GHG analysis work.

Because this lifecycle GHG emissions analysis is complex and requires the use of sophisticated computer models, we have taken several steps to increase the transparency associated with our analysis. For example, we have updated the model documentation for the Forest and Agricultural Sector Optimization Model (FASOM), which is included in the docket. In addition, we have highlighted key assumptions in FASOM and the Food and Agricultural Policy Research Institute (FAPRI) models that impact the results of our analysis. Finally, this NPRM provides an important opportunity for the Agency to present our work and to receive input from stakeholders and experts in this field. We will also continue to refine our analysis between the proposed and final rules, and we will add or update information to the docket as it becomes available.

B. Methodology

This section describes EPA's methodology for assessing the lifecycle GHG emissions associated with each biofuel evaluated as well as the petroleum-based gasoline and diesel fuel these biofuels would replace. Whereas lifecycle GHG emission methodologies have been well studied and established for petroleum-based gasoline and diesel fuel, much of EPA's work has focused on newly developing lifecycle methodologies for biofuels. Therefore, much of the following section describes the biofuels-related methodologies and identifies important issues for comment. Assessing the complete lifecycle GHG impact for each individual biofuel mandated by EISA requires that a number of key methodological issues be addressed—from the choice of a baseline to the selection of the most credible technique for predicting international land use conversion due to the increase in U.S. renewable fuels demand, to accounting for the time dimension of changes in GHG emissions. In this section, we first describe the scenarios we have analyzed for this proposal. Second, we discuss the scope of our analysis and what is included in our estimates. Third, we provide details on the tools and models we used to quantify the GHG emissions associated with the different fuels. Fourth, we discuss the uncertainties associated with lifecycle analysis and how we have addressed them. Fifth, we describe the different components of the lifecycle that we have analyzed and the key questions we have addressed in this analysis.

1. Scenario Description

To quantify the lifecycle GHG emissions associated with the increase in renewable fuel mandated by EISA, we compared the differences in total GHG emissions between two future scenarios. The first assumed a ''business as usual'' volume of a particular renewable fuel based on what would likely be in the fuel pool in 2022 without EISA, as predicted by the Energy Information Agency's Annual Energy Outlook (AEO) for 2007 (which took into account the economic and policy factors in existence in 2007 before EISA). The second assumed the higher volume of renewable fuels as mandated by EISA for 2022. For each individual biofuel, we analyzed the incremental GHG emission impacts of increasing the volume of that fuel to the total mix of biofuels needed to meet the EISA requirements. Rather than focus on the impacts associated with a specific gallon of fuel and tracking inputs and outputs across different lifecycle stages, we determined the overall aggregate impacts across sections of the economy in response to a given volume change in the amount of biofuel produced.[268]

This analysis is not a comparison of biofuel produced today versus biofuel produced in the future. Instead, it is a comparison of two future scenarios. Any projected changes in factors such as crop yields, energy costs, or production plant efficiencies, both domestically and internationally, are reflected in both scenarios. We focused our analyses on 2022 results for three reasons. First, it would require an extremely complex assessment and administratively difficult implementation program to track how biofuel production might continuously change from month to month or year to year. Instead, it seems appropriate that each biofuel be assessed a level of GHG performance that is constant over the implementation of this rule, allowing fuel providers to anticipate how these GHG performance assessments should affect their production plans. Second, it is appropriate to focus on 2022, the final year of ramp up in the required volumes of renewable fuel as this year. Assessment in this year allows the complete fuel volumes specified in EISA to be incorporated. Third, since the GHG assessment compares performance between a business as usual case and the mandated volumes case, many of the factors that change over time such as crop yield per acre are reflected in both cases. Therefore the differences in these parallel assessments are unlikely to vary significantly over time.

EPA requests comment on its proposal to adopt fixed assessments of fuels meeting the GHG thresholds based on a 2022 performance assessment. Additional information on the scenarios modeled and the supplemental analyses that will be conducted for the final rule is included in Chapter 2 of the DRIA.

In the existing Renewable Fuel Standard rules adopted in response to the Energy Policy Act of 2005, biofuels and RINs associated with them are not based on regional differences of where the feedstock was grown or the biofuel was produced. In effect, the RINs apply to a national average of the fuel type. Similarly, this proposal does not distinguish biofuel on the basis of where within the country the biofuel feedstock was grown or the biofuel produced. Thus, for example, ethanol produced from corn starch using the same production technology will receive the same GHG lifecycle assessment regardless of where the corn was grown or at what facility the biofuel was produced. There are regional differences in soil types, weather conditions, and other factors which could affect, for example, the amount of fertilizer applied and thus the GHG impact of corn production. Such factors could vary somewhat across a region, within a state and even within a county. The agricultural models used to conduct this analysis do distinguish crop production

[268] We then normalize those impacts for each gallon of fuel (or Btu) by dividing total impacts over the given volume change.

by region domestically and by country internationally. However, biofuel feedstocks such as corn or soybean oil are well traded commodities including internationally. So, for example, if corn in a certain location in Iowa is used to produce ethanol, corn from all other regions will be used to replace that corn for all its other potential uses. Therefore, it is not appropriate to ascribe the indirect affects, both domestically and internationally, to corn grown in one area differently to corn (or other biofuel feedstock) grown in another area. Our national treatment of biofuel feedstock also pertains to fuels produced in other countries. Thus for example, sugarcane-based ethanol produced in Brazil is all treated the same regardless of where the sugarcane was grown in Brazil. Nevertheless, comments are invited on the option of differentiating biofuels in the future based on the location of their feedstock production within a country.

2. Scope of the Analysis

a. Legal Interpretation of Lifecycle Greenhouse Gas Emissions

As described in VI.A.1, the definition of lifecycle greenhouse gas emissions refers to the ''aggregate quantity of GHG emissions'' that are ''related to the full fuel lifecycle.'' The fuel lifecycle includes ''all stages of fuel and feedstock production and distribution, from feedstock generation or extraction through * * * use of the finished fuel to the ultimate consumer.'' The aggregate quantity of GHG emissions includes ''direct emissions'' and ''significant indirect emissions such as significant emission from land use changes.'' This provision is written in generally broad and expansive terms, such as ''aggregate quantity'', ''related to'', ''full fuel lifecycle'', and ''all stages'' of production and distribution. At the same time, these and other terms are not themselves defined and provide discretion to the Administrator in implementing this definition. For example, the word ''significant,'' which is used to modify ''indirect emissions,'' is not defined.

The definition includes both ''direct'' and ''significant indirect'' emissions related to the full fuel lifecycle. We consider direct emissions as those that are emitted from each stage of the full fuel lifecycle, and indirect emissions as those from second order effects that occur as a consequence of the full fuel lifecycle. For example, direct emissions for a renewable fuel would include those from the growing of renewable fuel feedstock, the distribution of the feedstock to the renewable fuel producer, the production of renewable fuel, the distribution of the finished fuel to the consumer, and the use of the fuel by the consumer as transportation fuel. Similarly, direct emissions associated with the baseline fuel would include extraction of the crude oil, distribution of the crude oil to the refinery, the production of gasoline and diesel from the crude oil, the distribution of the finished fuel to the consumer, and the use of the fuel by the consumer. Indirect emissions would include other emissions impacts that result from fuel production or use, such as changes in livestock emissions resulting from changes in livestock numbers, or shifts in acreage between different crop types. The definition of indirect emissions specifically includes ''land use changes'' which would include changes in the kind of usage that land is put to such as changes in forest, pasture, savannah, and crop use.[269]

In considering how to address land use changes in our lifecycle analysis, two distinct questions have been raised—whether to account for emissions that occur outside of the U.S., and under what circumstances land use change should properly be included in the lifecycle analysis.

On the question of considering GHG emissions that occur outside of the U.S., it is important to be clear that including such emissions in the lifecycle analysis does not exercise regulatory authority over activities that occur solely outside the U.S., and does not raise questions of extra-territorial jurisdiction. EPA's regulatory action involves classification of products either produced in the U.S. or imported into the U.S. EPA is simply assessing whether the use of these products in the U.S. satisfies requirements under the Clean Air Act for the use of designated volumes of renewable fuel, cellulosic biofuel, biomass-based diesel and advanced biofuel, as those terms are defined in the Act. Considering international emissions in determining the lifecycle GHG emissions of the domestically produced or imported fuel does not change the fact that the actual regulation of the product involves its use solely inside the U.S.

When looking at the issue of international versus domestic emissions, it is important to recognize that a large variety of different activities outside the U.S. play a major part of the full fuel lifecycle of baseline and renewable fuels. For example, for baseline fuels (i.e., gasoline and diesel fuels used as transportation fuel in 2005), GHG emissions associated with extraction and delivery of crude oil imported to the U.S. all have occurred overseas. In addition, for imported gasoline or diesel, all of the crude extraction and delivery emissions, as well as the emissions associated with refining and distribution of the finished product to the U.S., would have occurred overseas. For imported renewable fuel all of the emissions associated with feedstock production and distribution, processing of the feedstock into renewable fuel, and delivery of the finished renewable fuel to the U.S. would have occurred overseas. The definition of lifecycle greenhouse gas emissions makes it clear that EPA is to determine the aggregate emissions related to the ''full'' fuel lifecycle, including ''all stages of fuel and feedstock production and distribution.'' Thus, EPA could not, as a legal matter, ignore those parts of a fuel lifecycle that occur overseas.

Drawing a distinction between GHG emissions that occur inside the U.S. as compared to emissions that occur outside the U.S. would dramatically alter the lifecycle analysis in a way that bears no apparent relationship to the purpose of this provision. The purpose of including lifecycle GHG thresholds in this statutory provision is to require the use of renewable fuels that achieve reductions in GHG emissions compared to the baseline. Drawing a distinction between domestic and international emissions would ignore a large part of the GHG emission associated with the different fuels, and would result in a GHG analysis of baseline renewable fuels that bears no relationship to the real world emissions impact of the fuels. The baseline would be significantly understated, given the large amount of imported crude used to produce gasoline and diesel, and the importation of finished gasoline and diesel, in 2005. Likewise, the emissions associated with imported renewable fuel would be understated, as it would only consider the emissions from distribution of the fuel to the consumer and the use of the fuel by the consumer, and would ignore both the emissions that occurred overseas as well as the emissions reductions from the intake of CO_2 from growing of the feedstock. While large percentages of GHG emissions would be ignored, this would take place in a context where the global warming impact of emissions is irrespective of

[269] Arguably shifts in acreage between different crops also could be considered a land use change, but we believe there will be less confusion if the term land use change is used with respect to changes in land such as changing from savannah or forest to cropland. There is no difference in result, as in both cases the emissions need to be significant.

where the emissions occur. Thus taking such an approach would essentially undermine the provision, and would be an arbitrary interpretation of the broadly phrased text used by Congress.

While the emissions discussed above would more typically be considered direct emissions related to the full fuel lifecycle, there would also be no basis to cover just foreign direct emissions while excluding foreign indirect emissions. The text of the statute draws no such distinction, nor is there a distinction in achieving the purposes of the provision. GHG emissions impact global warming wherever they occur, and if the purpose is to achieve some reduction in GHG emissions in order to help address global warming, then ignoring GHG emissions because they are emitted outside our borders versus inside our borders interferes with the ability to achieve this objective.

For example, domestic production of a renewable fuel could lead to indirect emissions, whether from land use changes or otherwise, some occurring within the U.S. and some occurring in other countries. Similarly, imported renewable fuel could have resulted in the same indirect emissions whether occurring in the country that produced the biofuel or in other countries. It would be arbitrary to assign the indirect emissions to the domestic renewable fuel but not to assign the identical indirect emissions that occur overseas to an imported product.

Based on the above, EPA believes that the definition of lifecycle greenhouse gas emissions is properly interpreted as including all direct and significant indirect GHG emissions related to the full fuel lifecycle, whether or not they occur in the U.S. This applies to both the baseline lifecycle greenhouse emissions as well as the lifecycle greenhouse gas emissions for various renewable fuels.

EPA recognizes, as discussed later, our estimates of domestic indirect emissions are more certain than our estimate of international indirect emissions. The issue of how to evaluate and weigh the various elements of the lifecycle analysis, and properly account for uncertainty in our estimates, is a different issue, however. The issue here is whether the definition of lifecycle greenhouse gas emissions is properly interpreted as including direct and significant indirect emissions that occur outside the U.S. as well as those that occur inside the U.S.

As to the question of which land use changes should be included in our lifecycle analyses, a central element to focus on is the requirement that such indirect emissions be related to the full fuel lifecycle. The term ''related to'' is generally interpreted as providing a broad and expansive scope for a provision. It has routinely been interpreted as meaning to have a connection to or refer to a matter. To determine whether an indirect emission has the appropriate connection to the full fuel lifecycle, we must look at both the objectives of this provision as well as the nature of the relationship.

In this case, EPA has used a global model that projects a variety of agricultural impacts that stem from the use of feedstocks to produce renewable fuel. We have estimated shifts in types of crops planted and increases in crop acres planted. There is a direct relationship between these shifts in the agricultural market as a consequence of the increased demand for biofuels in the U.S. Increased U.S. demand for biofuel feedstocks diverts these feedstocks from other competing uses, and also increases the price of the feedstock, thus spurring production. To the extent feedstocks like corn and soybeans are traded internationally, this combined impact of lower supply from the U.S. and higher commodity prices encourages international production to fill the gap. Our analysis uses country specific information to determine the amount, location, and type of land use change that would occur to meet this change in production patterns. The linkages are generally close, and are not extended or overly complex. While there is clearly significant uncertainty in determining the specific degree of land use change and the specific impact of those changes, there is considerable overall certainty as to the existence of the land use changes in general, the fact that GHG emissions will result, and the cause and effect linkage of these emissions impacts to the increased use of feedstock for production of renewable fuels.

Overall, EPA is confident that it is appropriate to consider the estimated emissions from land use changes as well as the other indirect emissions as ''related to'' the full fuel lifecycle, based on the reasonable technical basis provided by the modeling for the connection between the full fuel lifecycle and the indirect emissions, as well as for the determination that the emissions are significant. EPA believes uncertainty in the resulting aggregate GHG estimates should be taken into consideration, but that it would be inappropriate to exclude indirect emissions estimates from this analysis. Developing a reasonable estimate of these kinds of indirect emissions will allow for a reasoned evaluation of total GHG impacts, which is needed to promote the objectives of this provision, as compared to ignoring or not accounting for these indirect emissions.

b. System Boundaries

It is important to establish clear system boundaries in this analysis. By determining a common set of system boundaries, different fuel types can then be validly compared. As described in the previous section, we have assessed the direct and indirect GHG impacts in each stage of the full fuel lifecycle for biofuels and petroleum fuels.

To capture the direct emissions impacts of feedstock production in our analysis, we included the agricultural inputs (e.g., the fuel used in the tractor, the energy used to produce and transport fertilizer to the field) needed to grow crops directly used in biofuel production. We also included the N_2O emissions associated with agricultural sector practices used in biofuel production (including direct and indirect N_2O emissions from synthetic fertilizer application, N fixing crops, crop residue, and manure management), as well as the land use change associated with converting land to grow crops directly used in biofuel production. To capture the indirect, or secondary, GHG emissions that result from biofuel feedstock production, we relied on the internationally accepted lifecycle assessment standards developed by the International Organization for Standardization (ISO). Examples of significant secondary impacts include the agricultural inputs associated with crops indirectly impacted by the use of feedstock for biofuel production (domestically and internationally), the emissions associated with land use change that are indirectly impacted by using feedstocks for biofuel production (e.g., to make up for lost U.S. exports), changes in livestock herd numbers that result from higher feed costs, and changes in rice methane emissions indirectly impacted by shifts in acres to produce feedstocks for biofuel production. These indirect or secondary impacts would not have occurred if it were not for the use of biomass to produce a biofuel.

We did not include the infrastructure related GHG emissions (e.g., the energy needed to manufacture the tractor used on the farm) or the facility construction-related emissions (e.g., steel or concrete needed to construct a refinery). As part of the GHG analysis performed for RFS1, we performed a sensitivity analysis on expanding the corn production system to include farm equipment production to determine the impact it has on the overall results of our analysis. We found that including farm equipment production energy use and emissions increases corn ethanol lifecycle energy use and GHG emissions and decreases the corn ethanol lifecycle GHG benefit as compared to petroleum gasoline by approximately 1%. Furthermore, to be consistent in the modeling if system boundaries are expanded to include production of farming equipment they should also be expanded to include producing other material inputs to both the ethanol and petroleum lifecycles. The net effect of this would be a slight increase in both the ethanol and petroleum fuel lifecycle results and a smaller or negligible effect on the comparison of the two.

For this proposal, we have not yet incorporated secondary energy sector impacts, however we plan to have this analysis complete for the final rule. Additional details on the system boundaries are included in the DRIA Chapter 2.

3. Modeling Framework

Currently, no single model can capture all of the complex interactions associated with estimating lifecycle GHG emissions for biofuels, taking into account the ''significant indirect emissions such as significant emissions from land use change'' required by EISA. For example, some analysis tools used in the past focus on process modeling—the energy and resultant emissions associated with the direct production of a fuel at a petroleum refinery or biofuel production facility. But this is only one component in the production of the fuel. Clearly in the case of biofuels, impacts from and on the agricultural sector are important, because this sector produces feedstock for biofuel production. Commercial agricultural operations make many of their decisions based on an economic assessment of profit maximization. Assessment of the interactions throughout the agricultural sector requires an analysis of the commodity markets using economic models. However, existing economy wide general equilibrium economic models are not detailed enough to capture the specific agricultural sector interactions critical to our analysis (e.g., changes in acres by crop type) and would not provide the types of outputs needed for a thorough GHG analysis. As a result, EPA has used different tools that have different strengths for each specific component of the analysis to create a more comprehensive estimate of GHG emissions. Where no direct links between the different models exist, specific components and outputs of each are used and combined to provide an analytical framework and the composite lifecycle assessment results. As this is a new application of these modeling tools, EPA plans to organize peer review of our modeling approach. The individual models are described in the following sections and in more detail in Chapter 2 of the DRIA.

To quantify the emissions factors associated with different steps of the production and use of various fuels (e.g., extraction of petroleum products, transport of feedstocks), we used the spreadsheet analysis tool developed by Argonne National Laboratories, the Greenhouse gases, Regulated Emissions, and Energy use in Transportation (GREET) model. This analysis tool includes the GHG emissions associated with the production and combustion of fossil fuels (diesel fuel, gasoline, natural gas, coal, etc.). These fossil fuels are used both in the production of biofuels, (e.g., diesel fuel used in farm tractors and natural gas used at ethanol plants) and could also be displaced by renewable fuel use in the transportation sector. GREET also estimates the GHG emissions estimates associated with electricity production required for biofuel and petroleum fuel production. For the agricultural sector, we also relied upon GREET to provide GHG emissions associated with the production and transport of agricultural inputs such as fertilizer, herbicides, pesticides, etc. While GREET provides direct GHG emissions estimates associated with the extraction-through-combustion phases of fuel use, it does not capture some of the secondary impacts associated with the fuel, such as changes in the composition of feed used for animal production, which would be expected due to changes in cost. EPA addresses these secondary impacts through other models described later in this section. 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 GHG emissions of fossil energy consumed, we believe that GREET offers the most comprehensive treatment of emissions from the covered sources.

For some steps in the production of biofuels, we used more detailed models to capture some of the dynamic market interactions that result from various policies. Here, we briefly describe the different models incorporated into our analysis to provide specific details for various lifecycle components.

To estimate the changes in the domestic agricultural sector (e.g., changes in crop acres resulting from increased demand for biofuel feedstock or changes in the number of livestock due to higher corn prices) and their associated emissions, we used the FASOM model, developed by Texas A&M University and others. FASOM is a partial equilibrium economic model of the U.S. forest and agricultural sectors. EPA selected the FASOM model for this analysis for several reasons. FASOM is a comprehensive forestry and agricultural sector model that tracks over 2,000 production possibilities for field crops, livestock, and biofuels for private lands in the contiguous United States. It accounts for changes in CO_2, methane, and N_2O from most agricultural activities and tracks carbon sequestration and carbon losses over time. Another advantage of FASOM is that it captures the impacts of all crop production, not just biofuel feedstock. Thus, as compared to some earlier assessments of lifecycle emissions, using FASOM allows us to determine secondary agricultural sector impacts, such as crop shifting and reduced demand due to higher prices. It also captures changes in the livestock market (e.g., smaller herd sizes that result from higher feed costs) and U.S. export changes. FASOM also has been used by EPA to consider U.S. forest and agricultural sector GHG mitigation options.[270]

To estimate the impacts of biofuels feedstock production on international agricultural and livestock production, we used the integrated FAPRI international models, developed by Iowa State University and the University of Missouri. These models capture the biological, technical, and economic relationships among key variables within a particular commodity and across commodities. FAPRI is a worldwide agricultural sector economic model that was run by the Center for Agricultural and Rural Development (CARD) at Iowa State University on behalf of EPA. The FAPRI models have been previously employed to examine the impacts of World Trade Organization proposals and changes in the European Union's Common Agricultural Policy, to analyze farm bill proposals since 1984, and to evaluate the impact of biofuel development in the United States. In addition, the FAPRI models have been used by the USDA Office of Chief Economist, Congress, and the World Bank to examine agricultural impacts from government policy changes, market developments, and land use shifts.

Although FASOM predicts land use and export changes in the U.S. due to

[270] Greenhouse Gas Mitigation Potential in U.S. Forestry and Agriculture, EPA Document 430–R–05–006. *See http://www.epa.gov/sequestration/greenhouse_gas.html.*

greater demand for domestic biofuel feedstock, it does not assess how international agricultural production might respond to these changes in commodity prices and U.S. exports. The FAPRI model does predict how much crop land will change in other countries but does not predict what type of land such as forest or pasture will be affected. We used data analyses provided by Winrock International to estimate what land types will be converted into crop land in each country and the GHG emissions associated with the land conversions. Winrock has used 2001–2004 satellite data to analyze recent land use changes around the world that have resulted from the social, economic, and political forces that drive land use. Winrock has then combined the recent land use change patterns with various estimates of carbon stocks associated with different types of land at the state level. This international land use assessment is an important consideration in our lifecycle GHG assessment and is explained in more detail later in this section.

To test the robustness of the FASOM, FAPRI and Winrock results, we are also evaluating the Global Trade Analysis Project (GTAP) model, a multi-region, multi-sector, computable general equilibrium model that estimates changes in world agricultural production. Maintained through Purdue University, GTAP projects international land use change based on the economics of land conversion, rather than using the historical data approach applied by FAPRI/Winrock. GTAP is designed to project changes in international land use as a result of the change in U.S. biofuel policies, based on the relative land use values of cropland, forest, and pastureland. The GTAP design has the advantage of explicitly modeling the competition between different land types due to a change in policy. As further discussed in Section VI.B.5.iv, GTAP has several disadvantages, some of which prevented its use for the proposal. We expect to correct several of these shortcomings between the proposed and final rules and therefore continue to evaluate how the GTAP model could be used as part of the final rule.

The assessments provided in this proposal use the values provided by the Intergovernmental Panel on Climate Change (IPCC) to estimate the impacts of N_2O emissions from fertilizer application. However, due to concern that this may underestimate N_2O emissions from fertilizer application,[271] we are working with the CENTURY and DAYCENT models, developed by Colorado State University, to update our assessments. The DAYCENT model simulates plant-soil systems and is capable of simulating detailed daily soil water and temperature dynamics and trace gas fluxes (CH_4, N_2O, NO_X and N_2). The CENTURY model is a generalized plant-soil ecosystem model that simulates plant production, soil carbon dynamics, soil nutrient dynamics, and soil water and temperature. We anticipate the results of this new modeling work will be reflected in our assessments for the final rule. More description of this ongoing work is included in the Chapter 2 of the DRIA.

To estimate the GHG emissions associated with renewable fuel production, we used detailed ASPEN-based process models developed by USDA and DOE's National Renewable Energy Laboratory (NREL). While GREET contains estimates for renewable fuel production, these estimates are based on existing technology. We expect biofuel production technology to improve over time, and we projected improvements in process technology over time based on available information. These projections are discussed in DRIA Chapter 4. We then utilized the ASPEN-based process models to assess the impacts of these improvements. We also cross-checked the ASPEN-based process model predictions by comparing them to a number of industry sources and other modeling efforts that estimate potential improvements in ethanol production over time, including the Biofuel Energy Systems Simulator (BESS) model. BESS is a software tool developed by the University of Nebraska that calculates the energy efficiency, greenhouse gas (GHG) emissions, and natural resource requirements of corn-to-ethanol biofuel production systems. We used the GREET model to estimate the GHG emissions associated with current technology as used by petroleum refineries, because we do not expect significant changes in petroleum refinery technology.

We used the EPA-developed Motor Vehicle Emission Simulator (MOVES) to estimate vehicle tailpipe GHG emissions. The MOVES modeling system estimates emissions for on-road and nonroad sources, covers a broad range of pollutants, and allows multiple scale analysis, from fine-scale analysis to national inventory estimation.

Finally, for the FRM we intend to use an EPA version of the Energy Information Administration's National Energy Modeling System (NEMS) to estimate the secondary impacts on the energy market associated with increased renewable fuel production. NEMS is a modeling system that simulates the behavior of energy markets and their interactions with the U.S. economy by explicitly representing the economic decision-making involved in the production, conversion, and consumption of energy products. NEMS can reflect the secondary impacts that greater renewable fuel use may have on the prices and quantities of other sources of energy, and the greenhouse gas emissions associated with these changes in the energy sector. It was not possible to complete this analysis in time for the NPRM

While EPA is using state-of-the-art tools available today for each of the lifecycle components considered, using multiple models necessitates integrating these models and, where possible, applying a common set of assumptions. As discussed later in this section, this is particularly important for the two agricultural sector models, FASOM and FAPRI, which are being used in combination to describe the agricultural sector impacts domestically and internationally. As described in more detail in the DRIA Chapter 5, we have worked with the FAPRI and FASOM models to align key assumptions. As a result, the projected agricultural impacts described in Section IX are relatively consistent across both models. One outstanding issue is the differences between the modeling results associated with increased soybean-based biodiesel production. We intend to further refine the soybean biodiesel scenarios for the final rule. Additional details on all of the models used can be found in DRIA Chapter 2. Finally, as noted earlier, we are planning to have a number of aspects of our modeling framework peer reviewed before finalizing these regulations. In the sections below, we have identified specific peer review plans.

4. Treatment of Uncertainty

While EPA believes the methodology presented here represents a robust and scientifically credible approach, we recognize that some calculations of GHG emissions are relatively straight-forward, while others are not. The direct, domestic emissions are relatively well known. These estimates are based on well-established process models that can relatively accurately capture

[271] Crutzen, P. J., Mosier, A. R., Smith, K. A., and Winiwarter, W.: N_2O release from agro-biofuel production negates global warming reduction by replacing fossil fuels, Atmos. Chem. Phys., 8, 389–395, 2008. *See http://www.atmos-chem-phys.net/8/389/2008/acp-8-389-2008.pdf.*

emissions impacts. For example, the energy and GHG emissions used by a natural gas-fired ethanol plant to produce one gallon of ethanol can be calculated through direct observations, though this will vary somewhat between individual facilities. The indirect domestic emissions are also fairly well understood; however, these results are sensitive to a number of key assumptions (e.g., current and future corn yields). We address uncertainty in this area by testing the impact of changing these assumptions on our results. Finally, the indirect, international emissions are the component of our analysis with the highest level of uncertainty. For example, identifying what type of land is converted internationally and the emissions associated with this land conversion are critical issues that have a large impact on the GHG emissions estimates. We address this uncertainty by using sensitivity analyses to test the robustness of the results based on different assumptions. We also identify areas of additional work that will be completed prior to the final rulemaking. For example, while we utilized an approach using comprehensive agricultural sector models and recent satellite data to determine the emissions resulting from international land use impacts, we are also considering an alternative methodology (the analyses using GTAP) that estimates changes in land use based on the relative land use values of cropland, forest, and pastureland. Additionally, we are considering country-specific information which may allow us to better predict specific trends in land use such as the degree to which marginal or abandoned pasture land will need to be replaced if used instead for crop production. In addition to the sensitivity analysis approach, we will also explore options for more formal uncertainty analyses for the final rule to the extent possible. However, formal uncertainty analyses generally include an assumption of a statistically based distribution of likely outcomes. In the time available for developing this proposal, we have not developed an analytical technique which allows us to determine the likelihood of a range of possible outcome across the wide range of critical factors affecting lifecycle GHG assessment. We specifically ask for recommendations on how best to conduct a sound, statistically based uncertainty analysis for the final rule.

Despite the uncertainty associated with international land use change, we would expect at least some international land use change to occur as demand for crop land increases as a result of this rule. Furthermore, the conversion of crop land will lead to GHG emission from land conversion that must be accounted for in the calculation of lifecycle GHG emissions. As discussed above, we believe that uncertainty in the effects and extent of land use changes is not a sufficient reason for ignoring land use change emissions. Although uncertainties are associated with these estimates, it would be far less scientifically credible to ignore the potentially significant effects of land use change altogether than it is to use the best approach available to assess these known emissions. We anticipate that comment and information received in response to this proposal as well as additional analyses will improve our assessment of land use impacts for the final rule. Finally, we note that further research on key variables will result in a more robust assessment of these impacts in the future.

5. Components of the Lifecycle GHG Emissions Analysis

As described previously, GHG emissions from many stages of the full fuel lifecycle are included within the system boundaries of this analysis. Details on how these emissions were calculated are included in the DRIA Section 2. This section highlights the key questions that we have attempted to address in our analysis. In addition, this section identifies some of the key assumptions that influence the GHG emissions estimates in the following section.

a. Feedstock Production

Our analysis addresses the lifecycle GHG emissions from feedstock production by capturing both the direct and indirect impacts of growing corn, soybeans, and other renewable fuel feedstocks. For both domestic and international agricultural feedstock production, we analyzed four main sources of GHG emissions: agricultural inputs (e.g., fertilizer and energy use), fertilizer N_2O, livestock, and rice methane. (Emissions related to land use change are discussed in the next section).

As described in Section IX.A, EPA uses FASOM to model domestic agricultural sector impacts and uses FAPRI to model international agricultural sector impacts. However, we also recognize that these emission estimates rely on a number of key assumptions, including crop yields, fertilizer application rates, use of distiller grains and other co-products, and fertilizer N_2O emission rates. As described in the following sections, we have used sensitivity analyses to test the impact of changing these assumptions on our results.

i. Domestic Agricultural Sector Impacts

Agricultural Sector Inputs: GHG emissions from agricultural sector inputs (chemical and energy) are determined based on output from FASOM combined with default factors for GHG emissions from GREET. Fuel use emissions from GREET include both the upstream emissions associated with production of the fuel and downstream combustion emissions. Inputs are based on historic rates by region and include projected increases to account for yield improvements over time. This yield increase does not capture changes due to cropping practices such as shifts to corn-after-corn rotations.

N_2O Emissions: FASOM estimates N_2O emissions from fertilizer application and nitrogen fixing crops based on the amount of fertilizer used and different regional factors to represent the percent of nitrogen (N) fertilizer applied that result in N_2O emissions. This approach is consistent with IPCC guidelines for calculating N_2O emissions from the agricultural sector.[272] A recent paper [273] raised the question of whether N_2O emissions are significantly higher than previously estimated. To better understand this issue, we are working with Colorado State University to analyze N_2O emissions. Specifically, Colorado State University will provide several key refinements for a re-analysis of land use and cropping trends and GHG emissions in the FASOM assessment, including:

- Direct N_2O emissions based on DAYCENT simulations with an accounting of all N inputs to agricultural soils, including mineral N fertilizer, organic amendments, symbiotic N fixation, asymbiotic N fixation, crop residue N, and mineralization of soil organic matter. Colorado State University will provide (1) the total emission rate on an acre basis for each simulated bioenergy crop in the 63 FASOM regions and (2) a total emissions for each N source.
- Indirect N_2O emissions on a per acre basis using results from DAYCENT simulations of volatilization, leaching and runoff of N from each bioenergy crop included in the analysis for the 63 FASOM regions, combined with IPCC

[272] 2006 Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories, Volume 4, Chapter 11, N_2O emissions from Managed Soils, and C_O2 Emissions from lime and Urea Application. *See http://www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html.*

[273] Crutzen *et al.,* 2008.

factors for the N_2O emission associated with the simulated N losses.

The analyses with updated N_2O estimates are not yet complete and are not included in this proposal. We expect to complete these analyses for the final rule.

Livestock Emissions: GHG emissions from livestock have two main sources: enteric fermentation and manure management. Enteric fermentation produces methane emissions as part of the normal digestive processes in animals. The FASOM modeling reflects changes in livestock enteric fermentation emissions due to changes in livestock herds. As more corn is used in producing ethanol the price of corn increases, driving changes in livestock production costs and demand. The FASOM model predicts reductions in livestock herds. IPCC factors for different livestock types are applied to herd values to get GHG emissions. The management of livestock manure can produce methane and N_2O emissions. Methane is produced by the anaerobic decomposition of manure. N_2O is produced as part of the nitrogen cycle through the nitrification and denitrification of the organic nitrogen in livestock manure and urine. FASOM calculates these manure management emissions based on IPCC default factors for emissions factors from the different types of livestock and management methods. Manure management emissions are projected to be reduced as a result of lower livestock animal numbers. Use of distiller grains (DGs), as discussed in Section VI.B.5.b, has been shown to decrease methane produced from enteric fermentation if replacing corn as animal feed.[274] This effect is not currently captured in the models but will be considered for the final rule.

Methane from Rice: Most of the world's rice, and all rice in the United States, is grown in flooded fields. When fields are flooded, aerobic decomposition of organic material gradually depletes most of the oxygen present in the soil, causing anaerobic soil conditions. Once the environment becomes anaerobic, methane is produced through anaerobic decomposition of soil organic matter by methanogenic bacteria. FASOM predicts changes in rice acres resulting from the RFS2 program and calculates changes in methane emissions using IPCC factors.

[274] Salil Arora, May Wu, and Michael Wang, ''Update of Distillers Grains Displacement Ratios for Corn Ethanol Life-Cycle Analysis,'' September 2008. *See http://www.transportation.anl.gov/pdfs/AF/527.pdf.*

ii. International Agricultural Sector GHG Impacts

Agricultural Sector Inputs: The FAPRI model does not directly provide an assessment of the GHG impacts of changes in international agricultural practices (e.g., changes in fertilizer load and fuels usage), however it does predict changes in the land area and production by crop type and by country. We therefore determined international fertilizer and energy use based on international data collected by the Food and Agriculture Organization (FAO) of the United Nations and the International Energy Agency (IEA). We used the historical trends based on these FAO and IEA data to project chemical and energy use in 2022. Additional details on the data used are included in DRIA Chapter 2. We intend to review input changes required to increase yields for the final rule and request comment on the extent to which historic trends adequately project what could occur in 2022 or what alternative assumptions should be made and the bases for these assumptions. For example, will changes in farming practices or seed varieties likely result in significantly different impacts on fertilizer use internationally than suggested by recent trends? Additionally, we intend to have the selection and application of this data peer reviewed before the final rule.

N_2O Emissions: For international N_2O emissions from crops, we apply the IPCC emissions factors based on total amount of fertilizer applied and N_2O impacts of crop residue by type of crop produced. As noted above, we are also working with Colorado State University to update these factors as part of the final rule analysis. Additional details on the factors used are included in DRIA Chapter 2.

Livestock Emissions: Similar to domestic livestock impacts associated with an increase in biofuel production, FAPRI model predicts international changes in livestock production due to changes in commodity prices. The GHG impacts of these livestock changes, including enteric fermentation and manure management GHG emissions, were included in our analysis. Unlike FASOM, the FAPRI model does not have GHG emissions built in and therefore livestock GHG impacts were based on activity data provided by the FAPRI model (e.g., number and type of livestock by country) multiplied by IPCC default factors for GHG emissions. We seek comments on the extent to which the use of this methodology is appropriate.

Rice Emissions: To estimate rice emission impacts internationally, we used the FAPRI model to predict changes in international rice production as a result of the increase in biofuels demand in the U.S. Since FAPRI does not have GHG emissions factors built into the model, we applied IPCC default factors by country based on predicted changes in rice acres. We seek comments on this methodology.

b. Land Use Change

We are also addressing GHG emissions associated with land use changes that occur domestically and internationally as a result of the increase in renewable fuels demand in the U.S. Key questions we address in this analysis include the land area converted to crop production, where those acreage changes occur, lands types converted, and the GHG emission impacts associated with different types of land conversion.

EPA recognizes that analyzing international impacts of land use change can introduce additional uncertainty to the GHG emissions estimates. At this time, we do not have the same quality of data for international crop production and projected future trends as we do for the United States. For example, prediction of the economic and geographic development of developing country agricultural systems is far more difficult than prediction of future U.S. agricultural development. The U.S. has a very mature agriculture system in which the high quality agricultural lands are already under production and the infrastructure to move crops to market is already in place. This is not necessarily the case in other countries. Some very large countries expected to play a significant role in future agricultural production are still developing their agricultural system. Brazil, for example, has vast areas of land that may be suitable for commercial agricultural production that would allow for significant expansion in crop lands. One of the restraints on expansion is the relative lack of infrastructure (e.g., road and rail systems) that would allow shipment of expanded crop production to market. Identifying what type of land is converted internationally and the emissions associated with this land conversion can significantly affect our assessment of GHG impacts. We present a range of results for differences in these and other assumptions in Section VI.C.2, and we seek comment on our approach so that the final rule will use the best science to provide credible estimates of lifecycle GHG emissions for each biofuel.

i. Amount of Land Converted

The main question regarding the amount of new land needed to meet an increasing demand for biofuels hinges on assumptions about the intensification of existing production versus expansion of production to other lands. This interaction is driven by the relative costs and returns associated with each option, but there are other factors as described below.

Co-Products: One factor determining the amount of new crop acres required under an increased biofuel scenario is the treatment of co-products. For example, distillers grains (DGs) are the major co-product of dry mill ethanol production that is also used as animal feed. Therefore, using the DGs as an animal feed to replace the use of corn tends to offset the loss of corn to ethanol production, and reduces the need to grow additional corn to feed animals. As the renewable fuels industry expands, the handling and use of co-products is also expanding. Some uncertainty is associated with how these co-products will be used in the future (e.g., whether it can be reformulated for higher incorporation into pork and poultry diets, whether it will be dried and shipped long distances, whether fractionation will become widespread).

Both our FASOM and FAPRI models account for the use of DGs in the agricultural sector. The FASOM and FAPRI models both assume that a pound of co-product would displace roughly a pound of feed. However, a recent paper by Argonne National Laboratory [275] estimates that 1 pound of DGs can displace more than a pound of feed due to the higher nutritional value of DGs compared to corn.

The Argonne replacement ratios do not take into account the dynamic least cost feed decisions faced by livestock producers. The actual use of DGs will depend on the maximum inclusion rates for each type of animal (based on the digestibility of DGs), the displacement ratio for each type of animal (based on DGs energy and protein content), and the adoption rate (based on the feed value relative to price). Furthermore, as world vegetable oil prices increase, dry mill ethanol producers will have an incentive to extract the corn oil from the DGs. This step changes the nutritional content of the DGs, which results in different replacement rates than the ones currently used in FASOM or described by Argonne. As we plan to evaluate and incorporate a least cost feed rationing approach for the final rule, we invite comment on the expected future uses of DGs and their displacement ratios.

Crop Yields: Assumptions about yields and how they may change over time can also influence land use change predictions. Domestic yields were based on USDA projections, extrapolated out to 2022. In 2022, we estimate that the U.S. average corn yield will be approximately 180 bushels/acre (a 1.6% annual increase consistent with recent trends) and average U.S. soybean yields will be approximately 50 bushels per acre (a 0.4% annual increase).[276] Using the FASOM model, we conducted a sensitivity analysis on the impact of higher and lower yields in the U.S. Details on this scenario are included in DRIA Chapter 5.1. International yields changes are also based on the historic trends. The FAPRI model contains projected yields and yield growths that are generally lower in other countries compared to the U.S. We request comment on the projected increase in crop yields in the U.S (including consideration of how emerging seed types might be expected to increase average crop yields). We also request comment on the use of historical trends to predict future agricultural production in other countries and request information on alternative methodologies and supporting data that would allow us to base our predictions on alternative assumptions.

The FASOM and FAPRI models currently do not take into account changes in productivity as crop production shifts to marginal acres or the impact of price induced yield changes on land use change. We would expect these two factors could work in opposite directions and therefore could tend to offset each other's impacts. Marginal acres in fully developed agricultural systems are expected to have lower yields, because most productive acres are already under cultivation. This may not be the case in developing systems where prime agricultural lands are not currently in full production due to, for example, lack of supporting infrastructure. Changes in agricultural inputs (e.g., fertilizer, pesticides) can also change crop yield per acre. Higher commodity prices might provide an incentive to increase production in existing acres. If the costs of increasing productivity on existing land were minimal relative to the value of the increased production, then agricultural landowners would presumably adopt these productivity-enhancing actions under the reference case. Although it is reasonable to assume a trend wherein some productivity-enhancing practices may become profitable if commodity prices are high enough such as might occur as the result of increased biofuel production, it is not clear that farmers would find significant increases in production per acre profitable. If crop yields either domestically or international are significantly impacted by higher commodity prices driven by general increase in worldwide demand, this could affect our assessment of land use impacts and the resulting GHG emissions due to increased biofuel demand in the U.S. However, as described in Section IX, the change in commodity prices associated with the increase in U.S. biofuel as a result of the EISA mandates are very small and perhaps not large enough to induce significant increased yield changes. We invite comment on projected yields and the potential impact of increased use of marginal lands and price induced yield changes. For the final rule we plan to explicitly model the impact of price induced yield changes.

Land Conversion Costs: The assumed cost associated with different types of land conversion can also play a key role in determining how much land will be converted. In FASOM, the decision to convert land from pasture or forest to cropland is based on whether the landowner can increase the net present value of expected returns through conversion (including any costs of conversion). Among other things, the decision to convert land depends on regional yields, costs, and other factors affecting profitability and on the returns to alternative land uses. In other words, FASOM assumes that land conversion is based on maximizing profits rather than minimizing costs. Additional details on land conversions costs incorporated in FASOM are included in DRIA Chapter 2.

FAPRI does not explicitly model land conversion costs, however the international production supply curves used by the FAPRI model implicitly take into account conversion costs. FAPRI's supply curves are based on historical responses to price changes, which take into account the conversion costs of land, based on expected future returns associated with land conversion. Thus, we believe that our assessments of international land use changes are based on economic land-use decisions.

ii. Where Land is Converted

The first step in determining what domestic and international land will be converted due to biofuels production is to estimate the extent to which the increased demand for biofuel feedstock

[275] Salil *et al.*, 2008.

[276] Note that these same assumptions apply in both the reference case and the control cases.

will be met through increased U.S. agriculture production or reductions in U.S. exports.

This question has several implications. For example, U.S. agriculture production is typically more energy and input intensive but has higher yields than agricultural production in other parts of the world. This implies that increased production in the U.S. has higher input GHG emission impacts but lower land use change impacts compared to overseas production. In addition, the types of land where agriculture would expand would be different in the U.S. vs. other parts of the world.

EPA's analysis relies on FASOM predictions to represent changes in the U.S. agricultural sector, including land use, and on FAPRI to predict the resulting international agricultural sector impacts including the amount of additional cropland needed under different scenarios. The impact on the international agricultural sector is highly dependent on the U.S. export assumptions. As the FASOM model was used to represent domestic agricultural sector impacts with an assumed export picture, the international agricultural sector impacts from FAPRI needed to be based on a consistent set of export assumptions. We worked with FASOM and FAPRI modelers to ensure this consistency. This involved coordinating crop yields, ethanol yields and co-product use, assumptions regarding CRP acres, a consistent export response, and a consistent livestock demand and feed use in both models.

As shown in Chapter 2 of the DRIA, coordination of assumptions has generated a consistent export picture response from both the FASOM and FAPRI model for the majority of biofuel and feedstock scenarios considered. Differences in responses in the biodiesel scenario remain between the two models. FASOM assumes more biodiesel will come from new soybean acres (but total domestic acres are relatively constant as reductions in other crops offset the increase in soybean acres). In comparison, FAPRI contains more types of oil seed crops and has a more elastic demand in the soybean oil market. The FAPRI model also allows for some corn oil fractionation from DGs, which can be used as a substitute for soybean oil. The FASOM model predicts a larger change in net exports than the FAPRI model. Since we are using the FAPRI model as the basis for estimating international land use changes, we may be underestimating the international land use change emissions associated with soybean based biodiesel. For the final rule, EPA will work, in particular, to resolve the differences in soybean production impact between the models. This, too, may modify our assessment of the biodiesel lifecycle GHG emissions.

Due to the wide range of carbon and biomass properties associated with land in different parts of the world, the location of crop conversion is also important to our lifecycle analysis. For example, an average acre of forest in Southeast Asia stores a much larger quantity of carbon than a typical acre of forest in Northern Europe. The FAPRI model provides estimates of the acreage change by country and crop that result from a decrease in U.S. exports due to the increase in U.S. biofuel demand. These estimates are based on historic responsiveness to changes in prices in other countries. Implicit in these supply curves are the costs associated with converting new land to crop production and the relative competitiveness of each country to increase production based on production costs, yields, transportation costs, and currency fluctuations. FAPRI also includes in its baseline projections of future population growth, GDP growth, and other macroeconomic changes. FAPRI also takes into account the fact that not all U.S. exports will need to be made up in international production, as there is a small decreases in demand due to shifts in crop production and higher prices.

iii. What Type of Land is Converted

In the same way that the location of land conversion is important, the type of land that is converted is critical to the magnitude of impact on the GHG emissions associated with biofuel production. For example, the conversion of rainforest results in a much larger increase in GHG emissions than the conversion of grassland. There are several options for determining what type of land will be converted to crop acreage. One option is to model land rental rates for different types of land (e.g., forest, pasture, and crop production), and allow the model to choose the type of land that is expected to have the highest net returns. This approach is used by FASOM on the domestic side. Another option is to use historical land conversion trends in a given country or region. The FAPRI/Winrock approach uses this approach for international land use conversion.

Domestic: The FASOM model includes competition between land types, agriculture, pasture, and forest land. The interaction is based on providing the highest rate of return across the different land types. Therefore domestically we have the ability to explicitly model what types of land would be converted to increased agriculture based on the rates of return for different land types for the 63 regions in FASOM. For this draft proposal we incorporated the agricultural component (which includes both existing cropland and pasture) of the FASOM model, but not the forestry component (see Section IX.A for explanation). Therefore, this analysis assumes that all additional cropland predicted by FASOM comes from pasture. As we incorporate the forestry component for the final rule analysis we would expect to see more interaction between the forestry and agriculture sector such that there may be conversion of forest to agriculture based on additional cropland needed. While we do not know if forest will be converted to cropland or the extent that this might occur, if domestic forests were converted to cropland, we would expect domestic GHG emissions would increase. This work will be incorporated for our final rule.

International: Basing land use change on the economics and rates of return of different land uses offers advantages for capturing potential future land use changes. However, the only model potentially capable of fully incorporating this calculation internationally, GTAP, is still in the process of being updated and modified for this purpose. Thus, EPA has chosen to use historical patterns as identified by satellite images to estimate future land conversion. This approach is referred to here as the FAPRI/Winrock approach because it relies on the integration of each of these tools.

EPA believes that FAPRI/Winrock is a scientifically credible modeling approach at this time. However, we will continue to work with the GTAP model to help test the results generated by our primary approach.

FAPRI/Winrock

Since FAPRI does not contain information on what type of land is being converted into cropland, we worked with Winrock International, a global nonprofit organization, to address this question. A key advantage of Winrock is that they can accurately measure and monitor trends in forest and land use change, forest carbon content, biodiversity, and the impact of infrastructure development. Furthermore, several of the Winrock staff were involved in the development of the IPCC land use change good practice guidance and are widely recognized as the leaders in this field.

Using satellite data from 2001–2004, Winrock provided a breakdown of the types of land that have been converted into cropland for a number of key agriculturally producing countries based on the International Geosphere-Biosphere Programme (IGBP).[277] The IGBP land cover list includes eleven classes of natural vegetation, three classes of developed and mosaic lands, and three classes of non-vegetated lands. The natural vegetation units distinguish evergreen and deciduous, broadleaf and needle-leaf forests, mixed forests, where mixtures occur; closed shrublands and open shrublands; savannas and woody savannas; grasslands; and permanent wetlands of large areal extent. The three classes of developed and mosaic lands distinguish among croplands, urban and built-up lands, and cropland/natural vegetation mosaics. Classes of non-vegetated land cover units include snow and ice; barren land; and water bodies. Winrock aggregated these categories into five similar classes: five classes of forest were combined into one, two classes of savanna were combined into one, and two classes of shrubland were combined into one. The final land cover categories for this analysis are forest, cropland, grassland, savanna, and shrubland. The rest of the IGBP categories not of interest to this analysis were reclassified into the background. The satellite data represents different types of land cover, which we are using as a proxy for land use.

A key strength of this approach is that satellite information is based on empirical data instead of modeled predictions. Furthermore, it is reasonable to assume that recent land use changes have been driven largely by economics and recent historical patterns will continue in the future absent major economic or land use regime shifts caused, for example, by changes in government policies. We are using the FAPRI model to predict where in the world, based on economic conditions, the most likely increase in agriculture production will occur as a result of the EISA mandates. We are then using the historical satellite data to address the key question: If additional land is needed for crop production in a particular country, what type of land will be used? The Winrock analysis addresses this question by calculating the weighted average type of land that was converted to cropland between 2001 and 2004. Essentially, we are using the Winrock data to determine the type of land that is most likely to be converted to cropland, should additional acres be needed as predicted by FAPRI.

Table VI.B.5–1 shows the percentage of land converted to cropland between 2001 and 2004 according to the Winrock satellite data analysis for the countries currently available. We use these percentages to calculate a weighted average of the types of land converted into cropland. For example, if FAPRI predicts that one additional acre of cropland will be brought into production in Argentina, we used the Winrock data to estimate that 8% on average of that acre will come from forest, 40% of that acre will come from grassland, 45% of that land will come from savanna, and 8% of that land will come from shrubland. Using GTAP might result in different percentage weights.

TABLE VI.B.5–1—TYPES OF LAND CONVERTED TO CROPLAND BY COUNTRY

[In percent]

Country	Forest	Grassland	Savanna	Shrub
Argentina	8	40	45	8
Brazil	4	18	74	4
China	17	38	23	21
EU	27	16	36	21
India	7	7	33	53
Indonesia	34	5	58	4
Malaysia	74	3	19	3
Nigeria	4	56	36	4
Philippines	49	5	44	3
South Africa	10	22	53	15

Source: Winrock Satellite Data (2001–2004).

We are assuming that the weighted average, resulting from agriculture demand as well as other possible drivers, is a reasonable estimate of the land use change attributable to increased agricultural demand. A shortcoming of this approach is that it assumes that when new crop acres are needed to meet increased agricultural demand these crop acres will follow the average pattern of recent historical land conversion, recognizing that this pattern is based on a variety of drivers of land use change, not all of which are associated with agricultural demand. This approach is not able to isolate from the historical pattern the land use changes stemming just from increased agricultural demand. For example, it is likely that in some cases trees are being removed from forests for the value of the wood. However, having removed valuable wood, additional clearing may occur to allow the land to be used for pasture or cropland. In that case the GHG emissions associated with the removal of the trees would not occur as a consequence of increased agricultural demand, but as a consequence of increased demand for the wood, while the GHG emissions associated with the additional clearing would occur as a consequence of the agricultural demand.

As a result, the Winrock data also does not distinguish between the land-use impacts associated with one crop versus another. Indeed, at least in the case of sugarcane production in Brazil, a number of researchers argue that expanded sugarcane production is likely to occur in significant part through the use of degraded or abandoned pasture land without additional land use impact.[278] These research reports suggest that general historical trends in land use change to grow crops in Brazil may not pertain to expected growth in sugarcane production. Ideally, an analysis of a U.S. biofuels policy's influence on land use change would

[277] U.S. Geological Survey MODIS Data Set Documentation. *See http://edcdaac.usgs.gov/modis/mod12q1v4.asp*.

[278] *See* for example ''Mitigation of GHG emissions using sugarcane bio-ethanol—Working Paper'' by Isaias C. Macedo and Joaquim E. A. Seabra, and ''Prospects of the Sugarcane Expansion in Brazil: Impacts on Direct and Indirect Land Use Changes—Working Paper'' by Andre Nassar *et al.*, both received by EPA October 13, 2008.

model the marginal impact that U.S. biofuel would have on land use and land use change in addition to baseline land use change. Use of historic land use change data is capturing some of this baseline land use change. Comments are requested on our approach of assuming historical land use changes will continue to be followed in response to increased agricultural demand associated with our biofuel policy. We also invite comment on what alternative methodologies and data are available, if any, to better link the impacts of biofuels to land use change. To the extent additional information or data may be available for certain countries such as the example of Brazil, we also ask how this country-specific data and similar information might best be integrated with the modeling results otherwise available. Furthermore, to the extent different government policies can shift land use patterns (e.g., through regulations, financial supports), these weighted averages could change in the future. We request comment on whether these government policies and regulations should be incorporated into the future land use change calculations and the best methodology for taking into account these changes.

The Winrock data and analyses present an aggregate picture of land use changes; they cannot predict the nature of the land use change that will result due to an additional acre of corn planted in a country versus an additional acre of sugarcane or soybeans. In reality, sugarcane may be more suitable for planting in different regions with different soil types compared to corn or soybeans. However, because we are using weighted averages to characterize the type of land that is converted to crop acres, all additional crop acres in a particular country are treated identically.

Winrock also provides information on land conversions between other categories (e.g., forest to savanna). For one set of GHG analyses, we assumed that land taken out of actively managed use [279] (e.g., pasture used for livestock production) would have to be replaced with new pasture acreage, thereby capturing some of the domino effect associated with converting previously productive land into cropland. Therefore, in addition to land conversion shown in Table VI.B.5–1, we also include land conversion to replace some of the grassland and savanna that is used as pasture. An alternative approach would be to assume that no additional land is necessary, since there is a significant amount of pastureland that could be used more intensively for grazing purposes. For example, as noted above, in Brazil almost all of the direct land conversion associated with expanding sugarcane production is coming out of existing pasture land, in some cases, depleted, low value pasture land, that may have relatively low levels of stored carbon compared to other land. Also in Brazil there is a trend toward more intensive use of existing pasture land by grazing higher numbers of cattle per unit of pasture, decreasing the need to replace pasture converted to cropland. This more intensive use of pasture is encouraged by two factors: improved grasses which can sustain more intensive grazing and lack of transportation infrastructure which tends to constrain geographic expansion of pasture lands. However, we also note that depleted cropland in Brazil might also be suitable for other crop production. To extend sugarcane limits to production of these other crops on this land, the indirect effect could be that these crops move into other areas of Brazil and resulting in increased emissions due to land use change. We invite comment on alternative methodologies for predicting land use changes in particular in other countries. Some alternative methodologies are described in more detail in Chapter 2 of the DRIA.

The FAPRI model results have been used in peer reviewed literature in conjunction with satellite data to assess land use changes [280] and we also believe it is an appropriate method for projecting biofuel induced land use changes. However, we recognize the uncertainty associated with this approach and, in addition to seeking public comment, we plan to conduct an expert peer review of the data and methods used, including the appropriateness of using historic satellite data to project future land use changes.

iv. What Are the GHG Emissions Associated With Different Types of Land Conversion?

Our estimates of domestic land use change GHG emissions are based on outputs of the FASOM model. As we are just using the agricultural portion of the FASOM model for this analysis the land use change GHG emissions are limited to changes in land use for existing crop and pasture land. Some of that crop land could currently be fallow and some of the pasture land could currently be unused. However, no new crop or pasture land (beyond some Conservation Reserve Program (CRP) land due to legislative changes in the program) is added compared to current levels. Thus FASOM only models shifts in the use of this land.

Changes in the agricultural sector due to increased corn used for ethanol have impacts on land use change in a number of ways. FASOM explicitly models change in soil carbon from increased crop production acres and from different types of crop production. FASOM also models changes in soil carbon from converting non crop land into crop production. Land converted to crop land could include pasture land. As recommended by USDA, we are assuming that 32 million acres of CRP land will remain in that program even if crop prices increase and thus increase land values. This assumption is consistent with the 2008 Farm Bill, which limits CRP acres to 32 million. A sensitivity analysis on this assumption is included in Chapter 5 of the DRIA.

For the international impacts, we used the 2006 IPCC Agriculture, Forestry, and Other Land Use (AFOLU) Guidelines [281] and the Winrock provided GHG emissions factors for each country based on the weighted average type of land converted. GHG emissions estimates were based on immediate releases (e.g., changes in biomass carbon stocks, soil carbon stocks, and non-CO_2 emissions assuming the land is cleared with fire) and foregone forest sequestration (the future growth in vegetation and soil carbon). Additional details on these calculations are included in Chapter 2 of the DRIA. For the emissions factors presented, we assume forests cleared would have continued to sequester carbon for another 80 years, based on the amount of time it takes for forests to reach a general equilibrium stage. We request comment on whether it is appropriate to include foregone sequestration in the GHG emissions estimates. Carbon soil calculations [282] take into account the annual changes in carbon content in the top 30 centimeters of soil over the first 20 years, based on IPCC recommendations.[283] We also request comment on whether soil carbon calculations should be based on the top 30 centimeters of soil. These emission factors do not include credits for harvested wood products, based on the expectation that they would have a

[279] GTAP Land Cover Data (2000–2001).

[280] Searchinger *et al.,* 2008.

[281] 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 4, Agriculture, Forestry and Other Land Use (AFOLU). *See http://www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html.*

[282] *See ftp://www.daac.ornl.gov/data/global_soil/IsricWiseGrids.*

[283] 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 4, Section 5.3.3.4.

very small impact on our estimates of land use change emissions. However, we intend to analyze the impact of wood product credits for the final rule. We invite comment on whether it is appropriate to include wood product credits in the GHG emissions estimates.

GHG emissions associated with land use changes vary significantly based on the type of land and the geographic region. For example, the GHG emissions associated with converting an acre of grassland to cropland in China are lower than the emissions associated with converting an acre of shrubland to cropland in China. Similarly, the GHG emissions associated with converting an acre of forest to cropland in Malaysia are larger than the emissions associated with converting an acre of forest in Nigeria to cropland. Where country specific emission factors were not available in time for the proposal, we used world average. For the proposal, we focused on the countries with the largest projected changes in crop acreage. The Winrock data currently covers 63% of total land use change acres associated with corn ethanol, 53% of the acres associated with biodiesel, 57% of the acres associated with switchgrass, and 87% of the acres associated sugarcane ethanol. We will continue to add additional countries for our analysis for the final rule. Two changes that may impact these results for the final rule include the addition of perennial crops and the conversion on land with peat soils. We request comment on our calculation of emission factors due to land use change; improved data and assumptions are specifically requested. Additionally, we plan to have the calculation of these emissions factors reviewed by experts in this field. Details on the Winrock estimates are included in the DRIA Chapter 2.

GTAP Approach:

GTAP is an economy-wide general equilibrium model that was originally developed for addressing agricultural trade issues among countries. The databases and versions of the model are widely used internationally.[284] Since its inception in 1993, GTAP has rapidly become a common ''language'' for many of those conducting global economic analysis. For example, the WTO and the World Bank co-sponsored two conferences on the so-called Millennium Round of Multilateral Trade talks in Geneva. Here, virtually all of the quantitative, global economic analyses were based on the GTAP framework. Over the past few years, a version of the model was developed to explicitly model global competition among different land types (e.g., forest, agricultural land, pasture) and different qualities of land based on the relative value of the alternative land-uses. More recently, it was modified to include biofuel substitutes for gasoline and diesel. In simulating land use changes due to biofuels production, GTAP explicitly models land-use conversion decisions, as well as land management intensification. For example, it allows for price-induced yield changes (e.g., farmers can reallocate inputs to increase yields when commodity prices are high) and considers the marginal productivity of additional land (e.g., expansion of crop land onto lower quality land as a result of the increased use of biofuels). Most importantly, in contrast to other models, GTAP is designed with the framework of predicting the amount and types of land needed in a region to meet demands for both food and fuel production. The GTAP framework also allows predictions to be made about the types of land available in the region to meet the needed demands, since it explicitly represents different land types within the model.

The global modeling of land-use competition and land management decisions is relatively new, and evolving.[285] GTAP does not yet contain cellulosic feedstocks in the model. In addition, GTAP does not currently contain unmanaged land, which could be a major factor driving current GTAP land use projections and is a significant potential source of GHG emissions. We expect to update GTAP with cellulosic feedstocks and unmanaged land in time for the final rule.

Our proposal is therefore based on the FAPRI/Winrock estimates. There are advantages and disadvantages associated with any model choice and we have chosen the FAPRI/Winrock combination as the best approach available for preparing the proposal. Although we have not relied on the current version of GTAP for the principal analyses in this proposal, others have used versions of the current model to assess land use changes which could result from expanded biofuel demand. The California Air Resources Board as part of the analysis for their low carbon fuel standard used GTAP to model indirect land use change for biofuels. More information on their program and GTAP analysis can be found at *http://www.arb.ca.gov/fuels/lcfs/lcfs.htm.* Furthermore, researchers from Purdue University have released a report on work using GTAP to look at land use change associated with corn ethanol production scenarios.[286] This work was partially funded by Argonne National Lab for possible inclusion in the GREET model. We anticipate additional refinements will be made to the GTAP model between the proposal and final rule and we will include this information and results in the docket as they become available. We invite comments in this NPRM on the use of the GTAP model in helping to establish the GHG emissions estimates for the final rule.

v. Assessing GHG Emissions Impacts Over Time and Potential Application of a GHG Discount Rate

When comparing the lifecycle GHG emissions associated with biofuels to those associated with gasoline or diesel emissions, it is critical to take into consideration the time profile associated with each fuel's GHG emissions stream. With gasoline, a majority of the lifecycle GHG emissions associated with extraction, conversion, and combustion are likely to be released over a short period of time (i.e., annually) as crude oil is converted into gasoline or diesel fuel which quickly pass to market. This means that the lifecycle GHG emissions of a gallon of gasoline produced one year are unlikely to vary much from the lifecycle GHG emissions of a similar gallon of gasoline produced in a subsequent year.

In contrast, the lifecycle GHG emissions from the production of a typical biofuel may continue to occur over a long period of time. As with petroleum based fuels, renewable fuel lifecycle GHG emissions are associated with the conversion and combustion of biofuels in every year they are produced. In addition, GHG emissions could be released through time if new acres are needed to produce corn, soybeans or other crops as a replacement for crops that are directly used for biofuel production or displaced due to biofuels production. The GHG emissions associated with converting land into crop production would accumulate over time with the largest release occurring in the first few years due to clearing with fire or biomass decay. After the land is converted, moderate amounts of soil carbon would continue to be released for

[284] *https://www.gtap.agecon.purdue.edu.*

[285] *See* Hertel, Thomas, Steven Rose, Richard Tol (eds.), (in press). *Economic Analysis of Land Use in Global Climate Change Policy,* Routledge Publishing.

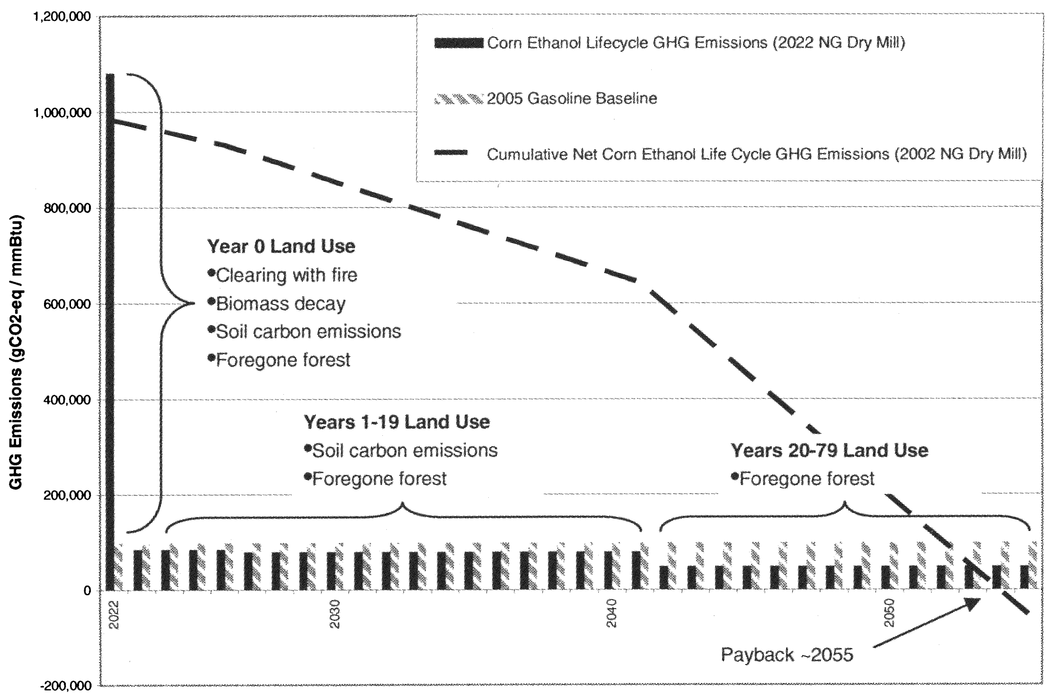
[286] *Land Use Change Carbon Emissions due to US Ethanol Production,* Wallace E. Tyner, Farzad Taheripour, Uris Baldos, January 2009. Available at *http://www.agecon.purdue.edu/papers/biofuels/Argonne-GTAP_Revision%204a.pdf.*

approximately 20 years.[287] Furthermore, there would be foregone sequestration associated with forest clearing as this forest would have continued to sequester carbon had it not been cleared for approximately 80 years.

Therefore, we have included an analysis which considers GHG emissions from land use change that may continue for up to 80 years, based on our estimate of the average length of foregone sequestration after a forest is cleared. Annual foregone sequestration rates were estimated by ecological region using growth rates for forests greater then 20 years old from the 2006 IPCC guidelines for Agriculture, Forestry and Other Land Use.[288] Studies have estimated that new forests grow for 90 years to over 120 years.[289] More recent estimates suggest that old growth forests accumulate carbon for up to 800 years.[290] The foregone sequestration methods used in this proposal are within the range supported by the scientific literature and the 2006 IPCC guidelines. Details of the foregone sequestration estimates are included in DRIA Chapter 2. We seek comment on our estimate of the average length of annual foregone forest sequestration for consideration in biofuel lifecycle GHG analysis.

Figure VI.B.5–1 shows how lifecycle GHG emissions vary over time for a natural gas fired dry mill corn ethanol plant assuming that all land use change occurs in 2022. While biomass feedstocks grown each year on new cropland can be converted to biofuels that offer an annual GHG benefit relative to the petroleum product they replace, these benefits may be small compared to the upfront release of GHG emissions from land use change. Depending on the specific biofuel in question, it can take many years for the benefits of the biofuel to make up for the large initial releases of carbon that result from land conversion (e.g., the payback period). As shown in Figure VI.B.5–1, the payback period for a natural gas-fired dry mill corn ethanol plant which begins operation in 2022 would be approximately 33 years. We present a similar payback period calculation for the full range of biofuels analyzed in Section VI.C.

Figure VI.B.5-1
Corn Ethanol Lifecycle GHG Emissions over Time and Payback Period



As required by EISA, our analysis must demonstrate whether biofuels reduce GHG emissions by the required percentage relative to the 2005 petroleum baseline. A payback period alone cannot answer that question. Since the payback period alone is not sufficient for our analysis, we have considered accounting methods for capturing the full stream of emissions and benefits over time. There are at least two necessary criteria for the accounting methods we have considered. First, they must provide an estimate of renewable fuel lifecycle GHG emissions that is consistent over time. Otherwise, for example, all of the upfront emissions due to land clearing would be assigned to corn ethanol produced in the first year, and none of those emissions to corn ethanol produced the following years even though this land use change is central to the production over these following years. Second, the accounting method must also provide a common metric that allows for a direct comparison of biofuels to gasoline or

[287] Following Section 5.3.3.4 of the IPCC AFOLU guidelines, the total difference in soil carbon stocks before and after conversion was averaged over 20 years.

[288] Table 4.9 from the 2006 GL AFOLU was used to estimate the lost C sequestration of forests that were converted to another land use.

[289] *See* Greenhouse Gas Mitigation Potential in U.S. Forestry and Agriculture, EPA Document 430–R–05–006 for a discussion of the time required for forests to reach carbon saturation.

[290] Luyassert, S *et al.,* 2008. Old-growth forests as global carbon sinks. *Nature* 455: 213–215. Link: *http://www.nature.com/nature/journal/v455/n7210/abs/nature07276.html.*

diesel. When accounting for the time profile of lifecycle GHG emissions, the two most important assumptions in the determination of whether a biofuel meets the specified emissions reduction thresholds include: (1) The time period considered and (2) the discount rate (which could be zero) applied to future emissions streams.

Time Periods Considered

The illustration of the payback period in Figure VI.B.5–1 demonstrates the importance of the time period over which to consider both the lifecycle GHG emissions increases associated with the production of a biofuel as well as the benefits from using the biofuel. As mentioned above, based on our lifecycle GHG analysis for this proposed rule we estimate that the payback period for corn ethanol produced in a natural gas-fired dry mill is approximately 33 years. In this case, if we measure GHG impacts over a time period of less than 33 years we will determine that the total corn ethanol produced over this time period increases lifecycle GHG emissions. Conversely, total corn ethanol production will reduce net lifecycle GHG emissions if we look beyond 33 years, with net emissions reductions increasing the further into the future we extend our analysis. To inform our decision of which time period for analysis is most appropriate, we must consider a number of factors including but not limited to the length of time over which we expect a particular biofuel to be produced, the time over which biofuel production continues to impact GHG emissions into the future, the importance of achieving near-term GHG emissions reductions, and the increasing uncertainty of projecting GHG emissions impacts into the future. Based on these considerations, our discussion of lifecycle analyses prepared for this proposed rule focuses on time periods of 100 years and 30 years.

There are advantages and disadvantages to using the 100 and 30 year time frames to represent both emissions impacts as well as emissions benefits of use of biofuels over time. There are several principal reasons for using the 100 year time frame. First, greenhouse gases are chemically stable compounds and persist in the atmosphere over long time scales that span two or more generations. Second, the 100 year time frame captures the emissions associated with land use change that may continue for a long period of time after biofuel-induced land conversion first takes place.[291] For example, physical changes in carbon stocks on unmanaged lands may not slow until after 100 years, and optimal forest rotation ages can influence greenhouse gas emissions for 100 years on managed lands. Similarly, a 100 year time frame would allow estimating the future changes in the land should the need for these changes due to biofuel production cease. For example, as discussed in more detail below, if production of a biofuel ended, then the land use impacts associated with that biofuel would also tend to go away in a process known as land use reversion. A longer time frame would allow assessment of the impacts of that land use reversion.

For a number of reasons we believe that biofuel production could continue for a long time into the future. As biofuel technologies advance and production costs are decreased, it is likely that renewable fuels will become increasingly competitive with petroleum-based fuels. Another reason for expecting long term biofuel production is that, unlike a specific facility that has an expected lifetime, the RFS program does not have a specified expiration date. The expectation that renewable fuel production will continue for a long time provides justification for using a longer time frame for analysis, such as 100 years. Another reason for considering an inter-generational time period such as 100 years for lifecycle GHG analysis is that climate change is a long-term environmental problem that may require GHG emissions reductions for many decades.

The 100 year time frame also has drawbacks. A general concern with projecting impacts over a very long time period is that uncertainty increases the further the analysis is extended into the future. For example, a 100 year analysis presumes that production of a particular biofuel will continue for at least 100 years. Although we expect renewable fuel production as a whole to continue for a long time, it is possible that due to changing market conditions or other factors, the use of first generation biofuels (e.g., corn ethanol) could see a decline in use over a shorter period of time.

For this proposal, we are also showing the results of analyzing both GHG emissions impacts of producing a biofuel as well as benefits from using the biofuel over 30 years, a time frame which has been used in the literature to estimate the greenhouse gas impacts of biofuels.[292] [293] Since a time period such as 30 years would truncate the potential GHG benefits that accumulate over time, this second option would reduce the GHG benefits of biofuels relative to gasoline or diesel compared to assuming a longer time frame for biofuel production such as 100 years.

One advantage of using a shorter time period is that it is more ''conservative'' from a climate change policy perspective. In general, the further out into the future an analysis projects, the more uncertainty is introduced into the results. For example, with a longer time period for analysis, it is more likely that significant changes in market factors or policies will change the incentives for producing biofuels. If a biofuel only has greenhouse benefits when considered in an extended future time frame, it is not clear that these benefits will be realized due to the inherent uncertainty of the future. Also, potential irreversible climate change impacts or future actions in other sectors of the economy, such as reductions from stationary sources, could influence the relative importance of renewable fuel GHG impacts. The timing and severity of these potential irreversible climate change impacts are clearly uncertain as is the degree to which near-term lifecycle emissions related to biofuel production influences these climate change impacts. Given these uncertainties, it may be appropriate to limit our analysis horizon to a much shorter time period such as 30 years.

Several disadvantages are also associated with choosing the 30 year time frame to represent both emissions impacts as well as emissions benefits. One key disadvantage is that it ignores the potential sources of GHG emissions impacts of producing biofuel after 30 years such as foregone sequestration from forests that may have been removed which could have continuing impacts even after production of a biofuel has ended. Thus, it doesn't account for the full land use emissions ''signature'' of biofuels. In addition, even if second generation fuels start to dominate new construction, building a first generation fuel production facility such as a corn ethanol refinery represents a significant capital investment. Once the facility is built and financed, it may continue

[291] Luyassert, S *et al.,* 2008. Old-growth forests as global carbon sinks. *Nature* 455: 213–215. Link: *http://www.nature.com/nature/journal/v455/n7210/abs/nature07276.html.*

[292] Searchinger *et al.,* 2008.

[293] M. Delucchi, ''A multi-country analysis of lifecycle emissions from transportation fuels and motor vehicles'' (UCD–ITS–RR–05–10, University of California at Davis, Davis, CA 2005). *See also http://www.its.ucdavis.edu/people/faculty/delucchi/.*

producing biofuel as long as it is covering its operating costs. This suggests that, once a plant is built, if the variable cost of corn ethanol production is less than the cost to produce gasoline, then corn ethanol production at that facility may continue. This economic advantage may contribute to the longevity of first generation biofuel production and usage far into the future.

An appropriate time frame for analysis could also be different for different biofuels. While we could assume that corn ethanol would be phased out after a shorter time period such as 30 years, it might be more appropriate to use a longer time period over which to analyze the benefits of other advanced biofuels such as cellulosic biofuels. It could be reasonably assumed that cellulosic biofuels will be produced for more than 30 years, perhaps for 100 years or longer. However, even if cellulosic biofuels are expected to be produced for 100 years or longer, a shorter time period, such as 30 years, may still be the most relevant period over which to assess GHG emissions, given the importance of near-term emissions reductions and the increasing uncertainty of future events. We specifically seek comments on the 100 year and 30 year time frames discussed in this proposal. We also seek general comments on the most appropriate time periods for analysis of biofuels, and whether we should use different time periods for different types of renewable fuels.

Another way to look at the time period issue, which we have not specifically analyzed for this proposed rule, would separate the time period into two parts. The first part would consider how long we expect production of a particular biofuel to continue into the future. We refer to this concept, which is similar to the project lifetime often considered in traditional cost benefit analysis, as the ''project'' time horizon. The second part would address the length over which to account for the changes in GHG emissions due to land use changes which result from biofuel production. We call this the ''impact'' time horizon.

Our analysis for this proposed rule has not considered a scenario where the project time horizon is shorter than impact time horizon. However, we are considering this option for the final rule. For example, we could look at a scenario where corn ethanol production continues for 30 years and land use related GHG emissions are estimated for 100 years. Specifically, we are considering whether to use 30 years after 2015 (as an approximation of when ethanol production from corn starch reaches 15 billion gallons) as a reasonable estimate of when corn will no longer be used for ethanol production due to advances in other biofuels and the competing demand to use corn for food rather than biofuel feedstock. We specifically ask whether a 30 year estimate of continued corn starch ethanol production (i.e., through 2045) is a reasonable estimate for assessing the stream of GHG benefits from corn ethanol use while 100 years would be appropriate for assessing impacts of the land use change. Under such an assumption a 100 time horizon would capture the longer term emission impacts of corn ethanol production (including indirect land use impacts) while the benefits from 31 through 100 years would be zero since corn ethanol would be modeled as no longer in use.

In that scenario, we would have to consider the lifecycle GHG impacts after the production of corn ethanol ends. This would include the issue of land reversion, or what happens to the land used to produce a biofuel feedstock after its use for biofuel production has ceased. A full accounting of land reversion would involve economic modeling to determine how long we expect production of a particular biofuel to last, and to determine the land use changes after that biofuel production ends. Ideally this modeling would extend well beyond 2022 to the point where land reversion is complete, and it would include projections for global crop yield improvements, population trends, food demand, and other key factors. For this proposal, we have not projected the GHG emissions associated with land reversion, but we plan to consider land reversion in our final rule analysis and we seek comments on methodologies and approaches for doing this. We also seek comment on the related issue of how best to estimate how long each type of biofuel is most likely to continue to be produced, and whether production of these biofuels is likely to end abruptly or phase out gradually.

Agricultural and economic models that look beyond 2022 would not only help to estimate the impacts of land reversion after biofuel production ends, they would also help to project how evolving agricultural conditions could influence the lifecycle GHG emissions of biofuels beyond 2022. For example, corn yields per acre are expected to continue increasing after 2022; this increase in yields per acre will decrease the amount of land required to produce a bushel of corn. At higher yields, fewer acres are required to grow the corn used for the 15 billion gallons of corn starch ethanol modeled for the rule. The indirect impacts of maintaining 15 billion gallons of corn ethanol production would similarly be reduced. EPA intends to more carefully model these transitions in particular to better account for future land use impacts and we invite comments on methodology, sources of data, factors that should be considered in assessing whether and when a particular biofuel such as ethanol from corn starch, for example, will no longer be produced and recommendations on how to improve on our assessment of the likely stream of GHG emissions after 2022 that will result from the EISA mandates.

A complicating consideration in this analysis arises in determining future use of the land (post-biofuel production) is the fact that perhaps significant land use change occurred as a result of biofuel production and that land is now more easily suited for alternative uses compared to its pre-biofuel state. For example, the demand created by biofuel production may have justified clearing forested lands and turning them into productive cropland. Even if the need for the land to produce crops in response to biofuel demand ceases when the biofuel production ends, the land will still be in an altered form making it, for example, more economically available for other crop production than when it had been forested. How this land is subsequently used can affect its impact on GHG emissions. If it is used for intensive crop production, the land will have a much different carbon sequestration profile, for example, than if it returned to its pre-biofuel forested state. EPA asks for suggestions on how to best treat these lingering effects of land use change when attributing the effects of biofuel demand to uses of land even after biofuel production ends.

For the determination of whether biofuels meet the GHG emissions reduction required by EISA, we present the results for a range of time periods, including both 100 years and 30 years in Section VI.C and specifically invite comment on whether use of a 100 year time frame, a 30 year time frame, or some other time frame, would be most appropriate.

In addition to this general issue of the appropriate time frames for analysis, several more specific issues exist. Since it would be likely that corn starch ethanol production will phase out gradually rather than stopping all of a sudden in 2045, we also are evaluating options for estimating the phase out of corn starch ethanol production. One simplifying assumption would have corn ethanol production phase out linearly between 2022 and 2045 as production of other biofuels such as cellulosic biofuels continue to expand. Comments are requested on the option of linearly phasing out corn ethanol production from 2022 through 2045 and other approaches for estimating this transition in corn ethanol production. Finally, its not only corn starch ethanol that might be replaced in future years. For example, the use of soy oil for biodiesel fuel production might be replaced by other non-food oils such as oil from algae. Comments are requested on whether other biofuels will similarly phase out of use and therefore the land use change impacts need to be similarly considered.

In addition to seeking comments on all of the issues related to the time periods for lifecycle analysis, EPA plans to convene a peer review of the range of time periods considered in this proposed rule. This peer review will also seek expert feedback on all of the issues raised above in this section, including how to determine the most appropriate time periods for consideration in the final rule.

Discounting of Lifecycle GHG Emissions

Economic theory suggests that in general consumers have a time preference for benefits received today versus receiving them in the future. Therefore, future benefits are often valued at a discounted rate. Although discount rates are most often applied to the monetary valuation of future versus present benefits, a discounting approach can also be used to compare physical quantities (i.e., total GHG emissions per gallon of fuel used).

The concept of weighting physical units accruing at different times has been used in the environmental and resource economics literature,[294] and is analogous to valuing the monetary cost and benefits of a policy, only that in this case the metric that we 'value' is the reduction in GHG emissions. [295] An important part of the economic theory of time is the idea that benefits expected to accrue in the long term are less certain than benefits in the near term. This is true in the case of GHG emissions changes from biofuel production which are dependent upon how long biofuel production will continue, how technologies will develop over time, and other factors.

[294] Herzog *et al.* 2003 (*See http://sequestration.mit.edu/pdf/climatic_change.pdf*), Richards 1997, Stavins and Richards 2005 (*See http://www.pewclimate.org/docUploads/Sequest_Final.pdf*).

[295] Sunstein and Rowell, 2007, On Discounting Regulatory Benefits: Risk, Money, and Intergenerational Equity, *Chicago Law Review*.

Another reason to give more weight to near-term emissions changes is that the risks associated with climate change in the future include the possibility of extreme climate change and threshold impacts (e.g., species and ecosystem thresholds, catastrophic events). Increased GHG emissions in the near-term may be more important in terms of physical damage to the world's environment. Some scientists, for example, believe that effects on factors such as arctic summer ice, Himalayan-Tibetan Glaciers, and the Greenland ice sheet are more likely to be effected by near-term GHG emissions, causing non-linearities in the effects attributable to GHG emissions.[296] Long-term GHG reductions may be too late to mitigate these irreversible impacts, providing further justification for discounting GHG emissions changes that are expected in the distant future. Under this perspective, it would be appropriate to discount the physical quantities of future emissions, and especially in a long term analysis of lifecycle GHG emissions. Thus in our analysis with a 100 year time frame, or impact horizon, we discount the value of future GHG emissions changes.

Despite the rationale for discounting future GHG emissions changes discussed above, there are reasons to be cautious about the application of discounting in lifecycle GHG analysis. One argument is that it may only be appropriate to discount monetized values. Our lifecycle analysis estimates GHG emission impacts, not their monetary value, and under this argument emissions should not be directly discounted. Rather, the physical GHG emissions should be converted into monetary impacts, where these monetary impacts are also a function of climate science. The resulting climate impacts would then have to be translated into monetary values. This presents significant challenges for lifecycle GHG analysis because it is difficult to translate dynamic GHG emissions into a single estimate of physical impacts, much less a single estimate of monetized impacts. This is the case for a number of reasons, including the complex physical systems associated with climate change (e.g., the relationship between atmospheric degradation rates with atmospheric carbon stocks) that may create non-constant marginal damages from GHG emissions over time. Furthermore, converting lifecycle GHG emissions into monetized impacts may be inconsistent with the EISA definition of lifecycle GHG emissions provided above in Section VI.A.1, which stipulates that lifecycle GHG emissions are the ''aggregate quantity of greenhouse gas emissions * * * where the mass values for all greenhouse gases are adjusted to account for their relative global warming potential.''

[296] Ramanathan and Feng, 2008. On avoiding dangerous anthropogenic interference with the climate system: Formidable challenges ahead. *Proceedings of the National Academy of Sciences* 105:143245–14250.

Another argument against discounting GHG emissions changes is the concept of inter-generational equity, which argues that benefits or damages affecting future generations merit just as much weight as impacts felt by current generations. It is argued that this would invalidate the practice of discounting emissions impacts that could affect future generations.

Finally, earlier in this section we discussed the possible ranges of time frames for analyzing the GHG emissions impacts. For shorter time frames such as 30 years, there would be less uncertainty in the emissions stream so the benefit of discounting to address uncertainty is also lessoned.

Comments are requested on the concept of discounting a stream of GHG emissions for the purpose of estimating lifecycle GHG emissions from transportation fuels as specified in EISA.

Appropriate Level of Discount Rate

As described in more detail in Section IX on GHG emission reduction benefits, GHG emissions have primarily consumption effects and inter-generational impacts, as changes in GHG emissions today will continue to have impacts on climate change for decades to centuries. If a discount rate is applied to future GHG emissions, an appropriate discount rate should be based on a consumption-based discount rate given that monetized climate change impacts are primarily consumption effects (i.e., impacts on household purchases of goods and services). A consumption-based discount rate reflects the implied tradeoffs between consumption today and in the future. Discount rates of 3% or less are considered appropriate for discounting climate change impacts, since they reflect the long run uncertainty in economic growth and interest rates and the risk of high impact climate damages that could reduce economic growth.[297]

[297] *Technical Support Document on Benefits of Reducing GHG Emissions,* U.S. Environmental Protection Agency, June 12, 2008, *www.regulations.gov* (search phrase ''Technical

Continued

When analyzing the GHG emissions associated with a 100 year time period, we examined a variety of alternative discount rates (e.g., 0, 2, 3, 7 percent) to show the sensitivity of greenhouse gas emissions estimates to the choice of the discount rate. A zero discount rate estimates GHG emission impacts as if each ton of GHG emissions is treated equally through time. Previous methodologies of lifecycle GHG benefits have presented results using a zero discount rate.[298] However, some of the climate change literature supports using a higher discount rate, as described in Section IX.C. We show the 7% discount rate for illustrative purposes; however climate change benefit analyses from global long-run growth models typically use discount rates well under 7% for standard analysis.[299] High discount rates imply very low values for the future GHG emission impacts resulting from today's actions on the welfare of future generations. Therefore, lower discount rates such as 2–3% are considered more appropriate for discounting long term climate change impacts.[300]

In the analysis for this proposal we use a 2% discount rate to assess the present value of GHG emissions changes which occur over a 100 year time frame. This discount rate is consistent with the Office of Management and Budget (OMB) [301] and EPA [302] guidance and is one of the discount rates that has been used in the literature to monetize the impacts of climate change.[303] EPA has considered this issue previously, and after weighing the pros and cons of different values, set forth a guidance document recommending using a range of consumption based discount rates of 0.5–3%. OMB and EPA guidance on inter-generational discounting suggests using a low but positive discount rate if there are important inter-generational benefits and costs. In selecting a 2% discount rate coupled with a 100 year emission stream estimate, EPA would be recognizing the long term nature of the emission impacts of biofuel production, the uncertainty in estimating these emission impacts and their consequences plus the significance of nearer term emission changes in avoiding future consequences. Other options for intergenerational discounting have been discussed in the economic literature, such as dealing with uncertainty by using a non-constant, declining, or negative discount rate.[304] Comments could consider how discounting appropriately reflects the uneven emission of greenhouse gases from biofuels over time, the uncertainty in predicting emissions in more distant futures and the impacts these emissions could have on climate change. Alternative approaches for inter-generational discounting are described in Chapter 5.3 of the DRIA.

Because we are considering not discounting GHG emissions and in particular since the justifications for discounting physical emissions are not as strong for shorter time periods, in Section VI.C.2, we also present the GHG emissions reductions associated with biofuels using a 30 year time period and no discount rate. Using a zero percent or no discount rate implies that all emission releases and uptakes during this time period are valued equally. For a shorter time period such as thirty years, we are relatively certain of the emission trends. Furthermore, all of these emissions occur in a relatively short period of time so their impact on climate change and the consequences of that climate change could all be considered the same regardless of whether those emissions occurred early or late in this 30-year time period.

We specifically invite comment on our use of a 2% discount rate with a 100 year time period for analysis of lifecycle GHG emissions, and our use of no discount rate in our analysis of GHG emissions over 30 years. We also invite comments on whether using physical science metrics such as the actual quantities of climate forcing gasses in the atmosphere, actual quantities of climate forcing gasses in the atmosphere weighted by global warming potential (GWP), or cumulative radiative forcing should be used to evaluate emissions over time. Specifically, we seek comment on an approach for comparing GHG emissions based on the time profile of the greenhouse gas emissions in the atmosphere, and whether this approach would be consistent with the legal definition of lifecycle GHG emissions in EISA. One such method is the Fuel Warming Potential as outlined in a memo to the EPA from the Union of Concerned Scientists which is available on the public docket for this rulemaking.[305] This approach is based on the ratio of the cumulative radiative forcing between the biofuel and the gasoline case over a specified time frame.

The EISA definition of lifecycle GHG emissions stipulates that the mass values for all greenhouse gas emissions shall be adjusted to account for their relative GWP. We are proposing to use the standard 100-year GWP's published in the IPCC Second Assessment Report.[306] [307] We invite comment on whether it is appropriate to discount GWP-weighted emissions and how such discounting might appropriately apply across the several greenhouse gases.

Furthermore, if alternative time periods for the production of biofuels and the GHG impacts of biofuel production are considered as discussed above, and the choice is made to discount GHG emissions, the question that arises is: What discount rate or combination of discount rates should be considered? For example, if ethanol production is assumed to occur for 30 years and the GHG impacts are assumed to span across 80–100 years, should a single discount rate be applied to the emissions stream or alternative discount rates based upon the different time frames? EPA is taking comment on whether and how to apply discounting when different time frames between the production and long-run GHG impacts are utilized to analysis biofuels. Specifically, EPA is considering and requests comment on the option of using either no discount rate or a 3% discount rate to assess those emissions that occur during the relatively shorter time frame for biofuel use which could phase out within 30 years as in our corn ethanol example and a 2% discount rate over the reminder of the 100 years in assessing the longer term GHG emissions impacts resulting from land use changes related to biofuel production (including land reversion considerations).

EPA is considering a range of discount rates including zero or no discounting for reasons as described above and requests comments on the appropriate discount rate to use when assessing the stream of GHG emission changes that are likely to result from biofuel production and use. Other

Support Document on Benefits of Reducing GHG Emissions'').

[298] Searchinger *et al.,* 2008.

[299] Tol, 2005.

[300] Newell and Pizer, 2003.

[301] OMB Circular A–4, 2003 provides a range of 1–3% for consumption based discount rates.

[302] EPA Guidelines for Preparing Economic Analyses, 2000.

[303] Tol (2005, 2007).

[304] Newell and Pizer, 2003, Weitzman (1999, 2001), Nordhaus (2008), Guo *et al.,* (2006), Saez, C.A. and J.C. Requena, ''Reconciling sustainability and discounting in Cost-Benefit Analysis: A methodological proposal'', *Ecological Economics,* 2007, vol. 60, issue 4, pages 712–725.

[305] *See* Memo to EPA, Office of Transportation and Air Quality from Union of Concerned Scientists, Re: Treatment of Time in Life Cycle Accounting, February 18, 2009.

[306] *See http://www.ipcc.ch/ipccreports/assessments-reports.htm*.

[307] O'Hare, Plevin, Martin, Jones, Kendal and Hopson; ''Proper accounting for time increases crop-based biofuel's greenhouse gas deficit versus petroleum''; Environmental Research Letters, 4 (2009) 024001.

options for intergenerational discounting have been discussed in the economic literature, such as dealing with uncertainty by using a non-constant, declining, or negative discount rate.[308] Comments could consider how discounting appropriately reflects the uneven release of greenhouse gases from biofuels over time, the uncertainty in predicting emissions in more distant futures and the impacts these emissions could have on climate change. Alternative approaches for inter-generational discounting are described in Chapter 5.3 of the DRIA.

EPA recognizes that the time horizon for analysis and the treatment of future emissions including the appropriateness of applying discount factors are key factors in determining biofuel lifecycle GHG impacts; therefore, we plan to organize an expert peer review of these issues before the final rule.

c. Feedstock Transport

The GHG impacts of transporting corn from the field to the ethanol facility and transporting the co-product DGs from the ethanol facility to the point of use were included in this analysis. The GREET default of truck transportation of 50 miles was used to represent corn transportation from farm to plant. Transportation assumptions for DGs transport were 14% shipped by rail 800 miles, 2% shipped by barge 520 miles, and 86% shipped by truck 50 miles. The percent shipped by mode was from data provided by USDA and based on Association of American Railroads, Army Corps of Engineers, Commodity Freight Statistics, and industry estimates. The distances DGs were shipped were based on GREET defaults for other commodities shipped by those transportation modes. The GHG emissions from transport of corn and DGs are based on GREET default emission factors for each type of vehicle including capacity, fuel economy, and type of fuel used. Similar detailed analyses were conducted for the transport of cellulosic biofuel feedstock and biomass-based diesel feedstock.

As part of this rulemaking analysis we have conducted a more detailed analysis of biofuel production locations and transportation distances and modes of transport used in the criteria pollutant emissions inventory calculations described in DRIA Chapter 1.6 and for the cost analysis of this rule described in DRIA Chapter 4.2. Given the timing of when the current analysis was completed we were not able to incorporate this updated transportation information into our lifecycle analysis but plan to do that for the final rule.

Furthermore, the transportation modes and distances assumed for corn and DGs do not account for the secondary or indirect transportation impacts. For example, decreases in exports might reduce overall domestic agricultural commodity transport and emissions but might increase transportation of commodities internationally. We plan to consider these secondary transportation impacts in our final rule analysis.

d. Processing

The GHG emissions estimates associated with the processing of renewable fuels is dependent on a number of assumptions and varies significantly based on a number of key variables. The ethanol yield impacts the total amount of corn used and associated agricultural sector GHG emissions. The amount of DGs and other co-products produced will also impact the agricultural sector emissions in terms of being used as a feed replacement. Finally the energy used by the ethanol plant will result in GHG emissions, both from producing the fuel used and through direct combustion emissions.

As mentioned above, in traditional lifecycle analyses, the energy consumed and emissions generated by a renewable fuel plant must be allocated not only to the renewable fuel, but also to each of the by-products. For corn ethanol production, our analysis avoids the need to allocate by accounting for the DGs and other co-products directly in the FASOM and FAPRI agricultural sector modeling described above. DGs are considered a partial replacement for corn and other animal feed and thus reduce the need to make up for the corn production that went into ethanol production. Since FASOM takes the benefits from the production and use of DGs into account (e.g., displacing the need to grow additional crops for feed and therefore reducing GHG emissions in the agricultural sector), no further allocation was needed at the ethanol plant and all plant emissions are accounted for here.

In terms of the energy used at renewable fuel facilities, there is a lot of variation between plants based on the process type (e.g., wet vs. dry milling) and the type of fuel used (e.g., coal vs. natural gas). There can also be variation between the same type of plants using the same fuel source based on the age of the plant and types of processes included, etc. For our analysis we considered different pathways for corn ethanol production. Our focus was to differentiate between facilities based on the key differences between plants, namely the type of plant and the type of fuel used. One other key difference we modeled between plants was the treatment of the co-products DGs. One of the main energy drivers of ethanol production is drying of the DGs. Plants that are co-located with feedlots have the ability to provide the co-product without drying. This has a big enough impact on overall results that we defined a specific category for wet vs. dry co-product. One additional factor that appears to have a significant impact on GHG emissions is corn oil fractionation from DGs. Therefore, this category is also broken out as a separate category in the following section. See DRIA Chapter 1.4 for a discussion of corn oil fractionation.

Furthermore, as our analysis was based on a future timeframe, we modeled future plant energy use to represent plants that would be built to meet requirements of increased ethanol production, as opposed to current or historic data on energy used in ethanol production. The energy use at dry mill plants was based on ASPEN models developed by USDA and updated to reflect changes in technology out to 2022 as described in DRIA Chapter 4.1.

The GHG emissions from renewable fuel production are calculated by multiplying the Btus of the different types of energy inputs by emissions factors for combustion of those fuel sources. The emission factors for the different fuel types are from GREET and are based primarily on assumed carbon contents of the different process fuels. The emissions from producing electricity are also taken from GREET and represent average U.S. grid electricity production emissions. The emissions from combustion of biomass fuel source are not assumed to increase net atmospheric CO_2 levels 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. Therefore, CO_2 emissions from biomass combustion as a process fuel source are not included in the lifecycle GHG inventory of the ethanol plant.

e. Fuel Transport

Transportation and distribution of ethanol, biomass-based diesel, petroleum diesel and gasoline were also included in this analysis based on GREET defaults. The GREET defaults for

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[308] Newell and Pizer, 2003, Weitzman (1999, 2001), Nordhaus (2008), Guo *et al.,* (2006), Saez, C.A. and J.C. Requena, ''Reconciling sustainability and discounting in Cost-Benefit Analysis: A methodological proposal'', *Ecological Economics,* 2007, vol. 60, issue 4, pages 712–725.

both ethanol and gasoline transport from plant/refinery to bulk terminals were used. The GREET defaults for both ethanol and gasoline distribution from the bulk terminal to the service station were also used.

As with feedstock transport we have conducted a more detailed analysis of fuel transport and distribution impacts for use in criteria pollutant inventories (see DRIA Chapter 1.6) and for our cost analysis described in DRIA Chapter 4.2. Due to the timing of this analysis we were not able to incorporate the results in our proposed lifecycle calculation but plan to do that for the final rule.

f. Tailpipe Combustion

Combustion CO_2 emissions for ethanol, biomass-based diesel, petroleum diesel and gasoline were based on the carbon content of the fuel. However, over the full lifecycle of the fuel, 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. Net carbon fluxes from changes in biogenic carbon reservoirs in wooded or crop lands are accounted for separately in the land use change analysis as outlined in the agricultural sector modeling above.

When calculating combustion GHG emissions, however, the methane and N_2O emitted during biomass-based fuels combustion are included in the analysis. Unlike CO_2 emissions, the combustion of biomass-based fuels does result in net additions of methane and N_2O to the atmosphere. Therefore, combustion methane and N_2O emissions are included in the lifecycle GHG emissions results for biomass-based fuels.

Combustion related methane and N_2O emissions for both biomass-based fuels and petroleum-based fuels are based on EPA MOVES model results.

6. Petroleum Baseline

To establish the lifecycle greenhouse gas emissions associated with the petroleum baseline against which the renewable fuels were compared, we used an updated version of the GREET model. Lifecycle energy use and associated emissions for petroleum-based fuels in GREET is calculated based on an energy efficiency metric for the different processes involved with petroleum-based fuels production. The energy efficiency metric is a measure of how many Btus of input energy are needed to make a Btu of product. GREET has assumptions on energy efficiency for different finished petroleum products as well as for different types of crude oil.

We are using the latest version of the GREET model for this analysis (Version 1.8b) which includes recent updates to the energy efficiencies of petroleum refining. To represent baseline petroleum fuels we have used the 2005 estimates of actual gasoline and diesel fuel used. For 2005, 86% of gasoline and 92% of diesel fuel was produced domestically with the rest imported finished product. To represent international production we assume the same GHG refinery emissions from GREET as used domestically. We did not include indirect land use impacts in assessing the lifecycle GHG performance of the 2005 baseline fuel pool as we believe these would insignificantly impact the average performance assessment of the baseline. Additionally, consistent with our assessment of energy security impacts, we did not include as an indirect GHG impact the potential impact of maintaining a military presence.

GREET also has assumptions on the mix of energy sources used to provide the energy input, which determine GHG emissions. For example if coal, natural gas, or purchased electricity is used as an energy source. The GHG emissions associated with petroleum fuel production are based on the emissions from producing and combusting the input energy sources needed, like GHG emissions from using natural gas at the petroleum refinery. Non-combustion GHG sources like fugitive methane emissions are added in where applicable.

Based on the EISA requirements, we used the 2005 mix of crude as the petroleum baseline. We developed emissions factors for those crude types since they are not currently included in GREET. In 2005, 5% of crude was Canadian tar sand, 1% was Venezuela extra heavy, and 23% was heavy crude.

For this proposal, we are using the average GHG emissions associated with the 2005 petroleum baseline, as required by EISA. However, we recognize that an additional gallon of renewable fuel replaces the marginal gallon of petroleum fuel. To the extent that the marginal gallon is from oil sands or other types of crude oil that are associated with higher than average GHG emissions, replacing these fuels could have a larger GHG benefit. Conversely to the extent the marginal gallon displaced is from imported gasoline produced from light crude, replacing these fuels would have a smaller GHG benefit. We solicit comment on whether—strictly for purposes of assessing the benefits of the rule (and not for purposes of determining whether certain renewable fuel pathways meet the GHG reduction thresholds set forth in EISA), we should assess benefits based on a marginal displacement approach and, if so, what assumptions we should use for the marginal displacements.

In December 2008, the U.S. Department of Energy's National Energy Technology Laboratory (NETL) released a report that estimates the average lifecycle GHG emissions from petroleum-based fuels sold or distributed in 2005.[309] The estimates in the report are based on a slightly different methodology than EPA's analysis of lifecycle GHG emissions for the petroleum baseline. The NETL report is available on the docket for this rulemaking. We invite comments on whether NETL's analysis has significant implications for how EPA is estimating petroleum baseline lifecycle GHG emissions.

7. Energy Sector Indirect Impacts

Increased demand for natural gas to power corn ethanol plants could have additional impacts on the U.S. energy sector. As demand for natural gas increases, the use of natural gas in other sectors (e.g., electric generation) could decrease. For this analysis, we are using the NEMS model to project the secondary or indirect impacts on the energy sector. However, we were not able to include this analysis in the GHG emissions estimates presented in this proposal. We hope to have this analysis for the final rule. Additional details on the methodology are included in the DRIA Chapter 2, and we invite comments on this approach.

We are assuming, for the proposal, that a gallon of renewable fuel replaces an energy equivalent gallon of petroleum fuel. This analysis presumes that petroleum-based fuels as they are currently produced will continue to be used for transportation fuels and will be replaced on a Btu for Btu basis. Many factors could affect this assumption including advances in petroleum fuel technology, availability of other fossil fuels for transportation use, and of course the supply and cost of petroleum. We have not tried to analyze these potential impacts in this rule. However we invite comment on such an approach.

We have also not assessed whether expanded use of biofuels in the U.S.

[309] DOE/NETL. 2008. Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels. DOE/NETL–2009/1346.

will impact the energy markets in other countries. For example, reducing demand for petroleum-based fuel in the U.S. may reduce worldwide petroleum prices and impact the use of petroleum in other countries. We invite comment on how best to assess these potential impacts and will attempt to do so for the final rule.

C. Fuel Specific GHG Emissions Estimates

While the results presented in this section represent the most up-to-date information currently available, this analysis is part of an ongoing process. Because lifecycle analysis is a new part of the RFS program, in addition to the formal comment period on the proposed rule, EPA is making multiple efforts to solicit public and expert feedback on our proposed approach. As discussed in Section XI, EPA plans to hold a public workshop focused specifically on lifecycle analysis during the comment period to assure full understanding of the analyses conducted, the issues addressed and options that should be considered. We expect that this workshop will allow the most thoughtful and useful comments to this proposal and assure the best methodology and assumptions are used for calculating GHG emissions impacts of fuels for the final rule. Additionally we will conduct peer-reviews of key components of our analysis. As part of ongoing analysis for the final rule, EPA will seek peer review of: Our use of satellite data to project future land use changes; the land conversion GHG emissions factors estimated by Winrock; our estimates of GHG emissions from foreign crop production; methods to account for the variable timing of GHG emissions; and how models are used together to provide overall lifecycle GHG estimates.

In addition to the refinements to the methodology that we plan to undertake for the final rule, we also intend to update our results periodically. EPA recognizes that the state of the science for lifecycle GHG analysis will continue to evolve over time as new data and modeling techniques become available and as there are improvements in agricultural and renewable fuel production practices as well as new feedstocks. We invite comments on the appropriate amount of time for periodic review of the lifecycle assessment methodology, but we propose that performing an update of the methodology every 3–5 years would be appropriate. We would expect the first update to this analysis would occur closer to 3 years. This timeframe would allow us to undergo a formal review process after the final rule to ensure that this methodology takes into account the most state-of-the-art science and reflects the input of appropriate experts in this field. However, any change in lifecycle methodology as contemplated here would not affect the eligibility of biofuels produced at facilities covered by the grandfathering provisions of EISA at section 211(o)(4)(g).

1. Greenhouse Gas Emissions Reductions Relative to the 2005 Petroleum Baseline

In this section we present detailed lifecycle GHG results for several specific biofuels representing a range biofuel pathways. This section also includes the results of sensitivity analysis for key variables. The sensitivity of the time period and discount rate are discussed below. In the rest of this section we focus on two sets of lifecycle GHG results. One set of results that uses a 100 year time period and 2% discount rate and a parallel set of results using a 30 year time period and a 0% discount rate. In Section IV.C.2 which follows, we also present the results for some additional combinations of time horizon for assessing GHG emission changes as well as assuming other discount rates. Additional pathways, not included in the results presented in this section, distinguishing other combinations of feedstock and processing technologies have been evaluated. These additional pathways are described in detail in the DRIA and are included in these proposed regulations.

a. Corn Ethanol

Table VI.C.1–1 presents the breakout of the net present value of lifecycle GHG emissions per million British thermal unit (mmbtu) of corn ethanol and gasoline. The results are broken out by lifecycle stage. Values are shown for a standard dry mill corn ethanol plant in 2022 using natural gas for process energy and drying the co-product of distillers grains (DGs). Results indicate where the major contributions of GHG emissions are across the fuel lifecycle. Fuel processing and indirect land use change are the main contributors to corn ethanol lifecycle GHG emissions. Net domestic and international agricultural impacts (w/o land use change) include direct and indirect impacts, such as reductions in livestock enteric fermentation.

TABLE VI.C.1–1—ABSOLUTE LIFECYCLE GHG EMISSIONS FOR CORN ETHANOL AND THE 2005 PETROLEUM BASELINE

[CO_2-eq/mmBtu]

	2005 Gasoline baseline	Natural gas dry mill with dry DGs	2005 Gasoline baseline	Natural gas dry mill with dry DGs
Lifecycle Stage	100 yr 2%		30 yr 0%	
Net Domestic Agriculture (w/o land use change)	N/A	−499,029	N/A	−347,365
Net International Agriculture (w/o land use change)	N/A	452,118	N/A	314,711
Domestic Land Use Change	N/A	79,547	N/A	92,575
International Land Use Change	N/A [310]	1,911,391	N/A	1,910,822
Fuel Production [311]	823,262	1,404,083	573,058	977,358
Fuel and Feedstock Transport	(see footnote 321)	174,327		121,346
Tailpipe Emissions [312]	3,417,311	37,927	2,378,800	26,400
Net Total Emissions	4,240,674	3,560,365	2,951,858	3,095,846

[310] For this proposal, our preliminary analysis suggests land use impacts of petroleum production for the fuels used in the U.S. in 2005 would not have an appreciable impact on the 2005 baseline GHG emissions assessment. However, we expect to more carefully consider potential land use impacts of petroleum-based fuel production for the final rule and invite comment and information that would support such an analysis.

[311] 2005 petroleum baseline fuel production includes crude oil extraction, transportation, refining, and transport of finished product.

[312] Ethanol tailpipe emissions include CH_4 and N_2O emissions but not CO_2 emissions as these are assumed to be offset by feedstock carbon uptake.

Table VI.C.1–1 demonstrates the importance of the discount rate and time period analyzed as well as the importance of significance of including GHG emissions from international land use changes. Assuming 100 years of corn ethanol produced in a basic dry mill ethanol production facility and using a 2% discount rate results in corn ethanol having a 16% reduction in GHG emissions compared to the 2005 baseline gasoline assumed to be replaced. In contrast, assuming 30 years of corn ethanol production and use and no discounting of the GHG emission impacts results in predicting that corn ethanol will have a 5% increase in GHG emissions compared to petroleum gasoline.

As discussed in Section VI.B.2.a, EPA's interpretation of the EISA statute compels us to include significant indirect emission impacts including those due to land use changes in other countries. The data in Table VI.C.1–1 indicate that excluding the international land use change would result in corn ethanol having an approximately 60% reduction in lifecycle GHG emissions compared to petroleum gasoline regardless of the timing or discount rate used.[313]

In Table VI.C.1–1, we project a standard dry mill ethanol plant in 2022 using corn as its feedstock, using natural gas for process energy, and drying the co-product of distillers grains (DGs). Different corn ethanol production technologies will have different lifecycle GHG results. For example, due to its high carbon content, using coal as the process energy source significantly worsens the lifecycle GHG impact of ethanol produced at such a facility. On the other hand, replacing natural gas with renewable biomass as the process energy source greatly improves the GHG assessment.

Other technology options are available to improve the efficiency of ethanol facilities. Table VI.C.1–2 shows the impact that different corn ethanol production process pathways will have on the overall lifecycle GHG results. Table VI.C.2–2 shows that currently available technologies could be applied to corn ethanol plants to reduce their net GHG emissions.

For example, a combined heat and power (CHP) configuration, used in combination with corn oil fractionation, would result in a GHG emissions reduction of 27% relative to the 2005 petroleum baseline over 100 years using a 2% discount rate, and a 6% reduction over 30 years with no discounting. In addition, advanced technologies such as membrane separation and raw starch hydrolysis could improve the emissions associated with corn ethanol production even more substantially. Combining all of these technologies in a state-of-the-art natural gas powered corn ethanol facility would produce ethanol that has approximately 35% less lifecycle GHG emissions than an energy equivalent amount of baseline gasoline displaced over 100 years using a 2% discount rate and, by comparison a 14% reduction when accounting for 30 years of emission changes but applying no discounting. Details on these different technologies are included in the DRIA Chapter 1.5.

Table VI.C.1–2 also shows that the choice of drying DGs can have a significant impact on the GHG emissions associated with an ethanol plan, since drying the ethanol byproduct is an energy intensive process. However, wet DGs are only suitable where a local market is available such as a dairy farm or cattle feedlot, since wet DGs are highly perishable.

TABLE VI.C.1–2—LIFECYCLE GHG EMISSIONS CHANGES FOR VARIOUS CORN ETHANOL PATHWAYS IN 2022 RELATIVE TO THE 2005 PETROLEUM BASELINE

Corn ethanol production plant type	Percent change from 2005 petroleum baseline (100 yr 2%)	Percent change from 2005 baseline (30 yr 0%)
Natural Gas Dry Mill with dry DGs	−16	+5
Natural Gas Dry Mill with dry DGs and CHP	−19	+2
Natural Gas Dry Mill with dry DGs, CHP, and Corn Oil Fractionation	−27	−6
Natural Gas Dry Mill with dry DGs, CHP, Corn Oil Fractionation, and Membrane Separation	−30	−10
Natural Gas Dry Mill with dry DGs, CHP, Corn Oil Fractionation, Membrane Separation, and Raw Starch Hydrolysis	−35	−14
Natural Gas Dry Mill with wet DGs	−27	−6
Natural Gas Dry Mill with wet DGs and CHP	−30	−9
Natural Gas Dry Mill with wet DGs, CHP, and Corn Oil Fractionation	−33	−12
Natural Gas Dry Mill with wet DGs, CHP, Corn Oil Fractionation, and Membrane Separation	−36	−15
Natural Gas Dry Mill with wet DGs, CHP, Corn Oil Fractionation, Membrane Separation, and Raw Starch Hydrolysis	−39	−18
Coal Fired Dry Mill with dry DGs	+13	+34
Coal Fired Dry Mill with dry DGs and CHP	+10	+31
Coal Fired Dry Mill with dry DGs, CHP, and Corn Oil Fractionation	−5	+15
Coal Fired Dry Mill with dry DGs, CHP, Corn Oil Fractionation, and Membrane Separation	−13	+8
Coal Fired Dry Mill with dry DGs, CHP, Corn Oil Fractionation, Membrane Separation, and Raw Starch Hydrolysis	−21	−1
Coal Fired Dry Mill with wet DGs	−9	+12
Coal Fired Dry Mill with wet DGs and CHP	−11	+10
Coal Fired Dry Mill with wet DGs, CHP, and Corn Oil Fractionation	−17	+3
Coal Fired Dry Mill with wet DGs, CHP, Corn Oil Fractionation, and Membrane Separation	−25	−4
Coal Fired Dry Mill with wet DGs, CHP, Corn Oil Fractionation, Membrane Separation, and Raw Starch Hydrolysis	−30	−9
Biomass Fired Dry Mill with dry DGs	−39	−18
Biomass Fired Dry Mill with wet DGs	−40	−19
Natural Gas Fired Wet Mill	−7	+14

[313] The treatment of emissions over time is not critical if international land use change emissions are excluded because the results without land use change are consistent over time. Therefore the overall lifecycle GHG results do not vary with time or discount rate assumptions.

TABLE VI.C.1–2—LIFECYCLE GHG EMISSIONS CHANGES FOR VARIOUS CORN ETHANOL PATHWAYS IN 2022 RELATIVE TO THE 2005 PETROLEUM BASELINE—Continued

Corn ethanol production plant type	Percent change from 2005 petroleum baseline (100 yr 2%)	Percent change from 2005 baseline (30 yr 0%)
Coal Fired Wet Mill	+20	+41
Biomass Fired Wet Mill	−47	−26

As described in Sections VI.A and VI.B, there are a number of parameters and modeling assumptions that could impact the overall renewable fuel GHG results. The estimates in Table VI.C.1–2 are based on the GHG emissions for a specific change in volumes analyzed in 2022 (12.3 to 15 Bgal). These volumes represent the change in corn ethanol production that would occur in 2022 without and then with EISA mandates in place. The GHG impact is then normalized to a per gallon or Btu basis in relation to gasoline. These values are used to represent every gallon of corn ethanol produced throughout the program.

There are several important implications associated with this methodology. First, this analysis focuses on the average impact of an increase in fuel produced using a technology pathway and does not distinguish the emission performance between biofuel production plants using the same basic production technology and type of feedstock. Thus it does not account for any incremental differences in facility design or operation which may affect the lifecycle GHG performance at that facility. Second, by focusing on 2022, this analysis does not track how biofuel GHG emission performance may change over time between now and 2022. Third, the results presented here are based on the GHG impacts of the volumes analyzed.

For this proposal, we believe that using the emissions assessment from a typical 2022 facility for each major technology pathway captures the appropriate level of detail needed to determine whether a particular biofuel meets the threshold requirements in EISA. To address whether the GHG emissions vary significantly over time, we also calculated corn ethanol lifecycle GHG emissions estimates in 2012 and 2017. As shown in Table VI.C.1–3, corn ethanol's lifecycle GHG emissions reductions are fairly consistent regardless of which base year is analyzed. This may be due to countervailing forces that stabilize land use change emissions over the period of our analysis. Crop yields increase over time (therefore reducing land use pressure), but there is also increasing production of other renewable fuels that require land for feedstock production (therefore increasing land use pressure). Although we are proposing to use 2022 as the base year for our lifecycle GHG emissions estimates, we invite comments on this approach.

TABLE VI.C.1–3—CORN ETHANOL LIFECYCLE GHG EMISSIONS CHANGES IN 2012, 2017, AND 2022

Scenario Description	Percent change from 2005 petroleum baseline (100 yr 2%)	Percent change from 2005 petroleum baseline (30 yr 0%)
Corn Ethanol Natural Gas Dry Mill in 2012 with dry DGs	−16	−3
Corn Ethanol Natural Gas Dry Mill in 2017 with dry DGs	−13	+9
Corn Ethanol Natural Gas Dry Mill in 2022 with dry DGs	−16	+5

We also tested the impact of analyzing a larger change in corn ethanol volumes on the GHG emissions estimates. Table VI.C.1–4 shows the sensitivity of our analysis to the volume changes analyzed. Based on this scenario, the GHG emissions estimates associated with a larger change (6.3 Bgal) in corn ethanol volumes (8.7 Bgal to 15 Bgal) results in lower GHG emission reductions. Additional details on these sensitivity analyses are included in the DRIA Chapter 2.

TABLE VI.C.1–4—CORN ETHANOL LIFECYCLE GHG EMISSIONS CHANGES ASSOCIATED WITH DIFFERENT VOLUME CHANGES

Scenario Description	Percent Change from 2005 Petroleum Baseline (100 yr 2%)	Percent Change from 2005 Petroleum Baseline (30 yr 0%)
Corn Ethanol Natural Gas Dry Mill in 2022 with dry DGs; 2.7 Bgal change in corn ethanol volumes	−16	+5
Corn Ethanol Natural Gas Dry Mill in 2022 with dry DGs; 6.3 Bgal change in corn ethanol volumes	−6	+14

The results presented in previous tables assume that managed pasture (i.e., land actively used for livestock grazing) converted from pasture to cropland would be replaced with new pasture in other areas. The area of managed pasture converted to cropland was estimated using satellite data from Winrock and land cover data from GTAP. As a sensitivity analysis, we also analyzed a scenario in which none of the pastureland converted to cropland would be replaced if, for example, livestock production could be more intensively developed on the remaining pasture (*see* first row in Table VI.C.1–5). Similarly, we also calculated results assuming that all pasture acres would be replaced (second row in Table VI.C.1–5). Finally, the third row of Table VI.C.1–5 includes lifecycle GHG results assuming that all of the land converted to cropland would come from pasture and that none of that pasture would be replaced, which is counter to the land use trends identified by the Winrock satellite data. As can be seen, the assumption of pastureland replacement can have a significant effect on the results. We ask for comment on the best assumptions to be made when considering the need to replace pasture that has been converted to crop production. We note that the best decision on pasture land replacement may vary by country or region due to such factors as the current intensity of use of pasture land as well as trends in demand for pasture. DRIA Chapter 2 includes more details about the treatment of pasture conversion, and sensitivity analysis of the types land use changes induced by corn ethanol production.

TABLE VI.C.1–5—CORN ETHANOL LIFECYCLE GHG EMISSIONS CHANGES ASSOCIATED WITH DIFFERENT ASSUMPTIONS ON LAND USE CHANGES

Scenario Description	Percent Change from 2005 Petroleum Baseline (100 yr 2%)	Percent Change from 2005 Petroleum Baseline (30 yr 0%)
Corn Ethanol Natural Gas Dry Mill in 2022 with dry DGs; 0% pastureland replaced	−34	−19
Corn Ethanol Natural Gas Dry Mill in 2022 with dry DGs; 100% pastureland replaced	−2	+24
Corn Ethanol Natural Gas Dry Mill in 2022 with dry DGs; grassland only conversion and 0% pastureland replaced	−48	−38

DRIA Chapter 2 includes results for additional sensitivity analysis of corn ethanol lifecycle GHG emissions. We also intend to conduct additional sensitivity analysis for the final rule. We invite comment on these assumptions.

b. Imported Ethanol

Table VI.C.1–6 presents the breakout of lifecycle GHG emissions for sugarcane ethanol compared to a 2005 petroleum baseline under different discount rate and time horizon scenarios and land use assumptions. This assessment was based on applying the same methodology as for other biofuels including the assessment of both direct and indirect impacts using the combination of FASOM, FAPRI and Winrock modeling results. Virtually all the ethanol from sugarcane is expected to be imported from Brazilian production. Applying the proposed FAPRI/Winrock methodology to sugarcane ethanol production in Brazil predicts a large increase in new acres planted, which has a relatively large impact on overall GHG emissions. The impact is from both new sugarcane production acres in Brazil resulting in land use change but also reduced commodity exports from Brazil resulting in land use change in other countries.

The proposed FAPRI/Winrock methodology predicts that new crop acreage is converted from a range of land types. In contrast, some studies suggest that sugarcane ethanol production can increase in Brazil by relying on existing excess pasture lands and will not significantly impact other land types.[314] Table VI.C.1–6 provides the range of lifecycle GHG emission reduction results under these different assumptions of type conversion patterns. As a sensitivity analysis, shows results for a scenario where none of the grassland converted to cropland in Brazil would be replaced if, for example, livestock production could be more intensively developed on the remaining pasture (see second row in Table VI.C.1–6). The third row of Table VI.C.1–6 includes lifecycle GHG results assuming that in Brazil all of the land converted to cropland would come from grassland and that none of that grassland would be replaced. As can be seen in the table, the assumption of pastureland replacement can have an important effect on the results. DRIA Chapter 2 includes more details about the treatment of pasture conversion, and sensitivity analysis of the types land use changes induced by sugarcane ethanol production.

TABLE VI.C.1–6—SUGARCANE ETHANOL GHG EMISSION CHANGES UNDER VARIED LAND USE ASSUMPTIONS AND VARIED DISCOUNT RATES AND TIME HORIZONS RELATIVE TO 2005 PETROLEUM BASELINE

Land Use Change Scenario Description	(100 yr 2%)	(30 yr 0%)
FAPRI/Winrock estimate with managed pasture replacement	−44	−26
FAPRI/Winrock estimate with no pasture replacement in Brazil	−59	−45
Only grassland conversion in Brazil and no pasture replacement in Brazil	−64	−52

We are aware that recent land use enforcement policies in Brazil may shift cropland expansion patterns (*see* also Section VI.B.5.b.iii). We seek comment on both pasture conversion patterns and Brazil land use enforcement policy impacts. We are conducting more detailed economic modeling of the Brazilian agricultural sector by state for inclusion in FAPRI to address pasture, enforcement and other assumptions for the final rule. State level production data could be used in conjunction with Winrock's state level satellite data, which may substantially change the

[314] Goldemberg, J.; Coelho, ST.; Guardabassi, PM. The sustainability of ethanol production from sugarcane. *Energy Policy*. 2008. doi:10.1016/j.enpol.2008.02.028.

estimates of the location and type of land being converted in Brazil for the final rule.

We have also assumed that sugarcane ethanol production relies on burning bagasse as an energy source and that the process produces excess electricity. We factor in credits from this excess electricity based on offsetting the Brazilian electricity grid. As Brazil implements limits on field burning of bagasse there may be additional bagasse used at sugarcane ethanol plants and additional electricity production. We plan to look at this further for the final rule analysis.

c. Cellulosic Ethanol

Given that commercially-viable cellulosic ethanol production is not yet a reality, analysis of this pathway relies upon significant assumptions regarding the development of production technologies. As described in the previous section, our analysis assumed corn stover required no international land use changes, since corn stover does not compete with other crops for acreage in the U.S. Therefore, using corn stover as a feedstock for cellulosic biofuel production would not have an impact on U.S. exports. We assumed some of the nutrients would have to be replaced through higher fertilizer rates on acres where stover is removed; however, increased stover removal was also associated with higher rates of reduced tillage or no tillage practices which results in soil carbon increase. See Section IX.A for details. In addition, cellulosic ethanol was assumed to be produced using the biochemical process which is expected to produce more electricity from the lignin in the feedstock than is required to power the ethanol plant, so excess electricity can be sold back to the grid. See DRIA Chapter 2 for additional details. This electricity provides a GHG benefit, which results in GHG emissions reductions from fuel production as shown in Table VI.C.1–7.

TABLE VI.C.1–7—ABSOLUTE LIFECYCLE GHG EMISSIONS FOR CORN STOVER CELLULOSIC ETHANOL AND THE 2005 PETROLEUM BASELINE

[CO_2-eq/mmBtu]

	2005 Petroleum baseline	Corn stover ethanol (selling excess electricity to grid)	2005 Petroleum baseline	Corn stover ethanol (selling excess electricity to grid)
Lifecycle Stage	(100 yr 2%)		(30 yr 0%)	
Net Domestic Agriculture (w/o land use change)	....	178,862	N/A	124,503
Net International Agriculture (w/o land use change)	....	0	N/A	....
Domestic Land Use Change	....	−78,448	N/A	−91,925
International Land Use Change	....	0	N/A	0
Fuel Production	823,262	−875,424	573,058	−609,367
Fuel and Feedstock Transport	....	107,214	....	74,629
Tailpipe Emissions	3,417,311	37,927	2,378,800	26,400
Net Total Emissions	4,240,674	−629,870	2,951,858	−475,130

Although switchgrass must compete with other crops for land in the U.S., average switchgrass ethanol yields are on average higher than corn ethanol yields (approximately 580 gallons/acre compared to 480 gallons/acre). Therefore, switchgrass would need approximately 20% less land to produce the same amount of ethanol compared to corn. In addition, FASOM predicts that switchgrass would generally be grown on more marginally productive land. Since switchgrass is not projected to displace crop acres with high yields, new switchgrass acres generally would not have a large impact on exports. Therefore, the international land use change impacts are modest. Like cellulosic ethanol from corn stover, switchgrass ethanol is also assumed to produce excess electricity that can be sold to the grid, therefore switchgrass cellulosic ethanol results in relatively large lifecycle GHG reductions compared to the replaced petroleum gasoline as shown in Table VI.C.1–8.

TABLE VI.C.1–8—ABSOLUTE GHG EMISSIONS FOR SWITCHGRASS CELLULOSIC ETHANOL AND THE 2005 PETROLEUM BASELINE

[CO_2-eq/mmBtu]

	2005 Petroleum baseline	Switchgrass ethanol (selling excess electricity to grid)	2005 Petroleum baseline	Switchgrass ethanol (selling excess electricity to grid)
Lifecycle Stage	(100 yr 2%)		(30 yr 0%)	
Net Domestic Agriculture (w/o land use change)	....	−470,620	....	−327,590
Net International Agriculture (w/o land use change)	....	−356,712	....	−248,301
Domestic Land Use Change	....	−65,318	....	−76,015
International Land Use Change	....	423,097	....	424,094
Fuel Production	823,262	−874,599	573,058	−608,793
Fuel and Feedstock Transport	....	136,663	....	95,129
Tailpipe Emissions	3,417,311	37,927	2,378,800	26,400

TABLE VI.C.1–8—ABSOLUTE GHG EMISSIONS FOR SWITCHGRASS CELLULOSIC ETHANOL AND THE 2005 PETROLEUM BASELINE—Continued

[CO_2-eq/mmBtu]

	2005 Petroleum baseline	Switchgrass ethanol (selling excess electricity to grid)	2005 Petroleum baseline	Switchgrass ethanol (selling excess electricity to grid)
Net Total Emissions	4,240,674	−1,169,561	2,951,858	−715,076

Cellulosic ethanol does not have nearly as significant an impact on land use as other biofuels, therefore we did not calculate sensitivity impacts of, for example, assuming full replacement of pasture versus no pasture replacement which could be important in the lifecycle GHG assessment of other biofuels. As the land use issue is not critical for the cellulosic feedstock fuels in the scenarios we analyzed, the impact of timing and discount rates also do not have a significant impact on the overall results for cellulosic ethanol. Both of the cellulosic ethanol pathways we examined, switchgrass and corn stover using enzymatic processing, reduced lifecycle GHG emissions by significantly more than the 60% threshold for cellulosic biofuel. Table VI.C.1–9 summarizes the lifecycle GHG results for cellulosic ethanol fuel pathways.

TABLE VI.C.1–9—CELLULOSIC ETHANOL GHG EMISSION CHANGES FROM DIFFERENT FEEDSTOCKS AND VARIED DISCOUNT RATES AND TIME HORIZONS RELATIVE TO 2005 PETROLEUM BASELINE

[In percent]

Assumption—feedstock type	(100 yr 2%)	(30 yr 0%)
Corn Stover	−115	−117
Switchgrass	−128	−121

d. Biodiesel

EPA's modeling predicts that soybean-based biodiesel production has a large land use impact for two major reasons. Soybean biodiesel has a relatively low gallon per acre yield (approximately 65 gal/acre for soybean biodiesel versus 480 gal/acre for corn ethanol). Thus, the impact of any land-use change tends to be magnified with soybean biodiesel. Even when the higher Btu value of biodiesel is taken into consideration, Btu/acre yields are still significantly lower for biodiesel than for ethanol (approximately 97 gal/acre ethanol equivalent). Furthermore, our analysis suggests that due to high world wide demand for soybeans for food, cooking and other non-biofuel uses, soybean and other edible oils used for biofuel are generally replaced by production in other countries including production in tropical climates where the GHG emissions released per acre of converted land are highest. This indicates that soy-based biodiesel lifecycle GHG emissions could be greatly reduced with the adoption of policies and agricultural practices that limit the amount of tropical deforestation induced by soy-based biodiesel production. DRIA Chapter 2 includes sensitivity analyses about the types of land converted to crops as a result of soy-based biodiesel production. Table VI.C.1–10 presents the breakout of the absolute lifecycle GHG emissions for soybean biodiesel and the petroleum diesel fuel baseline by lifecycle stage.

TABLE VI.C.1–10—ABSOLUTE LIFECYCLE GHG EMISSIONS FOR SOYBEAN BIODIESEL AND THE 2005 PETROLEUM BASELINE

[CO_2-eq/mmBtu]

	2005 Petroleum baseline	Soybean biodiesel	2005 Petroleum baseline	Soybean biodiesel
Lifecycle Stage	(100 yr 2%)		(30 yr 0%)	
Net Domestic Agriculture (w/o land use change)	....	−423,206	....	−294,586
Net International Agriculture (w/o land use change)	....	195,304	....	135,948
Domestic Land Use Change	....	−8,980	....	−10,451
International Land Use Change	....	2,474,074	....	2,469,574
Fuel Production	749,132	838,490	521,458	583,658
Fuel and Feedstock Transport	....	149,258	....	103,896
Tailpipe Emissions	3,424,635	30,169	2,383,828	21,000
Net Total Emissions	4,173,768	3,255,109	2,905,286	3,009,039

Our analysis is based on a change in biodiesel volumes from 0.4 Bgal to 0.7 Bgal. Similar to the analysis we conducted for corn-ethanol, we plan to run a sensitivity analysis on the impact of using different volumes for the final rule.

As discussed in Section VI.B.2.a, EPA's interpretation of the EISA statute compels us to include significant indirect emission impacts including those due to land use changes in other countries. The data in Table VI.C.1–10 indicate that excluding the international land use change would result in soy-based biodiesel having an approximately 80% reduction in lifecycle GHG emissions compared to petroleum gasoline regardless of the timing or discount rate used. The treatment of emissions over time is not critical if international land use change emissions are excluded because the results without land use change are consistent over time. Therefore the overall lifecycle GHG results do not vary with time or discount rate assumptions.

In contrast, GHG emissions from waste oil and greases are assumed to have no land use impacts. We assumed any land use change was attributed to the original use of the feedstock, for example, soy oil was produced for the purpose of using for cooking and the land required to produce this cooking oil is properly attributed to that use. Gathering and re-using the left over waste cooking oil would have no additional land use impact. This lack of land use impact greatly influences the lifecycle GHG analysis. Table VI.C.1–11 presents the breakout of the absolute lifecycle GHG emissions for waste grease biodiesel and the petroleum diesel fuel baseline by lifecycle stage.

TABLE VI.C.1–11—ABSOLUTE LIFECYCLE GHG EMISSIONS FOR WASTE GREASE BIODIESEL AND THE 2005 PETROLEUM BASELINE

[CO_2-eq/mmBtu]

	2005 Petroleum baseline	Waste grease biodiesel	2005 Petroleum baseline	Waste grease biodiesel
Lifecycle Stage	(100 yr 2%)		(30 yr 0%)	
Net Domestic Agriculture (w/o land use change)	....	0	....	0
Net International Agriculture (w/o land use change)	....	0	....	0
Domestic Land Use Change	....	0	....	0
International Land Use Change	....	0	....	0
Fuel Production	749,132	658,198	521,458	458,160
Fuel and Feedstock Transport	....	149,258	....	103,896
Tailpipe Emissions	3,424,635	30,169	2,383,828	21,000
Net Total Emissions	4,173,768	837,626	2,905,286	583,056

Table VI.C.1–12 summarizes the lifecycle GHG results for biodiesel fuel pathways. As the waste grease biodiesel is not assumed to have any land use impact the choice of timing or discount rate does not impact the waste grease biodiesel results. However, as the soybean biodiesel is found to have a large land use impact the choice of timing and discount rate has a big impact on the soybean biodiesel results.

TABLE VI.C.1–12—BIODIESEL LIFECYCLE GHG EMISSION CHANGES FROM DIFFERENT FEEDSTOCKS AND VARIED DISCOUNT RATES AND TIME HORIZONS RELATIVE TO 2005 PETROLEUM BASELINE

Assumption—feedstock type	(100 yr 2%)	(30 yr 0%)
Soybean	−22%	+4%
Waste Grease	−80%	−80%

Table VI.C.1–13 shows the sensitivity of our assessment for soy oil biodiesel assuming 100% of the grassland converted to cropland is replaced compared to an assumption that none of this grassland is replaced for livestock grazing. DRIA Section 2.8.2.4 provides more information about sensitivity analysis for the pasture replacement assumptions.

TABLE VI.C.1–13—SOY-BASED BIODIESEL GHG EMISSION CHANGES UNDER VARIED LAND USE ASSUMPTIONS AND VARIED DISCOUNT RATES AND TIME HORIZONS RELATIVE TO 2005 PETROLEUM BASELINE

Assumption—land types available for conversion	(100 yr 2%)	(30 yr 0%)
100% Pasture Replacement	−4%	+27%
No Pasture Replacement	−45%	−27%

2. Treatment of GHG Emissions Over Time

As described in Section VI.B.5, changes in indirect land use associated with increased biofuel production result in GHG emissions increases that accumulate over a long time period. Since there is a large release of carbon in the first year of land conversion, it can take many years for the benefits of the biofuel to make up for these early carbon emissions, depending on the specific biofuel in question. Table VI.C.2–1 contains the payback period associated with several types of biofuels and fuel production pathways. A payback period of 0 indicates that these pathways do not have land use change impacts and therefore reduce emissions in the first year that they are produced. Assessments are made in comparison to the baseline transportation fuel used in 2005 in the U.S. as mandated by EISA. The percent reduction goal is the lifecycle GHG emissions of the biofuel compared to the baseline petroleum fuel it is replacing.

TABLE VI.C.2–1—PAYBACK PERIOD

[in years]

Fuel type	Payback period (years)			
	Reduction goal: 0%	Reduction goal: 20%	Reduction goal: 50%	Reduction goal: 60%
Corn Ethanol 2022 Base Dry Mill NG [315]	33	54	[316] N/A	N/A
Corn Ethanol 2022 Best Case Dry Mill NG [317]	23	31	N/A	N/A
Corn Ethanol 2022 Base Dry Mill Coal [318]	75	>100	N/A	N/A
Corn Ethanol 2022 Base Dry Mill Biomass [319]	22	31	N/A	N/A
Soybean Biodiesel	32	46	105	N/A
Waste Grease Biodiesel	0	0	0	N/A
Sugarcane Ethanol	18	26	61	N/A
Switchgrass Ethanol	3	3	4	5
Corn Stover Ethanol	0	0	0	0

As described in Section VI.B.5, we have focused our lifecycle GHG analysis on two ways of accounting for GHG emissions over time. In one set of results we consider lifecycle GHG emissions over 100 years and discount future emissions with a 2% discount rate. In the other set of results we consider 30 years of GHG emissions with no discounting of future emissions (i.e., 0% discount rate). Whereas the discussion immediately above focused on lifecycle GHG impacts assuming 100 years with a 2% discount rate and 30 years with no discount rate, Table VI.C.2–2 shows the lifecycle GHG emissions reductions estimates with a variety of time periods and discount rates.

TABLE VI.C.2–2—LIFECYCLE GHG EMISSIONS CHANGES OF SELECT BIOFUELS RELATIVE TO THE 2005 PETROLEUM BASELINE

	Lifecycle GHG emissions changes of select biofuels relative to the 2005 petroleum baseline											
Time horizon	30 Years				50 Years				100 Years			
Discount rate	0%	2%	3%	7%	0%	2%	3%	7%	0%	2%	3%	7%
Corn Ethanol Dry Mill NG	5%	18%	25%	54%	−17%	−2%	7%	44%	−36%	−16%	−4%	41%
Corn Ethanol Best Case Dry Mill NG	−14%	−1%	6%	35%	−36%	−21%	−12%	25%	−55%	−35%	−23%	22%
Corn Ethanol Dry Mill Coal	34%	46%	53%	83%	11%	27%	35%	72%	−8%	13%	24%	69%
Corn Ethanol Dry Mill Biomass	−18%	−6%	1%	31%	−41%	−25%	−17%	20%	−60%	−39%	−28%	16%
Soybean Biodiesel	4%	20%	29%	68%	−24%	−4%	7%	55%	−48%	−22%	−7%	51%
Waste Grease Biodiesel	−80%	−80%	−80%	−80%	−80%	−80%	−80%	−80%	−80%	−80%	−80%	−80%
Sugarcane Ethanol	−27%	−17%	−11%	12%	−45%	−32%	−26%	3%	−61%	−44%	−35%	1%
Switchgrass Ethanol	−124%	−122%	−121%	−115%	−128%	−125%	−124%	−117%	−131%	−128%	−126%	−117%
Corn Stover Ethanol	−116%	−117%	−117%	−118%	−115%	−116%	−116%	−117%	−114%	−115%	−115%	−117%

D. Thresholds

EISA established GHG thresholds for each category of renewable fuel that it mandates. EISA also provided EPA with the authority to adjust the threshold levels for each category of renewable fuels if certain requirements are met. Renewable fuels must achieve a 20% reduction in lifecycle greenhouse gas emissions compared to the average lifecycle greenhouse gas emissions for gasoline or diesel sold or distributed as transportation fuel in 2005. Due to the grandfathering provisions of EISA as adopted in this rule, this threshold only pertains to renewable fuel produced at plants to be constructed in the future. EPA is permitted to adjust this threshold to as low as 10%, based on the ''maximum achievable level, taking cost into consideration, for natural gas fired corn-based ethanol plants allowing for the use of a variety of technologies.'' Based on our analysis, there are a number of corn ethanol natural gas plant configurations that could meet the 20% reduction in GHG emissions thresholds in 2022 if modeling emission over a 100 year time frame and then discounting these emissions 2%. Therefore, based on this assessment, we believe that an adjustment to the 20% threshold would be unnecessary and we are proposing to maintain it at the 20% level if we adopt the 100 year, 2% discounting methodology.

On the other hand, based on our current analyses, if we adopt an assessment methodology which assesses emissions over just 30 years, then no currently analyzed natural gas-fired corn ethanol pathway will meet the 20% threshold. However, some of the natural gas corn ethanol pathways do

[315] Dry Mill corn ethanol plant using natural gas with 2022 energy use and dry DDGS.

[316] Payback periods were not calculated for ethanol made from corn starch for the advanced biofuel reduction goals of 50% and 60% since this corn ethanol does not qualify under EISA as a potential advanced biofuel.

[317] Dry Mill corn ethanol plant using natural gas with 2022 energy use and w/CHP, Fractionation, Membrane Separation, and Raw Starch Hydrolysis (wet DGS).

[318] Dry Mill corn ethanol plant using coal with 2022 energy use and dry DDGS.

[319] Dry Mill corn ethanol plant using biomass with 2022 energy use and dry DDGS.

have lifecycle GHG emission benefits in the 10% to 20% range. Corn ethanol is expected to be the major biofuel contributing to meeting the renewable fuel standards through at least the middle of the next decade. Therefore, if we adopt a 30 year timeframe for emissions assessment and do not discount the results, we may adjust the renewable fuel thresholds to the minimum level as necessary to incorporate at least a few of the best GHG pathways for corn ethanol. While this adjusted threshold level could be revised based on pathway analyses done for the final rule, at this time we would intend to allow a full 10% adjustment of the renewable fuel threshold, down to a threshold value of 10% reduction compared to the 2005 gasoline baseline.

Cellulosic biofuels must meet a 60% reduction in GHG emissions relative to the petroleum baseline. EPA is permitted to adjust this threshold to as low as 50% if it is ''not commercially feasible for fuels made using a variety of feedstocks, technologies, and processes'' to achieve the 60% threshold. Our initial analysis indicates that cellulosic biofuels from corn stover, switchgrass, and bagasse will all meet the 60% threshold regardless of whether we use to 100 year, 2% discount methodology or the 30 year analysis time frame without discounting. Furthermore, we believe most fuels made from other cellulosic feedstocks would as well. Therefore we do not believe it is necessary to adjust the threshold for cellulosic biofuel at this time.

Biomass-based diesel must achieve a 50% reduction in GHG emissions relative to petroleum-based diesel. EPA is permitted to adjust this threshold to as low as 40% if it is ''not commercially feasible for fuels made using a variety of feedstocks, technologies, and processes'' to meet the 50% level. For biomass-based diesel, our analysis indicates that biodiesel from waste oils such as yellow grease and tallow would meet the 50% threshold, and we anticipate that biodiesel from chicken waste and non-food grade corn oil fractionation would as well regardless of whether we use a 100 year, 2% discount methodology or the 30 year analysis time frame without discounting. However, our current analysis indicates that there is insufficient feedstock from waste grease and fats to meet the one billion gallon volumetric requirement under EISA. Biodiesel from soy oil (and we believe biodiesel from other food grade vegetable oils) would reduce GHG emissions by no more than 22% using a 100 year, 2% discount methodology and would be estimated to increase GHG emissions if we analyze emission impacts over 30 years whether the emissions are discounted or not. Even if EPA adjusted the biomass-based diesel standard to the minimum allowable level of 40%, soybean-based biodiesel would still not meet the GHG emissions reductions threshold for biomass based diesel fuel. One option for meeting the volumetric requirement and the emissions reduction threshold, assuming a 100 year timeframe and a 2% discount rate for GHG emission impacts would be to allow biodiesel producers to average the emissions reductions from a blend of soy oil or food grade vegetable oil-based biodiesel with waste oil based biodiesel, as discussed in more detail in Section VI.E. However, this approach may still be insufficient to ensure that the required volumes of biomass-based diesel can be produced unless other sources of biomass-based diesel become available. Therefore, we invite comments on whether it be appropriate to both reduce the threshold to 40% and allow biodiesel producers to average their emissions to meet the one billion gallon volumetric requirement as discussed below in Section VI.E.3.c.

Advanced biofuels must achieve a 50% reduction in GHG emissions. EPA is permitted to adjust this threshold to as low as 40% if it is ''not commercially feasible for fuels made using a variety of feedstocks, technologies, and processes'' to achieve the 50% threshold. Our current lifecycle analysis suggests that sugarcane based ethanol only offers an estimated 44% reduction in GHG emissions relative to the gasoline it replaces when assessing 100 years of emission impacts and discounting these emissions 2%, and an estimated 27% reduction when assessing 30 years of emission impacts with no discounting. Therefore, it would not qualify as an advanced biofuel if we did not adjust the 50% GHG threshold. We are also unaware of other renewable fuels that may be available in sufficient volumes over the next several years to allow the statutory volume requirements for advanced biofuel to be met. As a result, we are proposing that the GHG threshold for advanced biofuels be adjusted to 44% or potentially as low as 40% depending on the results from the analyses that will be conducted for the final rule. Based on our current analysis of the lifecycle GHG impacts of sugarcane ethanol, such an adjustment would help ensure that the volume mandates for advanced biofuel can be met.

We invite comments on these proposed thresholds and our basis for them.

E. Assignment of Pathways to Renewable Fuel Categories

The lifecycle analyses that we conducted for a variety of fuel pathways formed the basis for our determination of which pathways would be permitted to generate RINs, and to which of the four renewable fuel categories (cellulosic biofuel, biomass-based diesel, advanced biofuel, and renewable fuel) those RINs should be assigned. This determination involved comparing the lifecycle GHG performance estimates to the GHG thresholds associated with each renewable fuel category, discussed in Section VI.D above. In addition, each of the four renewable fuel categories is defined in EISA to include or exclude certain types of feedstocks and production processes, and these definitions also played a role in determining the appropriate category for each pathway. This section describes our proposed assignments of pathways to one of the four renewable fuel categories. The GHG lifecycle values used in this assignment of fuel pathways to the four renewable fuel categories were based on the lifecycle analysis results over a 100-year timeframe and using a 2% discount rate, as described in Section VI.C. Different assignments of pathways to the four renewable fuel categories would occur with different lifecycle results, but we propose that the same assignment methodology would be followed regardless.

1. Statutory Requirements

EISA establishes requirements that are common to all four categories of renewable fuel in addition to requirements that are unique to each of the four categories. The common requirements determine which fuels are valid for generating RINs under the RFS2 program. For instance, all renewable fuel must be made from renewable biomass, which defines the types of feedstocks that can be used to produce renewable fuel that is valid under the RFS2 program, and also defines the types of land on which crops can be grown if those crops are used to produce valid renewable fuel under the RFS2 program. See Section III.B.4 for a more detailed discussion of renewable biomass. Moreover, all renewable fuel must displace fossil fuel present in transportation fuel, or be used as home heating oil or jet fuel.

The requirements that are unique to each of the four categories provide a basis for assigning each pathway to a category. For each of the four categories of renewable fuel, EISA provides a definition, specifies the associated GHG thresholds, lists the allowable feedstocks and/or fuel types, and in some cases provides exclusions. Table VI.E.1–1 summarizes these requirements as we are applying them under the proposed RFS2 program.

TABLE VI.E.1–1—REQUIREMENTS FOR RENEWABLE FUEL CATEGORIES

	Cellulosic biofuel	Biomass-based diesel	Advanced biofuel	Renewable fuel
GHG threshold	60%	50% [a]	40–44% [a]	20% [a, b].
Eligible Inclusions	Renewable fuel made from cellulose, hemicellulose, or lignin.	Any renewable fuel that is a diesel fuel substitute.	All cellulosic biofuel and biomass-based diesel, as well as other renewable fuels including ethanol from sugar, starch, or waste materials, biogas, and butanol and other alcohols.	All advanced biofuel, and any other fuel made from renewable biomass that is used to replace or reduce the quantity of fossil fuel present in a transportation fuel.
Exclusions		Any renewable fuel made from coprocessing with petroleum.	Ethanol derived from corn starch.	

[a] As discussed in Section VI.D, we are seeking comment on the need to adjust the thresholds, and are proposing that the GHG threshold for advanced biofuels be adjusted to as low as 40%.
[b] 20% threshold does not apply to grandfathered volumes. *See* discussion in Section III.B.3.

2. Assignments for Pathways Subjected to Lifecycle Analyses

There are a wide variety of pathways (unique combinations of feedstock, fuel type, and fuel production process) that could result in renewable fuel that would be valid under the RFS2 program. As described earlier in this section, we conducted lifecycle analyses for some of these pathways, and these analyses allowed us to determine if the GHG thresholds shown in Table VI.E.1–1 would be met under the assumption of a 100-year timeframe and discount rate of 2%. For other pathways that we have not yet subjected to lifecycle analyses, there were some cases in which we could nevertheless still make moderately confident determinations as to the likely GHG impacts by making comparisons to the pathways that we did analyze. A discussion of these other determinations is provided in Section VI.E.3 below.

For pathways that we subjected to lifecycle analysis, we were able to assign each pathway to one of the four renewable fuel categories defined in EISA by comparing the descriptions of each pathway and its associated GHG performance to the requirements shown in Table VI.E.1–1. The results are shown in Table VI.E.2–1.

TABLE VI.E.2–1—PROPOSED ASSIGNMENT OF PATHWAYS TO ONE OF THE FOUR RENEWABLE FUEL CATEGORIES FOR PATHWAYS SUBJECTED TO LIFECYCLE ANALYSES

Cellulosic biofuel pathways	Ethanol produced from corn stover or switchgrass in a process that uses enzymes to hydrolyze the cellulose and hemicellulose.
Biomass-based diesel pathways	Biodiesel (mono alkyl esters) produced from waste grease and waste oils.
Advanced biofuel pathways	Ethanol produced from sugarcane sugar in a process that uses sugarcane bagasse for process heat. [a]
Renewable fuel pathways	Ethanol produced from corn starch in a process that uses biomass for process heat.
	Ethanol produced from corn starch in a process that includes: —Dry mill plant. —Process heat derived from natural gas. —Combined heat and power (CHP). —Fractionation of feedstocks. —All distillers grains are dried.
	Ethanol produced from corn starch in a process that includes: —Dry mill plant. —Process heat derived from natural gas. —All distillers grains are wet.
	Ethanol produced from corn starch in a process that includes: —Dry mill plant. —Process heat derived from coal. —Combined heat and power (CHP). —Fractionation of feedstocks. —Membrane separation of ethanol. —Raw starch hydrolysis. —All distillers grains are dried.
	Ethanol produced from corn starch in a process that includes: —Dry mill plant. —Process heat derived from coal. —Combined heat and power (CHP). —Fractionation of feedstocks. —Membrane separation of ethanol. —All distillers grains are wet.

TABLE VI.E.2–1—PROPOSED ASSIGNMENT OF PATHWAYS TO ONE OF THE FOUR RENEWABLE FUEL CATEGORIES FOR PATHWAYS SUBJECTED TO LIFECYCLE ANALYSES—Continued

	Biodiesel (mono alkyl esters) produced from soybean oil.

[a] Our current analysis concludes that ethanol from sugarcane sugar would have a GHG performance of 44% in comparison to gasoline under our assumed 100-year timeframe and 2% discount rate. Since this falls short of the 50% GHG threshold for advanced biofuel, we have categorized it as general renewable fuel. However, we request comment on lowering the applicable GHG threshold for advanced biofuel so that ethanol from sugarcane sugar could be categorized as advanced biofuel. See further discussion in Section VI.D.

In addition, our lifecycle analyses also identified pathways that did not meet the minimum 20% GHG threshold under an assumed 100-year timeframe and 2% discount rate, and thus would be prohibited from generating RINs unless a facility met the prerequisites for grandfathering as described in Section III.B.3. These prohibited pathways all involved the production of ethanol from corn starch in a process that uses natural gas or coal for process heat, but which does not meet any of the process technology requirements listed in Table VI.E.2–1. Our proposal for temporary D codes in § 80.1416 would explicitly prohibit the generation of RINs for these pathways.

The proposed assignments of individual pathways to one of the four renewable fuel categories shown in the table above assumed a 100-year timeframe and discount rate of 2% for lifecycle GHG emission impacts. The assignments would be different if we had assumed a different timeframe and discount rate. By comparing the relative GHG emission reductions shown in Table VI.C.1–2 to the thresholds in Table VI.E.1–1, a variety of different assignments is possible covering timeframes of 30, 50, and 100 years, and discount rates of 0%, 2%, 3%, and 7%. For instance, under the assumption of 30 years and no discounting, switchgrass ethanol and corn stover ethanol would continue to be categorized as cellulosic biofuel and biodiesel made from waste grease would continue to be categorized as biomass-based diesel. However, sugarcane ethanol could no longer be potentially categorized as advanced biofuel but instead would be categorized as renewable fuel. Moreover, some pathways would not meet the minimum threshold of 20% for renewable fuel, and so could not generate RINs if the volume was not grandfathered. This would include soybean biodiesel and all of the corn starch ethanol pathways shown in Table VI.E.2–1 produced from newly constructed plants not meeting the grandfathering criteria discussed in Section III.B.3.

3. Assignments for Additional Pathways

We were not able to conduct lifecycle modeling for all potential pathways in time for this proposed rulemaking. Instead, we focused the lifecycle GHG emissions analysis on the feedstocks that, based on FASOM predictions and other information, we anticipate could contribute the largest volumes to the renewable fuel pool and the production processes representing the largest shares of the market. As more information becomes available, we anticipate that we will be updating the lifecycle methodology and expanding the list of emission factors.

Beyond the pathways that we explicitly subjected to lifecycle analysis, there are additional pathways that may not currently be significant contributors to the volume of renewable fuel produced, but their volumes could increase in the future. Moreover, we believe it is important that as many pathways as possible be included in the lookup table in the regulations to help ensure that the volume requirements in EISA can be met and to encourage the development of new fuels. To this end, we evaluated these additional pathways to determine if they could be deemed valid for generation of RINs, and if so which of the four renewable fuel categories they would fall into. This section describes our evaluation of these additional pathways and the resulting proposed assignment to one or more of the four renewable fuel categories.

a. Ethanol From Starch

Our lifecycle analysis focused on ethanol from corn starch. However, there are a variety of other sources of starch that use or could use a very similar process for conversion to ethanol. These include wheat, barley, oats, rice, and sorghum. Some existing corn-ethanol facilities already use small amounts of starch from these other plants along with corn in their production of ethanol.

Although we have not explicitly analyzed the land use or processing impacts of these other starch plants on their lifecycle GHG performance, we believe it would be reasonable to assume similar impacts to corn in terms of the types of land that would be displaced and other aspects of producing and transporting the feedstock. Therefore, we propose that the pathways shown in Table VI.E.2–1 for ethanol produced from corn starch also be applied to ethanol produced from other sources of starch.

The lifecycle analyses conducted for this proposal only examined cases in which a corn-ethanol facility dried 100% of its distiller's grains or left 100% of its distiller's grains wet. The treatment of the distiller's grains for corn-ethanol facilities impacts the determination of whether the 20% GHG threshold for renewable fuel has been met. However, in practice some facilities may dry only a portion of their distiller's grains and leave the remainder wet. As described in Section III.D.3, we are proposing that a facility that dried only a portion of its distiller's grain would be treated as if it dried 100% of its grains, and would thus need to implement additional GHG-reducing technologies as described in the lookup table in order to qualify to generate RINs. However, we are also taking comment on whether a selection of pathways should be included in the lookup table that represent corn-ethanol facilities that dry only a portion of their distiller's grains. We also request comment on whether RINs could be assigned to only a portion of the facility's ethanol in cases wherein only a portion of the distiller's grains are dried.

b. Renewable Fuels from Cellulosic Biomass

In analyzing the lifecycle GHG impacts of cellulosic ethanol, we determined that ethanol produced from corn stover or switchgrass through a process using enzymatic hydrolysis followed by fermentation of the resulting sugars met the GHG threshold of 60% for cellulosic biofuel by a wide margin (regardless of the discount rate and the time period over which the lifecycle GHG emissions are discounted). However, there are many other potential sources of cellulosic biomass, and other processing mechanisms to convert cellulosic biomass into fuel. For some of these cases, we believe that we can make determinations regarding whether the GHG thresholds shown in Table VI.E.1–1 are likely to be met. In addition, as the forestry component of the FASOM model is incorporated into the analysis, we will analyze pathways using planted trees, tree residue, and slash and pre-commercial thinnings from forestland, as qualify under the renewable biomass definition, for feedstock.

Cellulosic biomass sources include waste biomass such as corn stover, and crops grown specifically for fuel production such as switchgrass. While cellulosic crops grown for the purpose of fuel production could have land use implications in a lifecycle GHG analysis, waste materials produced during the harvesting of some other type of crop would not. Given that the GHG impacts of a fermentation-based fuel production process are likely to be very similar for cellulose from a variety of feedstocks, we believe it would be reasonable to conclude that any cellulosic feedstock from a waste source that is subjected to enzymatic hydrolysis followed by fermentation of the resulting sugars would be very likely to meet the 60% GHG threshold for cellulosic biofuel. Therefore, we propose that cellulosic ethanol produced through an enzymatic hydrolysis process followed by fermentation using any eligible waste cellulosic feedstock would be determined to meet the 60% GHG threshold for cellulosic biofuel. This would include such wastes as wheat straw, rice straw, sugarcane bagasse, forest slash and thinnings, and yard waste.

As stated earlier, cellulosic crops grown for the purpose of fuel production could have land use implications in a lifecycle GHG analysis. However, the only cellulosic crop that we subjected to lifecycle analysis was switchgrass which had a relatively small impact of land-use. Other cellulosic crops that have been considered for fuel production include miscanthus and trees such as poplar and willow. It is possible that the land use impacts of miscanthus and planted trees could be different from that for switchgrass. For instance, while switchgrass can be grown on marginal lands, planted trees may require more arable land to thrive. However, according to our lifecycle analysis for switchgrass, the land use impacts could significantly increase and the 60% threshold for cellulosic biofuel would still be met. Therefore, we propose that the pathways shown in Table VI.E.2–1 for ethanol produced from switchgrass through an enzymatic hydrolysis process followed by fermentation also be applied to ethanol produced from miscanthus and planted trees. We intend to examine this pathway more closely for the final rule to determine if this categorization is appropriate, and request comment on the land use impacts of miscanthus and planted trees.

Renewable fuels can also be produced from cellulosic biomass through various thermochemical processes rather than enzymatic hydrolysis followed by fermentation. One example of such thermochemical processes would be biomass gasification to produce ''syngas'' (a mixture of hydrogen and carbon monoxide) which is then catalytically synthesized through a Fischer-Tropsch process to produce ethanol, diesel, gasoline, or other transportation fuels. Another example would be a catalytic depolymerization process in which the biomass is first catalytically cracked to smaller molecules and then polymerized under specific combinations of temperature, pressure, and residence time to produce a transportation fuel. We have not conducted a lifecycle analysis of these pathways, but we believe that we can nonetheless make a reasonable determination regarding the appropriate renewable fuel category. For instance, we would expect that the GHG emissions produced during fuel production would be higher for a thermochemical process than for enzymatic hydrolysis due to the need for greater process heat produced through the combustion of fossil fuels. However, the yield of fuel produced per ton of biomass is likely to be greater for thermochemical processing due to the conversion of the lignin to fuel in addition to the cellulose and hemicellulose. Thus, while the lifecycle GHG analyses we conducted for corn stover and switchgrass demonstrated that the 60% GHG threshold for cellulosic biofuel would be met by a wide margin, this margin may be smaller if a thermochemical process was used. While we intend to conduct further analyses of this family of pathways for the final rule, we believe that a change from enzymatic hydrolysis to a thermochemical process would be expected to meet the 60% GHG threshold associated with cellulosic biofuel. Therefore, we propose that the use of corn stover or other waste cellulosic biomass, switchgrass, or planted trees in a thermochemical process would qualify as cellulosic biofuel under the RFS2 program. This would include pathways that produce ethanol, cellulosic diesel, or cellulosic gasoline. Since cellulosic diesel fuel produced in this way would also meet the requirements for biomass-based diesel, we propose to allow it to be categorized as either cellulosic biofuel or biomass-based diesel at the producer's discretion. See further discussion of this issue in Section III.D.2.a. We request comment on our proposed assignment of categories for renewable fuels produced through a thermochemical process, as well as data and other information relating to the various types of thermochemical fuel production processes.

c. Biodiesel

Our lifecycle analysis of biodiesel (mono alkyl esters) produced from waste greases/oils demonstrated that the 50% GHG threshold for biomass-based diesel would be met. Much of the GHG benefit of these waste greases/oils derives from the fact that they have no land use impacts. While we did not subject corn oil that is non-food grade to lifecycle analysis, it is likely that it would also have no land use impacts. Moreover, such non-food grade corn oil would require nearly the same process energy to convert it into biodiesel. Therefore, we propose that the pathway shown in Table VI.E.2–1 for biodiesel produced from waste greases/oils also be applied to biodiesel produced from non-food grade corn oil. We intend to analyze this pathway in more depth for the final rule.

Our lifecycle analysis of biodiesel produced from soybean oil may also be applicable to biodiesel produced from other types of virgin (not waste) oils. This would include canola oil, rapeseed oil, sunflower oil, and peanut oil. While we have not conducted a detailed assessment of the land use impacts of these other virgin oils, it is possible that they would meet the 20% threshold for generic renewable fuel. Therefore, we propose that the pathway shown in Table VI.E.2–1 for biodiesel produced from soybean oil also be applied to biodiesel produced from other these virgin oils. We request comment on whether this is appropriate.

Although our proposed list of RIN-generating pathways would allow biodiesel made from waste greases/oils to qualify as biomass-based diesel, it is likely that there would be insufficient quantities of these feedstocks to reach the 1.0 billion gallon requirement by 2012. Biodiesel produced from soybean oil would not qualify as biomass-based diesel, but instead would be categorized as generic renewable fuel based on our current analysis of its lifecycle GHG performance. However, biodiesel production facilities can process either soybean oil or waste grease with relatively minor changes in operations, and many facilities that formerly used soybean oil have recently switched to waste grease due to its more favorable economics. Since the GHG performance of biodiesel made from waste greases/oils met the 50% GHG threshold by a wide margin, and since it is common industry practice for biodiesel facilities to use these two feedstock sources, we believe it may be appropriate to allow a biodiesel production facility to average the GHG benefit generated through the use of waste grease with the lower GHG performance of biodiesel produced from soybean oil at the same facility.

We recognize that an approach in which we allow a biodiesel production facility to average the GHG benefit of waste grease with that from soybean oil raises questions about whether similar averaging could be allowed for other combinations of feedstocks, other types of fuel, or across multiple facilities within the same company. While we believe that the circumstances surrounding biodiesel production are somewhat unique—two different feedstocks subjected to essentially the same production process in a single facility—we nevertheless request comment on the appropriateness of such an averaging approach for biodiesel.

Based on our lifecycle analyses, biodiesel produced from waste grease has a GHG performance of 80% reduction from the conventional diesel baseline, while biodiesel produced from soybean oil has a GHG performance of 22% reduction. In order to meet the GHG threshold of 50% for biomass-based diesel, a biodiesel production facility would need to use a minimum of 48% waste grease and a maximum of 52% soybean oil. Thus, a pathway that would allow a biodiesel production facility to designate all of its biodiesel as biomass-based diesel would include a requirement that the producer demonstrate that every batch has been produced from no less than 48% waste grease and no more than 52% soybean oil.

Although this approach would allow the total volume of biomass-based diesel to be larger than if waste greases/oils alone qualified, it is still possible than the 1.0 billion gallon requirement would not be met due to limits on the availability of waste greases and oils. For instance, we estimate that the total volume of waste greases and oils may be no larger than 0.3–0.4 billion gallons. As a result, we request comment on whether it would also be appropriate to lower the GHG threshold for biomass-based diesel. If this GHG threshold were lowered to 40%, a biodiesel production facility would only need to use a minimum of 31% waste greases/oils instead of 48%.

We recognize that it may be difficult for a biodiesel production facility to process a consistent mixture of waste grease and soybean oil every day. Therefore, we request comment on alternative approaches. For instance, if a biodiesel production facility processed only waste grease for the first 175 days (48% × 365 days) of a calendar year, we could allow it to designate any biodiesel produced from soybean oil for the remainder of the year as biomass-based diesel. However, this may be difficult for some producers who must contend with cold temperature storage and blending issues in the early part of a calendar year by processing only soybean oil. Alternatively, we could allow a company to average the production at all of its facilities, where one facility processed only waste grease and another processed only soybean oil.

Finally, we request comment on an alternative approach in which an obligated party, rather than the biodiesel production facility, would demonstrate that a minimum number of waste grease-based biodiesel RINs is used to meet the biomass-based diesel standard in comparison to the number of soybean oil-based biodiesel RINs. In essence, the averaging would be carried out by the obligated party instead of the biodiesel producer. In this approach, biodiesel RINs would not be placed into biomass-based diesel category shown in Table VI.E.1–1, but instead would be placed into two separate categories as waste grease RINs or soybean oil RINs. This designation would require that the list of applicable D codes for use in the RIN be expanded from four to six as shown in Table VI.E.3.c–1.

TABLE VI.E.3.C–1—ALTERNATIVE APPROACH TO D CODES FOR AVERAGING WASTE GREASE AND SOYBEAN OIL BIODIESEL RINS IN COMPLIANCE

D value	Proposal meaning	Alternative approach meaning
1	Cellulosic biofuel	Cellulosic biofuel
2	Biomass-based diesel.	Biomass-based diesel
3	Advanced biofuel	Biodiesel made from soybean oil
4	Renewable fuel ...	Biodiesel made from waste grease
5	(Not applicable) ..	Advanced biofuel
6	(Not applicable) ..	Renewable fuel

Since other types of renewable fuel may still qualify as biomass-based diesel, we would retain a separate D code for this category under this approach. This could allow biodiesel producers who choose the process a minimum of 48% waste greases/oils each day to continue to assign a D code of 2 to their biodiesel.

An obligated party could use any combination of RINs with a D code of 2, 3, or 4 in order to comply with the biomass-based diesel standard. However, he would also be subject to an additional requirement that the ratio of D=3 RINs to D=4 RINs must be less than 1.08. This criterion would ensure that a minimum of 47 RINs representing biodiesel from waste grease would be used for compliance purposes for every 53 RINs representing biodiesel from soybean oil that are also used for compliance.

We request comment on these alternative approaches to the treatment of biodiesel.

d. Renewable Diesel Through Hydrotreating

We did not conduct a lifecycle analysis for the production of non-ester renewable diesel through a hydrotreating process. However, we believe that our analysis of biodiesel provides sufficient information to allow us to designate the renewable fuel category for various pathways leading to the production of renewable diesel.

Renewable diesel is generally made from the same feedstocks as biodiesel, namely soybean oil, waste greases/oils, tallow, and chicken fat. Therefore, the GHG impacts associated with producing/collecting the feedstock and transporting it to the production facility would be the same regardless of whether the final product is biodiesel or renewable diesel.

The fossil energy requirements of the production process contribute a relatively small amount to the overall GHG performance for biodiesel. For example, the 50% GHG threshold would still be met for biodiesel produced from waste grease even if the fossil energy requirements doubled. As a result, compared to the transesterification process used to produce biodiesel, any small variations in fossil energy requirements for renewable diesel production in a hydrotreater would be unlikely to change compliance with the broad categories created by the GHG thresholds for biomass-based diesel and generic renewable fuel. Therefore, we believe that it would be appropriate to assign applicable renewable fuel categories to renewable diesel pathways in parallel with the assignments we are proposing for biodiesel, including the potential for averaging of soyoil and waste grease derived volumes. Renewable diesel produced from waste grease, tallow, or chicken fat in a hydrotreater that does not coprocess petroleum feedstocks would be categorized as biomass-based diesel. Renewable diesel produced from waste grease, tallow, or chicken fat in a hydrotreater that does coprocess petroleum feedstocks would be categorized as advanced biofuel. Finally, renewable diesel produced from soybean oil in a hydrotreater would be categorized as generic renewable fuel.

4. Summary

Based on the discussion above, we have identified 15 pathways that we propose could be used to produce fuel that would meet the volume requirements in EISA assuming a 100 year analysis time frame and discounting GHG emissions over time by 2%. As noted above, these pathways would be adjusted should we adopt other time frames or discount rates (including a zero discount rate) for the final rule. Each pathway would be assigned a D code for use in generating RINs that corresponds to one of the four renewable fuel categories. Our proposed list of allowable pathways is shown in Table VI.E.4–1.

TABLE VI.E.4–1—APPLICABLE CATEGORIES FOR EACH FUEL PATHWAY [a]

Fuel type	Feedstock	Production process requirements	Category
Ethanol	Starch from corn, wheat, barley, oats, rice, or sorghum.	—Process heat derived from biomass.	Renewable fuel.
Ethanol	Starch from corn, wheat, barley, oats, rice, or sorghum.	—Dry mill plant —Process heat derived from natural gas. —Combined heat and power (CHP). —Fractionation of feedstocks. —Some or all distillers grains are dried.	Renewable fuel.
Ethanol	Starch from corn, wheat, barley, oats, rice, or sorghum.	—Dry mill plant —Process heat derived from natural gas. —All distillers grains are wet.	Renewable fuel.
Ethanol	Starch from corn, wheat, barley, oats, rice, or sorghum.	—Dry mill plant —Process heat derived from coal. —Combined heat and power (CHP). —Fractionation of feedstocks. —Membrane separation of ethanol. —Raw starch hydrolysis. —Some or all distillers grains are dried.	Renewable fuel.
Ethanol	Starch from corn, wheat, barley, oats, rice, or sorghum.	—Dry mill plant —Process heat derived from coal. —Combined heat and power (CHP). —Fractionation of feedstocks. —Membrane separation of ethanol. —All distillers grains are wet.	Renewable fuel.
Ethanol	Cellulose and hemicellulose from corn stover, switchgrass, miscanthus, wheat straw, rice straw, sugarcane bagasse, forest waste, yard waste, or planted trees.	—Enzymatic hydrolysis of cellulose. —Fermentation of sugars. —Process heat derived from lignin.	Cellulosic biofuel.
Ethanol	Cellulose and hemicellulose from corn stover, switchgrass, miscanthus, wheat straw, rice straw, sugarcane bagasse, forest waste, yard waste, or planted trees.	—Thermochemical gasification of biomass. —Fischer-Tropsch process.	Cellulosic biofuel.
Ethanol	Sugarcane sugar	—Process heat derived from sugarcane bagasse.	Advanced biofuel.
Biodiesel (mono alkyl ester)	Waste grease, waste oils, tallow, chicken fat, or non-food grade corn oil.	—Transesterification	Biomass-based diesel.
Biodiesel (mono alkyl ester)	Soybean oil and other virgin plant oils.	—Transesterification	Renewable fuel.

TABLE VI.E.4–1—APPLICABLE CATEGORIES FOR EACH FUEL PATHWAY [a]—Continued

Fuel type	Feedstock	Production process requirements	Category
Cellulosic diesel	Cellulose and hemicellulose from corn stover, switchgrass, miscanthus, wheat straw, rice straw, sugarcane bagasse, forest waste, yard waste, or planted trees.	—Thermochemical gasification of biomass.	Cellulosic biofuel or biomass-based diesel.
		—Fischer-Tropsch process.	
		—Catalytic depolymerization.	
Non-ester renewable diesel	Waste grease, waste oils, tallow, chicken fat, or corn oil.	—Hydrotreating.	
		—Dedicated facility that processes only renewable biomass.	Biomass-based diesel.
Non-ester renewable diesel	Waste grease, waste oils, tallow, chicken fat, or non-food grade corn oil.	—Hydrotreating	Advanced biofuel.
		—Coprocessing facility that also processes petroleum feedstocks.	
Non-ester renewable diesel	Soybean oil and other virgin plant oils.	—Hydrotreating	Renewable fuel.
Cellulosic gasoline	Cellulose and hemicellulose from corn stover, switchgrass, miscanthus, wheat straw, rice straw, sugarcane bagasse, forest waste, yard waste, or planted trees.	—Thermochemical gasification of biomass.	Cellulosic biofuel.
		—Fischer-Tropsch process.	
		—Catalytic depolymerization.	

[a] Under our assumed 100-year timeframe and 2% discount rate.

As stated earlier, there may be other potential pathways that could lead to qualifying renewable fuel. While we do not have sufficient information at this time to evaluate the likely lifecycle GHG impact and thus assign those pathways to one of the four renewable fuel categories, we do plan on doing these evaluations for the final rule. Pathways that we intend to subject to lifecycle analysis include butanol from starches or oils and renewable diesel from biomass using pyrolysis or catalytic reforming. We request comment on the inputs necessary to apply lifecycle analysis to these pathways. We also request comment on other pathways that should be analyzed and the data that would be necessary for those analyses.

For pathways that are not included in the lookup table in the final rule, we are also proposing a regulatory mechanism whereby a producer could temporarily assign their renewable fuel to one of the four renewable fuel categories under certain conditions. For further discussion of this issue, see Section III.D.5.

F. Total GHG Emission Reductions

Our analysis of the overall GHG emission impacts of this proposed rulemaking was performed in parallel with the lifecycle analysis performed to develop the individual fuel thresholds described in previous sections. The same system boundaries apply such that this analysis includes the effects of three main areas: (a) emissions related to the production of biofuels, including the growing of feedstock (corn, soybeans, etc.) with associated domestic and international land use change impacts, transport of feedstock to fuel production plants, fuel production, and distribution of finished fuel; (b) emissions related to the extraction, production and distribution of petroleum gasoline and diesel fuel that is replaced by use of biofuels; and (c) difference in tailpipe combustion of the renewable and petroleum based fuels. As discussed in the previous sections we will be updating our lifecycle approach for the final rule and there are some areas that we were not able to quantify at this time, such as secondary impacts in the energy sector. We are working to include this for our final rule analysis.

Consistent with the fuel volume feasibility analysis and criteria pollutant emissions, our analysis of the GHG impacts of increased renewable fuel use was conducted by comparing the impacts of the 2022 36 Bgal of renewable fuel volumes required by EISA to a projected 2022 reference case of approximately 14 Bgal of renewable fuel volumes. Similar to what was done to calculate lifecycle thresholds for individual fuels we considered the change in 2022 of these two volume scenarios of renewable fuels to determine overall GHG impacts of the rule. The reference case for the GHG emission comparisons was taken from the AEO 2007 projected renewable fuel production levels for 2022 prior to enactment of EISA. This scenario provided a point of comparison for assessing the impacts of the RFS2 standard volumes on GHG emissions. We ran these multi-fuel scenarios through our FASOM and FAPRI models and applied the Winrock land use change assumptions to determine to overall GHG impacts. We were only able to analyze 2022 reference and control cases. However, in reality the impacts of corn ethanol and soybean biodiesel will be experienced beginning in 2009, with the impacts of cellulosic ethanol and sugarcane ethanol growing in later years as their volumes increase.

The main difference between this overall impacts analysis and the analysis conducted to develop the threshold values for the individual fuels is that we analyzed the total change in renewable fuels in one scenario as opposed to looking at individual fuel impacts. When analyzing the impact of the total 36 billion gallons of renewable fuel, we also took into account the agricultural sector interactions necessary to produce the full complement of feedstock. We also considered a mix of plant types and configurations for the 2022 renewable fuel production representing the mix of plants we project to be in operation in 2022. This is based on the same analysis used in the plant location and fuel feasibility analysis described in Section V.B.

For this overall impacts analysis we used a different petroleum baseline fuel that is offset from renewable fuel use. The lifecycle threshold values are required by EISA to be based on a 2005 petroleum fuel baseline. For this inventory analysis of the overall impacts of the rule we considered the crude oil and finished product that would be replaced in 2022. Displaced petroleum product analysis was consistent with work performed for the energy security analysis described in Section IX.B. For this analysis we consider that 25% of displaced gasoline will be imported gasoline. For the domestic production we assumed replacement of the 2022 crude mix which is projected to include 7.6% tar sands and 3.8% Venezuelan heavy crude which is higher then the projected mix in 2005 which includes 5% tar sands and 1% Venezuelan heavy crude.

Given these many differences, simply adding up the individual lifecycle results determined in Section VI.C. multiplied by their respective volumes would yield a different assessment of the overall rule impacts. The two analyses are separate in that the overall rule impacts capture interactions between the different fuels that can not be broken out into per fuels impacts, while the threshold values represent impacts of specific fuels but do not account for all the interactions.

For example, when we consider the combined impact of the different fuel volumes when analyzed separately, the overall land use change is 9.0 million acres. However, when we analyze the volume changes all together, the overall land use change is approximately 10% higher.

The primary reason for the difference in acre change between the sum of the individual fuel scenarios and the combined fuel scenarios is that when looking at individual fuels there is some interaction between different crops (e.g., corn replacing soybeans), but with combined volume scenario when all mandates need to be met there is less opportunity for crop replacement (e.g., both corn and soybean acres needed) and therefore more land is required.

Important findings of our analysis include:

- As with the threshold lifecycle calculations, assumptions about timing to consider impacts over and discount rates will have a significant impact on results.
- We estimate the largest overall agricultural sector impact is an increase in land use change impacts, reflecting the shift of crop production internationally to meet the biofuel demand in the U.S. Increased crop production internationally resulted in land use change emissions associated with converting land into crop production.
- Our analysis indicates that overall domestic agriculture emissions would increase. There is a relatively small increase in total domestic crop acres however, there are additional inputs required due to the removal of crop residues. The assumption is that removal will require more inputs to make up for lost residue nutrients. These additional inputs result in GHG emissions from production and from N_2O releases from application. This effect is somewhat offset by reductions due to lower livestock production. These results are dependent on our agricultural sector input and emission assumptions that are being updated for the final rule (e.g., N_2O emission factor work).
- In particular due to this international impact, the potential overall GHG emission reductions of biofuels produced from food crops such as corn ethanol and soy biodiesel are significantly impacted. Large near term emission increases due to land use change require a number of years before the emission reductions due to corn ethanol and soy biodiesel use will offset the near term emission increase as discussed in the threshold calculation section.
- Cellulosic biofuels contribute by far the most to the total emission reductions due to both their superior per gallon emission reductions and the large volume of these fuels anticipated to be used by 2022.

The timing of the impact of land use change and ongoing renewable fuels benefits were discussed in the previous lifecycle fuel threshold section. The issue is slightly different for this analysis since we are considering absolute tons of emissions and not determining a threshold comparison to petroleum fuels. However the results can be presented in a similar manner to our individual fuels analysis in that we can determine net benefits over time with different discount rates and over a different time frame for consideration.

As discussed in previous sections on lifecycle GHG thresholds there is an initial one time release from land conversion and smaller ongoing releases but there are also ongoing benefits of using renewable fuels over time replacing petroleum fuel use. Based on the volume scenario considered, the one time land use change impacts result in 448 million metric tons of CO2–eq. emissions increase. There are, however, based on the biofuel use replacing petroleum fuels, GHG reductions in each year. When modeling the program as if all fuel volume changes occur in 2022, and considering 100 years of emission impacts that are discounted by 2% per year, we get an estimated total discounted NPV reduction in GHG emissions of 6.8 billion tons over 100 years. Totaling the emissions impacts over 30 years but assuming a 0% discount rate over this 30 year period would result in an estimated total NPV reduction in GHG emissions of 4.5 billion tons over 30 years.

This total NPV reduction can be converted into annual average GHG reductions, which can be used for the calculations of the *monetized* GHG benefits as shown in Section IX.C.4. This annualized value is based on converting the lump sum present values described above into their annualized equivalents. For this analysis we convert the NPV results for the 100 year 2% discount rate into an annualized average such that the NPV of the annualized average emissions will equal the NPV of the actual emission stream over 100 years with a 2% discount rate. This results in an annualized average emission reduction of approximately160 million metric tons of CO2–eq. emissions. A comparable value assuming 30 years of GHG emissions changes but not applying a discount rate to those emissions results in an estimated annualized average emission reduction of approximately 150 million metrics tons of CO2–eq. emissions.

G. Effects of GHG Emission Reductions and Changes in Global Temperature and Sea Level

1. Introduction

The reductions in CO_2 and other GHGs associated with the proposal will affect climate change projections. Because GHGs mix well in the atmosphere and have long atmospheric lifetimes, changes in GHG emissions will affect future climate for decades to centuries. One common indicator of climate change is global mean surface temperature and sea level rise. This section estimates the response in global mean surface temperature projections to the estimated net global GHG emissions reductions associated with the proposed rulemaking (See Section VI.F for the estimated net reductions in global emissions over time by GHG).

2. Estimated Projected Reductions in Global Mean Surface Temperatures

EPA estimated changes in projected global mean surface temperatures to 2100 using the MiniCAM (Mini Climate Assessment Model) integrated assessment model [320] coupled with the MAGICC (Model for the Assessment of Greenhouse-gas Induced Climate Change) simple climate model.[321] MiniCAM was used to create the globally and temporally consistent set of climate relevant variables required for running MAGICC. MAGICC was then used to estimate the change in the global mean surface temperature over time. Given the magnitude of the estimated emissions reductions associated with the proposed rule, a simple climate model such as MAGICC is reasonable for estimating the climate response.

EPA applied the estimated annual GHG emissions changes for the proposal to the MiniCAM U.S. Climate Change Science Program (CCSP) Synthesis and Assessment Product baseline emissions.[322] Specifically, the CO_2, N_2O, and CH_4 annual emission changes from 2022–2121 from Section VI.F were applied as net reductions to the MiniCAM CCSP global baseline net emissions for each GHG. Post-2121, we assumed no change in emissions from the baseline. This assumption is more conservative than allowing the emissions reductions to continue.

Table VI.G.2 provides our estimated reductions in projected global mean surface temperatures and sea level associated with the proposed increase in renewable fuels in 2022. To capture some of the uncertainty in the climate system, we estimated the changes in projected temperatures and sea level across the most current Intergovernmental Panel on Climate Change (IPCC) range of climate sensitivities, 1.5 °C to 6.0 °C.[323] To illustrate the time profile of the estimated reductions in projected global mean surface temperatures and sea level, we have also provided Figures VI.G.2–1 and VI.G.2–2.

TABLE VI.G.2–1—ESTIMATED REDUCTIONS IN PROJECTED GLOBAL MEAN SURFACE TEMPERATURE AND GLOBAL MEAN SEA LEVEL FROM BASELINE IN 2030, 2050, 2100, AND 2200 FOR THE PROPOSED STANDARD IN 2022

	Climate sensitivity				
	1.5	2	3	4.5	6
Change in global mean surface temperatures (degrees Celsius)					
2030	0.000	0.000	−0.001	−0.001	−0.001
2050	−0.001	−0.002	−0.002	−0.002	−0.003
2100	−0.003	−0.004	−0.005	−0.006	−0.007
2200	−0.003	−0.004	−0.006	−0.008	−0.009
Change in global mean sea level rise (centimeters)					
2030	−0.002	−0.002	−0.003	−0.003	−0.003
2050	−0.012	−0.014	−0.017	−0.020	−0.022
2100	−0.045	−0.052	−0.063	−0.074	−0.082
2200	−0.077	−0.091	−0.114	−0.143	−0.172

The results in Table VI.G.2–1 and Figures VI.G.2–1 and VI.G.2–2 show small, but detectable, reductions in the global mean surface temperature and sea level rise projections across all climate sensitivities. Overall, the reductions are small relative to the IPCC's ''best estimate'' temperature increases by 2100 of 1.8 °C to 4.0 °C.[324] Although IPCC does not issue ''best estimate'' sea level rise projections, the model-based range across SRES scenarios is 18 to 59 cm by 2099.[325] Both figures illustrate that the overall emissions reductions can decrease projected annual temperature and sea level for all climate sensitivities. This means that the distribution of potential temperatures in any particular year is shifting down. However, the shift is not uniform. The magnitude of the decrease is larger for higher climate

[320] MiniCAM is a long-term, global integrated assessment model of energy, economy, agriculture and land use, that considers the sources of emissions of a suite of greenhouse gases (GHG's), emitted in 14 globally disaggregated global regions (i.e., U.S., Western Europe, China), the fate of emissions to the atmosphere, and the consequences of changing concentrations of greenhouse related gases for climate change. MiniCAM begins with a representation of demographic and economic developments in each region and combines these with assumptions about technology development to describe an internally consistent representation of energy, agriculture, land-use, and economic developments that in turn shape global emissions. Brenkert A, S. Smith, S. Kim, and H. Pitcher, 2003: Model Documentation for the MiniCAM. PNNL–14337, Pacific Northwest National Laboratory, Richland, Washington. For a recent report and detailed description and discussion of MiniCAM, *see* Clarke, L., J. Edmonds, H. Jacoby, H. Pitcher, J. Reilly, R. Richels, 2007. Scenarios of Greenhouse Gas Emissions and Atmospheric Concentrations. Sub-report 2.1A of Synthesis and Assessment Product 2.1 by the U.S. Climate Change Science Program and the Subcommittee on Global Change Research. Department of Energy, Office of Biological & Environmental Research, Washington, DC., USA, 154 pp.

[321] MAGICC consists of a suite of coupled gas-cycle, climate and ice-melt models integrated into a single framework. The framework allows the user to determine changes in GHG concentrations, global-mean surface air temperature and sea-level resulting from anthropogenic emissions of carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), reactive gases (e.g., CO, NO_X, VOCs), the halocarbons (e.g. HCFCs, HFCs, PFCs) and sulfur dioxide (SO2). MAGICC emulates the global-mean temperature responses of more sophisticated coupled Atmosphere/Ocean General Circulation Models (AOGCMs) with high accuracy. Wigley, T.M.L. and Raper, S.C.B. 1992. Implications for Climate and Sea-Level of Revised IPCC Emissions Scenarios Nature 357, 293–300. Raper, S.C.B., Wigley T.M.L. and Warrick R.A. 1996. in Sea-Level Rise and Coastal Subsidence: Causes, Consequences and Strategies J.D. Milliman, B.U. Haq, Eds., Kluwer Academic Publishers, Dordrecht, The Netherlands, pp. 11–45. Wigley, T.M.L. and Raper, S.C.B. 2002. Reasons for larger warming projections in the IPCC Third Assessment Report J. Climate 15, 2945–2952.

[322] Clarke *et al.*, 2007.

[323] In IPCC reports, equilibrium climate sensitivity refers to the equilibrium change in the annual mean global surface temperature following a doubling of the atmospheric equivalent carbon dioxide concentration. The IPCC states that climate sensitivity is ''likely'' to be in the range of 2 °C to 4.5 °C and described 3 °C as a ''best estimate.'' The IPCC goes on to note that climate sensitivity is ''very unlikely'' to be less than 1.5 °C and ''values substantially higher than 4.5 °C cannot be excluded.'' IPCC WGI, 2007, *Climate Change 2007—The Physical Science Basis*, Contribution of Working Group I to the Fourth Assessment Report of the IPCC, *http://www.ipcc.ch/*.

[324] IPCC WGI, 2007. The baseline increases by 2100 from our MiniCAM–MAGICC runs are 2 °C to 5 °C for global mean surface temperature and 35 to 74 centimeters for global mean sea level.

[325] ''Because understanding of some important effects driving sea level rise is too limited, this report does not assess the likelihood, nor provide a best estimate or an upper bound for sea level rise.'' IPCC Synthesis Report, p. 45

sensitivities. Thus, the probability of a higher temperature or sea level in any year is lowered more than the probability of a lower temperature or sea level. For instance, in 2100, the reduction in projected temperature for climate sensitivities of 3 and 6 is approximately 65% and 140% greater than the reduction for a climate sensitivity of 1.5. This difference grows over time, to approximately 80% and 185% by 2200. The same pattern appears in the reductions in the sea level rise projections.[326] Also noteworthy in Figures VI.G.2–1 and VI.G.2–2 is that the size of the decreases grows over time due to the cumulative effect of a lower stock of GHGs in the atmosphere (i.e., concentrations).[327]

The bottom line is that the risk of climate change is being lowered, as the probabilities of any level of temperature increase and sea level rise are reduced and the probabilities of the largest temperature increases and sea level rise are reduced even more. For the Final Rulemaking, we hope to more explicitly estimate the shapes of the distributions and the estimated shifts in the shapes in response to the Rulemakings.

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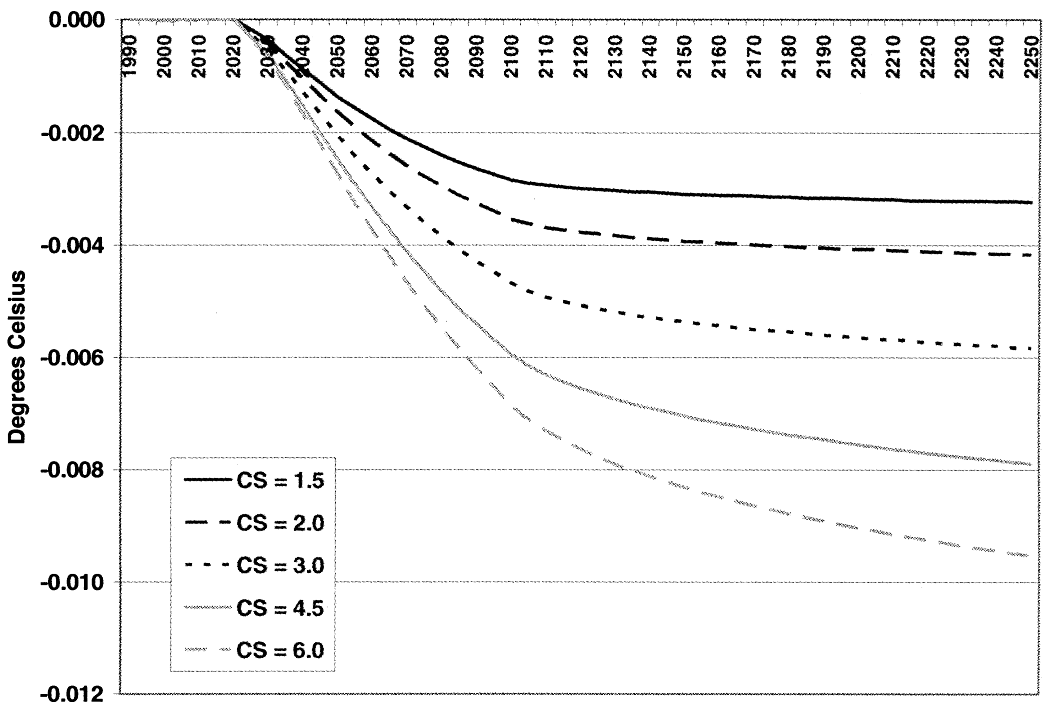
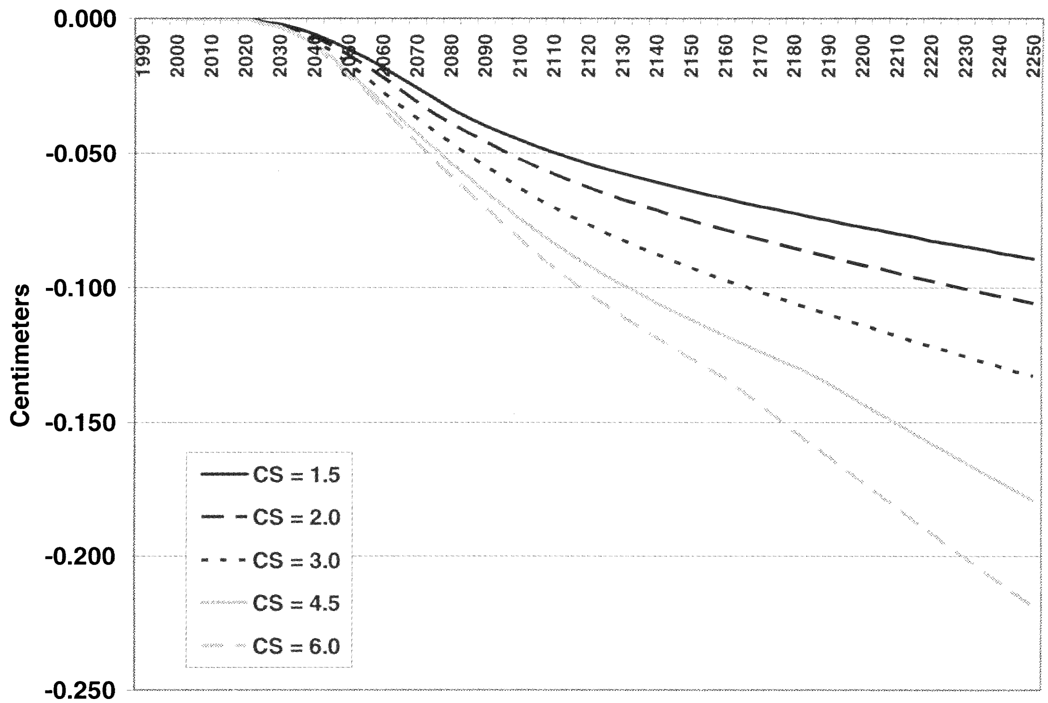
Figure VI.G.2-1
Estimated Projected Reductions in Global Mean Surface Temperatures across Climate Sensitivities (CS) for the Proposed Standard in 2022



[326] In 2100, the reduction in projected sea level rise for climate sensitivities of 3 and 6 is approximately 40% and 80% greater than the reduction for a climate sensitivity of 1.5. This difference grows over time, to approximately 50% and 120% by 2200.

[327] For global average temperature after 2100, the growth in the size of the decrease noticeable slows. This is because the emissions changes associated with the policy were only estimated for 100 years. Note that even with emissions reductions stopping after 100 years, there continues to be a decrease in projected temperatures due to reduced inertia in the climate system from the earlier emissions reductions. However, unlike temperature, after 2100, the size of the decrease in sea level rise increases as the projected reduction in warming has a continued effect on ice melt and ocean thermal expansion.

Figure VI.G.2-2
Estimated Projected Reductions in Global Mean Sea Level across Climate Sensitivities (CS) for the Proposed Standard in 2022



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VII. How Would the Proposal Impact Criteria and Toxic Pollutant Emissions and Their Associated Effects?

A. Overview of Impacts

Today's proposal would influence the emissions of ''criteria'' pollutants (those pollutants for which a National Ambient Air Quality Standard has been established), criteria pollutant precursors,[328] and air toxics, which may affect overall air quality and health. Emissions would be affected by the processes required to produce and distribute large volumes of biofuels proposed in today's action and the direct effects of these fuels on vehicle and equipment emissions. As detailed in Chapter 3 of the Draft Regulatory Impact Analysis (DRIA), we have estimated emissions impacts of production and distribution-related emissions using the life cycle analysis methodology described in Section VI with emission factors for criteria and toxic emissions for each stage of the life cycle, including agriculture, feedstock transportation, and the production and distribution of biofuel; included in this analysis are the impacts of reduced gasoline and diesel refining as these fuels are displaced by biofuels. Emission impacts of tailpipe and evaporative emissions for on and off road sources have been estimated by incorporating ''per vehicle'' fuel effects from recent research into mobile source emission inventory estimation methods.

For today's proposal we are presenting two sets of emission impacts meant to present a range of the possible effects of ethanol blends on light-duty vehicle emissions. This approach is carried forward from analysis supporting the first RFS rule, which presented ''primary'' and ''sensitivity'' fuel effects cases differentiated by E10 effects on cars and trucks. For this analysis we also analyze two fuel effects scenarios, now termed ''less sensitive'' and ''more sensitive,'' referring to the sensitivity of car and truck exhaust emissions to both E10 and E85 blends. As detailed in Section VII.C, the ''less sensitive'' case does not apply any E10 effects to NOx or HC emissions for later model year vehicles, or E85 effects for any pollutant, while the ''more sensitive'' case assumes that later model year vehicles have lower fuel sensitivity than earlier model vehicles. EPA and other parties are in the midst of gathering additional data to help clarify emissions impacts of ethanol on light-duty vehicles, and should be able to reflect the new data for the final rule.

Analysis of criteria and toxic emission impacts was performed for calendar year 2022, since this year reflects the full implementation of today's proposal. Our 2022 projections account for projected growth in vehicle travel and the effects of applicable emission and fuel economy standards, including Tier 2 and Mobile Source Air Toxics (MSAT) rules for cars and light trucks and recently finalized controls on spark-ignited off-road engines. The impacts were analyzed relative to three different reference case ethanol volumes, ranging from 3.64 to 13.2 billion gallons per year, in order to understand the impacts of today's proposal in different contexts. To assess the total impact of the RFS program, emissions were analyzed relative to the RFS1 rule base case of 3.64 billion gallons in 2004. To assess the impact of today's proposal relative to the current mandated volumes, we analyzed impacts relative to RFS1 mandate of 7.5 billion gallons of renewable fuel use by 2012, which was estimated to include 6.7 billion gallons of ethanol.[329] In order to assess the impact of today's proposal relative to the level of ethanol projected to already be in place by 2022, the AEO2007 projection of 13.2 billion gallons of

[328] NO_X and VOC are precursors to the criteria pollutant ozone; we group them with criteria pollutants in this chapter for ease of discussion.

[329] For this analysis these RFS1 base and mandated ethanol levels were assumed constant to 2022.

ethanol in 2022 was analyzed. For this analysis our modeling was based on the differences between the AEO2007 reference case and the control case; to generate impacts for the RFS1 base and mandated volumes we simply scaled the modeled AEO2007-based impacts up according to the larger increases in renewable fuel volumes relative to the other reference cases. For the final rule we plan to directly model the RFS1 mandate reference case as well as the AEO2007 case.

For the proposal we have only estimated the change in national emission totals that would result from today's proposal. These totals may not be a good indication of local or regional air quality and health impacts. These results are aggregated across highly localized sources, such as emissions from ethanol plants and evaporative emissions from cars, and reflect offsets such as decreased emissions from gasoline refineries. The location and composition of emissions from these disparate sources may strongly influence the air quality and health impacts of today's proposed action, and full-scale photochemical air quality modeling is necessary to accurately assess this. These localized impacts will be assessed in the final rule as discussed in Section VII.D.

Our projected emission impacts for the ''less sensitive'' and ''more sensitive'' cases are shown in Table VII.A–1 and VII.A–2 for 2022. Shown relative to each reference case are the expected emission changes for the U.S. in that year, and the percent contribution of this impact relative to the total U.S. inventory. Overall we project the proposed program will result in significant increases in ethanol and acetaldehyde emissions—increasing the total U.S. inventories of these pollutants by 30–40% in 2022 relative to the RFS1 mandate case. We project more modest increases in NO_x, HC, PM, SO_2, formaldehyde, and acrolein relative to the RFS1 mandate case. We project a decrease in ammonia (NH_3) emissions due to reductions in livestock agricultural activity, CO (due to impacts of ethanol on exhaust emissions from vehicles and nonroad equipment), and benzene (due to displacement of gasoline with ethanol in the fuel pool). As shown, the direction of changes for 1,3-butadiene and naphthalene depends on whether it is the ''less sensitive'' or ''more sensitive'' case.

TABLE VII.A–1—RFS2 ''LESS SENSITIVE'' CASE EMISSION IMPACTS IN 2022 RELATIVE TO EACH REFERENCE CASE

Pollutant	RFS1 base		RFS1 mandate		AEO2007	
	Annual short tons	Percent of total U.S. inventory	Annual short tons	Percent of total U.S. inventory	Annual short tons	Percent of total U.S. inventory
NO_x	312,400	2.8	274,982	2.5	195,735	1.7
HC	112,401	1.0	72,362	0.6	−8,193	−0.07
PM_{10}	50,305	1.4	37,147	1.0	9,276	0.3
$PM_{2.5}$	14,321	0.4	11,452	0.3	5,376	0.16
CO	−2,344,646	−4.4	−1,669,872	−3.1	−240,943	−0.4
Benzene	−2,791	−1.7	−2,507	−1.5	−1,894	−1.1
Ethanol	210,680	36.5	169,929	29.4	83,761	14.5
1,3-Butadiene	344	2.9	255	2.1	65	0.5
Acetaldehyde	12,516	33.7	10,369	27.9	5,822	15.7
Formaldehyde	1,647	2.3	1,348	1.9	714	1.0
Naphthalene	5	0.03	3	0.02	−1	−0.01
Acrolein	290	5.0	252	4.4	174	3.0
S_{O2}	28,770	0.3	4,461	0.05	−47,030	−0.5
NH_3	−27,161	−0.6	−27,161	−0.6	−27,161	−0.6

TABLE VII.A–2—RFS2 ''MORE SENSITIVE'' CASE EMISSION IMPACTS IN 2022 RELATIVE TO EACH REFERENCE CASE

Pollutant	RFS1 base		RFS1 Mandate		AEO2007	
	Annual short tons	Percent of total U.S. inventory	Annual short tons	Percent of total U.S. inventory	Annual short tons	Percent of total U.S. inventory
NO_x	402,795	3.6	341,028	3.0	210,217	1.9
HC	100,313	0.9	63,530	0.6	−15,948	−0.14
PM_{10}	46,193	1.3	33,035	0.9	5,164	0.15
$PM_{2.5}$	10,535	0.3	7,666	0.2	1,589	0.05
CO	−3,779,572	−7.0	−3,104,798	−5.8	−1,675,869	−3.1
Benzene	−5,962	−3.5	−5,494	−3.3	−4,489	−2.7
Ethanol	228,563	39.6	187,926	32.5	105,264	18.2
1,3-Butadiene	−212	−1.8	−282	−2.4	−430	−3.6
Acetaldehyde	16,375	44.0	14,278	38.4	9,839	26.5
Formaldehyde	3,373	4.7	3,124	4.3	2,596	3.6
Naphthalene	−175	−1.2	−178	−1.3	−187	−1.3
Acrolein	253	4.4	218	3.8	143	2.5
SO_2	28,770	0.3	4,461	0.05	−47,030	−0.5
NH_3	−27,161	−0.6	−27,161	−0.6	−27,161	−0.6

The breakdown of these results by the fuel production/distribution (''well-to-pump'' emissions) and vehicle and equipment (''pump-to-wheel'') emissions is discussed in the following sections.

B. Fuel Production & Distribution Impacts of the Proposed Program

Fuel production and distribution emission impacts of the proposed program were estimated in conjunction with the development of life cycle GHG emission impacts and the GHG emission inventories discussed in Section VI. These emissions are calculated according to the breakdowns of agriculture, feedstock transport, fuel production, and fuel distribution; the basic calculation is a function of fuel volumes in the analysis year and the emission factors associated with each process or subprocess. Additionally, the emission impact of displaced petroleum is estimated, using the same domestic/import shares discussed in Section VI above.

In general the basis for this life cycle evaluation was the analysis conducted as part of the Renewable Fuel Standard (RFS1) rulemaking, but enhanced significantly. While our approach for the RFS1 was to rely heavily on the ''Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation'' (GREET) model, developed by the Department of Energy's Argonne National Laboratory (ANL), we are now able to take advantage of additional information and models to significantly strengthen and expand our analysis for this proposed rule. In particular, the modeling of the agriculture sector was greatly expanded beyond the RFS1 analysis, employing economic and agriculture models to consider factors such as land-use impact, agricultural burning, fertilizer, pesticide use, livestock, crop allocation, and crop exports.

Other updates and enhancements to the GREET model assumptions include updated feedstock energy requirements and estimates of excess electricity available for sale from new cellulosic ethanol plants, based on modeling by the National Renewable Energy Laboratory (NREL). EPA also updated the fuel and feedstock transport emission factors to account for recent EPA emission standards and modeling, such as the diesel truck standards published in 2001 and the locomotive and commercial marine standards finalized in 2008. Emission factors for new corn ethanol plants continue to use the values developed for the RFS1 rule, which were based on data submitted by states for dry mill plants. There are no new standards planned at this time that would offer any additional control of emissions from corn or cellulosic ethanol plants. In addition, GREET does not include air toxics or ethanol. Thus emission factors for ethanol and the following air toxics were added: benzene, 1,3-butadiene, formaldehyde, acetaldehyde, acrolein and naphthalene.

Results of these calculations relative to each of the reference cases for 2022 are shown in Table VII.B–1 for the criteria pollutants, ammonia, ethanol and individual air toxic pollutants. It should be noted that the impacts relative to the two RFS1 reference cases (3.64 and 6.7 billion gallons) rely on applying ethanol volume proportions to the modeling results of the AEO2007 reference case (13.2 billion gallons). Due to the complex interactions involved in projections in the agricultural modeling, we did not attempt to adjust the agricultural inputs of the AEO reference case for the other two reference cases. So the fertilizer and pesticide quantities, livestock counts, and total agricultural acres were the same for all three reference cases. The agricultural modeling that had been done for the RFS1 rule itself was much simpler and inconsistent with the new modeling, so it would be inappropriate to use those estimates. Thus, we plan to conduct additional agricultural modeling specifically for the RFS1 mandate case prior to finalizing this rule.

The fuel production and distribution impacts of the proposed program on VOC are mainly due to increases in emissions connected with biofuel production, countered by decreases in emissions associated with gasoline production and distribution as ethanol displaces some of the gasoline. Increases in NO_X, $PM_{2.5}$, and SO_X are driven by combustion emissions from the substantial increase in corn and cellulosic ethanol production. Ethanol plants (corn and cellulosic) tend to have greater combustion emissions relative to petroleum refineries on a per-BTU of fuel produced basis. Increases in SO_X emissions are primarily due to corn ethanol production. Ammonia emissions are expected to decrease substantially due to lower livestock counts, which more than offsets increased ammonia from fertilizer use.

Ethanol vapor and most air toxic emissions associated with fuel production and distribution are projected to increase. Relative to the U.S. total reference case emissions with RFS1 mandate ethanol volumes, increases of 10–20% for acetaldehyde and ethanol vapor are especially significant because they are driven directly by the increased ethanol production and distribution. Formaldehyde and acrolein increases are smaller, on the order of 1–5%. Benzene emissions are estimated to decrease by 1% due to decreased gasoline production. There are also very small increases in 1,3-butadiene and decreases in naphthalene relative to the U.S. total emissions.

TABLE VII.B–1—FUEL PRODUCTION AND DISTRIBUTION IMPACTS IN 2022 RELATIVE TO EACH REFERENCE CASE

Pollutant	RFS1 base		RFS1 mandate		AEO2007	
	Annual short tons	Percent of total U.S. inventory	Annual short tons	Percent of total U.S. inventory	Annual short tons	Percent of total U.S. inventory
NO_X	241,041	2.1	222,732	2.0	183,951	1.6
HC	77,295	0.7	46,702	0.4	−17,501	−0.2
PM_{10}	50,482	1.4	37,324	1.1	9,453	0.3
$PM_{2.5}$	14,419	0.4	11,550	0.3	5,473	0.16
CO	186,559	0.3	179,855	0.3	165,656	−0.5
Benzene	−1,670	−1.0	−1,686	−1.0	−1,719	−1.0
Ethanol	115,187	19.9	100,134	17.3	68,379	11.8
1,3-Butadiene	16	0.13	16	0.14	17	0.14
Acetaldehyde	7,460	20.1	6,680	18.0	5,029	13.5
Formaldehyde	877	1.2	800	1.1	638	0.9
Naphthalene	−6	−0.04	−5	−0.04	−4	−0.03
Acrolein	278	4.8	244	4.2	174	3.0

TABLE VII.B–1—FUEL PRODUCTION AND DISTRIBUTION IMPACTS IN 2022 RELATIVE TO EACH REFERENCE CASE—Continued

Pollutant	RFS1 base		RFS1 mandate		AEO2007	
	Annual short tons	Percent of total U.S. inventory	Annual short tons	Percent of total U.S. inventory	Annual short tons	Percent of total U.S. inventory
SO_2	28,770	0.3	4,461	0.05	−47,030	−0.5
NH_3	−27,161	−0.6	−27,161	−0.6	−27,161	−0.6

C. Vehicle and Equipment Emission Impacts of Fuel Program

The effects of the fuel program on vehicle and equipment emissions are a direct function of the effects of these fuels on exhaust and evaporative emissions from vehicles and off-road equipment, and evaporation of fuel from portable containers. To assess these impacts we conducted separate analyses to quantify the emission impacts of additional E10 due to today's proposal on gasoline vehicles, nonroad spark-ignited engines and portable fuel containers; E85 on cars and light trucks; biodiesel on diesel vehicles; and increased refueling events due to lower energy density of biofuels.[330]

For the proposal we have analyzed inventory impacts for two fuel effects scenarios to attempt to bound the potential impacts on ethanol on gasoline-fueled vehicle exhaust emissions:

(1) ''Less Sensitive'': No exhaust VOC or NO_X emission impact on Tier 1 and later vehicles due to E10, and no impact due to E85. This was termed the ''primary'' case in the RFS1 rule.

(2) ''More Sensitive'': VOC and NO_X emission impacts due to E10 based on limited test data from newer technology vehicles that were analyzed as part of the RFS1 rule. This data showed a 7% reduction in exhaust VOC emissions and an 8% increase in per-vehicle NO_X emissions for Tier 1 and later vehicles using E10 relative to E0. The E10 effects are consistent with the ''sensitivity'' case from the RFS1 rule. For RFS2 this case also includes E85 effects reflecting significant increases in acetaldehyde, formaldehyde and ethanol emissions, and reductions in PM and CO.

EPA and other parties are in the midst of gathering additional data on the emission impacts of ethanol fuels on later model vehicles, which we plan to consider in updating our final rule analysis.

We have also estimated the E10 effects on permeation emissions from light-duty vehicles based on testing previously completed by the Coordinating Research Council (CRC). Nonroad spark ignition (SI) emission impacts of E10 were based on EPA's NONROAD model and show trends similar to light duty vehicles. Biodiesel effects for this analysis were based on a new analysis of recent biodiesel testing, detailed in the DRIA, showing a 2% increase in NO_X with a 20% biodiesel blend, a 16% decrease in PM, and a 14% decrease in HC. These results essentially confirm the results of an earlier EPA analysis.

Summarized vehicle and equipment emission impacts in 2022 are shown in Table VII.C–1 and VII.C–2 for the ''less sensitive'' and ''more sensitive'' cases. Table VII.C–3 shows the biodiesel contribution to these impacts, which are comparatively small. While the two fuel effect scenarios only differ with respect to exhaust emissions from cars and trucks, the totals shown below reflect the net impacts from all mobile sources, including car and truck evaporative emissions, off road emissions, and portable fuel containers, using the same emissions impacts for these sources in both cases. Additional breakdowns by mobile source category can be found in Chapter 3 of the DRIA.

As shown in Tables VII.C–1 and VII.C–2, the vehicle and equipment ethanol impacts vary widely between the two fuel effects cases. Under the ''less sensitive'' case, CO and benzene are projected to decrease in 2022 under today's proposal, while NO_X, HC and the other air toxics (except acrolein) are projected to increase due to the impacts of E10. For the ''more sensitive'' case, NO_X impacts are higher and HC impacts lower due to the E10 effects on cars and trucks, and the inclusion of E85 effects leads to larger reductions in CO, benzene and 1,3-butadiene but more significant increases in ethanol, acetaldehyde and formaldehyde. The impacts on acrolein emissions in both cases, and on naphthalene in the ''more sensitive'' case depend on which reference case is considered, with small increases relative to the RFS1 base and mandate cases and a decrease relative to the AEO reference case.

TABLE VII.C–1—2022 VEHICLE AND EQUIPMENT ''LESS SENSITIVE'' CASE EMISSION IMPACTS BY FUEL TYPE RELATIVE TO EACH REFERENCE CASE

Pollutant	RFS1 base		RFS1 mandate		AEO2007	
	Annual short tons	Percent of total U.S. inventory	Annual short tons	Percent of total U.S. inventory	Annual short tons	Percent of total U.S. inventory
NO_X	71,359	0.6	52,250	0.5	11,784	0.11
HC	35,106	0.3	25,659	0.2	9,308	0.08
PM_{10}	−177	0.00	−177	0.00	−177	0.00
$PM_{2.5}$	−98	0.00	−98	0.00	−98	0.00
CO	−2,531,205	−4.7	−1,849,728	−3.4	−406,599	−0.8
Benzene	−1,122	−0.7	−821	−0.5	−174	−0.1
Ethanol	95,493	16.5	69,795	12.1	15,383	2.7
1,3-Butadiene	328	2.7	238	2.0	48	0.4
Acetaldehyde	5,057	13.6	3,689	9.9	793	2.1

330 The impact of renewable diesel was not estimated for the proposal; we expect little overall impact on criteria and toxic emissions due to the relatively small volume change, and because emission effects relative to conventional diesel are presumed to be negligible.

TABLE VII.C–1—2022 VEHICLE AND EQUIPMENT "LESS SENSITIVE" CASE EMISSION IMPACTS BY FUEL TYPE RELATIVE TO EACH REFERENCE CASE—Continued

Pollutant	RFS1 base		RFS1 mandate		AEO2007	
	Annual short tons	Percent of total U.S. inventory	Annual short tons	Percent of total U.S. inventory	Annual short tons	Percent of total U.S. inventory
Formaldehyde	771	1.1	548	0.8	76	0.11
Naphthalene	10	0.07	8	0.05	3	0.02
Acrolein	12	0.2	8	0.14	−0.4	−0.01
SO_2	0	0.0	0	0.0	0	0.0
NH_3	0	0.0	0	0.0	0	0.0

TABLE VII.C–2—2022 VEHICLE AND EQUIPMENT "MORE SENSITIVE" CASE EMISSION IMPACTS BY FUEL TYPE RELATIVE TO EACH REFERENCE CASE

Pollutant	RFS1 base		RFS1 mandate		AEO2007	
	Annual short tons	Percent of total U.S. inventory	Annual short tons	Percent of total U.S. inventory	Annual short tons	Percent of total U.S. inventory
NO_X	161,754	1.4	118,295	1.1	26,266	0.2
HC	23,018	0.2	16,828	0.15	1,553	0.01
PM_{10}	−4,289	−0.12	−4,289	−0.12	−4,289	−0.12
$PM_{2.5}$	−3,884	−0.12	−3,884	−0.12	−3,884	−0.12
CO	−3,966,131	−7.4	−3,284,654	−6.1	−1,841,524	−3.4
Benzene	−4,293	−2.6	−3,808	−2.3	−2,770	−1.6
Ethanol	113,376	19.6	87,792	15.2	36,886	6.4
1,3-Butadiene	−228	−1.9	−298	−2.5	−446	−3.7
Acetaldehyde	8,915	24.0	7,598	20.4	4,809	12.9
Formaldehyde	2,497	3.5	2,324	3.2	1,958	2.7
Naphthalene	−170	−1.2	−172	−1.2	−182	−1.3
Acrolein	−25	−0.4	−27	−0.5	−31	−0.5
SO_2	0	0.0	0	0.0	0	0.0
NH_3	0	0.0	0	0.0	0	0.0

TABLE VII.C–3—2022 VEHICLE AND EQUIPMENT BIODIESEL EMISSION IMPACTS RELATIVE TO ALL REFERENCE CASES

[these impacts are included in Tables VII.C–1 and VII.C–2]

Pollutant	Biodiesel impacts
	Annual short tons
NO_X	418
HC	−753
PM_{10}	−177
$PM_{2.5}$	−98
CO	−1,275
Benzene	−9.4
Ethanol	0.0
1,3-Butadiene	−5.1
Acetaldehyde	−21
Formaldehyde	−57
Naphthalene	−0.12
Acrolein	−2.7
SO_2	0.0
NH_3	0.0

D. Air Quality Impacts

Although the purpose of this proposal is to implement the renewable fuel requirements established by the Energy Independence and Security Act (EISA) of 2007, this proposed rule would also impact emissions of criteria and air toxic pollutants. We first present current levels of $PM_{2.5}$, ozone and air toxics and then discuss the national-scale air quality modeling analysis that will be performed for the final rule.

1. Current Levels of $PM_{2.5}$, Ozone and Air Toxics

This proposal may have impacts on levels of $PM_{2.5}$, ozone and air toxics.[331] Nationally, levels of $PM_{2.5}$, ozone and air toxics are declining.[332] [333] However, as of December 16, 2008, approximately 88 million people live in the 39 areas that are designated as nonattainment for the 1997 $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS) and approximately 132 million people live in the 57 areas that are designated as nonattainment for the 1997 8-hour ozone NAAQS. The 1997 $PM_{2.5}$ NAAQS was recently revised and the 2006 24-hour $PM_{2.5}$ NAAQS became effective on December 18, 2006. Area designations for the 2006 24-hour $PM_{2.5}$ NAAQS are expected to be promulgated in 2009 and become effective 90 days after publication in the **Federal Register**. In addition, the majority of Americans continue to be exposed to ambient concentrations of air toxics at levels which have the potential to cause adverse health effects.[334] The levels of air toxics to which people are exposed vary depending on where people live and work and the kinds of activities in which they engage, as discussed in

[331] The proposed standards may also impact levels of ambient CO, a criteria pollutant (see Table VII.A–1 above for co-pollutant emission impacts). For this analysis, however, we focus on the proposal's impacts on ambient $PM_{2.5}$ and ozone formation, since CO is a relatively minor problem in comparison to some of the other criteria pollutants. For example, as of August 15, 2008 there are approximately 675,000 people living in 3 areas (which include 4 counties) that are designated as nonattainment for CO.

[332] U.S. EPA (2003) National Air Quality and Trends Report, 2003 Special Studies Edition. Office of Air Quality Planning and Standards, Research Triangle Park, NC. Publication No. EPA 454/R–03–005. *http://www.epa.gov/air/airtrends/aqtrnd03/ http://www.epa.gov/air/airtrends/aqtrnd03/*.

[333] U.S. EPA (2007) Final Regulatory Impact Analysis: Control of Hazardous Air Pollutants from Mobile Sources, Office of Transportation and Air Quality, Ann Arbor, MI, Publication No. EPA420–R–07–002. *http://www.epa.gov/otaq/toxics.htm*

[334] U.S. Environmental Protection Agency (2007). Control of Hazardous Air Pollutants from Mobile Sources; Final Rule. 72 FR 8434, February 26, 2007.

detail in U.S. EPA's recent Mobile Source Air Toxics Rule.[335]

EPA has already adopted many emission control programs that are expected to reduce ambient $PM_{2.5}$, ozone and air toxics levels. These control programs include the Small SI and Marine SI Engine Rule (73 FR 59034, October 8, 2008), Locomotive and Commercial Marine Rule (73 FR 25098, May 6, 2008), Mobile Source Air Toxics Rule (72 FR 8428, February 26, 2007), Clean Air Interstate Rule (70 FR 25162, May 12, 2005), Clean Air Nonroad Diesel Rule (69 FR 38957, June 29, 2004), Heavy Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements (66 FR 5002, Jan. 18, 2001) and the Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements (65 FR 6698, Feb. 10, 2000). As a result of these programs, the ambient concentration of air toxics, $PM_{2.5}$ and ozone in the future is expected to decrease.

2. Impacts of Proposed Standards on Future Ambient Concentrations of $PM_{2.5}$, Ozone and Air Toxics

The atmospheric chemistry related to ambient concentrations of $PM_{2.5}$, ozone and air toxics is very complex, making predictions based solely on emissions changes extremely difficult. For the final rule, a national-scale air quality modeling analysis will be performed to analyze the impacts of the proposed standards on ambient concentrations of $PM_{2.5}$, ozone, and selected air toxics (i.e., benzene, formaldehyde, acetaldehyde, ethanol, acrolein and 1,3-butadiene). The length of time needed to prepare necessary inventory and model updates has precluded us from performing air quality modeling for this proposal.

The air quality modeling we plan to perform (described more specifically below), will allow us to account for changes in the spatial distribution of PM and PM precursors, and changes in VOC speciation which could impact secondary PM formation. For example, reductions in aromatics in gasoline may reduce ambient PM concentrations by reducing secondary PM formation. Section 3.3 of the Draft Regulatory Impact Analysis (DRIA) for this proposal contains more information on aromatics and secondary aerosol formation.

In addition, air quality modeling will account for changes in fuel type and spatial distribution of fuels that would change emissions of ozone precursor species and thus could affect ozone concentrations. Section 3.3 of the DRIA for this proposed rule provides more detail on the atmospheric chemistry and potential changes in ozone formation due to increased usage of ethanol fuels.

Section VII.A above presents projections of the changes in air toxics emissions due to the proposed standards. The substantial increase in emissions of ethanol and acetaldehyde suggests a likely increase in ambient levels of acetaldehyde from both direct emissions and secondary formation as ethanol breaks down in the atmosphere. Formaldehyde and acrolein emissions would also increase somewhat, while emissions of benzene and 1,3-butadiene would decrease as a result of the proposed standards. Full-scale photochemical modeling is necessary to provide the needed spatial and temporal detail to more completely and accurately estimate the changes in ambient levels of these pollutants.

For the final rule, EPA intends to use a 2005-based Community Multi-scale Air Quality (CMAQ) modeling platform as the tool for the air quality modeling. The CMAQ modeling system is a comprehensive three-dimensional grid-based Eulerian air quality model designed to estimate the formation and fate of oxidant precursors, primary and secondary PM concentrations and deposition, and air toxics, over regional and urban spatial scales (e.g., over the contiguous U.S.).[336 337 338] The CMAQ model is a well-known and well-established tool and is commonly used by EPA for regulatory analyses, for instance the recent ozone NAAQS proposal, and by States in developing attainment demonstrations for their State Implementation Plans.[339] The CMAQ model (version 4.6) was peer-reviewed in February of 2007 for EPA as reported in ''Third Peer Review of CMAQ Model,'' and the peer review report for version 4.7 (described below) is currently being finalized.[340]

CMAQ includes many science modules that simulate the emission, production, decay, deposition and transport of organic and inorganic gas-phase and particle-phase pollutants in the atmosphere. We intend to use the most recent CMAQ version (version 4.7) which was officially released by EPA's Office of Research and Development (ORD) in December 2008, and reflects updates to earlier versions in a number of areas to improve the underlying science. These include (1) enhanced secondary organic aerosol (SOA) mechanism to include chemistry of isoprene, sesquiterpene, and aged in-cloud biogenic SOA in addition to terpene; (2) improved vertical convective mixing; (3) improved heterogeneous reaction involving nitrate formation; and (4) an updated gas-phase chemistry mechanism, Carbon Bond 05 (CB05), with extensions to model explicit concentrations of air toxic species as well as chlorine and mercury. This mechanism, CB05-toxics, also computes concentrations of species that are involved in aqueous chemistry and that are precursors to aerosols. Section 3.3.3 of the DRIA for this proposal discusses SOA formation and details about the improvements made to the SOA mechanism within this recent release of CMAQ.

E. Health Effects of Criteria and Air Toxic Pollutants

1. Particulate Matter

a. Background

Particulate matter (PM) represents a broad class of chemically and physically diverse substances. It can be principally characterized as discrete particles that exist in the condensed (liquid or solid) phase spanning several orders of magnitude in size. PM is further described by breaking it down into size fractions. PM_{10} refers to particles generally less than or equal to 10 micrometers (µm) in aerodynamic diameter. $PM_{2.5}$ refers to fine particles, generally less than or equal to 2.5 µm in aerodynamic diameter. Inhalable (or ''thoracic'') coarse particles refer to those particles generally greater than 2.5 µm but less than or equal to 10 µm in aerodynamic diameter. Ultrafine PM refers to particles less than 100 nanometers (0.1 µm) in aerodynamic diameter. Larger particles tend to be removed by the respiratory clearance mechanisms (e.g., coughing), whereas

[335] U.S. Environmental Protection Agency (2007). Control of Hazardous Air Pollutants from Mobile Sources; Final Rule. 72 FR 8434, February 26, 2007.

[336] U.S. Environmental Protection Agency, Byun, D.W., and Ching, J.K.S., Eds, 1999. Science algorithms of EPA Models-3 Community Multiscale Air Quality (CMAQ modeling system, EPA/600/R–99/030, Office of Research and Development).

[337] Byun, D.W., and Schere, K.L., 2006. Review of the Governing Equations, Computational Algorithms, and Other Components of the Models-3 Community Multiscale Air Quality (CMAQ) Modeling System, J. Applied Mechanics Reviews, 59 (2), 51–77.

[338] Dennis, R.L., Byun, D.W., Novak, J.H., Galluppi, K.J., Coats, C.J., and Vouk, M.A., 1996. The next generation of integrated air quality modeling: EPA's Models-3, Atmospheric Environment, 30, 1925–1938.

[339] U.S. EPA (2007). Regulatory Impact Analysis of the Proposed Revisions to the National Ambient Air Quality Standards for Ground-Level Ozone. EPA document number 442/R–07–008, July 2007.

[340] Aiyyer, A., Cohan, D., Russell, A., Stockwell, W., Tanrikulu, S., Vizuete, W., Wilczak, J., 2007. Final Report: Third Peer Review of the CMAQ Model. p. 23.

smaller particles are deposited deeper in the lungs.

Fine particles are produced primarily by combustion processes and by transformations of gaseous emissions (e.g., SO_X, NO_X and VOC) in the atmosphere. The chemical and physical properties of $PM_{2.5}$ may vary greatly with time, region, meteorology and source category. Thus, $PM_{2.5}$ may include a complex mixture of different pollutants including sulfates, nitrates, organic compounds, elemental carbon and metal compounds. These particles can remain in the atmosphere for days to weeks and travel hundreds to thousands of kilometers.

b. Health Effects of PM

Scientific studies show ambient PM is associated with a series of adverse health effects. These health effects are discussed in detail in the 2004 EPA Particulate Matter Air Quality Criteria Document (PM AQCD), and the 2005 PM Staff Paper.[341] [342] Further discussion of health effects associated with PM can also be found in the DRIA for this rule.

Health effects associated with short-term exposures (hours to days) to ambient PM include premature mortality, increased hospital admissions, heart and lung diseases, increased cough, adverse lower-respiratory symptoms, decrements in lung function and changes in heart rate rhythm and other cardiac effects. Studies examining populations exposed to different levels of air pollution over a number of years, including the Harvard Six Cities Study and the American Cancer Society Study, show associations between long-term exposure to ambient $PM_{2.5}$ and both total and cardiovascular and respiratory mortality.[343] In addition, a reanalysis of the American Cancer Society Study shows an association between fine particle and sulfate concentrations and lung cancer mortality.[344]

[341] U.S. EPA (2004) Air Quality Criteria for Particulate Matter (Oct. 2004), Volume I Document No. EPA600/P–99/002aF and Volume II Document No. EPA600/P–99/002bF. This document is available in Docket EPA–HQ–OAR–2005–0161.

[342] U.S. EPA (2005) Review of the National Ambient Air Quality Standard for Particulate Matter: Policy Assessment of Scientific and Technical Information, OAQPS Staff Paper. EPA–452/R–05–005. This document is available in Docket EPA–HQ–OAR–2005–0161.

[343] Dockery, D.W.; Pope, C.A. III: Xu, X.; et al. 1993. An association between air pollution and mortality in six U.S. cities. N Engl J Med 329:1753–1759.

[344] Pope, C.A., III; Burnett, R.T.; Thun, M.J.; Calle, E.E.; Krewski, D.; Ito, K.; Thurston, G.D. (2002) Lung cancer, cardiopulmonary mortality, and long-term exposure to fine particulate air pollution. J. Am. Med. Assoc. 287:1132–1141.

2. Ozone

a. Background

Ground-level ozone pollution is typically formed by the reaction of volatile organic compounds (VOC) and nitrogen oxides (NO_X) in the lower atmosphere in the presence of heat and sunlight. These pollutants, often referred to as ozone precursors, are emitted by many types of pollution sources, such as highway and nonroad motor vehicles and engines, power plants, chemical plants, refineries, makers of consumer and commercial products, industrial facilities, and smaller area sources.

The science of ozone formation, transport, and accumulation is complex.[345] Ground-level ozone is produced and destroyed in a cyclical set of chemical reactions, many of which are sensitive to temperature and sunlight. When ambient temperatures and sunlight levels remain high for several days and the air is relatively stagnant, ozone and its precursors can build up and result in more ozone than typically occurs on a single high-temperature day. Ozone can be transported hundreds of miles downwind from precursor emissions, resulting in elevated ozone levels even in areas with low local VOC or NO_X emissions.

b. Health Effects of Ozone

The health and welfare effects of ozone are well documented and are assessed in EPA's 2006 Ozone Air Quality Criteria Document (ozone AQCD) and 2007 Staff Paper.[346] [347] Ozone can irritate the respiratory system, causing coughing, throat irritation, and/or uncomfortable sensation in the chest. Ozone can reduce lung function and make it more difficult to breathe deeply; breathing may also become more rapid and shallow than normal, thereby limiting a person's activity. Ozone can also aggravate asthma, leading to more asthma attacks that require medical attention and/or the use of additional medication. In addition, there is suggestive evidence of a contribution of ozone to cardiovascular-related morbidity and highly suggestive evidence that short-term ozone exposure directly or indirectly contributes to non-accidental and cardiopulmonary-related mortality, but additional research is needed to clarify the underlying mechanisms causing these effects. In a recent report on the estimation of ozone-related premature mortality published by the National Research Council (NRC), a panel of experts and reviewers concluded that short-term exposure to ambient ozone is likely to contribute to premature deaths and that ozone-related mortality should be included in estimates of the health benefits of reducing ozone exposure.[348] Animal toxicological evidence indicates that with repeated exposure, ozone can inflame and damage the lining of the lungs, which may lead to permanent changes in lung tissue and irreversible reductions in lung function. People who are more susceptible to effects associated with exposure to ozone can include children, the elderly, and individuals with respiratory disease such as asthma. Those with greater exposures to ozone, for instance due to time spent outdoors (e.g., children and outdoor workers), are also of particular concern.

The 2006 ozone AQCD also examined relevant new scientific information that has emerged in the past decade, including the impact of ozone exposure on such health effects as changes in lung structure and biochemistry, inflammation of the lungs, exacerbation and causation of asthma, respiratory illness-related school absence, hospital admissions and premature mortality. Animal toxicological studies have suggested potential interactions between ozone and PM, with increased responses observed to mixtures of the two pollutants compared to either ozone or PM alone. The respiratory morbidity observed in animal studies along with the evidence from epidemiologic studies supports a causal relationship between acute ambient ozone exposures and increased respiratory-related emergency room visits and hospitalizations in the warm season. In addition, there is

[345] U.S. EPA Air Quality Criteria for Ozone and Related Photochemical Oxidants (Final). U.S. Environmental Protection Agency, Washington, D.C., EPA 600/R–05/004aF–cF, 2006. This document is available in Docket EPA–HQ–OAR–2005–0161. This document may be accessed electronically at: *http://www.epa.gov/ttn/naaqs/standards/ozone/s_o3_cr_cd.html.*

[346] U.S. EPA Air Quality Criteria for Ozone and Related Photochemical Oxidants (Final). U.S. Environmental Protection Agency, Washington, DC, EPA 600/R–05/004aF–cF, 2006. This document is available in Docket EPA–HQ–OAR–2005–0161. This document may be accessed electronically at: *http://www.epa.gov/ttn/naaqs/standards/ozone/s_o3_cr_cd.html.*

[347] U.S. EPA (2007) Review of the National Ambient Air Quality Standards for Ozone, Policy Assessment of Scientific and Technical Information. OAQPS Staff Paper.EPA–452/R–07–003. This document is available in Docket EPA–HQ–OAR–2005–0161. This document is available electronically at: *http:www.epa.gov/ttn/naaqs/standards/ozone/s_o3_cr_sp.html..*

[348] National Research Council (NRC), 2008. Estimating Mortality Risk Reduction and Economic Benefits from Controlling Ozone Air Pollution. The National Academies Press: Washington, DC.

suggestive evidence of a contribution of ozone to cardiovascular-related morbidity and non-accidental and cardiopulmonary mortality.

3. Carbon Monoxide

Carbon monoxide (CO) forms as a result of incomplete fuel combustion. CO enters the bloodstream through the lungs, forming carboxyhemoglobin and reducing the delivery of oxygen to the body's organs and tissues. The health threat from CO is most serious for those who suffer from cardiovascular disease, particularly those with angina or peripheral vascular disease. Healthy individuals also are affected, but only at higher CO levels. Exposure to elevated CO levels is associated with impairment of visual perception, work capacity, manual dexterity, learning ability and performance of complex tasks. Carbon monoxide also contributes to ozone nonattainment since carbon monoxide reacts photochemically in the atmosphere to form ozone.[349] Additional information on CO related health effects can be found in the Carbon Monoxide Air Quality Criteria Document (CO AQCD).[350]

4. Air Toxics

The population experiences an elevated risk of cancer and noncancer health effects from exposure to the class of pollutants known collectively as ''air toxics.''[351] Fuel combustion contributes to ambient levels of air toxics that can include, but are not limited to, acetaldehyde, acrolein, benzene, 1,3-butadiene, formaldehyde, ethanol, naphthalene and peroxyacetyl nitrate (PAN). Acrolein, benzene, 1,3-butadiene, formaldehyde and naphthalene have significant contributions from mobile sources and were identified as national or regional risk drivers in the 1999 National-scale Air Toxics Assessment (NATA).[352] PAN, which is formed from precursor compounds by atmospheric processes, is not assessed in NATA. Emissions and ambient concentrations of compounds are discussed in the DRIA chapter on emission inventories and air quality (Chapter 3).

a. Acetaldehyde

Acetaldehyde is classified in EPA's IRIS database as a probable human carcinogen, based on nasal tumors in rats, and is considered toxic by the inhalation, oral, and intravenous routes.[353] Acetaldehyde is reasonably anticipated to be a human carcinogen by the U.S. DHHS in the 11th Report on Carcinogens and is classified as possibly carcinogenic to humans (Group 2B) by the IARC.[354] [355] EPA is currently conducting a reassessment of cancer risk from inhalation exposure to acetaldehyde.

The primary noncancer effects of exposure to acetaldehyde vapors include irritation of the eyes, skin, and respiratory tract.[356] In short-term (4 week) rat studies, degeneration of olfactory epithelium was observed at various concentration levels of acetaldehyde exposure.[357] [358] Data from these studies were used by EPA to develop an inhalation reference concentration. Some asthmatics have been shown to be a sensitive subpopulation to decrements in functional expiratory volume (FEV1 test) and bronchoconstriction upon acetaldehyde inhalation.[359] The agency is currently conducting a reassessment of the health hazards from inhalation exposure to acetaldehyde.

b. Acrolein

EPA determined in 2003 that the human carcinogenic potential of acrolein could not be determined because the available data were inadequate. No information was available on the carcinogenic effects of acrolein in humans and the animal data provided inadequate evidence of carcinogenicity.[360] The IARC determined in 1995 that acrolein was not classifiable as to its carcinogenicity in humans.[361]

Acrolein is extremely acrid and irritating to humans when inhaled, with acute exposure resulting in upper respiratory tract irritation, mucus hypersecretion and congestion. Levels considerably lower than 1 ppm (2.3 mg/m^3) elicit subjective complaints of eye and nasal irritation and a decrease in the respiratory rate.[362] [363] Lesions to the lungs and upper respiratory tract of rats, rabbits, and hamsters have been observed after subchronic exposure to acrolein. Based on animal data, individuals with compromised respiratory function (e.g., emphysema, asthma) are expected to be at increased risk of developing adverse responses to strong respiratory irritants such as acrolein. This was demonstrated in mice with allergic airway disease by comparison to non-diseased mice in a study of the acute respiratory irritant effects of acrolein.[364]

The intense irritancy of this carbonyl has been demonstrated during controlled tests in human subjects, who suffer intolerable eye and nasal mucosal sensory reactions within minutes of exposure.[365]

c. Benzene

The EPA's IRIS database lists benzene as a known human carcinogen (causing leukemia) by all routes of exposure, and concludes that exposure is associated with additional health effects, including

349 U.S. EPA (2000). Air Quality Criteria for Carbon Monoxide, EPA/600/P–99/001F. This document is available in Docket EPA–HQ–OAR–2005–0161.

350 U.S. EPA (2000). Air Quality Criteria for Carbon Monoxide, EPA/600/P–99/001F. This document is available in Docket EPA–HQ–OAR–2005–0161.

351 U. S. EPA. 1999 National-Scale Air Toxics Assessment. *http://www.epa.gov/ttn/atw/nata1999/risksum.html*

352 U.S. EPA. 2006. National-Scale Air Toxics Assessment for 1999. *http://www.epa.gov/ttn/atw/nata1999*

353 U.S. EPA. 1991. Integrated Risk Information System File of Acetaldehyde. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at.

354 U.S. Department of Health and Human Services National Toxicology Program 11th Report on Carcinogens available at: *ntp.niehs.nih.gov/index.cfm?objectid=32BA9724-F1F6-975E-7FCE50709CB4C932*.

355 International Agency for Research on Cancer (IARC). 1999. Re-evaluation of some organic chemicals, hydrazine, and hydrogen peroxide. IARC Monographs on the Evaluation of Carcinogenic Risk of Chemical to Humans, Vol 71. Lyon, France.

356 U.S. EPA. 1991. Integrated Risk Information System File of Acetaldehyde. This material is available electronically at *http://www.epa.gov/iris/subst/0290.htm*.

357 Appleman, L. M., R. A. Woutersen, V. J. Feron, R. N. Hooftman, and W. R. F. Notten. 1986. Effects of the variable versus fixed exposure levels on the toxicity of acetaldehyde in rats. *J. Appl. Toxicol.* 6: 331–336.

358 Appleman, L.M., R.A. Woutersen, and V.J. Feron. 1982. Inhalation toxicity of acetaldehyde in rats. I. Acute and subacute studies. *Toxicology.* 23: 293–297.

359 Myou, S.; Fujimura, M.; Nishi, K.; Ohka, T.; and Matsuda, T. 1993. Aerosolized acetaldehyde induces histamine-mediated bronchoconstriction in asthmatics. *Am. Rev. Respir. Dis.* 148 (4 Pt 1): 940–3.

360 U.S. EPA. 2003. Integrated Risk Information System File of Acrolein. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available at *http://www.epa.gov/iris/subst/0364.htm*.

361 International Agency for Research on Cancer (IARC). 1995. Monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 63, Dry cleaning, some chlorinated solvents and other industrial chemicals, World Health Organization, Lyon, France.

362 Weber-Tschopp, A.; Fischer, T.; Gierer, R.; *et al.* (1977) Experimentelle reizwirkungen von Acrolein auf den Menschen. Int Arch Occup Environ Hlth 40(2):117–130. In German.

363 Sim, V.M.; Pattle, R.E. (1957) Effect of possible smog irritants on human subjects. J Am Med Assoc 165(15):1908–1913.

364 Morris J.B., Symanowicz P.T., Olsen J.E., *et al.* 2003. Immediate sensory nerve-mediated respiratory responses to irritants in healthy and allergic airway-diseased mice. J Appl Physiol 94(4):1563–1571.

365 Sim V.M., Pattle R.E. Effect of possible smog irritants on human subjects. JAMA 165:1980–2010, 1957.

genetic changes in both humans and animals and increased proliferation of bone marrow cells in mice.[366] [367] [368] EPA states in its IRIS database that data indicate a causal relationship between benzene exposure and acute lymphocytic leukemia and suggest a relationship between benzene exposure and chronic non-lymphocytic leukemia and chronic lymphocytic leukemia. The International Agency for Research on Carcinogens (IARC) has determined that benzene is a human carcinogen and the U.S. Department of Health and Human Services (DHHS) has characterized benzene as a known human carcinogen.[369] [370]

A number of adverse noncancer health effects including blood disorders, such as preleukemia and aplastic anemia, have also been associated with long-term exposure to benzene.[371] [372] The most sensitive noncancer effect observed in humans, based on current data, is the depression of the absolute lymphocyte count in blood.[373] [374] In addition, recent work, including studies sponsored by the Health Effects Institute (HEI), provides evidence that biochemical responses are occurring at lower levels of benzene exposure than previously known.[375] [376] [377] [378] EPA's IRIS program has not yet evaluated these new data.

d. 1,3-Butadiene

EPA has characterized 1,3-butadiene as carcinogenic to humans by inhalation.[379] [380] The IARC has determined that 1,3-butadiene is a human carcinogen and the U.S. DHHS has characterized 1,3-butadiene as a known human carcinogen.[381] [382] There are numerous studies consistently demonstrating that 1,3-butadiene is metabolized into genotoxic metabolites by experimental animals and humans. The specific mechanisms of 1,3-butadiene-induced carcinogenesis are unknown; however, the scientific evidence strongly suggests that the carcinogenic effects are mediated by genotoxic metabolites. Animal data suggest that females may be more sensitive than males for cancer effects associated with 1,3-butadiene exposure; there are insufficient data in humans from which to draw conclusions about sensitive subpopulations. 1,3-butadiene also causes a variety of reproductive and developmental effects in mice; no human data on these effects are available. The most sensitive effect was ovarian atrophy observed in a lifetime bioassay of female mice.[383]

e. Ethanol

EPA is conducting an assessment of the cancer and noncancer effects of exposure to ethanol, a compound which is not currently listed in EPA's IRIS. A description of these effects to the extent that information is available will be presented, as required by Section 1505 of EPAct, in a report to Congress on public health, air quality and water resource impacts of fuel additives. We expect to release that report in 2009.

Extensive data are available regarding adverse health effects associated with the ingestion of ethanol while data on inhalation exposure effects are sparse. As part of the IRIS assessment, pharmacokinetic models are being evaluated as a means of extrapolating across species (animal to human) and across exposure routes (oral to inhalation) to better characterize the health hazards and dose-response relationships for low levels of ethanol exposure in the environment.

The IARC has classified ''alcoholic beverages'' as carcinogenic to humans based on sufficient evidence that malignant tumors of the mouth, pharynx, larynx, esophagus, and liver are causally related to the consumption of alcoholic beverages.[384] The U.S. DHHS in the 11th Report on Carcinogens also identified ''alcoholic beverages'' as a known human carcinogen (they have not evaluated the cancer risks specifically from exposure to ethanol), with evidence for cancer of the mouth, pharynx, larynx, esophagus, liver and breast.[385] There are no studies reporting carcinogenic effects from inhalation of ethanol. EPA is currently evaluating the available human and animal cancer data to identify which cancer type(s) are the most relevant to an assessment of risk to humans from a low-level oral and inhalation exposure to ethanol.

Noncancer health effects data are available from animal studies as well as epidemiologic studies. The epidemiologic data are obtained from studies of alcoholic beverage

[366] U.S. EPA. 2000. Integrated Risk Information System File for Benzene. This material is available electronically at *http://www.epa.gov/iris/subst/0276.htm*.

[367] International Agency for Research on Cancer (IARC). 1982. Monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Some industrial chemicals and dyestuffs, World Health Organization, Lyon, France, p. 345–389.

[368] Irons, R.D.; Stillman, W.S.; Colagiovanni, D.B.; Henry, V.A. 1992. Synergistic action of the benzene metabolite hydroquinone on myelopoietic stimulating activity of granulocyte/macrophage colony-stimulating factor in vitro, Proc. Natl. Acad. Sci. 89:3691–3695.

[369] International Agency for Research on Cancer (IARC). 1987. Monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Supplement 7, Some industrial chemicals and dyestuffs, World Health Organization, Lyon, France.

[370] U.S. Department of Health and Human Services National Toxicology Program, 11th Report on Carcinogens, available at: *http://ntp.niehs.nih.gov/go/16183*.

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[374] U.S. EPA (2002) Toxicological Review of Benzene (Noncancer Effects). Environmental Protection Agency, Integrated Risk Information System (IRIS), Research and Development, National Center for Environmental Assessment, Washington DC. This material is available electronically at *http://www.epa.gov/iris/subst/0276.htm*.

[375] Qu, O.; Shore, R.; Li, G.; Jin, X.; Chen, C.L.; Cohen, B.; Melikian, A.; Eastmond, D.; Rappaport, S.; Li, H.; Rupa, D.; Suramaya, R.; Songnian, W.; Huifant, Y.; Meng, M.; Winnik, M.; Kwok, E.; Li, Y.; Mu, R.; Xu, B.; Zhang, X.; Li, K. (2003) HEI Report 115, Validation & Evaluation of Biomarkers in Workers Exposed to Benzene in China.

[376] Qu, Q., R. Shore, G. Li, X. Jin, L.C. Chen, B. Cohen, *et al.* (2002) Hematological changes among Chinese workers with a broad range of benzene exposures. Am. J. Industr. Med. 42:275–285.

[377] Lan, Qing, Zhang, L., Li, G., Vermeulen, R., *et al.* (2004) Hematotoxicity in Workers Exposed to Low Levels of Benzene. Science 306:1774–1776.

[378] Turtletaub, K.W. and Mani, C. (2003) Benzene metabolism in rodents at doses relevant to human exposure from Urban Air. Research Reports Health Effect Inst. Report No. 113.

[379] U.S. EPA (2002) Health Assessment of 1,3–Butadiene. Office of Research and Development, National Center for Environmental Assessment, Washington Office, Washington, DC. Report No. EPA600–P–98–001F. This document is available electronically at *http://www.epa.gov/iris/supdocs/buta-sup.pdf*.

[380] U.S. EPA (2002) Full IRIS Summary for 1,3-butadiene (CASRN 106–99–0). Environmental Protection Agency, Integrated Risk Information System (IRIS), Research and Development, National Center for Environmental Assessment, Washington, DC, *http://www.epa.gov/iris/subst/0139.htm*.

[381] International Agency for Research on Cancer (IARC) (1999) Monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 71, Re-evaluation of some organic chemicals, hydrazine and hydrogen peroxide and Volume 97 (in preparation), World Health Organization, Lyon, France.

[382] U.S. Department of Health and Human Services (2005) National Toxicology Program, 11th Report on Carcinogens, available at: *http://ntp.niehs.nih.gov/index.cfm?objectid=32BA9724–F1F6–975E–7FCE50709CB4C932*.

[383] Bevan, C.; Stadler, J.C.; Elliot, G.S.; *et al.* (1996) Subchronic toxicity of 4-vinylcyclohexene in rats and mice by inhalation. Fundam. Appl. Toxicol. 32:1–10.

[384] International Agency for Research on Cancer (IARC). 1988. Monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 44, Alcohol Drinking, World Health Organization, Lyon, France.

[385] U.S. Department of Health and Human Services. 2005. National Toxicology Program 11th Report on Carcinogens available at: *ntp.niehs.nih.gov/index.cfm?objectid=32BA9724-F1F6-975E-7FCE50709CB4C932*.

consumption. Effects include neurological impairment, developmental effects, cardiovascular effects, immune system depression, and effects on the liver, pancreas and reproductive system.[386] There is evidence that children prenatally exposed via mothers' ingestion of alcoholic beverages during pregnancy are at increased risk of hyperactivity and attention deficits, impaired motor coordination, a lack of regulation of social behavior or poor psychosocial functioning, and deficits in cognition, mathematical ability, verbal fluency, and spatial memory.[387] [388] [389] [390] [391] [392] [393] [394] In some people, genetic factors influencing the metabolism of ethanol can lead to differences in internal levels of ethanol and may render some subpopulations more susceptible to risks from the effects of ethanol.

f. Formaldehyde

Since 1987, EPA has classified formaldehyde as a probable human carcinogen based on evidence in humans and in rats, mice, hamsters, and monkeys.[395] EPA is currently reviewing recently published epidemiological data. For instance, research conducted by the National Cancer Institute (NCI) found an increased risk of nasopharyngeal cancer and lymphohematopoietic malignancies such as leukemia among workers exposed to formaldehyde.[396] [397] NCI is currently performing an update of these studies. A recent National Institute of Occupational Safety and Health (NIOSH) study of garment workers also found increased risk of death due to leukemia among workers exposed to formaldehyde.[398] Extended follow-up of a cohort of British chemical workers did not find evidence of an increase in nasopharyngeal or lymphohematopoietic cancers, but a continuing statistically significant excess in lung cancers was reported.[399] Recently, the IARC re-classified formaldehyde as a human carcinogen (Group 1).[400]

Formaldehyde exposure also causes a range of noncancer health effects, including irritation of the eyes (burning and watering of the eyes), nose and throat. Effects from repeated exposure in humans include respiratory tract irritation, chronic bronchitis and nasal epithelial lesions such as metaplasia and loss of cilia. Animal studies suggest that formaldehyde may also cause airway inflammation—including eosinophil infiltration into the airways. There are several studies that suggest that formaldehyde may increase the risk of asthma—particularly in the young.[401] [402]

g. Naphthalene

Naphthalene is found in small quantities in gasoline and diesel fuels. Naphthalene emissions have been measured in larger quantities in both gasoline and diesel exhaust compared with evaporative emissions from mobile sources, indicating it is primarily a product of combustion. EPA released an external review draft of a reassessment of the inhalation carcinogenicity of naphthalene based on a number of recent animal carcinogenicity studies.[403] The draft reassessment completed external peer review.[404] Based on external peer review comments received, additional analyses are being undertaken. This external review draft does not represent official agency opinion and was released solely for the purposes of external peer review and public comment. Once EPA evaluates public and peer reviewer comments, the document will be revised. The National Toxicology Program listed naphthalene as ''reasonably anticipated to be a human carcinogen'' in 2004 on the basis of bioassays reporting clear evidence of carcinogenicity in rats and some evidence of carcinogenicity in mice.[405] California EPA has released a new risk assessment for naphthalene, and the IARC has reevaluated naphthalene and re-classified it as Group 2B: possibly carcinogenic to humans.[406] Naphthalene also causes a number of chronic non-cancer effects in animals, including abnormal cell changes and growth in respiratory and nasal tissues.[407]

h. Peroxyacetyl Nitrate (PAN)

Peroxyacetyl nitrate (PAN) has not been evaluated by EPA's IRIS program. Information regarding the potential carcinogenicity of PAN is limited. As noted in the EPA air quality criteria

[386] U.S. Department of Health and Human Services. 2000. 10th Special Report to the U.S. Congress on Alcohol and Health. June 2000.

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[400] International Agency for Research on Cancer (IARC). 2006. Formaldehyde, 2-Butoxyethanol and 1-tert-Butoxypropan-2-ol. Volume 88. (in preparation), World Health Organization, Lyon, France.

[401] Agency for Toxic Substances and Disease Registry (ATSDR). 1999. Toxicological profile for Formaldehyde. Atlanta, GA: U.S. Department of Health and Human Services, Public Health Service. *http://www.atsdr.cdc.gov/toxprofiles/tp111.html.*

[402] WHO (2002) Concise International Chemical Assessment Document 40: Formaldehyde. Published under the joint sponsorship of the United Nations Environment Programme, the International Labour Organization, and the World Health Organization, and produced within the framework of the Inter-Organization Programme for the Sound Management of Chemicals. Geneva.

[403] U.S. EPA. 2004. Toxicological Review of Naphthalene (Reassessment of the Inhalation Cancer Risk), Environmental Protection Agency, Integrated Risk Information System, Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at *http://www.epa.gov/iris/subst/0436.htm.*

[404] Oak Ridge Institute for Science and Education. (2004). External Peer Review for the IRIS Reassessment of the Inhalation Carcinogenicity of Naphthalene. August 2004. *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=84403.*

[405] National Toxicology Program (NTP). (2004). 11th Report on Carcinogens. Public Health Service, U.S. Department of Health and Human Services, Research Triangle Park, NC. Available from: *http://ntp-server.niehs.nih.gov.*

[406] International Agency for Research on Cancer (IARC). (2002). Monographs on the Evaluation of the Carcinogenic Risk of Chemicals for Humans. Vol. 82, Lyon, France.

[407] U.S. EPA. 1998. Toxicological Review of Naphthalene, Environmental Protection Agency, Integrated Risk Information System, Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at *http://www.epa.gov/iris/subst/0436.htm*.

document for ozone and related photochemical oxidants, cytogenetic studies indicate that PAN is not a potent mutagen, clastogen (a compound that can cause breaks in chromosomes), or DNA-damaging agent in mammalian cells either in vivo or in vitro. Some studies suggest that PAN may be a weak bacterial mutagen at high concentrations much higher than exist in present urban atmospheres.[408]

Effects of ground-level smog causing intense eye irritation have been attributed to photochemical oxidants, including PAN.[409] Animal toxicological information on the inhalation effects of the non-ozone oxidants has been limited to a few studies on PAN. Acute exposure to levels of PAN can cause changes in lung morphology, behavioral modifications, weight loss, and susceptibility to pulmonary infections. Human exposure studies indicate minor pulmonary function effects at high PAN concentrations, but large inter-individual variability precludes definitive conclusions.[410]

i. Other Air Toxics

In addition to the compounds described above, other compounds in gaseous hydrocarbon and PM emissions from vehicles will be affected by today's proposed action. Mobile source air toxic compounds that will potentially be impacted include ethylbenzene, polycyclic organic matter, propionaldehyde, toluene, and xylene. Information regarding the health effects of these compounds can be found in EPA's IRIS database.[411]

F. Environmental Effects of Criteria and Air Toxic Pollutants

In this section we discuss some of the environmental effects of PM and its precursors, such as visibility impairment, atmospheric deposition, and materials damage and soiling, as well as environmental effects associated with the presence of ozone in the ambient air, such as impacts on plants, including trees, agronomic crops and urban ornamentals, and environmental effects associated with air toxics.

1. Visibility

Visibility can be defined as the degree to which the atmosphere is transparent to visible light.[412] Airborne particles degrade visibility by scattering and absorbing light. Visibility is important because it has direct significance to people's enjoyment of daily activities in all parts of the country. Individuals value good visibility for the well-being it provides them directly, where they live and work, and in places where they enjoy recreational opportunities. Visibility is also highly valued in natural areas such as national parks and wilderness areas and special emphasis is given to protecting visibility in these areas. For more information on visibility see the final 2004 PM AQCD as well as the 2005 PM Staff Paper.[413] [414]

EPA is pursuing a two-part strategy to address visibility. First, to address the welfare effects of PM on visibility, EPA has set secondary $PM_{2.5}$ standards which act in conjunction with the establishment of a regional haze program. In setting this secondary standard EPA has concluded that $PM_{2.5}$ causes adverse effects on visibility in various locations, depending on PM concentrations and factors such as chemical composition and average relative humidity. Second, section 169 of the Clean Air Act provides additional authority to address existing visibility impairment and prevent future visibility impairment in the 156 national parks, forests and wilderness areas categorized as mandatory class I federal areas (62 FR 38680–81, July 18, 1997).[415] In July 1999 the regional haze rule (64 FR 35714) was put in place to protect visibility in mandatory class I federal areas. Visibility can be said to be impaired in both $PM_{2.5}$ nonattainment areas and mandatory class I federal areas.

2. Atmospheric Deposition

Wet and dry deposition of ambient particulate matter delivers a complex mixture of metals (e.g., mercury, zinc, lead, nickel, aluminum, cadmium), organic compounds (e.g., POM, dioxins, furans) and inorganic compounds (e.g., nitrate, sulfate) to terrestrial and aquatic ecosystems. The chemical form of the compounds deposited depends on a variety of factors including ambient conditions (e.g., temperature, humidity, oxidant levels) and the sources of the material. Chemical and physical transformations of the particulate compounds occur in the atmosphere as well as the media onto which they deposit. These transformations in turn influence the fate, bioavailability and potential toxicity of these compounds. Atmospheric deposition has been identified as a key component of the environmental and human health hazard posed by several pollutants including mercury, dioxin and PCBs.[416]

Adverse impacts on water quality can occur when atmospheric contaminants deposit to the water surface or when material deposited on the land enters a waterbody through runoff. Potential impacts of atmospheric deposition to waterbodies include those related to both nutrient and toxic inputs. Adverse effects to human health and welfare can occur from the addition of excess particulate nitrate nutrient enrichment, which contributes to toxic algae blooms and zones of depleted oxygen, which can lead to fish kills, frequently in coastal waters. Particles contaminated with heavy metals or other toxins may lead to the ingestion of contaminated fish, ingestion of contaminated water, damage to the marine ecology, and limits to recreational uses. Several studies have been conducted in U.S. coastal waters and in the Great Lakes Region in which the role of ambient PM deposition and runoff is

[408] U.S. EPA. 2006. Air Quality Criteria for Ozone and Related Photochemical Oxidants (Ozone CD). Research Triangle Park, NC: National Center for Environmental Assessment; report no. EPA/600/R–05/004aF–cF.3v. page 5–78. Available at *http://cfpub.epa.gov/ncea/.*

[409] U.S. EPA. 2006. Air Quality Criteria for Ozone and Related Photochemical Oxidants (Final). U.S. Environmental Protection Agency, Washington, DC, EPA 600/R–05/004aF–cF. pages 5–63. This document is available in Docket EPA–HQ–OAR–2005–0161. This document may be accessed electronically at: *http://www.epa.gov/ttn/naaqs/standards/ozone/s_o3_cr_cd.html.*

[410] U.S. EPA. 2006. Air Quality Criteria for Ozone and Related Photochemical Oxidants (Final). U.S. Environmental Protection Agency, Washington, DC, EPA 600/R–05/004aF–cF. pages 5–78. This document is available in Docket EPA–HQ–OAR–2005–0161. This document may be accessed electronically at: *http://www.epa.gov/ttn/naaqs/standards/ozone/s_o3_cr_cd.html.*

[411] U.S. EPA. Integrated Risk Information System (IRIS) database is available at: *www.epa.gov/iris.*

[412] National Research Council, 1993. Protecting Visibility in National Parks and Wilderness Areas. National Academy of Sciences Committee on Haze in National Parks and Wilderness Areas. National Academy Press, Washington, DC. This document is available in Docket EPA–HQ–OAR–2005–0161. This book can be viewed on the National Academy Press Web site at *http://www.nap.edu/books/0309048443/html/.*

[413] U.S. EPA (2004) Air Quality Criteria for Particulate Matter (Oct 2004), Volume I Document No. EPA600/P–99/002aF and Volume II Document No. EPA600/P–99/002bF. This document is available in Docket EPA–HQ–OAR–2005–0161.

[414] U.S. EPA (2005) Review of the National Ambient Air Quality Standard for Particulate Matter: Policy Assessment of Scientific and Technical Information, OAQPS Staff Paper. EPA–452/R–05–005. This document is available in Docket EPA–HQ–OAR–2005–0161.

[415] These areas are defined in CAA section 162 as those national parks exceeding 6,000 acres, wilderness areas and memorial parks exceeding 5,000 acres, and all international parks which were in existence on August 7, 1977.

[416] U.S. EPA (2000) Deposition of Air Pollutants to the Great Waters: Third Report to Congress. Office of Air Quality Planning and Standards. EPA–453/R–00–0005. This document is available in Docket EPA–HQ–OAR–2005–0161.

investigated.[417] [418] [419] [420] [421] In addition, the process of acidification affects both freshwater aquatic and terrestrial ecosystems. Acid deposition causes acidification of sensitive surface waters. The effects of acid deposition on aquatic systems depend largely upon the ability of the ecosystem to neutralize the additional acid. As acidity increases, aluminum leached from soils and sediments, flows into lakes and streams and can be toxic to both terrestrial and aquatic biota. The lower pH concentrations and higher aluminum levels resulting from acidification make it difficult for some fish and other aquatic organisms to survive, grow, and reproduce.

Adverse impacts on soil chemistry and plant life have been observed for areas heavily influenced by atmospheric deposition of nutrients, metals and acid species, resulting in species shifts, loss of biodiversity, forest decline and damage to forest productivity. Potential impacts also include adverse effects to human health through ingestion of contaminated vegetation or livestock (as in the case for dioxin deposition), reduction in crop yield, and limited use of land due to contamination. Research on effects of acid deposition on forest ecosystems has come to focus increasingly on the biogeochemical processes that affect uptake, retention, and cycling of nutrients within these ecosystems. Decreases in available base cations from soils are at least partly attributable to acid deposition. Base cation depletion is a cause for concern because of the role these ions play in acid neutralization and because calcium, magnesium and potassium are essential nutrients for plant growth and physiology. Changes in the relative proportions of these nutrients, especially in comparison with aluminum concentrations, have been associated with declining forest health.

[417] U.S. EPA (2004) National Coastal Condition Report II. Office of Research and Development/ Office of Water. EPA–620/R–03/002. This document is available in Docket EPA–HQ–OAR–2005–0161.

[418] Gao, Y., E.D. Nelson, M.P. Field, et al. 2002. Characterization of atmospheric trace elements on $PM_{2.5}$ particulate matter over the New York-New Jersey harbor estuary. *Atmos. Environ.* 36: 1077–1086.

[419] Kim, G., N. Hussain, J.R. Scudlark, and T.M. Church. 2000. Factors influencing the atmospheric depositional fluxes of stable Pb, 210Pb, and 7Be into Chesapeake Bay. *J. Atmos. Chem.* 36: 65–79.

[420] Lu, R., R.P. Turco, K. Stolzenbach, et al. 2003. Dry deposition of airborne trace metals on the Los Angeles Basin and adjacent coastal waters. *J. Geophys. Res.* 108(D2, 4074): AAC 11–1 to 11–24.

[421] Marvin, C.H., M.N. Charlton, E.J. Reiner, et al. 2002. Surficial sediment contamination in Lakes Erie and Ontario: A comparative analysis. *J. Great Lakes Res.* 28(3): 437–450.

The deposition of airborne particles can reduce the aesthetic appeal of buildings and culturally important articles through soiling and can contribute directly (or in conjunction with other pollutants) to structural damage by means of corrosion or erosion.[422] Particles affect materials principally by promoting and accelerating the corrosion of metals, by degrading paints, and by deteriorating building materials such as concrete and limestone. Particles contribute to these effects because of their electrolytic, hygroscopic, and acidic properties and their ability to adsorb corrosive gases (principally sulfur dioxide). The rate of metal corrosion depends on a number of factors, including: The deposition rate and nature of the pollutant; the influence of the metal protective corrosion film; the amount of moisture present; variability in the electrochemical reactions; the presence and concentration of other surface electrolytes; and the orientation of the metal surface.

3. Plant and Ecosystem Effects of Ozone

Ozone contributes to many environmental effects, with impacts to plants and ecosystems being of most concern. Ozone can produce both acute and chronic injury in sensitive species depending on the concentration level and the duration of the exposure. Ozone effects also tend to accumulate over the growing season of the plant, so that even lower concentrations experienced for a longer duration have the potential to create chronic stress on vegetation. Ozone damage to plants includes visible injury to leaves and a reduction in food production through impaired photosynthesis, both of which can lead to reduced crop yields, forestry production, and use of sensitive ornamentals in landscaping. In addition, the reduced food production in plants and subsequent reduced root growth and storage below ground can result in other, more subtle plant and ecosystems impacts. These include increased susceptibility of plants to insect attack, disease, harsh weather, interspecies competition and overall decreased plant vigor. The adverse effects of ozone on forest and other natural vegetation can potentially lead to species shifts and loss from the affected ecosystems, resulting in a loss or reduction in associated ecosystem goods and services. Last, visible ozone injury to leaves can result in a loss of aesthetic value in areas of special scenic significance like national parks and wilderness areas. The final 2006 Ozone Air Quality Criteria Document presents more detailed information on ozone effects on vegetation and ecosystems.

[422] U.S. EPA (2005). Review of the National Ambient Air Quality Standards for Particulate Matter: Policy Assessment of Scientific and Technical Information, OAQPS Staff Paper. This document is available in Docket EPA–HQ–OAR–2005–0161.

4. Welfare Effects of Air Toxics

Fuel combustion emissions contribute to ambient levels of pollutants that contribute to adverse effects on vegetation. PAN is a well-established phytotoxicant causing visible injury to leaves that can appear as metallic glazing on the lower surface of leaves with some leafy vegetables exhibiting particular sensitivity (e.g., spinach, lettuce, chard).[423] [424] [425] PAN has been demonstrated to inhibit photosynthetic and non-photosynthetic processes in plants and retard the growth of young navel orange trees.[426] [427] In addition to its oxidizing capability, PAN contributes nitrogen to forests and other vegetation via uptake as well as dry and wet deposition to surfaces. As noted in Section X, nitrogen deposition can lead to saturation of terrestrial ecosystems and research is needed to understand the impacts of excess nitrogen deposition experienced in some areas of the country on water quality and ecosystems.[428]

Volatile organic compounds (VOCs), some of which are considered air toxics, have long been suspected to play a role in vegetation damage.[429] In laboratory experiments, a wide range of tolerance to VOCs has been observed.[430] Decreases in harvested seed pod weight

[423] Nouchi I, S Toyama. 1998. Effects of ozone and peroxyacetyl nitrate on polar lipids and fatty acids in leaves of morning glory and kidney bean. Plant Physiol. 87:638–646.

[424] Oka E, Y Tagami, T Oohashi, N Kondo. 2004. A physiological and morphological study on the injury caused by exposure to the air pollutant, peroxyacetyl nitrate (PAN), based on the quantitative assessment of the injury. J Plant Res. 117:27–36.

[425] Sun E-J, M-H Huang. 1995. Detection of peroxyacetyl nitrate at phytotoxic level and its effects on vegetation in Taiwan. Atmos. Env. 29:2899–2904.

[426] Koukol J, WM Dugger, Jr., RL Palmer. 1967. Inhibitory effect of peroxyacetyl nitrate on cyclic photophosphorylation by chloroplasts from black valentine bean leaves. Plant Physiol. 42:1419–1422.

[427] Thompson CR, G Kats. 1975. Effects of ambient concentrations of peroxyacetyl nitrate on navel orange trees. Env. Sci. Technol. 9:35–38.

[428] Bytnerowicz A, ME Fenn. 1995. Nitrogen deposition in California forests: A Review. Environ. Pollut. 92:127–146.

[429] U.S. EPA. 1991. Effects of organic chemicals in the atmosphere on terrestrial plants. EPA/600/3–91/001.

[430] Cape JN, ID Leith, J Binnie, J Content, M Donkin, M Skewes, DN Price, AR Brown, AD Sharpe. 2003. Effects of VOCs on herbaceous plants in an open-top chamber experiment. Environ. Pollut. 124:341–343.

have been reported for the more sensitive plants, and some studies have reported effects on seed germination, flowering and fruit ripening. Effects of individual VOCs or their role in conjunction with other stressors (e.g., acidification, drought, temperature extremes) have not been well studied. In a recent study of a mixture of VOCs including ethanol and toluene on herbaceous plants, significant effects on seed production, leaf water content and photosynthetic efficiency were reported for some plant species.[431]

Research suggests an adverse impact of vehicle exhaust on plants, which has in some cases been attributed to aromatic compounds and in other cases to nitrogen oxides.[432 433 434] The impacts of VOCs on plant reproduction may have long-term implications for biodiversity and survival of native species near major roadways. Most of the studies of the impacts of VOCs on vegetation have focused on short-term exposure and few studies have focused on long-term effects of VOCs on vegetation and the potential for metabolites of these compounds to affect herbivores or insects.

VIII. Impacts on Cost of Renewable Fuels, Gasoline, and Diesel

We have assessed the impacts of the renewable fuel volumes required by EISA on their costs and on the costs of the gasoline and diesel fuels into which the renewable fuels will be blended. More details of feedstock costs are addressed in Section X.A.

A. Renewable Fuel Production Costs

1. Ethanol Production Costs

a. Corn Ethanol

A significant amount of work has been done in the last decade surveying and modeling the costs involved in producing ethanol from corn in order 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 models developed and maintained by USDA. Their work has been described in a peer-reviewed journal paper on cost modeling of the dry-grind corn ethanol process, and compares well with cost information found in surveys of existing plants.[435 436]

For our policy case scenario, we used corn prices of $3.34/bu in 2022 with corresponding DDGS prices of $139.78/ton (all 2006$). These estimates are taken from agricultural economics modeling work done for this proposal using the Forestry and Agricultural Sector Optimization Model (*see* Section IX.A).

For natural gas-fired ethanol production producing dried co-product (currently describes the largest fraction of the industry), in the policy case corn feedstock minus DDGS sale credit represents about 57% of the final per-gallon cost, while utilities, facility, and labor comprise about 22%, 11%, and 4%, respectively. Thus, the cost of ethanol production is most sensitive to the prices of corn and the primary co-product, DDGS, and relatively insensitive to economy of scale over the range of plant sizes typically seen (40–100 MMgal/yr).

We expect that several process fuels will be used to produce corn ethanol (see DRIA Section 1.4), which are presented by their projected 2022 volume production share in Table VIII.A.1–1a and cost impacts for each in Table VIII.A.1–1b.[437] We request comment on the projected mix of plant fuel sources in the future as well as the cost impacts of various technologies.

TABLE VIII.A.1–1a—PROJECTED 2022 BREAKDOWN OF FUEL TYPES USED TO ESTIMATE PRODUCTION COST OF CORN ETHANOL, PERCENT SHARE OF TOTAL PRODUCTION VOLUME

Plant type	Fuel type				Total by plant type
	Biomass (percent)	Coal (percent)	Natural gas (percent)	Biogas (percent)	All fuels (percent)
Coal/Biomass Boiler	11	0			11
Coal/Biomass Boiler + CHP	10	4			14
Natural Gas Boiler			49	14	63
Natural Gas Boiler + CHP			12		12
Total by Fuel Type	21	4	61	14	100

TABLE VIII.A.1–1b—PROJECTED 2022 BREAKDOWN OF COST IMPACTS BY FUEL TYPE USED IN ESTIMATING PRODUCTION COST OF CORN ETHANOL, DOLLARS PER GALLON RELATIVE TO NATURAL GAS BASELINE

Plant type	Fuel type				Total by plant type
	Biomass [a]	Coal	Natural gas	Biogas [b]	All fuels
Coal/Biomass Boiler	−$0.02	−$0.02			
Coal/Biomass Boiler + CHP	+$0.14	+$0.14			
Natural Gas Boiler			baseline	+$0.00	

[431] Cape JN, ID Leith, J Binnie, J Content, M Donkin, M Skewes, DN Price, AR Brown, AD Sharpe. 2003. Effects of VOCs on herbaceous plants in an open-top chamber experiment. Environ. Pollut. 124:341–343.

[432] Viskari E-L. 2000. Epicuticular wax of Norway spruce needles as indicator of traffic pollutant deposition. Water, Air, and Soil Pollut. 121:327–337.

[433] Ugrekhelidze D, F Korte, G Kvesitadze. 1997. Uptake and transformation of benzene and toluene by plant leaves. Ecotox. Environ. Safety 37:24–29.

[434] Kammerbauer H, H Selinger, R Rommelt, A Ziegler-Jons, D Knoppik, B Hock. 1987. Toxic components of motor vehicle emissions for the spruce Pciea abies. Environ. Pollut. 48:235–243.

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

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

[437] Projected fuel mix was taken from Mueller, S., Energy Research Center at the University of Chicago; An Analysis of the Projected Energy Use of Future Dry Mill Corn Ethanol Plants (2010–2030); cost estimates were derived from modifications to the USDA process models. We are aware that the cost impacts of CHP are likely overestimated here and will be revised in the final rulemaking.

TABLE VIII.A.1–1b—PROJECTED 2022 BREAKDOWN OF COST IMPACTS BY FUEL TYPE USED IN ESTIMATING PRODUCTION COST OF CORN ETHANOL, DOLLARS PER GALLON RELATIVE TO NATURAL GAS BASELINE—Continued

Plant type	Fuel type				Total by plant type
	Biomass [a]	Coal	Natural gas	Biogas [b]	All fuels
Natural Gas Boiler + CHP	....	....	+$0.16	....	....
Total by Fuel Type	....	....	....	....	$0.04

[a] Assumes biomass has same plant-delivered cost as coal.
[b] Assumes biogas has same plant-delivered cost as natural gas.

Based on energy prices from EIA's Annual Energy Outlook (AEO) 2008 baseline case ($53/bbl crude oil), we arrive at a production cost of $1.49/gal. In the case of EIA's high price scenario ($92/bbl crude), this figure increases by 6 cents per gallon. More details on the ethanol production cost estimates can be found in Chapter 4 of the DRIA. This estimate 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. The capital cost for a 65 MMgal/yr natural gas fired dry mill plant is estimated at $89MM (this the projected average size of such plants in 2022). Similarly, coal and biomass fired plants were assumed to be 110 MGY in capacity, with an estimated capital cost of $200MM.[438] On average, ethanol produced in a facility using coal or biomass as a primary energy source results in a per-gallon cost $0.02/gal lower compared to production using natural gas.

In this cost estimation work, we did not assume any pelletizing of DDGS. Pelletizing is expected to improve ease of shipment to more distant markets, which may become more important at the larger volumes projected for the future. However, while many in industry are aware of this technology, those we spoke with are not employing it in their plants, and do not expect widespread use in the foreseeable future. According to USDA's model, pelletizing adds $0.035/gal to the ethanol production cost. We request comment on whether pelletizing should be included in our program cost estimates.

In support of our biodiesel and renewable diesel volume feasibility estimates, we included recovery of corn oil from distillers' grains streams in our ethanol production cost estimates at a rate of 37% of ethanol production by 2022.[439] According to economic analyses done by USDA based on the GS Cleantech corn oil extraction process, the capital cost to install the system for a 50 MMgal/yr ethanol plant is approximately $6 million. The system is capable of extracting about one third of the corn oil entering the plant, and produces a low-quality corn oil co-product stream. In our analysis, we assumed the value of this additional co-product to be 70% that of soy oil (the same as yellow grease, $0.27/lb), resulting in a credit per gallon of ethanol of $0.04 for a 50 MMgal/yr plant operating such a system.

Note that the ethanol production cost given here does not account for any subsidies on production or sale of ethanol, and is independent of the market price of ethanol.

b. Cellulosic Ethanol

i. Feedstock Costs

Cellulosic Feedstock Costs

To estimate the cost of producing cellulosic biofuels, it was first necessary to estimate the cost of harvesting, storing, processing and transporting the feedstocks to the biofuel production facilities. Ethanol or other cellulosic biofuels can be produced from crop residues such as corn stover, wheat, rice, oat, and barley straw, sugar cane bagasse, and sorghum, from other cellulosic plant matter such as forest thinnings and forest-fuel removal, pulping residues, and from the cellulosic portions of municipal solid waste (MSW). Currently, there are no energy crops such as switchgrass nor short rotation woody crops (SRWC poplars, etc.) grown specifically for energy production.

Our feedstock supply analysis projected that crop residue, primarily corn stover, will be the most abundant of the cellulosic feedstocks, comprising about 61% of the total biomass feedstock inventory. Forest residues make up about 25% of the total, and MSW makes up the remaining 14%. At present, there are no commercial sized cellulosic ethanol plants in the U.S. Likewise, there are no commercially proven, fully-integrated feedstock supply systems dedicated to providing any of the feedstocks we mentioned to ethanol facilities of any size, although certain biomass is harvested for other purposes. For this reason, our feedstock cost estimates are projections and not based on any existing market data.

Our feedstock costs include an additional preprocessing cost that many other feedstock cost estimates do not include—thus our costs may seem higher. We used biofuel plant cost estimates provided by NREL which no longer includes the cost for finely grinding the feedstock prior to feeding it to the biofuel plant. Thus, our feedstock costs include an $11 per dry ton cost to account for the costs of this grinding operation, regardless of whether this operation occurs in the field or at the plant gate.

Crop Residue and Energy Crops

Crop residue harvest is currently a secondary harvest; that is they are harvested or gathered only after the prime crop has been harvested. In most northern areas, the harvest periods will be short due to the onset of winter weather. In some cases, it may be necessary to gather a full year's worth of residue within just a few weeks. Consequently, to accomplish this hundreds of pieces of farm equipment will be required for a few weeks each year to complete a harvest. Winter conditions in the South make it somewhat easier to extend the harvest periods; in some cases, it may be possible to harvest a residue on an as needed basis.

During the corn grain harvest, generally only the cob and the leaves above the cob are taken into the harvester. Thus, the stover harvest would likely require some portion of the

[438] Capital costs for a natural gas fired plant were taken from USDA cost model; incremental costs to use coal as the primary energy source were derived from conversations with ethanol plant construction contractors.

[439] Although some oil extraction may be done as front-end fractionation of the kernel, we believe the majority will be produced via separation from distillers' grains streams. For more discussion of corn oil extraction and fractionation, *see* Chapter 4 of the DRIA.

standing-stalks be mowed or shredded, following which the entire residue, including that discharged from the combine residue-spreader, would need to be raked. Balers, likely a mix of large round and large square balers, would follow the rakes. The bales would then be removed from the field, usually to the field-side in the first operation of the actual harvest, following which they would then be hauled to a satellite facility for intermediate storage. For our analysis we assumed that bales would then be hauled by truck and trailer to the processing plant on an as needed basis.

The small grain straws (wheat, rice, oats, barley, sorghum) are cut near the ground at the time of grain harvest and thus likely won't require further mowing or shredding. They will likely need to be raked into a windrow prior to baling. Because small grain straws have been baled and stored for many years, we don't expect unusual requirements for handling these residues. Their harvest and storage costs will likely be less than those for corn stover, but their overall quantity is much less than corn stover (corn stover makes up about 71% of all the crop residues), so we don't expect their lower costs to have, individually or collectively, a huge effect on the overall feedstock costs. Thus, we project that for several years, the feedstock costs will be largely a function of the cost to harvest, store, and haul corn stover.

For the crop residues, we relied on the FASOM agricultural cost model for farm harvesting and collection costs. FASOM estimates it would cost $33 per dry ton to mow, rake, bale, and field haul the bales and replace nutrients. We added $10 per dry ton as a farmer payment, which we believe is a necessary reimbursement to farmers to cover their costs associated with this additional harvest. Thus, $43 per dry ton covers the cost of making the crop residue available at the farm gate. This farm gate cost could be lower if new equipment is developed that would allow the farmer to harvest the corn stover at the same time as the corn. We also conducted our own independent analysis of the farm gate feedstock costs for corn stover, and our farm gate cost estimate for stover feedstock is very similar to FASOM's. For the steps involved in moving the corn stover from the farm gate to the cellulosic ethanol plant, we relied upon our own cost analysis. Our cost analysis estimates that an additional $32 per dry ton would be required to haul the bales to satellite storage, pay for the storage facilities, and grind the residue. Because of the low density of corn stover and other crop residues, we estimate that 60 or more secondary storage sites would be necessary to minimize the combined transportation and storage costs for a 100 million gallon per year plant. We estimated it would cost about $14 per dry ton to haul the feedstock from the satellite storage to the processing plant. Adding up all the costs, corn stover is estimated to cost $88 per dry ton delivered to the cellulosic biofuel plant. A more detailed discussion of our corn stover feedstock cost analysis is contained in Chapter 4.1 of the DRIA.

Energy crops such as switchgrass and miscanthus would be harvested, baled, stored and transported very similar to crop residues. Because of their higher production density per acre, though, we would expect that the ''farm gate'' costs to be slightly lower than crop residues (we estimate the costs to be about $1 per dry ton lower). Also, the higher production density would allow for fewer secondary storage facilities compared to crop residue and a shorter transportation distance. For example, we estimate that switchgrass would require less than 30 secondary storage facilities which would help to lower the feedstock costs for a 100 million gallon per year plant compared to crop residues. As a result the secondary storage and transportation costs are estimated to be $9 per ton lower than crop residue such as corn stover. Thus, we estimate that cellulosic feedstock costs sourced from switchgrass would be about $78 per dry ton. Chapter 4.1 of the DRIA contains a more in-depth discussion of the feedstock costs for energy crops such as switchgrass.

Forestry Residue

Harvest and transport costs for woody biomass in its different forms vary due to tract size, tree species, volumes removed, distance to the wood-using/storage facility, terrain, road condition, and other many other considerations. There is a significant variation in these factors within the United States, so timber harvest and delivery systems must be designed to meet constraints at the local level. Harvesting costs also depend on the type of equipment used, season in which the operation occurs, along with a host of other factors. Much of the forest residue is already being harvested by logging operations, or is available from milling operations. However, the smaller branches and smaller trees proposed to be used for biofuel production are not collected for their lumber so they are normally left behind. Thus, this forest residue would have to be collected and transported out of the forest, and then most likely chipped before transport to the biofuel plant.

In general, most operators in the near future would be expected to chip at roadside in the forest, blowing the chips directly into a chip van. When the van is full it will be hauled to an end user's facility and a new van will be moved into position at the chipper. The process might change in the future as baling systems become economically feasible or as roll-off containers are proven as a way to handle logging slash. At present, most of the chipping for biomass production is done in connection with forest thinning treatments as part of a forest fire prevention strategy. The major problem associated with collecting logging residues and biomass from small trees is handling the material in the forest before it gets to the chipper. Specially-built balers and roll-off containers offer some promise to reduce this cost. Whether the material is collected from a forest thinning operation or a commercial logging operation, chips from residues will be dirty and will require screening or some type of filtration at the end-user's facility.[440]

Results from a study in South Georgia show that under the right conditions, a small chipper could be added to a larger operation to obtain additional chip production without adversely impacting roundwood production, and that the chips could be produced from limbs and tops of harvested trees at costs ranging from $11 per ton and up. Harvesting understory (the layer formed by grasses, shrubs, and small trees under the canopy of larger trees and plants) for use in making fuel chips was estimated to be about $1 per ton more expensive.

Per-ton costs decrease as the volume chipped increases per acre. Some estimates suggest that if no more than 10 loads of roundwood are produced before a load of chips is made, that chipper-modified system could break even. Cost projections suggest that removing only limbs and tops may be marginal in terms of cost since one load of chips is produced for about every 15 loads of roundwood.

Instead of conducting our own detailed cost estimate for making forest residue chips available at the edge of the harvested forests, we instead relied upon the expertise of the U.S. Forest Service. The U.S. Forest Service provided us a cost curve for different categories of forest residue, including logging residue, other removals (i.e., clearing trees for new building construction), timberland trimmings

[440] Personal Communication, Eini C. Lowell, Research Scientist, USDA Forest Service.

(forest fire prevention strategy) and mill residues. They recommended that we choose $45 per dry ton as the price point for our cost analysis. This seemed reasonable since this price point was roughly the same as the farm gate crop residue discussed above, and so we used this price point for our analysis. Assuming that the wood chips would be ground further in the field adds an additional $11 per dry ton to the feedstock cost.

Delivery of woody biomass from the harvesting site to a conversion facility, like delivery of more conventional forest products, accounts for a significant portion of the delivered cost. In fact, transportation of wood fiber (including hauling within the forest) accounts for about 25 to 50% of the total delivered costs and highly depends on fuel prices, haul distance, material moisture content, and vehicle capacity and utilization. Also, beyond a certain distance, transportation becomes the limiting factor and the costs become directly proportional to haul distance.[441] Based on our own cost analysis, we anticipate that hauling woody biomass to plant will cost about $14 per ton, for a total delivered price of about $70 per dry ton. Chapter 4.1 of the DRIA contains a more detailed discussion on the feedstock costs for forest residue.

Municipal Solid Waste

Millions of tons of municipal solid waste (MSW) continue to be disposed of in landfills across the country, despite recent large gains in waste reduction and diversion. The biomass fraction of this total stream represents a potentially significant resource for renewable energy (including electricity and biofuels). Because this waste material is already being generated, collected and transported (it would only need to be transported to a different location), its use is likely to be less expensive than other cellulosic feedstocks. One important difficulty facing those who plan to use MSW fractions for fuel production is that in many places, even today, MSW is a mixture of all types of wastes, including biomaterials such as animal fats and grease, tin, iron, aluminum, and other metals, painted woods, plastics, and glass. Many of these materials can't be used in biochemical and thermochemical ethanol production, and, in fact, would inflate the transportation costs, impede the operations at the cellulosic ethanol plant and cause an expensive waste stream for biofuel producers.

Thus, accessing sorted MSW would likely be a requirement for firms planning on using MSW for producing cellulosic biofuels. In a confidential conversation, a potential producer who plans to use MSW to produce ethanol indicated that their plant plans are based on obtaining cellulosic biowaste which has already been sorted at the waste source (e.g., at the curbside, where the refuse hauler picks up waste already sorted by the generating home-owner or business). For example, in a tract of homes, one refuse truck would pick up glass, plastic, and perhaps other types of waste destined for a specific disposal depot, whereas a different truck would follow to pick up wood, paper, and other cellulosic materials to be hauled to a depot that supplies an ethanol plant. However, only a small fraction of the MSW generated today is sorted at the curbside.

Another alternative would be to sort the waste either at a sorting facility, or at the landfill, prior to dumping. There are two prominent options here. The first is that there is no sorting at the waste creation site, the home or business, and thus a single waste stream must be sorted at the facility. This operation would likely be done by hand or by automated equipment at the facility. To do so by hand is very labor intensive and somewhat slower than using an automated system. In most cases the 'by-hand' system produces a slightly cleaner stream, but the high cost of labor usually makes the automated system more cost-effective. Perhaps the best approach for low cost and a clean stream is the combination of hand sorting with automated sorting.

The third option is a combination of the two which requires that there is at least some sorting at the home or business which helps to prevent contamination of the waste material, but then the final sorting occurs downstream at a sorting site, or at the landfill.

We have little data and few estimates for the cost to sort MSW. One estimate generated by our Office of Solid Waste for a combination of mechanically and manually sorting a single waste stream downstream of where the waste is generated puts the cost in the $20 to $30 per ton range. There is a risk, though, that the waste stream could still be contaminated and this would increase the cost of both transporting the material and using this material at the biofuel plant due to the toxic ash produced which would require disposal at a toxic waste facility. If a less contaminated stream is desired it would probably require sorting at the generation site—the home or business—which would likely be more costly since many more people in society would then have to be involved and special trucks would need to be used. Also, widespread participation is difficult when a change in human behavior is required as some may not be so willing to participate. Offering incentives could help to speed the transition to curbside recycling (i.e., charging a fee for nonsorted waste, or paying a small amount for sorted tree trimmings and construction and demolition waste). Assuming that curbside sorting is involved, at least in a minor way, total sorting costs might be in the $30 to $40 per ton range. We request comment on the costs incurred for sorting cellulosic material from the rest of MSW waste.

These sorting costs would be offset by the cost savings for not disposing of the waste material. Most landfills charge tipping fees, the cost to dump a load of waste into a landfill. In the United States, the national average nominal tipping fee increased fourfold from 1985 to 2000. The real tipping fee almost doubled, up from a national average (in 1997 dollars) of about $12 per ton in 1985 to just over $30 in 2000. Equally important, it is apparent that the tipping fees are much higher in densely populated regions and for areas along the U.S. coast. For example, in 2004, the tipping fees were $9 per ton in Denver and $97 per ton in Spokane. Statewide averages also varied widely, from $8 a ton in New Mexico to $75 in New Jersey. Tipping fees ranged from $21 to 98 per ton in 2006 for MSW and $18/ton to $120/ton for construction and demolition waste. It is likely that the tipping fees are highest for contaminated waste that requires the disposal of the waste in more expensive waste sites that can accept the contaminated waste as opposed to a composting site. However, this same contaminated material would probably not be desirable to biofuel producers. Presuming that only the noncontaminated cellulosic waste (yard trimmings, building construction and demolition waste and some paper) is collected as feedstocks for biofuel plants, the handling and tipping fees are likely much lower, in the $30 per ton range.[442]

The avoidance of tipping fees, however, is a complex issue since landfills are generally not owned by municipalities anymore. Both large and small municipalities recognized their

[441] Ashton, S.; B. Jackson; R. Schroeder. *Cost Factors in Harvesting and Transporting Woody Biomass,* 2007. Module 4: Introduction to Harvesting, Transportation, and Processing:: Fact Sheet 4.7.

[442] We plan on conducting a more thorough analysis of tipping fees by waste type for the final rulemaking.

inability to handle the new and complex solid waste regulations at a reasonable cost. Only 38 out of the 100 largest cities own their own landfills. To deal with the solid waste, large private companies built massive amounts of landfill capacity. The economic incentive is for private landfill operators to fill their landfills with garbage as early as possible to pay off their capital investment (landfill site) quickly. Also, the longer the landfill is operating the greater is its exposure to liability due to leakages and leaching. Furthermore, landfills can more cost-effectively manage the waste as the scale of the landfill is enlarged. As a result, there are fewer landfills and landfill owners, and an expansion of market share by large private waste management firms, thus decreasing the leverage a biofuel producer may have.[443] Many waste management firms have been proactive by using the waste material to produce biogas, another fuel type that would qualify under RFS2. Yet other parties interested in procuring MSW are waste-to-energy (WTE) facilities, which burn as much waste material as possible to produce electricity. These three different interests may compete for MSW for producing biofuels. This competition is desirable, resulting in lower overall cost and the production of the most cost-effective types of biofuels. We request comment on the costs avoided for diverting cellulosic material from landfills.

Once the cellulosic biomass has been sorted from the rest of MSW, it would have to be transported to the biofuels plant. Transporting is different for MSW biomass compared to forest and crop residues. Forest and crop residues are collected from forests and farms, which are both rural sites, and transported to the biofuel plant which likely is located at a rural site. The trucks which transport the forest and crop residues can be large over-the-road trucks which can average moderate speeds because of the lower amount of traffic that they experience. Conversely, MSW is being collected throughout urban areas and would have to transported through those urban areas to the plant site. If the cellulosic biomass is being collected at curbside, it would likely be collected in more conventional refuse trucks. If the plant is nearby, then the refuse trucks could transport the cellulosic biomass directly to the plant. However, if the plant is located far away from a portion of the urban area, then the refuse trucks would probably have to be offloaded to more conventional over-the-road trucks with sizable trailers to make transport more cost-effective. We estimate that the cost to transport the cellulosic biomass sourced from MSW to the biofuel plant be $15 per ton.

A significant advantage of MSW over other cellulosic biomass is that it can be generated year-round in many parts of the U.S. If a steady enough stream of this material is available, then secondary storage would not be necessary, thus avoiding the need to install secondary storage. We assumed that no secondary storage costs would be incurred for MSW-sourced cellulosic biomass.

The total costs for MSW-sourced cellulosic biomass is estimated to be $30 −$40 per ton for sorting costs, a savings of $30 per ton for tipping costs avoided, $15 per ton for transportation costs and $11 per ton for grinding the cellulose to prepare it as a feedstock—resulting in a total feedstock cost of $26 to $36 per ton. In our cost analysis, we assumed an average cost of $31 per ton. Chapter 4.1 of the DRIA contains a more detailed discussion of the feedstock costs for MSW.

Table VIII.A.1–2 below summarizes major cost components for each cellulosic feedstock.

TABLE VIII.A.1–2—SUMMARY OF CELLULOSIC FEEDSTOCK COSTS

[$53/ton crude oil costs]

Ag residue	Switchgrass	Forest residue	MSW
60% of total feedstock	1% of total feedstock	25% of total feedstock	14% of total feedstock
Mowing, Raking, Baling, Hauling, Nutrients and Farmer Payment $43/ton.	Mowing, Raking, Baling, Hauling, Nutrients and Farmer Payment $42/ton.	Harvesting, Hauling to Forest Edge, Chipping $45/ton.	Sorting, Contaminant Removal, Tipping Fees Avoided $0–$10/ton.
Hauling to Secondary Storage, Secondary Storage, Hauling to Plant $45/ton.	Hauling to Secondary Storage, Secondary Storage, Hauling to Plant $37/ton.	Grinding, Hauling to Plant $25/ton	Grinding, Hauling to Plant $26/ton.
Total $88/ton	Total $77/ton	Total $70/ton	Total Avg $31/ton.

Weighting the cellulosic feedstock costs by their supply quantities results in an average cellulosic feedstock cost of $71 per ton which we used at the reference crude oil price of $53/bbl. We estimate that this average cost increases to $76 per ton at the high crude oil price of $92/bbl due to more expensive harvesting and transportation costs.

ii. Production Costs

In this section, we discuss the cost to biochemically and thermochemically convert cellulosic feedstocks into fuel ethanol. At a DOE sponsored workshop in 2005, a DOE biochemical expert commented that the challenges of converting cellulosic biomass to ethanol are very closely linked to solving the problems associated with both the hydrolysis and the fermentation of the carbohydrates in the feedstocks. He then stated that the resistance of cellulosic feedstock to bioprocessing will remain the central problem and will likely be the limiting factor in creating an economy based on cellulosic ethanol production.[444]

Notwithstanding the fact that all cellulosic biomass is made up of some combination of cellulose, hemicellulose, lignin, and trace amounts of other organic and inorganic chemicals and minerals, there are significant differences among the molecular structures of different plants. For example, a corn stalk is relatively lighter, more porous, and much more flexible than a tree branch of similar diameter. The tree branch (in most cases) is harder or denser and less porous throughout the stem and the

[443] Osamu Sakamoto, *The Financial Feasibility Analysis of Municipal Solid Waste to Ethanol Conversion,* Michigan State University, Plan B Master Research Paper in partial fulfillment of the requirement for the degree of Master of Science, Department of Agricultural Economics, 2004

[444] *Breaking the Biological Barriers to Cellulosic Ethanol: A Joint Research Agenda,* A Research Roadmap Resulting from the Biomass to Biofuels Workshop Sponsored by the U.S. Department of Energy, December 7–9, 2005, Rockville, Maryland; DOE/SC–0095, Publication Date: June 2006

outside or bark is less permeable and flexible.

These differences among the cellulosic feedstock plant structures, e.g., density, rigidity, hardness, etc., suggest that different conversion processes, namely biochemical and thermochemical may be necessary to convert into ethanol as much of the available plant material as possible. For example, if wood chips, e.g., poplar trees, are to be treated biochemically, the chips must be reduced in size to 1-mm or less in order to increase the surface area for contact with acid, enzymes, etc. Breaking up a 5-in stem to such small pieces would consume a large amount of energy. On the other hand, processing corn stover into cellulosic ethanol has a maximum size of up to 1.5 inches (28 millimeters) in length because corn stover is so thin.[445] By comparison, the particle size requirement for a thermochemical process is around 10-mm to 100-mm in diameter.[446] Because of this, we believe feedstocks such as corn stover, wheat and rice straw, and switchgrass will likely be feedstocks for biochemical processes. Biochemical plants will likely be constructed in those areas of the country where these feedstocks are most abundant, e.g., the corn belt and upper Midwest. On the other hand, thermochemical plants will likely be constructed in those areas of the country where forest thinnings, forest fuel-removal operations, lumber production, and paper mills are most predominant, e.g., the South. Thermochemical or gasification units could be constructed near starch or biochemical cellulosic plants in order to take advantage of byproduct streams. We expect switchgrass (SG) will preferentially be fed to biochemical units since it is similar to straw, whereas short-rotation woody crops (SRWC) such as willows or poplars will preferentially be fed to thermochemical units.

Biochemically, it is much more difficult to convert cellulosic plant matter into ethanol than it is to convert the starch from corn grain into ethanol. Corn starch consists of long polysaccharide chains that are weakly attracted to each other, quite flexible, and tend to curl up to form tiny particle-like bundles. This loose, flexible structure permits water and water-borne hydrolyzing enzymes to easily penetrate the polymer during the process stage known as hydrolysis. Once hydrolyzed, the corn starch sugar residues are easily fermentable.

The hydrolysis of cellulosic biomass is much more challenging. Unlike starch, cellulosic plant matter is made up of three main constituents: Cellulose, hemicellulose, lignin, and minor amounts of various other organic and inorganic chemicals.

Cellulose, the major constituent, is a polymer made up of only β-linked glucose monosaccharides. This molecular arrangement allows intra-molecular hydrogen bonds to develop within each monomer and inter-molecular hydrogen bonds to develop between adjacent polymers to form tight, rigid, strong, mostly straight polymer bundles that are insoluble in water and resistant to chemical attack. The net result of the structural characteristics makes cellulose much more difficult to hydrolyze than is hemicellulose.

Hemicellulose contributes significantly to the total fermentable sugars of the lignocellulosic biomass. Unlike cellulose, hemicellulose is chemically heterogeneous and highly substituted. Compared to cellulose, this branching renders it amorphous and relatively easy to hydrolyze to its constituent sugars.[447]

Lignin, the third principle component, is a complex, cross-linked polymeric, high molecular weight substance derived principally from coniferyl alcohol by extensive condensation polymerization. While cellulose and hemicellulose contribute to the amount of fermentable sugars for ethanol production, lignin is not so readily digestable, but can be combusted to provide process energy in a biochemical plant or used as feedstock to a thermochemical process.[448]

Because of the complexities in digesting cellulosic biomass, the residence time is longer to digest the cellulose and perform the fermentation. Thus, the cellulosic plant capital costs are higher than those of corn (starch) ethanol plants. However, because corn is a food source with an intrinsic food value, corn ethanol's feedstock costs are almost two times higher per ton (more than two times higher in the case for cellulose from MSW) than the feedstocks of a cellulosic ethanol plant. It is conceivable that depending on the cellulosic plant technology which drives its capital and operating costs that cellulosic ethanol plants' lower feedstock costs could offset its higher capital costs resulting in lower production costs than corn-based ethanol.

The National Renewable Energy Laboratory has been evaluating the state of biochemical cellulosic plant technology over the past decade or so, and it has identified principal areas for improvement. In 1999, it released its first report on the likely design concept for an nth generation biochemical cellulosic ethanol plant which projected the state of technology in some future year after the improvements were adopted. In 2002, NREL released a follow-up report which delved deeper into biochemical plant design in areas that it had identified in the 1999 report as deserving for additional research. Again, the 2002 report estimated the ethanol production cost for an nth generation biochemical cellulosic ethanol plant. These reports not only helped to inform policy makers on the likely capability and cost for biochemically converting cellulose to ethanol, but it helped to inform biochemical technology researchers on the most likely technology improvements that could be incorporated into these plant designs.

To comply with the RFS 2 requirements, NREL assessed the likely state of biochemical cellulosic plant technology over the years that the RFS standard is being phased in. The specific years assessed by NREL were 2010, 2015 and 2022. The year 2010 technology essentially represents the status of today's biochemical cellulosic plants. The year 2015 technology captures the expected near-term improvements including the rapid improvements being made in enzyme technology. The year 2022 technology captures the cost of mature biochemical cellulosic plant technology. Table VIII.A.1–3 summarizes NREL's estimated and projected production costs for biochemical cellulosic ethanol plant technology in these three years

[445] A. Aden, M. Ruth, K. Ibsen, J. Jechura, K. Neeves, J. Sheehan, and B. Wallace, National Renewable Energy Laboratory (NREL); L. Montague, A. Slayton, and J. Lukas Harris Group, Seattle, Washington, *Ethanol Process Design and Economics Utilizing Co-Current Dilute Acid Prehydrolysis and Enzymatic Hydrolysis for Corn Stover;* June 2002; NREL is a U.S. Department of Energy Laboratory operated by Midwest Research Institute • Battelle • Bechtel; Contract No. DE–AC36–99–GO10337.

[446] Lin Wei, Graduate Research Assistant, Lester O. Pordesimo, Assistant Professor, Willam D. Batchelor, Professor, Department of Agricultural and Biological Engineering, Mississippi State University, MS 39762, USA, *Ethanol Production from Wood: Comparison of Hydrolysis Fermentation and Gasification Biosynthesis,* Paper Number: 076036, Written for presentation at the 2007 ASABE Annual International Meeting. Minneapolis Convention Center, Minneapolis, MN, 17–20 June 2007.

[447] Hans P. Blaschek, Professor and Thaddeus C. Ezeji, Research Assistant, Department of Food Science and Human Nutrition, University of Illinois, Urbana-Champaign. *Science of Alternative Feedstocks.*

[448] Glossary of Biomass Terms, National Renewable Energy Laboratory, Golden, CO. *http://www.nrel.gov/biomass/glossary.html.*

reflecting our average feedstock costs and adjusting the capital costs to a 7 percent before tax rate of return.

TABLE VIII.A.1–3—BIOCHEMICAL CELLULOSIC ETHANOL PRODUCTION COSTS PROVIDED BY NREL

Year technology	2010		2015		2022	
Plant Size MMgal/yr	56		69		71	
Capital Cost $MM	232		220		199	
	$MM/yr	c/gal	$MM/yr	c/gal	$MM/yr	c/gal
Capital Cost 7% ROI before taxes	25	46	24	35	22	31
Fixed Costs	9	16	9	12	8	12
Feedstock Cost	55	99	55	79	55	77
Other raw matl. costs	17	30	4	5	16	16
Enzyme Cost	18	32	7	10	5	8
Enzyme nutrients	8	14	2	3	2	2
Electricity	−6	−10	−7	−9	−12	−16
Waste disposal	1	2	3	4	1	1
Total Costs	127	229	96	139	84	131

NREL's projected improvements in production costs over time are based on improved reaction biochemistry. Before discussing the expected improvements in the reaction biochemistry, we will discuss the reaction pathway for cellulosic biochemical.

There are two primary reaction steps in a biochemical cellulosic ethanol plant. The first is hydrolysis. Hydrolysis breaks the polysaccharides into their sugar residues. The pretreated slurry is fed to a hydrolysis reactor; there may be multiple reactors, depending on the desired production rate. Dilute sulfuric acid is used to hydrolyze, primarily, the hemicellulose polysaccharides, xylan, mannan, arabinan, and galactan, to produce the mixed sugars. Very little of the cellulose polysaccharide, glucan, is hydrolyzed.

The second is saccharification and co-fermentation. Using a cellulase enzyme cocktail, saccharification of the cellulose to glucose occurs first at an elevated temperature to take advantage of increased enzyme activity, which reduces the quantity of required enzyme as well as the reaction time. Following cellulose saccharification, both the glucose and xylose sugars are co-fermented. Although xylan, the hemicellulose polysaccharide, is more easily hydrolyzed than glucan (cellulose polysaccharides), the xylose sugar is more difficult to ferment than the glucose sugar. Different microbes as well as different residence times and process conditions are required for each. Therefore, it may be necessary to separate the glucose and xylose monomers before fermentation.

Because xylan can make up as much as 25% of plant matter it is imperative that most of be available for ethanol production; the economic viability of biochemically produced ethanol depends heavily it. Good progress has been toward that end during the past few years.[449]

Also during the past few years, researchers have been developing ways to combine saccharification and fermentation into a single step through the use of enzyme/microbe cocktails. DOE and the National Renewable Energy Laboratory (NREL) have also supported research into more efficient, less costly enzymes for SSF. With their support, a less expensive, more efficient enzyme cocktail for cellulosic biomass fermentation has been developed.[450] Others have also reported some success in co-fermenting glucose and xylose.[451]

As the biochemical enzymatic pathway is streamlined using more cost-effective enzymes, and as these enzymes can more comprehensively saccarify and ferment the cellulose, the conversion fraction of the cellulose to ethanol will increase and the conversion time will decrease. An important benefit for these efficiency improvements is that the number and size of reaction vessels decrease, leading to lower capital costs and lower fixed operating costs. It is also estimated that less nutrients would be needed to maintain the enzymes reactivity. Because the production volume of ethanol will increase relative to the quantity of feedstock, it lowers the operating costs per gallon of ethanol. Between these various effects, the per-gallon costs for producing cellulosic ethanol through the biochemical pathway are expected to decrease dramatically. It is through these expected improvements that NREL has estimated reduced production costs for biochemical cellulosic ethanol plants.

Thermochemical conversion is another reaction pathway which exists for converting cellulose to ethanol. Thermochemical technology is based on the heat and pressure-based gasification or pyrolysis of nearly any biomass feedstock, including those we've highlighted as likely biochemical feedstocks. The syngas is converted into mixed alcohols, hydrocarbon fuels, chemicals, and power. A thermochemical unit can also complement a biochemical processing plant to enhance the economics of an integrated biorefinery by converting lignin-rich, non-fermentable material left over from high-starch or cellulosic. NREL has not yet estimated the cost of thermochemically converting cellulose to ethanol, so we did not include a cost estimate using this potential conversion pathway in our analysis and based our cost analysis entirely on the biochemical route.[452] However, one

[449] *Purdue yeast makes ethanol from agricultural waste more effectively,* Purdue News, June 28, 2004 *http://www.purdue.edu/UNS/html4ever/2004/040628.Ho.ethanol.html.*

[450] *GENENCOR LAUNCHES FIRST EVER COMMERCIAL ENZYME PRODUCT FOR CELLULOSIC ETHANOL,* ROCHESTER, NY, World-Wire, October 22, 2007 Copyright© 2007. All rights reserved. World-Wire is a resource provided by Environment News Service. *http://world-wire.com/news/0710220001.html.*

[451] Ali Mohagheghi, Kent Evans, Yat-Chen Chou, and Min Zhang, Biotechnology Division for Fuels and Chemicals, National Renewable Energy Laboratory, Golden, CO 80401, *Co-fermentation of Glucose, Xylose, and Arabinose by Genomic DNA–Integrated Xylose/Arabinose Fermenting Strain of Zymomonas mobilis AX101,* Applied Biochemistry and Biotechnology Vols. 98–100, 2002, Copyright© 2002 by Humana Press Inc., All rights of any nature whatsoever reserved.

[452] NREL has authored a thermochemical report: Phillips, S Thermochemical Ethanol via Indirect Gasification and Mixed Alcohol Synthesis of Lignocellulosic Biomass; April, 2007, which does provide a cost estimate. However, this report only hypothesized how a thermochemical ethanol plant could achieve production costs at $1 per gallon, and

Continued

report estimated that the costs are similar for converting cellulose to ethanol either through either the biochemical or thermochemical routes. Thus, we believe that our cellulosic ethanol costs are representative of both technologies. In Section VIII.A.3 below, we discuss the costs for a thermochemical route for producing diesel fuel, often referred to as biomass-to-liquids (BTL) process.

c. Imported Sugarcane Ethanol

We based our imported ethanol fuel costs on cost estimates of sugarcane ethanol in Brazil. Generally, ethanol from sugarcane produced in developing countries with warm climates is much cheaper to produce than ethanol from grain or sugar beets. This is due to favorable growing conditions, relatively low cost feedstock and energy inputs, and other cost reductions gained from years of experience.

As discussed in Chapter 4 of the DRIA, our literature search of production costs for sugar cane ethanol in Brazil indicates that production costs tend to range from as low as $0.57 per gallon of ethanol to as high as $1.48 per gallon of ethanol. This large range for estimating production costs is partly due to the significant variations over time in exchange rates, costs of sugarcane and oil products, etc. For example, earlier estimates may underestimate current crude and natural gas costs which influence the cost of feedstock as well as energy costs at the plant. Another possible difference in production cost estimates is whether or not the estimates are referring to hydrous or anhydrous ethanol. Costs for anhydrous ethanol (for blending with gasoline) are typically several cents per gallon higher than hydrous ethanol (for use in dedicated ethanol vehicles in Brazil).[453] It is not entirely clear from the majority of studies whether reported costs are for hydrous or anhydrous ethanol. Yet another difference could be the slate of products the plant is producing, for example, future plants may be dedicated ethanol facilities while others involve the production of both sugar and ethanol in the same facility. Due to economies of scale, production costs are also typically smaller per gallon for larger facilities.

The study by OECD (2008) entitled ''Biofuels: Linking Support to Performance'', appears to provide the most recent and detailed set of assumptions and production costs. As such, our estimate of sugarcane production costs primarily relies on the assumptions made for the study, which are shown in Table VIII.A.1–4. The estimate assumes an ethanol-dedicated mill and is based off an internal rate of return of 12%, a debt/equity ratio of 50% with an 8% interest rate and a selling of surplus power at $57 per MWh.

TABLE VIII.A.1–4—COST OF PRODUCTION IN A STANDARD ETHANOL PROJECT IN BRAZIL

Sugarcane Productivity	71.5 t/ha.
Sugarcane Consumption	2 million tons/year.
Harvesting days	167.
Ethanol productivity	85 liters/ton (22.5 gal/ton).
Ethanol production	170 million liters/year (45 MGY).
Surplus power produced	40 kWh/ton sugarcane.
Investment cost in mill	USD 97 million.
Investment cost for sugarcane production	USD 36 million.
O & M (Operating & Maintenance) costs	$0.26/gal.
Sugarcane costs	$0.64/gal.
Capital costs	$0.49/gal.
Total production costs	$1.40/gal.

The estimate above is based on the costs of producing ethanol in Brazil on average, today. However, we are interested in how the costs of producing ethanol will change by the year 2022. Although various cost estimates exist, analysis of the cost trends over time shows that the cost of producing ethanol in Brazil has been steadily declining due to efficiency improvements in cane production and ethanol conversion processes. Between 1980 and 1998 (total span of 19 years) ethanol cost declined by approximately 30.8%.[454] This change in the cost of production over time in Brazil is known as the ethanol cost ''Learning Curve''.

The change in ethanol costs will depend on the likely productivity gains and technological innovations that can be made in the future. As the majority of learning may have already occurred, it is likely that the decline in sugarcane ethanol costs will be less drastic as the production process and cane practices have matured. This is in contrast to younger technologies such as those used to produce cellulosic biofuels which could likely have larger cost reductions over the same period of time. In fact, there are few perspectives for substantial efficiency gains with the sugarcane processing technology. Industrial efficiency gains are already at about 85% and are expected to increase to 90% in 2015.[455] Most of the productivity growth is expected to come from sugarcane production, where yields are expected to grow from the current 70 tons/ha, to 96 tons/ha in 2025.[456] Sugarcane quality is also expected to improve, with sucrose content growing from 14.5% to 17.3% in 2025.[457] All productivity gains together could allow the increase in the production of ethanol from 6,000 liters/ha (at 85 liters/ton sugarcane in 2005) to 10,400 liters/ha (at 109 liters/ton sugarcane) by 2025.[458] Although not reflected here, there could also be cost and efficiency improvements related to feedstock collection, storage, and distribution.

Assuming that ethanol productivity increases to 100 liters/ton by 2015 and 109 liters/ton by 2025, sugarcane costs are be expected to decrease to approximately $0.51/gal from $0.64/gal since less feedstock is needed to produce the same volume of ethanol

thus it could not be relied upon for any part of our real-world program cost analysis.

[453] International Energy Agency (IEA), ''Biofuels for Transport: An International Perspective,'' 2004.

[454] Goldemberg, J. as sited in Rothkopf, Garten, ''A Blueprint for Green Energy in the Americas,'' 2006.

[455] Unicamp ''A Expansão do Proalcool como Programa de Desenvolvimento Nacional''. Powerpoint presentation at *Ethanol Seminar* in BNDES, 2006. As sited in OECD, ''Biofuels: Linking Support to Performance,'' ITF Round Tables No. 138, March 2008.

[456] *Ibid.*

[457] *Ibid.*

[458] *Ibid.*

using the estimates from Table VIII.A.1–4, above. We assumed a linear decrease between data points for 2005, 2015, and 2025. Adding operating ($0.26/gal) and capital costs ($0.49/gal) from Table VIII.A.1–4, to a sugarcane cost of $0.51/gal, total production costs are $1.26/gal in 2022.

Brazil sugarcane producers are also expected to move from burned cane manual harvesting to mechanical harvesting. As a result, large amounts of straw are expected to be available. Costs of mechanical harvesting are lower compared to manually harvesting, therefore, we would expect costs for sugarcane to decline as greater sugarcane producers move to mechanical harvesting. However, it is important to note that diesel use increases with mechanical harvesting, and with diesel fuel prices expected to increase in the future, costs may be higher than expected. Therefore, we have not assumed any changes to harvesting costs due to the switchover from manual harvesting to mechanical harvesting.

As more straw is expected to be collected at future sugarcane ethanol facilities, there is greater potential for production of excess electricity. The production costs estimates in the OECD study assumes an excess of 40kWh per ton sugarcane, however, future sugarcane plants are expected to produce 135 kWh per ton sugarcane.[459] Assuming excess electricity is sold for $57 per MWh, the production of 95 kWh per ton would be equivalent to a credit of $0.22 per gallon ethanol produced. We did not include this potential additional credit from greater use of bagasse and straw in our estimates at this time. Our cost estimates do include, however, the excess electricity produced from bagasse that is currently used today (40 kWh/ton). We are asking for comment on whether such a credit should be included in our production cost estimates.

It is also important to note that ethanol production costs can increase if the costs of compliance with various sustainability criteria are taken into account. For instance, using organic or green cane production, adopting higher wages, etc. could increase production costs for sugarcane ethanol.[460] Such sustainability criteria could also be applicable to other feedstocks, for example, those used in corn- or soy-based biofuel production. If these measures are adopted in the future, production costs will be higher than we have projected.

In addition to production costs, there are also logistical and port costs. We used the report from AgraFNP to estimate such costs since it was the only resource that included both logistical and port costs. The total average logistical and port cost for sugarcane ethanol is $0.19/gal and $0.09/gal, respectively, as shown in Table VIII.A.1–5.

TABLE VIII.A.1–5—IMPORTED ETHANOL COST AT PORT IN BRAZIL (2006 $)

Region	Logistical costs U.S. ($/gal)	Port cost U.S. ($/gal)
NE Sao Paulo	0.146	0.094
W Sao Paulo	0.204	0.094
SE Sao Paulo	0.100	0.094
S Sao Paulo	0.170	0.094
N Parana	0.232	0.094
S Goias	0.328	0.094
E Mato Grosso do sul	0.322	0.094
Triangulo mineiro	0.201	0.094
NE Cost	0.026	0.058
Sao Francisco Valley	0.188	0.058
Average	0.192	0.087

Total fuel costs must also include the cost to ship ethanol from Brazil to the U.S. In 2006, this cost was estimated to be approximately $0.15 per gallon of ethanol.[461] Costs were estimated as the difference between the unit value cost of insurance and freight (CIF) and the unit value customs price. The average cost to ship ethanol from Caribbean countries (e.g., El Salvador, Jamaica, etc.) to the U.S. in 2006 was approximately $0.12 per gallon of ethanol. Although this may seem to be an advantage for Caribbean countries, it should be noted that there would be some additional cost for shipping ethanol from Brazil to the Caribbean country. Therefore, we assume all costs for shipping ethanol to be $0.15 per gallon regardless of the country importing ethanol to the U.S.

Total imported ethanol fuel costs (at U.S. ports) prior to tariff and tax for 2022 is shown in Table VIII.A.1–6, at $1.69/gallon. Direct Brazilian imports are also subject to an additional $0.54 per gallon tariff, whereas those imports arriving in the U.S. from Caribbean Basin Initiative (CBI) countries are exempt from the tariff. In addition, all imports are given an ad valorem tax of 2.5% for undenatured ethanol and a 1.9% tax for denatured ethanol. We assumed an ad valorem tax of 2.5% for all ethanol. Thus, including tariffs and ad valorem taxes, the average cost of imported ethanol is shown in Table VIII.A.1–7 in the ''Brazil Direct w/Tax & Tariff'' and ''CBI w/Tax'' columns for 2022.

[459] Macedo. I.C., ''Green house gases emissions in the production and use of ethanol from sugarcane in Brazil: The 2005/2006 Averages and a Prediction for 2020,'' *Biomass and Bioenergy,* 2008.

[460] Smeets E, Junginger M, Faaij A, Walter A, Dolzan P, Turkenburg W, ''The sustainability of Brazilian ethanol—An Assessment of the possibilities of certified production,'' Biomass and Bioenergy, 2008.

[461] Official Statistics of the U.S. Department of Commerce, USITC.

TABLE VIII.A.1–6—AVERAGE IMPORTED ETHANOL COSTS PRIOR TO TARIFF AND TAXES IN 2022

Sugarcane production cost ($/gal)	Operating cost ($/gal)	Capital cost ($/gal)	Logistical cost ($/gal)	Port cost ($/gal)	Transport cost from port to U.S. ($/gal)	Total cost ($/gal)
0.51	0.26	0.49	0.19	0.09	0.15	1.69

TABLE VIII.A.1–7—AVERAGE IMPORTED ETHANOL COSTS IN 2022

Brazil direct ($/gal)	Brazil direct w/tax & tariff ($/gal)	CBI ($/gal)	CBI w/tax ($/gal)
1.69	2.27	1.69	1.73

2. Biodiesel and Renewable Diesel Production Costs

Biodiesel and renewable diesel production costs are primarily a function of the feedstock cost, and to a much lesser extent, the capital and other operating costs of the facility.

a. Biodiesel

Biodiesel production costs for this rule were estimated using two versions of a biodiesel production facility model obtained from USDA, one using degummed soy oil as a feedstock and the other using yellow grease. The biodiesel from yellow grease model includes the acid pre-treatment steps required to utilize feedstocks with high free fatty acid content.

This production model simulates a 10 million gallon per year plant operating a continuous flow transesterification process. USDA used the SuperPro Designer chemical process simulation software to estimate heat and material flowrates and equipment sizing. Outputs from this software were then combined in a spreadsheet with equipment, energy, labor, and chemical costs to generate a final estimate of production cost. The model is described in a 2006 publication in Bioresource Technology, peer-reviewed scientific journal.[462] Table VIII.A.2–1 shows the production cost allocation for the soy oil-to-biodiesel facility as modeled in the 2022 policy case.

TABLE VIII.A.2–1—PRODUCTION COST ALLOCATION FOR SOY BIODIESEL DERIVED FROM THIS ANALYSIS

Cost category	Contribution to cost (percent)
Soy Oil	87
Other Materials [a]	5
Capital & Facility	4
Labor	3
Utilities	1

[a] Includes acids, bases, methanol, catalyst.

[462] Haas, M.J., A process model to estimate biodiesel production costs, Bioresource Technology 97 (2006) 671–678.

Soy oil costs were generated by the FASOM agricultural model (described in more detail in Section IX.A). Historically, the majority of biodiesel production in the U.S. has used soy oil, a relatively high-value feedstock, but a growing fraction of biodiesel is being made from yellow grease, the name given to reclaimed or highly-processed oil (including corn oil extracted from distillers' grains) that is not suitable for use in food products. This material typically sells for about 70% of the value of virgin soy oil. Conversion of yellow grease into biodiesel requires an additional acid pretreatment step, and therefore the processing costs are higher than for virgin soy oil (about $0.40/gal at equal feedstock costs). Table VIII.A.2–2 shows the feedstock and biodiesel costs used in our cost analysis.

TABLE VIII.A.2–2—BIODIESEL FEEDSTOCK AND PRODUCTION COSTS USED IN THIS ANALYSIS (2006$)

	Soy oil	Yellow grease [a]
Reference Case		
Feedstock $/lb	$0.23	$0.16
Biodiesel $/gal	$2.11	$1.99
Policy Case		
Feedstock $/lb	$0.32	$0.22
Biodiesel $/gal	$2.75	$2.47

[a] Includes corn oil extracted from thin stillage/DGS, rendered fats, recycled greases, etc.

A co-product of transesterification is crude glycerin. With the upswing in worldwide biodiesel production in recent years, its market price is relatively low: In our modeling we assume its value to be $0.03/lb. As a result, the sale of this material as a co-product only reduces biodiesel production cost by about $0.02/gal.

b. Renewable Diesel

Renewable diesel is produced in one of three general configurations: (1) A new standalone unit located within a refinery, (2) co-processing in an existing refinery diesel hydrotreater, or (3) a standalone unit at a rendering plant or another location outside of a refinery. We expect that the largest fraction of the capacity for refinery installation will be produced using the co-processing method, as the production costs are lower than those for a new standalone unit in a refinery. Thus, we speculate that about 50% of renewable diesel being produced by the refinery co-processing route, 17% from a new stand alone unit at a refinery and 33% at rendering plants or as a new site installation. Recent business partnership and construction announcements related to renewable diesel production (such as involving ConocoPhillips facilities in Texas, and

Tyson-Syntroleum facilities in Louisiana) generally support such a split.

We derived our production cost estimates from documents made available publicly by UOP, Inc., to make renewable diesel in a grass roots standalone production process inside a refinery.[463] The process has a pre-treating unit that removes alkali and acidic producing compounds from feed streams, which removes the catalyst poisons. We also used the UOP engineering estimate to derive costs for co-processing renewable diesel in an existing refinery's diesel hydrotreater. For this, we assumed that refiners will: (1) revamp their existing diesel hydrotreater to add capacity and (2) add a pre-treater to remove feedstock contaminants. Lastly, we derived costs for a standalone unit at a location outside a refinery at a rendering plant other facility, using a capital cost estimate from Syntroleum Corp.[464]

The extent of the depolymerization and hydrotreating reactions depend on the process conditions, as some of the carbon backbone of the oils can be cracked to naphtha and lighter products with higher severity. For our analysis, we assume no such cracking and predict yields resulting in ninety-nine percent diesel fuel with the balance as propane (which could also be considered renewable fuel) and water. We assume that all of the renewable diesel production will take place in PADD 2, as feedstock shipping costs are reduced since most of the sources for feedstock supply are located primarily in the Midwest. Average processing cost per gallon (in addition to the feedstock) is 41 cents for making renewable diesel from yellow grease/animal fats, based on our cost methodology.

As with biodiesel, renewable diesel cost estimates were based on soy oil feedstock prices taken from the FASOM modeling work, given in Section IX.A. Our cost estimates for renewable diesel were focused on use of yellow grease as a feedstock, given the project announcements mentioned above, as well as the relative insensitivity of the hydrotreating process to fatty acids and other contaminates relative to the transesterification process. Oil from corn fractionation, yellow grease, and animal fat prices were assumed to be 70% the price of soy oil (consistent with historical market trends). For our 2022 policy case, with a yellow grease price of $0.23/lb, the production cost is $2.47/gal for biodiesel and $2.10/gal for renewable diesel (2006$). Table VIII.A.2–3 shows the projected volume contribution to the biodiesel and renewable diesel total volume, their production costs, and the weighted average production cost used for biodiesel and renewable diesel in this proposal. These results assume feedstock prices are plant-gate and do not include any product transportation costs. Note also that the volumes here include co-processed renewable diesel which does not qualify as biomass-based diesel but which may be counted as advanced biofuel.

TABLE VIII.A.2–3—PROJECTED COSTS AND VOLUME CONTRIBUTION FOR BIODIESEL AND RENEWABLE DIESEL

[Policy case, 2006$ and million gallons]

Fuel	Cost	Volume
Biodiesel from virgin plant oil	2.75	660
Biodiesel from oil extraction at ethanol plants, yellow grease	2.47	150
Renewable diesel from fat, oil, yellow grease	2.10	375
Weighted average cost & total volume	2.51	1,185

Although the per-gallon cost for making renewable diesel from yellow grease is significantly less than using the biodiesel process, there are a number of reasons why we believe the latter will still be used to process some yellow grease (and most of the virgin oil feedstocks). The primary reason is that there is already sufficient biodiesel capacity existing or under construction to cover the projected volumes. Secondly, the per-gallon capital cost to build new hydroprocessing capacity for renewable diesel is expected to be significantly higher than for the biodiesel process. The low per-gallon renewable diesel cost given here is based on the majority of the production being done by co-processing at existing petroleum refineries.

3. BTL Diesel Production Costs

Biofuels-to-Liquids (BTL) processes, which are also thermochemical processes, convert biomass to liquid fuels via a syngas route. The primary product produced by this process is diesel fuel.

There are many steps involved in a BTL process which makes this a capital-intensive process. The first step, like all the cellulosic processes, requires that the feedstocks be processed to be dried and ground to a fine size. The second step is the syngas step, which thermochemically reacts the biomass to carbon monoxide and hydrogen. Since carbon monoxide production exceeds the stoichiometric ideal fraction of the mixture, a water shift reaction must be carried out to increase the relative balance of hydrogen. The syngas products must then be cleaned to facilitate the following Fischer-Tropsch reaction. The Fischer-Tropsch reaction reacts the syngas to a range of hydrocarbon compounds—a type of synthetic crude oil. This hydrocarbon mixture is then hydrocracked to maximize the production of high cetane diesel fuel, although some low octane naphtha is also produced. The many steps of the BTL process contribute to its high capital cost.

One estimate made by Iowa State University estimates the total cost for a cellulosic Fischer-Tropsch plant that produces 35 million gallons per year diesel fuel at $2.37 per gallon. This cost estimated the capital costs to be $341 million. These costs were estimated in the year 2002. We adjusted the operating and capital costs to a 2006 investment environment and to 2006 dollars based the costs on our average $71/dry ton feedstock costs which increases the total cost to $2.85 per gallon of diesel fuel.

Initially, the estimated cost of $2.85 per gallon seems high relative to the projected cost for a year 2015 biochemical cellulosic plant, which is $1.39 per gallon of ethanol in 2006 dollars. However, ethanol provides about half the energy content as Fischer-Tropsch diesel fuel. So if we double the biochemical cellulosic ethanol costs to $2.78 per diesel fuel-equivalent gallon,

[463] A New Development in Renewable Fuels: Green Diesel, AM–07–10 Annual Meeting NPRA, March 18–20, 2007.

[464] From Securities and Exchange Commission Form 8–K for Syntroleum Corp, June 25th 07.

the estimated costs are very consistent between the two. The cellulosic biofuel tax subsidy favors the biochemical ethanol plant, though, because it is a per-gallon subsidy regardless of the energy content, and it therefore offsets twice as much cost as the BTL plant producing diesel fuel. There is one more issue worth considering and that is the relative price of diesel fuel to that of E85. Recently diesel fuel has been priced much higher than gasoline, and if this trend continues to hold, it would provide a better market for selling the BTL diesel fuel than for selling biochemical ethanol into the E85 market, which we believe will be a challenging pricing market for refiners.

4. Catalytic Depolymerization Costs

A new technology was developed by Cello Energy which catalytically depolymerizes cellulose, and then repolymerizes it to produce synthetic hydrocarbon fuels such as gasoline, jet fuel and diesel fuel The company claims that they can produce diesel fuel for about $0.40 per gallon by processing hay, wood chips and used tires. Based on our projections of future cellulosic feedstock costs, their production costs for using only cellulosic feedstocks and assuming the cellulosic feedstock costs developed above would likely be about $1.00 per gallon. In late 2008 the company started up a 20 million gallon per year commercial demonstration plant as a first step towards commercializing their process. We discuss this technology and its costs in more detail in the DRIA.

B. Distribution Costs

Our analysis of the costs associated with distributing the volumes of renewable fuels that we project will be used under RFS2 focuses on: (1) The capital cost of making the necessary upgrades to the fuel distribution infrastructure system directly related to handling these fuels, and (2) the ongoing additional freight costs associated with shipping renewable fuels to the point where they are blended with petroleum-based fuels.[465] The following sections outline our estimates of the distribution costs for the additional volumes of ethanol, FAME biodiesel, and renewable diesel fuel that would be used in response to the RFS2 standards.[466]

[465] The anticipated ways that the renewable fuels projected to be used in response to the EISA will be distributed is discussed in Section V.C. of today's preamble.

[466] Please refer to Section 4.2 of the DRIA for additional discussion of how these estimates were derived.

A discussion of the capability of the transportation system to accommodate the volumes of renewable fuels projected to be used under RFS2 is contained in Section V.C. of today's preamble. There will be ancillary costs associated with upgrading the basic rail, marine, and road transportation nets to handle the increase in freight volume due to the RFS2. We have not sought to quantify these ancillary costs because (1) the growth in freight traffic that is attributable to RFS2 represents a minimal fraction of the total anticipated increase in freight tonnage (approximately 2% by 2022, see Section V.C.4.), and (2) we do not believe there is an adequate way to estimate such non-direct costs. We will continue to evaluate issues associated with the expansion of the basic transportation net to accommodate the volumes of renewable fuels projected under RFS2 and will update our analysis for the final rule based on our findings.

1. Ethanol Distribution Costs

a. Capital Costs To Upgrade the Distribution System for Increased Ethanol Volume

Table VIII.B.1–1 contains our estimates of the infrastructure changes and associated capital costs to support the use of the additional 21 BGY of ethanol that we project will be used under RFS2 by 2022 relative to the AEO 2007 forecast of 13 BGY.[467] The total estimated capital costs are estimated at $12.1 billion which when amortized equates to approximately 6.9 cents per gallon of this additional ethanol volume.[468]

TABLE VIII.B.1–1—ESTIMATED ETHANOL DISTRIBUTION INFRASTRUCTURE CAPITAL COSTS [A]

	Million $
Fixed Facilities:	
Marine Import Facilities	49
Ethanol Receipt Rail Hub Terminals:	
Rail Car Handling & Misc. Equipment	1,264
Ethanol Storage Tanks	354
Petroleum Terminals:	
Rail Receipt Facilities	2,482
Ethanol Storage Tanks	1,611
Ethanol Blending & Misc. Equipment	545
Retail	2,957
Mobile Facilities:	
Rail Cars	2,938
Barges	183
Tank Trucks	223
Total Capital Costs	12,066

[a] Relative to a 13.18 BGY 2022 reference case.

[467] *See* Section V.C. of today's preamble for discussion of the upgrades we project will be needed to the distribution system to handle the increase in ethanol volumes under EISA.

[468] These capital costs will be incurred incrementally through 2022 as ethanol volumes increase. Capital costs for tank trucks were amortized over 10 years with a 7% cost of capital. Other capital costs were amortized over 15 years with a 7% return on capital.

We request comment on our basis for these estimates as detailed in chapter 4.2 of the DRIA. Comment is specifically requested on the extent to which ethanol rail receipt would be accommodated within petroleum terminals rather than being cited at rail hub terminals (to be further shipped by tank truck to petroleum terminals). Our current analysis estimated that half of the new ethanol rail receipt capability needed to support the use of the projected ethanol volumes under the EISA would be installed at petroleum terminals, and half would be installed at rail terminals. A recently completed study by ORNL estimated that all new ethanol rail receipt capability would be installed at existing rail terminals given the limited ability to install such capability at petroleum terminals.[469]

b. Ethanol Freight Costs

We estimate that ethanol freight costs would be 11.3 cents per gallon on a national average basis. Ethanol freight costs are based on those we derived for the Renewable Fuel Standard final rule updated to reflect the projected ethanol use patterns and effect on distribution patterns of increased imports and more dispersed domestic ethanol production locations.[470] Specifically, we estimated freight costs by assessing the location of production and import volumes, where ethanol would be used, and the modes and distances for transportation between production and use.[471] We intend to update our estimate of ethanol freight costs for the final rule based on a recently completed analysis conducted for EPA by Oak Ridge National Laboratory (ORNL). The ORNL

[469] ''Analysis of Fuel Ethanol Transportation Activity and Potential Distribution Constraints'', prepared for EPA by Oak Ridge National Laboratory, March 2009.

[470] Please refer to Section 4.2 of the DRIA for additional discussion of ethanol freight costs.

[471] Our projections regarding the location of ethanol production/import volumes and where ethanol would be used is discussed in Sections V.B. and V.D. of today's preamble respectively.

analysis contains more detailed projections of which transportation modes and combination of modes (e.g., unit train to barge) are best suited for delivery of ethanol to specific markets considering ethanol source and end use locations, the current configuration and projected evolution of the distribution system, and cost considerations for the different transportation modes.

2. Biodiesel and Renewable Diesel Distribution Costs

a. Capital Costs To Upgrade the Distribution System for Increased FAME Biodiesel Volume

Table VIII.B.2–1 contains our estimates of the infrastructure changes and associated capital costs to support the use of the additional 430 MGY of FAME biodiesel that we project will be used under RFS2 by 2022.[472] The total capital costs are estimated at $381 million which equates to approximately 9.8 cents per gallon of additional biodiesel volume.[473]

TABLE VIII.B.2–1—ESTIMATED FAME BIODIESEL DISTRIBUTION INFRASTRUCTURE CAPITAL COSTS [a]

	Million $
Fixed Facilities:	
Petroleum Terminals:	
Storage Tanks	129
Biodiesel Blending & Misc. Equipment	192
Mobile Facilities:	
Rail Cars	35
Barges	17
Tank Trucks	8
Total Capital Costs	381

[a] Relative to a 380 MGY 2022 reference case.

b. Biodiesel Freight Costs

We estimate that biodiesel freight costs would be 9.3 cents per gallons on a national average basis. Priority regional demand for biodiesel was estimated by reviewing State biodiesel mandates/incentives and assuming a demand for 2% biodiesel in most heating oil used in the Northeast by 2022. This priority regional demand was assumed to be filled first from local plants that could ship economically by tank truck. The remaining fraction of priority regional demand was assumed to be satisfied from more distant plants via shipment by manifest rail car. Overall shipping distances were minimized in selecting which plants would satisfy the demand for a given area. The amount of biodiesel that we project would be consumed which would not be directed to priority demand was assumed to be used within trucking distance of the production plant to the extent possible while maintaining biodiesel blend concentrations below 5%. The remaining volume needed to match our estimated production volume was assumed to be shipped via manifest rail car to the nearest areas where diesel fuel use was not already saturated with biodiesel to the 5% level.

c. Renewable Diesel Distribution System Capital and Freight Costs

We project that there would be no additional costs associated with distributing the 250 MGY of renewable diesel fuel that we estimate will be produced at refineries by 2022.[474] This renewable diesel fuel will be blended into finished diesel fuel at the refinery and be distributed to petroleum terminals in the same way 100% petroleum-based distillate fuel is distributed. This is based on our belief that renewable diesel will be confirmed to be sufficiently similar to petroleum-based diesel with respect to distribution system compatibility.

We project that 125 MGY of renewable diesel will be produced at stand-alone facilities that are not connected to a refinery or petroleum terminal. We estimate that such renewable diesel will be trucked to nearby petroleum terminals at a cost of 5 cents per gallon. We estimate that 8 additional tank trucks would be needed to carry this renewable diesel to terminals at a total cost of approximately $1.3 million dollars. Amortized over 10 years with a 7% cost of capital, the total capital costs equate to approximately 0.2 cents per gallon of renewable diesel fuel produced at stand-alone facilities. We estimate that no further capital costs would need to be incurred to handle renewable diesel fuel. This is based on the assumption that renewable diesel delivered to terminals from stand-alone production facilities can be mixed directly into storage tanks that contain petroleum-based diesel fuel or can be stored separately in existing storage tanks for later blending with petroleum-based diesel fuel. We further estimate the terminals that receive renewable diesel will not need to install additional facilities to allow the receipt by tank truck.

C. Reduced Refining Industry Costs

As renewable and alternative fuel use increases, the volume of petroleum-based products, such as gasoline and diesel fuel, would decrease. This reduction in finished refinery petroleum products is associated with reduced refinery industry costs. The reduced costs would essentially be the volume of fuel displaced multiplied by the cost for producing the fuel. There is also a reduction in capital costs which is important because by not investing in new refinery capital, more resources are freed up to build plants that produce renewable and alternative fuels.

Although we conducted refinery modeling for estimating the cost of blending ethanol, we did not rely on the refinery model results for estimating the volume of displaced petroleum. Instead we conducted an energy balance around the increased use of renewable fuels, estimating the energy-equivalent volume of gasoline or diesel fuel displaced. This allowed us to more easily apply our best estimates for how much of the petroleum would displace imports of finished products versus crude oil for our energy security analysis which is discussed in Section IX.B of this preamble.

As part of this analysis we accounted for the change in petroleum demanded by upstream processes related to additional production of the renewable fuels as well as reduced production of petroleum fuels. For example, growing corn used for ethanol production requires the use of diesel fuel in tractors, which reduces the volume of petroleum displaced by the ethanol. Similarly, the refining of crude oil uses by-product hydrocarbons for heating within the refinery, therefore the overall effect of reduced gasoline and diesel fuel consumption is actually greater because of the additional upstream effect. We used the lifecycle petroleum demand estimates provided for in GREET model to account for the upstream consumption of petroleum for each of the renewable and alternative fuels, as well as for gasoline and diesel fuel. Although there may be some renewable fuel used for upstream energy, we assumed that this entire volume is petroleum because the volume of renewable and alternative fuels is fixed as described in Section V above.

For this proposed rule, we assumed that a portion of the gasoline displaced

[472] We project that by 2022 380 MGY of FAME biodiesel would be used absent the requirements under EISA and that a total of 810 MGY of FAME biodiesel would be used under the EISA.

[473] These capital costs will be incurred incrementally through 2022 as FAME biodiesel volumes increase. Capital costs for tank trucks were amortized over 10 years with a 7% cost of capital. Other capital costs were amortized over 15 years with a 7% return on capital.

[474] This includes co-processed renewable diesel fuel as well as renewable diesel fuel produced in separate processing units located at refineries.

by ethanol is imported, while the other portion is produced from domestic refineries. The assumption we made is that one half of the ethanol market in the Northeast, which comprises about half of the nation's gasoline demand, would displace imported gasoline or gasoline blend stocks. Therefore, to derive the portion of the new renewable fuels which would offset imports (and not impact domestic refinery production), we multiplied the total volume of petroleum fuel displaced by 50% to represent that portion of the ethanol which would be used in the Northeast, and 50% again to only account for that which would offset imports. The rest of the ethanol, including half of the ethanol presumed to be used in the Northeast, is presumed to offset domestic gasoline production. In the case of biodiesel and renewable diesel, all of it is presumed to offset domestic diesel fuel production. For ethanol, biodiesel and renewable diesel, the amount of petroleum fuel displaced is estimated based on the relative energy contents of the renewable fuels to the fuels which they are displacing. The savings due to lower imported gasoline and diesel fuel is accounted for in the energy security analysis contained in Section IX.B.

For estimating the U.S. refinery industry cost reductions, we multiplied the estimated volume of domestic gasoline and diesel fuel displaced by the wholesale price for each of these fuels, which are $157 per gallon for gasoline, and $161 per gallon for diesel fuel at $53/bbl crude oil, and $267 per gallon for gasoline, and $335 per gallon for diesel fuel at $92/bbl crude oil. For the volume of petroleum displaced upstream, we valued it using the wholesale diesel fuel price. Table VIII.C.1–1 shows the net volumetric impact on the petroleum portion of gasoline and diesel fuel demand, as well as the reduced refining industry costs for 2022.

TABLE VIII.C.1–1—REDUCED U.S. REFINERY INDUSTRY COSTS FOR THE RFS2 PROGRAM IN 2022

		Total volume displaced (billion gallons)	Cost savings at $53/bbl crude oil price (billion dollars)	Cost savings at $92/bbl crude oil price (billion dollars)
Upstream	Petroleum	0.8	−$1.3	−$2.7
End Use	Gasoline	10.4	16.3	27.7
	Diesel Fuel	0.6	0.9	1.9
	Total		15.9	26.9

D. Total Estimated Cost Impacts

The previous sections of this chapter presented estimates of the cost of producing and distributing corn-based and cellulosic-based ethanol, imported ethanol, biodiesel, and renewable diesel. In this section, we briefly summarize the methodology used and the results of our analysis to estimate the cost and other implications for increased use of renewable fuels to displace gasoline and diesel fuel. An important aspect of this analysis is refinery modeling which primarily was used to estimate the costs of blending ethanol into gasoline, as well as the overall refinery industry impacts of the proposed fuel program. The refinery modeling was conducted by Jacobs Consultancy under subcontract to Southwest Research Institute. A detailed discussion of how the renewable fuel volumes affect refinery gasoline production volumes and cost is contained in Chapter 4 of the DRIA.

1. Refinery Modeling Methodology

The refinery modeling was conducted in three distinct steps. The first step involved the establishment of a 2004 base case which calibrated the refinery model against 2004 volumes, gasoline quality, and refinery capital in place. The EPA and ASTM fuel quality constraints in effect by 2004 are imposed on the products.

For the second step, we established a 2022 future year reference case which represents a business-as-usual case as estimated by the 2007Annual Energy Outlook (AEO). The refinery model assumed that the price of crude oil would average about $51 per barrel, though the results were later adjusted to reflect $53 and $92 per barrel crude oil prices. We also modeled the implementation of several new environmental programs that will have required changes in fuel quality by 2022, including the 30 part per million (ppm) average gasoline sulfur standard, the 15 ppm cap standards on highway and nonroad diesel fuel, the Mobile Source Air Toxics (MSAT) 0.62 volume percent benzene standard. We modeled the implementation of EPAct of 2005, which by rescinding the reformulated gasoline oxygenate standard, resulted in the discontinued use of MTBE, and a large increase in the amount of ethanol blended into reformulated gasoline. We also modeled the EISA Energy Bill corporate average fuel economy (café) standards in the reference case because it will be phasing-in, and affect the phase-in of the RFS2. We modeled 13.2 billion gallons of ethanol in the gasoline pool and 0.4 billion gallons of biodiesel in the diesel pool for 2022, which is the ''business-as-usual'' volume as projected by AEO 2007.

The third step, or the control case, involved the modeling of the 34 billion gallons of ethanol and 1 billion gallons of biodiesel and renewable diesel in 2022 to comply with EISA when the proposed renewable fuels program is fully phased-in. All the other environmental and ASTM fuel quality constraints are assumed to apply to the control case as well to solely model the impact of the RFS2 standards.

The price of ethanol and E85 used in the refinery modeling is a critical determinant of the overall economics of using ethanol. Ethanol was priced initially based on the historical average price spread between regular grade conventional gasoline and ethanol, but then adjusted post-modeling to reflect the projected production cost for both corn and cellulosic-based ethanol. The refinery modeling assumed that all ethanol added to gasoline for E10 is match-blended for octane by refiners in the reference and control cases, although splash blending of ethanol was assumed to be appropriate for the conventional gasoline for the base case based on EPA gasoline data. For the control case, E85 was assumed to be priced much lower than gasoline to reflect its lower energy content, longer refueling time and lower availability (*see* Chapter 4 of the DRIA for a detailed discussion for how we projected E85 prices). E85 is assumed to be blended with gasoline blendstock designed for blending with E10, and a small amount of butane to bring the RVP of E85 up to that of gasoline. Thus, unlike current practices today where E85 is blended at 85% in the summer and E70 in the winter, we assumed that E85 is blended at 85% year-round. E85 use in any one market is limited to levels which we estimated would reflect the ability of FFV vehicles in the area to consume the E85 volume.

The refinery model was provided some flexibility and also was constrained with respect to the applicable gasoline volatility standards for blending up E10. The refinery model allowed conventional gasoline and most low RVP control programs to increase by 1.0 pounds per square inch (psi) in Reid Vapor Pressure (RVP) waiver during the summer. However, wintertime conventional gasoline was assumed to comply with the wintertime ASTM RVP and Volume/Liquid (V/L) standards.

The costs for producing, distributing and using biodiesel and renewable diesel are accounted for outside the refinery modeling. Their production and distribution costs are estimated first, compared to the costs of producing diesel fuel, and then are added to the costs estimated by the refinery cost model for blending the ethanol.

The costs were adjusted to reflect the crude oil prices estimated by EIA in its Annual Energy Outlook (AEO). The AEO 2008 reference case projects that crude oil will be $53 per barrel in 2022, so we adjusted our costs slightly to reflect that slightly higher crude oil price. We also evaluated a higher crude oil price case. The high crude oil case price modeled for the AEO projects that crude oil will be $92 per barrel in 2022, so we adjusted our cost model to also estimate the program costs based on this higher crude oil cost. We estimated the program costs based on these different crude oil prices by adjusting the gasoline and diesel fuel prices to reflect the cost of crude oil. The crude oil costs also have a secondary impact on the production costs of various renewable and alternative fuels (e.g., petroleum used to grow corn which also has been reflected in our cost analysis).

2. Overall Impact on Fuel Cost

Based on the refinery modeling conducted for today's proposed rule, we calculated the costs for consuming the additional 22 billion gallons of renewable fuels in 2022 relative to the reference case. The costs are reported separately for blending ethanol into gasoline as E10 and E85, and for blending biodiesel and renewable diesel with diesel fuel. The costs are expressed two different ways. First, we express the full ''engineering'' cost of the program without the ethanol consumption tax subsidies in which the costs are based on the total accumulated costs of each of the fuels changes, at both reference case and high crude oil prices. Second, we express the costs subtracting the ethanol and biodiesel and renewable diesel consumption tax subsidies since some or perhaps most of the cost of the tax subsidy may not be reflected in the price consumers pay at retail. In all cases, the capital costs are amortized at seven percent return on investment (ROI) before taxes, and based on 2006 dollars.

a. Costs Without Federal Tax Subsidies

Table VIII.D.2–1 summarizes the costs without ethanol tax subsidies for each of the two 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.[475] This estimate of costs reflects the changes in gasoline that are occurring with the expanded use of renewable and alternative fuels. These costs include the labor, utility and other operating costs, fixed costs and the capital costs for all the fuel changes expected. The per-gallon costs are derived by dividing the total costs over all U.S. gasoline and diesel fuel projected to be consumed in 2022. Note that these costs are incremental only to the reference case volumes of renewable fuels (costing out about 20 billion gallons of new renewable fuels) and does not reflect the costs of the renewable fuel volumes in the reference case.

TABLE VIII.D.2–1—ESTIMATED COSTS OF THE RFS2 PROGRAM IN 2022

[2006 dollars, 7% ROI before taxes]

		$53 per barrel of crude oil incremental to reference case	$92 per barrel of crude oil incremental to reference case
Gasoline Impacts	$billion/yr	17.0	4.1
	c/gal	10.91	2.65
Diesel Fuel Impacts	$billion/yr	0.78	−0.05
	c/gal	1.20	−0.07
Total Impact	$billion/yr	17.8	4.1

Our analysis shows, as expected, that the RFS2 program is more cost effective at the higher assumed price of crude oil. At our assumed crude oil price of $53 per barrel, the gasoline and diesel fuel costs are projected to increase by $17.0 billion and $0.78 billion, respectively, or $17.8 billion in total. Expressed as per-gallon costs, these fuel changes would increase the cost of producing gasoline and diesel fuel by 10.91 and 1.20 cents per gallon, respectively. At the assumed crude oil price of $92 per barrel, the gasoline costs are projected to increase by $4.1 billion and the diesel fuel costs are projected to decrease by $0.05 billion, or increase by $4.1 billion in total. Expressed as per-gallon costs, these fuel changes would increase gasoline costs by 2.65 and decrease diesel fuel costs by 0.07 cents per gallon at the higher crude oil price. Our analysis shows that at the higher crude oil price, ethanol, biodiesel and renewable diesel fuel use would be much less costly to use.

The increased use of renewable and alternative fuels would require capital investments in corn and cellulosic ethanol plants, and renewable diesel fuel plants. In addition to producing the fuels, storage and distribution facilities along the whole distribution chain, including at retail, will have to be constructed for these new fuels. Conversely, as these renewable and

[475] 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.

alternative fuels are being produced, they supplant gasoline and diesel fuel demand which results in less new investments in refineries compared to business as usual. In Table VIII.D.2–2, we list the total incremental capital investments that we project would be made for this proposed RFS2 rulemaking incremental to the AEO 2007 reference case.

TABLE VIII.D.2–2—TOTAL PROJECTED U.S. CAPITAL INVESTMENTS FOR THE RFS2 PROGRAM

[billion dollars]

Plant Type	Capital Costs
Corn Ethanol	4.0
Cellulosic Ethanol	50.1
Ethanol Distribution	12.4
Bio/Renew Diesel Fuel Production and Distribution	0.25
Refining	−7.9
Total	58.9

Table VIII.D.2–2 shows that the total U.S. incremental capital investments attributed to this program for 2022 are $58.9 billion. One contributing reason why the capital investments made for renewable fuels technologies is so much more than the decrease in refining industry capital investments is that a large part of the decrease in petroleum gasoline supply was from reduced imports. In addition, renewable fuels technologies are more capital intensive per gallon of fuel produced than incremental increases in gasoline and diesel fuel production at refineries.

b. Gasoline and Diesel Costs Reflecting the Tax Subsidies

Table VIII.D.2–3 below expresses the total and per-gallon gasoline costs for the two control scenarios showing the effect of the Federal tax subsidies. The Federal tax subsidy is 45 cents per gallon for each gallon of new corn ethanol blended into gasoline and $1.01 per gallon for each gallon of cellulosic ethanol. Imported ethanol also receives the 45 cents per gallon Federal tax subsidy, although the portion of imported ethanol which exceeds the volume of imported ethanol exempted through the Caribbean Basin Initiative (CBI) would have to pay a 51 cents per gallon tariff. We estimate that in 2022 imported ethanol would receive a net 23 cents per gallon subsidy after we account for both the subsidy and projected volume of imported ethanol subjected to the tariff. While there are also state ethanol tax subsidies we did not consider those subsidies. A $1 per gallon subsidy currently applies to biodiesel produced from virgin plant oils (i.e., soy) and a 50 cent per gallon subsidy applies to biodiesel and renewable diesel fuel produced from waste fats and oils; we assume that these subsidies continue.[476] The subsidies, if passed along to the consumer, reduce the apparent cost of the program to the consumer at retail since part of the program cost is being paid through taxes. The cost reduction attributed to the subsidies is estimated by multiplying the value of the subsidies times the volume of new corn and cellulosic ethanol used in transportation fuels.

TABLE VIII.D.2–3—ESTIMATED COSTS OF THE RFS2 PROGRAM IN 2022

[Reflecting Tax Subsidies, 2006 dollars, 7% ROI before taxes]

		$53 per barrel of crude oil incremental to reference case	$93 per barrel of crude oil incremental to reference case
Gasoline Impacts	$billion/yr	−0.74	−13.6
	c/gal	−0.48	−8.74
Diesel Fuel Impacts	$billion/yr	0.25	−0.57
	c/gal	0.39	−0.88
Total Impact	$billion/yr	−0.49	−14.2

Our analysis shows, as expected, that the overall costs of the RFS2 program appears to be lower when considering the ethanol consumption subsidies. At the assumed crude oil price of $53 per barrel, the gasoline and diesel fuel costs are projected to decrease by $0.74 billion and increase $0.25 billion, respectively, or $−0.49 billion in total. Expressed as per-gallon costs, these fuel changes would decrease gasoline costs by −0.48 cents per gallon and increase diesel fuel costs by 0.39 cents per gallon. At the assumed crude oil price of $92 per barrel, the gasoline and diesel fuel costs are projected to decrease by $13.6 billion and $0.57 billion, respectively, or $14.2 billion in total. Expressed as per-gallon costs, these fuel changes would decrease gasoline and diesel fuel by 8.74 and 0.88 cents per gallon, respectively. Reducing the cost by the tax subsidies, which more closely represents the prices paid by consumers at the pump, our analysis shows that at lower crude oil prices that the cost of the program would be very small. However, at the higher oil prices and including the subsidies, the program's costs are very negative.

IX. Economic Impacts and Benefits of the Proposal

A. Agricultural Impacts

EPA used two principal tools to model the potential domestic and international impacts of the RFS2 on the U.S. and global agricultural sectors. The Forest and Agricultural Sector Optimization Model (FASOM), developed by Professor Bruce McCarl of Texas A&M University and others, provides detailed information on domestic agricultural and greenhouse gas impacts of renewable fuels. The Food and Agricultural Policy Research Institute (FAPRI) at Iowa State University and the University of Missouri-Columbia maintains a number of econometric models that are capable of providing detailed information on impacts on international agricultural markets from the wider use of renewable fuels in the U.S.

FASOM is a long-term economic model of the U.S. agriculture sector that attempts to maximize total revenues for producers while meeting the demands of consumers. FASOM can be utilized to estimate which crops, livestock, and processed agricultural products would be produced in the U.S. given RFS2 biofuel requirements. In each model simulation, crops compete for price sensitive inputs such as land and labor at the regional level and the cost of

[476] The recent economic bailout law increased the subsidy provided to renewable diesel fuel to $1 per gallon, but we were not able incorporate this change in time for this proposed rulemaking.

these and other inputs are used to determine the price and level of production of primary commodities (e.g., field crops, livestock, and biofuel products). FASOM also estimates prices using costs associated with the processing of primary commodities into secondary products (e.g., converting livestock to meat and dairy, crushing soybeans to soybean meal and oil, etc.). FASOM does not capture short-term fluctuations (i.e., month-to-month, annual) in prices and production, however, as it is designed to identify long-term trends (i.e., five to ten years). The domestic results provided throughout this analysis incorporate the agricultural sector component of the FASOM model.

The FASOM model also contains a forestry component. Running both the forestry and agriculture components of the model would show the interaction between these two sectors. However, the analysis for this proposal only shows the results from the agriculture component with no interaction from the forestry sector, as the forestry component of the model is in the process of being updated. We plan to utilize a complete version of the model for our analysis in the final rule, where agricultural land use impacts also affect forestry land use, and cellulosic ethanol produced from the forestry sector will affect cellulosic ethanol production in the agriculture sector.

The FAPRI models are econometric models covering many agricultural commodities. These models capture the biological, technical, and economic relationships among key variables within a particular commodity and across commodities. They are based on historical data analysis, current academic research, and a reliance on accepted economic, agronomic, and biological relationships in agricultural production and markets. The international modeling system includes international grains, oilseeds, ethanol, sugar, and livestock models. In general, for each commodity sector, the economic relationship that supply equals demand is maintained by determining a market-clearing price for the commodity. In countries where domestic prices are not solved endogenously, these prices are modeled as a function of the world price using a price transmission equation. Since econometric models for each sector can be linked, changes in one commodity sector will impact other sectors. Elasticity values for supply and demand responses are based on econometric analysis and on consensus estimates. Additional information on the FASOM and FAPRI models is included in the Draft Regulatory Impact Analysis (DRIA Chapter 5).

For the agricultural sector analysis using the FASOM and FAPRI models of the RFS2 biofuel volumes, we assumed 15 billion gallons (Bgal) of corn ethanol would be produced for use as transportation fuel by 2022, an increase of 2.7 Bgal from the Reference Case. Also, we modeled 1.0 Bgal of biodiesel used as fuel in 2022, an increase of 0.6 Bgal from the Reference Case. In addition, we modeled an increase of 10 Bgal of cellulosic ethanol in 2022. In FASOM, this volume consists of 7.5 billion gallons of cellulosic ethanol coming from corn residue in 2022, 1.3 billion gallons from switchgrass and 1.4 billion gallons from sugarcane bagasse. Though these volumes differ slightly from those analyzed in Section V.B.2.c.iv, we will work to align the volumes for the final rulemaking.

Given the short timeframe for conducting this analysis, some of the projected sources of biofuels analyzed in the RFS2 proposal are not currently modeled in FASOM and FAPRI. For example, biodiesel from corn oil fractionation is not currently accounted for in FASOM. In addition, since FASOM is a domestic agricultural sector model, it can't be utilized to examine the impacts of the wider use of biofuel imports into the U.S. Also, neither of the two models used for this analysis—FASOM or FAPRI—include biofuels derived from domestic municipal solid waste or from the U.S. forestry sector. Thus, for the RFS2 agricultural sector analysis, these biofuel sources are analyzed outside of the agricultural sector models.

All the results presented in this section are relative to the AEO 2007 Reference Case renewable fuel volumes, which include 12.3 Bgal of grain-based ethanol, 0.4 Bgal of biodiesel, and 0.3 Bgal of cellulosic ethanol in 2022. The domestic figures are provided by FASOM, and all of the international numbers are provided by FAPRI. The detailed FASOM results, detailed FAPRI results, and additional sensitivity analyses are described in more detail in the DRIA. We seek comment on this analysis of the agricultural sector impacts resulting from the wider use of renewable fuels.

TABLE IX.A.1–1—BIOFUEL VOLUMES MODELED IN 2022

[Billions of Gallons]

Biofuel	Reference Case	Control Case	Change
Corn Ethanol	12.3	15.0	2.7
Corn Residue Cellulosic Ethanol	0	7.5	7.5
Sugarcane Bagasse Cellulosic Ethanol	0.3	1.4	1.1
Switchgrass Cellulosic Ethanol	0	1.3	1.3
Other Ethanol	0	0.2	0.2
Biodiesel	0.4	1.0	0.6

1. Commodity Price Changes

For the scenario modeled, FASOM predicts that in 2022 U.S. corn prices would increase by $0.15 per bushel (4.6%) above the Reference Case price of $3.19 per bushel. By 2022, U.S. soybean prices would increase by $0.29 per bushel (2.9%) above the Reference Case price of $9.97 per bushel. The price of sugarcane would increase $13.34/ton (41%) above the Reference Case price of $32.49 per ton by 2022. In 2022, beef prices would increase $0.93 per hundred pounds (1.4%), relative to the Reference Case price of $67.72 per hundred pounds. Additional price impacts are included in Section 5.1.1 of the DRIA.

TABLE IX.A.1–2—CHANGE IN U.S. COMMODITY PRICES FROM THE REFERENCE CASE

[2006$]

Commodity	Change	% Change
Corn	$0.15/bushel	4.6
Soybeans	$0.29/bushel	2.9
Sugarcane	$13.34/ton	41

TABLE IX.A.1–2—CHANGE IN U.S. COMMODITY PRICES FROM THE REFERENCE CASE—Continued

[2006$]

Commodity	Change	% Change
Fed Beef	$0.93/hundred pounds.	1.4

By 2022, the price of switchgrass is $30.18 per wet ton and the farm gate feedstock price of corn stover is $32.74/wet ton. These prices do not include the storage, handling, or delivery costs, which would result in a delivered price to the ethanol facility of at least twice the farm gate cost, depending on the region. We intend to update the costs assumptions (described in more detail in Section 4.1.1 of the DRIA) for the final rule and invite comment on these assumptions.

2. Impacts on U.S. Farm Income

The increase in renewable fuel production provides a significant increase in net farm income to the U.S. agricultural sector. FASOM predicts that net U.S. farm income would increase by $7.1 billion dollars in 2022 (10.6%), relative to the AEO 2007 Reference Case.

3. Commodity Use Changes

Changes in the consumption patterns of U.S. corn can be seen by the increasing percentage of corn used for ethanol. FASOM estimates the amount of domestically produced corn used for ethanol in 2022 would increase to 33%, relative to the 28% usage rate under the Reference Case. The rising price of corn and soybeans in the U.S. would also have a direct impact on how corn is used. Higher domestic corn prices would lead to lower U.S. exports as the world markets shift to other sources of these products or expand the use of substitute grains. FASOM estimates that U.S. corn exports would drop 263 million bushels (−9.9%) to 2.4 billion bushels by 2022. In value terms, U.S. exports of corn would fall by $487 million (−5.7%) to $8 billion in 2022.

U.S. exports of soybeans would also decrease under this proposal. FASOM estimates that U.S. exports of soybeans would decrease 96.6 million bushels (−9.3%) to 943 million bushels by 2022. In value terms, U.S. exports of soybeans would decrease by $691 million (−6.7%) to $9.7 billion in 2022.

TABLE IX.A.3–1—REDUCTIONS IN U.S. EXPORTS FROM THE REFERENCE CASE IN 2022

Exports	Change	% Change
Corn in Bushels	263 million	−9.9
Soybeans in Bushels	96.6 million	−9.3
Total Value of Exports	Change	% Change
Corn (2006$)	$487 million	−5.7
Soybeans (2006$)	$691 million	−6.7

Higher U.S. demand for corn for ethanol production would cause a decrease in the use of corn for U.S. livestock feed. Substitutes are available for corn as a feedstock, and this market is price sensitive. Several ethanol processing byproducts could also be used to replace a portion of the corn used as feed, depending on the type of animal. Distillers dried grains with solubles (DDGS) are a byproduct of dry milling ethanol production, and gluten meal and gluten feed are byproducts of wet milling ethanol production. By 2022, FASOM predicts ethanol byproducts used in feed would increase 19% to 30 million tons, compared to 25 million tons under the Reference Case.

TABLE IX.A.3–2—PERCENT CHANGE IN ETHANOL BYPRODUCTS USE IN FEED RELATIVE TO THE REFERENCE CASE

Category	2022
Ethanol Byproducts	19%

The EISA cellulosic ethanol requirements result in the production of residual agriculture products as well as dedicated energy crops. By 2022, FASOM predicts production of 90 million tons of corn residue and 18 million tons of switchgrass. Sugarcane bagasse for cellulosic ethanol production increases by 15.7 million tons to 19.7 million tons in 2022 relative to the Reference Case.

4. U.S. Land Use Changes

Higher U.S. corn prices would have a direct impact on the value of U.S. agricultural land. As demand for corn and other farm products increases, the price of U.S. farm land would also increase. Our analysis shows that land prices would increase by about 21% by 2022, relative to the Reference Case. FASOM estimates an increase of 3.2 million acre increase (3.9%) in harvested corn acres, relative to 83.4 million acres harvested under the Reference Case by 2022.[477] Most of the new corn acres come from a reduction in existing crop acres, such as rice, wheat, and hay.

Though demand for biodiesel increases, FASOM predicts a fall in U.S. soybean acres harvested, assuming soybean-based biodiesel meets the EISA GHG emission reduction thresholds. According to the model, harvested soybean acres would decrease by approximately 0.4 million acres (−0.5%), relative to the Reference Case acreage of 71.5 million acres in 2022. Despite the decrease in soybean acres in 2022, soybean oil production would increase by 0.4 million tons (4.0%) by 2022 over the Reference Case. Additionally, FASOM predicts that soybean oil exports would decrease 1.3 million tons by 2022 (−52%) relative to the Reference Case.

As the demand for cellulosic ethanol increases, most of the production is derived from corn residue harvesting. As demand for cellulosic ethanol from bagasse increases, sugarcane acres increase by 0.7 millions acres (55%) to 1.9 million acres by 2022. In addition, some of the cellulosic ethanol comes from switchgrass, which is not produced under the Reference Case. In the scenario analyzed, 2.8 million acres of switchgrass will be planted by 2022. As described in Section V, for both the Reference Case and the Control Case, we assume 32 million acres would remain in the Conservation Reserve Program (CRP). Therefore, some of the new corn, soybean, and switchgrass acres may be indirectly coming from former CRP land that is not re-enrolled in the program.

[477] Total U.S. planted acres increases to 92.2 million acres from the Reference Case level of 89 million acres in 2022.

TABLE IX.A.4–1—CHANGE IN U.S. CROP ACRES RELATIVE TO THE REFERENCE CASE IN 2022

[Millions of acres]

Crop	Change	% Change
Corn	3.2	3.9
Soybeans	−0.4	−0.5
Sugarcane	0.7	55
Switchgrass	2.8	N/A

The additional demand for corn and other crops for biofuel production also results in increased use of fertilizer in the U.S. In 2022, FASOM estimates that U.S. nitrogen fertilizer use would increase 897 million pounds (3.4%) over the Reference Case nitrogen fertilizer use of 26.2 billion pounds. In 2022, U.S. phosphorous fertilizer use would increase by 496 million pounds (8.6%) relative to the Reference Case level of 5.8 billion pounds.

TABLE IX.A.4–2—CHANGE IN U.S. FERTILIZER USE RELATIVE TO THE REFERENCE CASE

[Millions of pounds]

Fertilizer	Change	% Change
Nitrogen	897	3.4
Phosphorous	496	8.6

5. Impact on U.S. Food Prices

Due to higher commodity prices, FASOM estimates that U.S. food costs [478] would increase by roughly $10 per person per year by 2022, relative to the Reference Case.[479] Total effective farm gate food costs would increase by $3.3 billion (0.2%) in 2022.[480] To put these changes in perspective, average U.S. per capita food expenditures in 2007 were $3,778 or approximately 10% of personal disposable income. The total amount spent on food in the U.S. in 2007 was $1.14 trillion dollars.[481]

6. International Impacts

Changes in the U.S. agriculture economy are likely to have effects in other countries around the world in terms of trade, land use, and the global price and consumption of fuel and food. We utilized the FAPRI model to assess the impacts of the increased use of renewable fuels in the U.S. on world agricultural markets.

The FAPRI modeling shows that world corn prices would increase by 7.5% to $3.69 per bushel in 2022, relative to the Reference Case. The impact on world soybean prices is somewhat smaller, increasing 5.6% to $9.94 per bushel in 2022.

Changes to the global commodity trade markets and world commodity prices result in changes in international land use. The FAPRI model provides international change in crop acres as a result of the RFS2 proposal. Brazil has the largest positive change in crop acres in 2022, followed by the U.S., Nigeria, India, Paraguay, and China. The FAPRI model estimates that Brazil crop acres increase by 3.1 million acres (2.0%) to 153.6 million acres relative to the Reference Case. Total U.S. acres increase by 2.3 million acres (1.0%) in 2022 to 232.6 million acres. Nigeria has an increase in crop acres of 1.5 million acres (5.9%) to 27.3 million acres in 2022. India's total crop acres increase by 1.0 million acres (0.3%) to 326 million acres in 2022. Total crop acres in Paraguay increase by 0.8 million acres (6.9%) to 12 million acres. China's total crop acres increase by 0.4 million acres (0.2%) to 257.8 million acres in 2022.

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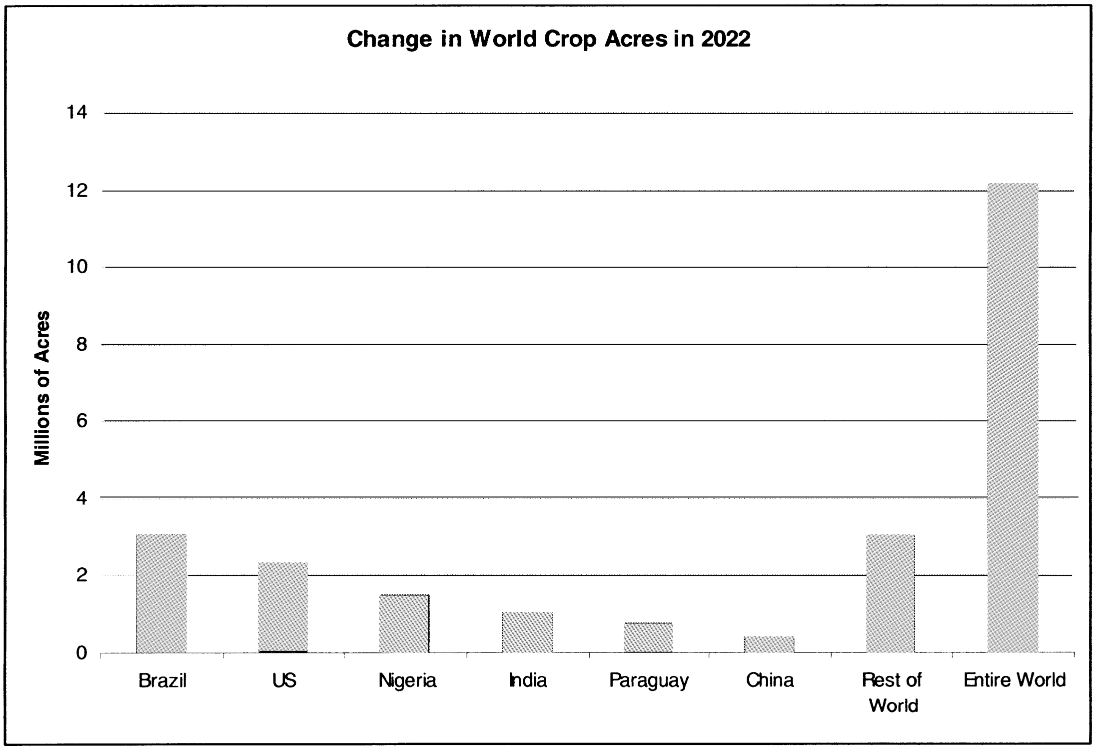
[478] FASOM does not calculate changes in price to the consumer directly. The proxy for aggregate food price change is an indexed value of all food prices at the farm gate. It should be noted, however, that according to USDA, approximately 80% of consumer food expenditures are a result of handling after it leaves the farm (e.g., processing, packaging, storage, marketing, and distribution). These costs consist of a complex set of variables, and do not necessarily change in proportion to an increase in farm gate costs. In fact, these intermediate steps can absorb price increases to some extent, suggesting that only a portion of farm gate price changes are typically reflected at the retail level. *See http://www.ers.usda.gov/publications/foodreview/septdec00/FRsept00e.pdf.*

[479] These estimates are based on U.S. Census population projections of 318 million people in 2017 and 330 million people in 2022. *See http://www.census.gov/population/www/projections/natsum.html.*

[480] Farm Gate food prices refer to the prices that farmers are paid for their commodities.

[481] *See* www.ers.usda.gov/Briefing/CPIFoodAndExpenditures/Data/table15.htm.

Figure IX.A.6-1
Change in World Crop Acres By Country in 2022
(millions of acres)



The RFS2 proposal results in higher international commodity prices, which would impact world food consumption.[482] The FAPRI model indicates that world consumption of corn for food would decrease by 1.1 million metric tons in 2022 relative to the Reference Case. Similarly, the FAPRI model estimates that world consumption of wheat for food would decrease by 0.6 million metric tons in 2022. World consumption of oil for food (e.g., vegetable oils) decreases 1.8 million metric tons by 2022. The model also estimates a small change in world meat consumption, decreasing by 0.3 million metric tons in 2022. When considering all the food uses included in the model, world food consumption decreases by 0.9 million metric tons by 2022 (−0.04%). While FAPRI provides estimates of changes in world food consumption, estimating effects on global nutrition is beyond the scope of this analysis.

TABLE IX.A.6–1—CHANGE IN WORLD FOOD CONSUMPTION RELATIVE TO THE REFERENCE CASE

[Millions of metric tons]

Category	2022
Corn	−1.1
Wheat	−0.6
Vegetable Oils	−1.8
Meat	−0.3
Total Food	−0.9

Additional information on the U.S. agricultural sector and international trade impacts of this proposal is described in more detail in the DRIA (Chapter 5).

B. Energy Security Impacts

Increasing usage of renewable fuels helps to reduce U.S. petroleum imports. A reduction of U.S. petroleum imports reduces both financial and strategic risks associated with a potential disruption in supply or a spike in cost of a particular energy source. This reduction in risks is a measure of improved U.S. energy security. In this section, we estimate the monetary value of the energy security benefits of the RFS2 mandated volumes in comparison to the Reference Case by estimating the impact of the expanded use of renewable fuels on U.S. oil imports and avoided U.S. oil import expenditures. In the second section, a methodology is described for estimating the energy security benefits of reduced U.S. oil imports. The final section summarizes the energy security benefits to the U.S. associated with this proposal.

1. Implications of Reduced Petroleum Use on U.S. Imports

In 2007, U.S. petroleum imports represented 19.5% of total U.S. imports of all goods and services.[483] In 2005, the United States imported almost 60% of the petroleum it consumed. This compares roughly to 35% of petroleum from imports in 1975.[484] Transportation accounts for 70% of the U.S. petroleum consumption. It is clear that petroleum imports have a significant impact on the U.S. economy. Diversifying transportation fuels in the U.S. is expected to lower U.S. petroleum imports. To estimate the impacts of this proposal on the U.S.'s dependence on

[482] The food commodities included in the FAPRI model include corn, wheat, sorghum, barley, soybeans, sugar, peanuts, oils, beef, pork, poultry, and dairy products.

[483] Bureau of Economic Affairs: ''U.S. International Transactions, Fourth Quarter of 2007'' by Elena L. Nguyen and Jessica Melton Hanson, April 2008.

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

imported oil, we calculate avoided U.S. expenditures on petroleum imports.

For the proposal, EPA analyzed two approaches to estimate the reductions in U.S. petroleum imports. The first approach utilizes a model of the U.S. energy sector, the National Energy Modeling System (NEMS), to quantify the type and volume of reduced petroleum imports based on supply and demand for specific fuels in a given year. The National Energy Modeling System (NEMS) is a computer-based, energy-economy modeling system of U.S. energy markets through the 2030 time period. NEMS projects U.S. production, imports, conversion, consumption, and prices of energy; subject to assumptions on world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics. NEMS is designed and implemented by the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE). For this analysis, the NEMS model was run with the 2007 AEO levels of biofuels in the Reference Case compared with the biofuel volume RFS2 requirements.

Considering the regional nature of U.S. imports of petroleum imports, a second approach was utilized as well to estimate the impacts of the RFS2 proposal on U.S. oil imports. This approach is labeled ''Regional Gasoline Market'' approach. This approach makes the assumption that one half of the ethanol market is in the Northeast region of the U.S., which also comprises about half of the nation's gasoline demand. For this analysis, it is estimated that ethanol would displace imported gasoline or gasoline blend stocks in the Northeast, but not elsewhere in the country. Therefore, to derive the portion of the new renewable fuels which would offset U.S. petroleum imports (and not impact domestic refinery production), we multiplied the total volume of petroleum fuel displaced by 50 percent to represent that portion of the ethanol which would be used in the Northeast, and 50 percent again to only account for that which would offset imports. The rest of the ethanol, including half of the ethanol presumed to be used in the Northeast, is presumed to offset domestic gasoline production, which ultimately offsets crude oil inputs at refineries. Biodiesel and renewable diesel are presumed to offset domestic diesel fuel production.

The results shown in Table IX.B.1–1 below reflect the net lifecycle reductions in U.S. oil imports projected by NEMS. The net lifecycle reductions include the upstream petroleum used to produce renewable fuels, gasoline and diesel, as well as the petroleum directly used by end-users.

TABLE IX.B.1–1—NET REDUCTIONS IN OIL IMPORTS IN 2022 (NEMS MODEL RESULTS)

[Millions of barrels per day]

Category of reduction	2022
Imports of Finished Petroleum Products	0.823
Imports of Crude Oil	(0.007)
Total Reduction	0.815
Percent Reduction	6.15%

The NEMS model projects that for the year 2022 all of the reduction in petroleum imports comes out of finished petroleum products. NEMS projects that 91% of the reductions in 2022 come from reduced net imports of crude oil and finished petroleum products (as compared to a 9% reduction in domestic U.S. production).

The results shown in Table IX.B.1–2 below reflect the net lifecycle reductions in U.S. oil imports projected by the use of the Regional Gasoline Market approach detailed above.

TABLE IX.B.1–2—NET REDUCTIONS IN OIL IMPORTS IN 2022 (REGIONAL GASOLINE MARKET APPROACH RESULTS)

[Millions of barrels per day]

Category of reduction	2022
Imports of Finished Petroleum Products	0.250
Imports of Crude Oil	0.637
Total Reduction	0.887
Percent Reduction	6.17%

The Regional Gasoline Market approach projects that for 2022, 72% of the petroleum supply displacement (on a volume basis) comes out of reduced net crude oil imports, and 28% out of net imports of finished petroleum products (excluding biofuels). Using our two approaches for projecting total petroleum import reductions (the NEMS and the Regional Gasoline Market), we estimate that petroleum product imports will fall between 0.815 to 0.887 million barrels per day in 2022 as a result of the RFS2 proposal.

Using the NEMS model, we also calculated the change in expenditures in both U.S. petroleum and ethanol imports with the RFS2 proposal and compared these with the U.S. trade position measured as U.S. net exports of all goods and services economy-wide. Changes in fuel expenditures were estimated by multiplying the changes in gasoline, diesel, and ethanol net imports by the respective AEO 2008 wholesale gasoline and distillate price forecasts, and ethanol price forecasts from the Food and Agricultural Policy Research Institute (FAPRI) for the specific analysis years. In Table IX.B.1–3, the net expenditures in reduced petroleum imports and increased ethanol imports are compared to the total value of U.S. net exports of goods and services for the whole economy for 2022. The U.S. net exports of goods and services estimates are taken from Energy Information Administration's Annual Energy Outlook 2008. We project that avoided expenditures on imported petroleum products due to this proposal would be roughly $16 billion in 2022. Relative to the 2022 projection, the total avoided expenditures on liquid transportation fuels are projected to be $12.4 billion with the RFS2 proposal.

TABLE IX.B.1–3—CHANGES IN EXPENDITURES ON TRANSPORTATION FUEL NET IMPORTS

[Billions of 2006$]

Category	2022
AEO Total Net Exports	16
Expenditures on Net Petroleum Imports	(15.96)
Expenditures on Net Ethanol and Biodiesel Imports	3.52
Net Expenditures on Transportation Fuel Imports	(12.44)

2. Energy Security Implications

In order to understand the energy security implications of reducing U.S. oil imports, EPA has worked with Oak Ridge National Laboratory (ORNL), which has developed approaches for evaluating the social costs and energy security implications of oil use. In a new study entitled *''The Energy Security Benefits of Reduced Oil Use, 2006–2015,''* completed in February, 2008, ORNL has updated and applied the analytical approach used in the 1997 Report *''Oil Imports: An Assessment of Benefits and Costs.''* [485] [486] This new study is included as part of the record in this rulemaking.[487]

[485] Leiby, Paul N., Donald W. Jones, T. Randall Curlee, and Russell Lee, *Oil Imports: An Assessment of Benefits and Costs*, ORNL–6851, Oak Ridge National Laboratory, November, 1997.

[486] The 1997 ORNL paper was cited and its results used in DOT/NHTSA's rules establishing CAFE standards for 2008 through 2011 model year light trucks. *See* DOT/NHTSA, Final Regulatory Impacts Analysis: Corporate Average Fuel Economy and CAFE Reform MY 2008–2011, March 2006.

[487] Leiby, Paul N. ''Estimating the Energy Security Benefits of Reduced U.S. Oil Imports,'' Oak Ridge

Continued

The approach developed by ORNL estimates the incremental benefits to society, in dollars per barrel, of reducing U.S. oil imports, called the ''oil premium.'' Since the 1997 publication of the ORNL Report, changes in oil market conditions, both current and projected, suggest that the magnitude of the oil premium has changed. Significant driving factors that have been revised include: Oil prices, current and anticipated levels of OPEC production, U.S. import levels, the estimated responsiveness of regional oil supplies and demands to price, and the likelihood of oil supply disruptions. For this analysis, oil prices from the AEO 2007 were used. Using the ''oil premium'' approach, the analysis calculates estimates of benefits of improved energy security from reduced U.S. oil imports due to this proposal.

When conducting this analysis, ORNL considered the full economic cost of importing petroleum into the U.S. The full economic cost of importing petroleum into the U.S. is defined for this analysis to include two components in addition to the purchase price of petroleum itself. These are: (1) The higher costs for oil imports resulting from the effect of U.S. import demand on the world oil price and OPEC market power (i.e., the ''demand'' or ''monopsony'' costs); and (2) the risk of reductions in U.S. economic output and disruption of the U.S. economy caused by sudden disruptions in the supply of imported oil to the U.S. (i.e., macroeconomic disruption/adjustment costs). Maintaining a U.S. military presence to help secure stable oil supply from potentially vulnerable regions of the world was excluded from this analysis because its attribution to particular missions or activities is difficult.

Also excluded from the prior analysis was risk-shifting that might occur as the U.S. reduces its dependency on petroleum and increases its use of biofuels. The analysis to date focused on the potential for biofuels to reduce oil imports, and the resulting implications of lower imports for energy security. The Agency recognizes that as the U.S. relies more heavily on biofuels, such as corn-based ethanol, there could be adverse consequences from a supply-disruption associated with, for example, a long-term drought. While the causal factors of a supply-disruption from imported petroleum and, alternatively, biofuels, are likely to be unrelated, diversifying the sources of U.S. transportation fuel will provide energy security benefits. The Agency was not able to conduct an analysis of biofuel supply disruption issue for this proposal.

Between today's proposal and the final rulemaking, EPA will attempt to broaden our energy security analysis to incorporate estimates of overall motor fuel supply and demand flexibility and reliability, and impacts of possible agricultural sector market disruptions (for example, a drought) for presentation in the final rule. The expanded analysis will also consider how the use of biofuels can alter short and long run elasticity (flexibility) in the motor fuel market, with implications for robustness of the fuel system in the face of diverse supply shocks. As part of this analysis, the Agency plans on analyzing those factors that can cause shifts in the prices of biofuels, and the impact these factors have on the energy security estimate.

EPA sponsored an independent-expert peer review of the most recent ORNL study. A report compiling the peer reviewers' comments is provided in the docket.[488] In addition, EPA has worked with ORNL to address comments raised in the peer review and develop estimates of the energy security benefits associated with a reduction in U.S. oil imports for this proposal. In response to peer reviewer comments, EPA modified the ORNL model by changing several key parameters involving OPEC supply behavior, the responsiveness of oil demand and supply to a change in the world oil price, and the responsiveness of U.S. economic output to a change in the world oil price. EPA is soliciting comments on how to incorporate additional peer reviewer comments into the ORNL energy security analysis. (*See* the DRIA, Chapter 5, for more information on how EPA responded to peer reviewer comments.)

With these changes for this proposal, ORNL has estimated that the total energy security benefits associated with a reduction of imported oil is $12.38/barrel. Based upon alternative sensitivities about OPEC supply behavior and the responsiveness of oil demand and supply to a change in the world oil price, the energy security premium ranged from $7.65 to $17.23/barrel. Highlights of the analysis are described below.

a. Effect of Oil Use on Long-Run Oil Price, U.S. Import Costs, and Economic Output

The first component of the full economic costs of importing petroleum into the U.S. follows from the effect of U.S. import demand on the world oil price over the long-run. Because the U.S. is a sufficiently large purchaser of foreign oil supplies, its purchases can affect the world oil price. This monopsony power means that increases in U.S. petroleum demand can cause the world price of crude oil to rise, and conversely, that reduced U.S. petroleum demand can reduce the world price of crude oil. Thus, one benefit of decreasing U.S. oil purchases is the potential decrease in the crude oil price paid for all crude oil purchased. ORNL estimates this component of the energy security benefit to be $7.65/barrel of U.S. oil imports reduced. A number of the peer reviewers suggested a variety of ways OPEC and other oil market participants might react to a decrease in the quantity of oil purchased by the U.S. ORNL has attempted to reflect a variety of possible market reactions in the analysis, but continues to evaluate ways to more explicitly model OPEC and other market participants' behavior. EPA welcomes comments on this issue. Based upon alternative sensitivities about OPEC supply behavior, the price-responsiveness of combined non-OPEC, non-U.S. supply and demand and a lower GDP elasticity with respect to disrupted oil prices, the monopsony premium ranged from $3.35–$12.45/barrel of U.S. imported oil reduced.

EPA recognizes that as the world price of oil falls in response to lower U.S. demand for oil, there is the potential for an increase in oil use outside the U.S. This so-called international oil ''take back'' or ''rebound'' effect is hard to estimate. Given that oil consumption patterns vary across countries, there will be different demand responses to a change in the world price of crude oil. For example, in Europe, the price of crude oil comprises a much smaller portion of the overall fuel prices seen by consumers than in the U.S. Since Europeans pay significantly more than their U.S. counterparts for transportation fuels, a decline in the price of crude oil is likely to have a smaller impact on demand. In many other countries, particularly developing countries, such as China and India, oil is used more widely in industrial and even electricity applications, although China and India's energy picture is evolving rapidly. In addition, many countries around the world subsidize

National Laboratory, ORNL/TM–2007/028, Final Report, 2008.

[488] *Peer Review Report Summary: Estimating the Energy Security Benefits of Reduced U.S. Oil Imports*, ICF, Inc., September 2007.

their oil consumption. It is not clear how oil consumption would change due to changes in the market price of oil with the current pattern of subsidies. Emerging trends in worldwide oil consumption patterns illustrates the difficulty in trying to estimate the overall effect of a reduction in world oil price. However, the Agency recognizes that this effect is important to capture and is examining methodologies for quantifying this effect. EPA is exploring the development of this effect at the regional and country level in an effort to capture the net effect of different drivers. For example, a lower world oil price might encourage consumption of oil, but a country might deploy programs and policies discouraging oil consumption, which would have the net effect of lowering oil consumption to some level less than otherwise would be expected. EPA solicits comments on how to estimate this effect.

b. Short-Run Disruption Premium From Expected Costs of Sudden Supply Disruptions

The second component of the external economic costs resulting from U.S. oil imports arises from the vulnerability of the U.S. economy to oil shocks. The cost of shocks depends on their likelihood, size, and length; the capabilities of the market and U.S. Strategic Petroleum Reserve (SPR), the largest stockpile of government-owned emergency crude oil in the world, to respond; and the sensitivity of the U.S. economy to sudden price increases. While the total vulnerability of the U.S. economy to oil price shocks depends on the levels of both U.S. petroleum consumption and imports, variation in import levels or demand flexibility can affect the magnitude of potential increases in oil price due to supply disruptions. Disruptions are uncertain events, so the costs of alternative possible disruptions are weighted by disruption probabilities. The probabilities used by the ORNL study are based on a 2005 Energy Modeling Forum [489] synthesis of expert judgment and are used to determine an expected value of disruption costs, and the change in those expected costs given reduced U.S. oil imports. ORNL estimates this component of the energy security benefit to be $4.74/barrel of U.S. imported oil reduced. Based upon alternative sensitivities about OPEC supply behavior, the price-responsiveness of combined non-OPEC, non-U.S. supply and demand and a lower GDP elasticity with respect to disrupted oil prices, the macroeconomic disruption premium ranged from $2.64–$6.96/barrel of U.S. imported oil reduced. EPA continues to review recent literature on the macroeconomic disruption premium and welcomes comment on this issue.

c. Costs of Existing U.S. Energy Security Policies

Another often-identified component of the full economic costs of U.S. oil imports is the cost to the U.S. taxpayers of existing U.S. energy security policies. The two primary examples are maintaining a military presence to help secure stable oil supply from potentially vulnerable regions of the world and maintaining the SPR to provide buffer supplies and help protect the U.S. economy from the consequences of global oil supply disruptions.

U.S. military costs are excluded from the analysis performed by ORNL because their attribution to particular missions or activities is difficult. Most military forces serve a broad range of security and foreign policy objectives. Attempts to attribute some share of U.S. military costs to oil imports are further challenged by the need to estimate how those costs might vary with incremental variations in U.S. oil imports. Similarly, while the costs for building and maintaining the SPR are more clearly related to U.S. oil use and imports, historically these costs have not varied in response to changes in U.S. oil import levels. Thus, while SPR is factored into the ORNL analysis, the cost of maintaining the SPR is excluded.

A majority of the peer reviewers agreed with the exclusion of military expenditures from the current premium analysis primarily because of the difficulty in defining and measuring how military programs and expenditures might respond to incremental changes in U.S. oil imports. One reviewer clearly opposed including military costs on principle, and one peer reviewer clearly supported their inclusion if they could be shown to vary with import levels. The matter of whether military needs and programs can and do vary with U.S. oil imports or consumption levels would require careful consideration and analysis. It also calls for expertise in areas outside the scope of the peer review such as national security and military affairs. EPA solicits comment in this area.

d. Anticipated Future Effort

Between the proposal and the final rule, EPA intends to undertake a variety of actions to improve its energy security premium estimates. For the monopsony premium, we intend to develop energy security premiums with alternative AEO oil price cases (e.g., Reference, High, Low), develop a dynamic analysis methodology (i.e., how the energy security premium evolves through time), and assess and apply literature on OPEC strategic behavior/gaming models where possible. For the macroeconomic disruption impacts, EPA intends to examine recent literature on the elasticity of GDP to the oil price. Based upon that literature review, we intend to determine whether there is a difference in macro disruption impacts in the pre-2000 and post-2000 time period. Further, we intend to break down the macroeconomic disruption costs by GDP losses and oil import costs.

EPA solicits comments on the energy security analysis in a number of areas. Specifically, EPA is requesting comment on its interpretation of ORNL's results, ORNL's methodology, the monopsony effect, and the macroeconomic disruption effect.

e. Total Energy Security Benefits

Total annual energy security benefits associated with this proposal were derived from the estimated reductions in imports of finished petroleum products and crude oil using an energy security premium price of $12.38/barrel of reduced U.S. oil imports. Based on these values, we estimate that the total annual energy security benefits would be $3.7 billion in 2022 (in 2006 dollars).

C. Benefits of Reducing GHG Emissions

1. Introduction

The wider use of renewable fuels from this proposal results in reductions in greenhouse gas (GHG) emissions. Carbon dioxide (CO_2) and other GHGs mix well in the atmosphere, regardless of the location of the source, with each unit of emissions affecting global regional climates; and therefore, influencing regional biophysical systems. The effects of changes in GHG emissions are felt for decades to centuries given the atmospheric lifetimes of GHGs. This section provides estimates for the marginal and total benefits that could be monetized for the projected GHG emissions reductions of the proposal. EPA requests comment on the approach utilized to estimate the GHG benefits associated with the proposal.

2. Marginal GHG Benefits Estimates

The projected net GHG emissions reductions associated with the proposal reflect an incremental change to projected total global emissions.

[489] Stanford Energy Modeling Forum, Phillip C. Beccue and Hillard G. Huntington, ''An Assessment of Oil Market Disruption Risks,'' Final Report, EMF SR 8, October, 2005.

Therefore, as shown in Section VI.G, the projected global climate signal will be small but discernable (i.e., incrementally lower projected distribution of global mean surface temperatures). Given that the climate response is projected to be a marginal change relative to the baseline climate, it is conceptually appropriate to use an approach that estimates the marginal value of changes in climate change impacts over time as an estimate for the monetized marginal benefit of the GHG emissions reductions projected for this proposal. The marginal value of carbon is equal to the net present value of climate change impacts over hundreds of years of one additional net global metric ton of GHGs emitted to the atmosphere at a particular point in time. This marginal value (i.e., cost) of carbon is sometimes referred to as the ''social cost of carbon.''

Based on the global implications of GHGs and the economic principles that follow, EPA has developed ranges of global, as well as U.S., *marginal* benefits estimates (Table IX.C.2–1).[490] It is important to note at the outset that the estimates are incomplete since current methods are only able to reflect a partial accounting of the climate change impacts identified by the IPCC (discussed more below). Also, domestic estimates omit potential impacts on the United States (e.g., economic or national security impacts) resulting from climate change impacts in other countries. The global estimates were developed from a survey analysis of the peer reviewed literature (i.e., meta analysis). U.S. estimates, and a consistent set of global estimates, were developed from a single model and are highly preliminary, under evaluation, and likely to be revised. The latter set of estimates was developed because the peer reviewed literature does not currently provide regional (i.e., at the U.S. or China level) marginal benefits estimates, and it was important to have a consistent set of regional and global estimates. Ranges of estimates are provided to capture some of the uncertainties associated with modeling climate change impacts.

The range of estimates is wide due to the uncertainties relating to socio-economic futures, climate responsiveness, impacts modeling, as well as the choice of discount rate. For instance, for 2007 emission reductions and a 2% discount rate the global meta analysis estimates range from $−3 to $159/t$CO_2$, while the U.S. estimates range from $0 to $16/t$CO_2$. For 2007 emission reductions and a 3% discount rate, the global meta-estimates range from $−4 to $106/t$CO_2$, and the U.S. estimates range from $0 to $5/t$CO_2$.[491] The global meta analysis mean values for 2007 emission reductions are $68 and $40/t$CO_2$ for discount rates of 2% and 3%, respectively (in 2006 real dollars), while the domestic mean value from a single model are $4 and $1/t$CO_2$ for the same discount rates. The estimates for future year emission changes will be higher as future marginal emissions increases are expected to produce larger incremental damages as physical and economic systems become more stressed as the magnitude of climate change increases.[492]

TABLE IX.C.2–1—MARGINAL GHG BENEFITS ESTIMATES FOR DISCOUNT RATES OF 2%, 3%, AND 7% AND YEAR OF EMISSIONS CHANGE IN 2022

[All values are reported in 2006$/t$CO_2$]

	2%			3%			7% [b]		
	Low	Central	High	Low	Central	High	Low	Central	High
Meta global	−2	105	247	−2	62	165	n/a	n/a	n/a
FUND global	−4	136	1083	−4	26	206	−2	−1	9
FUND domestic	[a] 0	7	26	[a] 0	2	9	[a] 0	[a] 0	[a] 0

[a] These estimates, if explicitly estimated, may be greater than zero, especially in later years. They are currently reported as zero because the explicit estimates for an earlier year were zero and were grown at 3% per year. However, we do not anticipate that the explicit estimates for these later years would be significantly above zero given the magnitude of the current central estimates for discount rates of 2% and 3% and the effect of the high discount rate in the case of 7%.

[b] Except for illustrative purposes, the marginal benefits estimates in the peer reviewed literature do not use consumption discount rates as high as 7%.

The meta analysis ranges were developed from the Tol (2008) meta analysis. The meta analysis range only includes global estimates generated by more recent peer reviewed studies (i.e., published after 1995). In addition, the ranges only consider regional aggregations using simple summation and intergenerational consumption discount rates of approximately 2% and 3%.[493] Discount rates of 2% and 3% are consistent with EPA and OMB guidance on intergenerational discount rates (EPA, 2000; OMB, 2003).[494] The estimated distributions of the meta global estimates are right skewed with long right tails, which is consistent with characterizations of the low probability high impact damages (see the DRIA for the estimated probability density functions by discount rate).[495] The central meta estimates in Table IX.C.2–1 are means, and the low and high are the 5th and 95th percentiles. Means are

[490] For background on economic principles and the marginal benefit estimates, *see Technical Support Document on Benefits of Reducing GHG Emissions,* U.S. Environmental Protection Agency, June 12, 2008, *www.regulations.gov* (search phrase ''Technical Support Document on Benefits of Reducing GHG Emissions'').

[491] See Table IX.C.1 for global (FUND) estimates consistent with the U.S. estimates.

[492] The IPCC suggests an increase of 2–4% per year (IPCC WGII, 2007. *Climate Change 2007—Impacts, Adaptation and Vulnerability.* Contribution of Working Group II to the Fourth Assessment Report of the IPCC, *http://www.ipcc.ch/*). For Table IX.C.1., we assumed the estimates increased at 3% per year. For the final rule, we anticipate that we will explicitly estimate FUND marginal benefits values for each emissions reduction year.

[493] Tol (2008) is an update of the Tol (2005) meta analysis. Tol (2005) was used in the IPCC Working Group II's Fourth Assessment Report (IPCC WGII, 2007).

[494] OMB and EPA guidance on inter-generational discounting suggests using a low but positive discount rate if there are important intergenerational benefits/costs. Consumption discount rates of 1–3% are given by OMB and 0.5–3% by EPA (OMB Circular A–4, 2003; EPA Guidelines for Preparing Economic Analyses, 2000).

[495] E.g., Webster, M., C. Forest, J.M. Reilly, M.H. Babiker, D.W. Kicklighter, M. Mayer, R.G. Prinn, M. Sarofim, A.P. Sokolov, P.H. Stone & C. Wang, 2003. Uncertainty Analysis of Climate Change and Policy Response, Climatic Change 61(3): 295–320. Also, see Weitzman, M., 2007, ''The Stern Review of the Economics of Climate Change,'' *Journal of Economic Literature.* Weitzman, M., 2007, ''Structural Uncertainty and the Statistical Life in the Economics of Catastrophic Climate Change,'' Working paper *http://econweb.fas.harvard.edu/faculty/weitzman/papers/ValStatLifeClimate.pdf.*

presented because, as a central statistic, they better represent the skewed shape of these distributions compared to medians.

The consistent domestic and global estimates were developed using the FUND integrated assessment model (i.e., the Climate Framework for Uncertainty, Negotiation, and Distribution).[496] The ranges were generated from sensitivity analyses where we varied assumptions with respect to climate sensitivity (1.5 to 6.0 degrees Celsius),[497] the socio-economic and emissions baseline scenarios (the FUND default baseline and three baselines from the Intergovernmental Panel on Climate Change (IPCC) Special Report on Emissions Scenarios, SRES),[498] and the consumption discount rates of approximately 2%, 3%, and 7%, where 2% and 3% are consistent with intergenerational discounting.[499] Furthermore, the model was calibrated to the EPA value of a statistical life of $7.4 million (in 2006 real dollars).[500] The FUND global estimates are the sum of the regional estimates within FUND. The FUND global and domestic central values in Table IX.C.2–1 are weighted averages of the FUND estimates from the sensitivity analysis (see the DRIA for details). The low and high values are the low and high estimates across the sensitivity runs.

From Table IX.C.2–1, we see that, in terms of the current monetized benefits, the domestic marginal benefits are a fraction of the global marginal benefits. Given uncertainties and omitted impacts, it is difficult to estimate the actual ratio of total domestic benefits to total global benefits. The estimates suggest that an emissions reduction will have direct benefits for current and future U.S. populations and large benefits for global populations. The long-run and intergenerational implications of GHG emissions are evident in the difference in results across discount rates. In the current modeling, there are substantial long-run benefits (beyond the next two decades to over 100 years) and some near-term benefits as well as negative effects (e.g., agricultural productivity and heating demand). High discount rates give less weight to the distant benefits in the net present value calculations, and more weight to near-term effects. While not obvious in Table IX.C.2–1, an additional unit of emissions in the higher climate sensitivity scenarios, versus the lower climate sensitivity scenarios, is estimated to have a proportionally larger effect on the rest of the world compared to the U.S. (see more detailed results in DRIA). These points are discussed more below.

3. Discussion of Marginal GHG Benefits Estimates

This section briefly discusses important issues relevant to the marginal benefits estimates in Table IX.C.2–1 (see the DRIA for more extensive discussion). The broad range of estimates in Table IX.C.2–1 reflects some of the uncertainty associated with estimating monetized marginal benefits of climate change. The meta analysis range reflects differences in these assumptions as well as differences in the modeling of changes in climate and impacts considered and how they were modeled. EPA considers the meta analysis results to be more robust than the single model estimates in that the meta results reflect uncertainties in both models and assumptions.

The current state-of-the-art for estimating benefits is important to consider when evaluating policies. There are significant partially unquantified and omitted impact categories not captured in the estimates provided above. The IPCC WGII (2007) concluded that current estimates are ''very likely'' to be underestimated because they do not include significant impacts that have yet to be monetized.[501] Current estimates do not capture many of the main reasons for concern about climate change, including nonmarket damages (e.g., species existence value and the value of having the option for future use), the effects of climate variability, risks of potential extreme weather (e.g., droughts, heavy rains and wind), socially contingent effects (such as violent conflict or humanitarian crisis), and thresholds (or tipping points) associated with species, ecosystems, and potential long-term catastrophic events (e.g., collapse of the West Antarctic Ice Sheet, slowing of the Atlantic Ocean Thermohaline Circulation). Underestimation is even more likely when one considers that the current trajectory for GHG emissions is higher than typically modeled, which when combined with current regional population and income trajectories that are more asymmetric than typically modeled, imply greater climate change and vulnerability to climate change. See the DRIA for an initial, partial list of impacts that are currently not modeled in the FUND model and are thus not reflected in the FUND estimates. EPA is planning to develop a full assessment of what is not currently being captured in FUND for the final rule. In addition, EPA plans to quantify omitted impacts and update impacts currently represented to the maximum extent possible for the final rule.

The current estimates are also deterministic in that they do not account for the value people have for changes in risk due to changes in the likelihood of potential impacts associated with reductions in CO_2 and other GHG emissions (i.e., a risk premium). This is an issue that has concerned Weitzman and other economists.[502] We plan to conduct a formal uncertainty analysis for the final rule to attempt to account for, to the extent possible, these and other changes in uncertainty.

The estimates in Table IX.C.2–1 are only relevant for incremental policies relative to the projected baselines (that do not reflect potential future climate policies) and there is substantial uncertainty associated with the estimates themselves both in terms of what is being modeled and what is not being modeled, with many uncertainties outside of observed variability.[503] Both

[496] FUND is a spatially and temporally consistent framework—across regions of the world (e.g., U.S., China), impacts sectors, and time. FUND explicitly models impacts sectors in 16 global regions. FUND is one of the few models in the world that explicitly models global and regional marginal benefits estimates. Numerous applications of FUND have been published in the peer reviewed literature dating back to 1997. *See http://www.fnu.zmaw.de/FUND.5679.0.html*.

[497] In IPCC reports, equilibrium climate sensitivity refers to the equilibrium change in the annual mean global surface temperature following a doubling of the atmospheric equivalent carbon dioxide concentration. The IPCC states that climate sensitivity is ''likely'' to be in the range of 2 °C to 4.5 °C and described 3 °C as a ''best estimate'', which is the mode (or most likely) value. The IPCC goes on to note that climate sensitivity is ''very unlikely'' to be less than 1.5 °C and ''values substantially higher than 4.5 °C cannot be excluded.'' IPCC WGI, 2007, Climate Change 2007—The Physical Science Basis, Contribution of Working Group I to the Fourth Assessment Report of the IPCC, *http://www.ipcc.ch/*.

[498] The IMAGE model SRES baseline data was used for the A1b, A2, and B2 scenarios (IPCC, 2000. *Special Report on Emissions Scenarios.* A special report of Working Group III of the Intergovernmental Panel on Climate Change. Cambridge University Press, Cambridge).

[499] The EPA guidance on intergenerational discounting states that ''[e]conomic analyses should present a sensitivity analysis of alternative discount rates, including discounting at two to three percent and seven percent as in the intra-generational case, as well as scenarios using rates in the interval one-half to three percent as prescribed by optimal growth models.'' (EPA, 2000).

[500] This number may be updated to be consistent with recent EPA regulatory impact analyses that have used a value of $6.4 million (in 2006 real dollars).

[501] IPCC WGII, 2007. In the IPCC report, ''very likely'' was defined as a greater than 90% likelihood based on expert judgment.

[502] E.g, Webster *et al.*, 2003; Weitzman, M., 2007. *http://econweb.fas.harvard.edu/faculty/weitzman/papers/ValStatLifeClimate.pdf.*

[503] Because some types of potential climate change impacts may occur suddenly or begin to

Continued

of these points are important for non-marginal emissions changes and estimating total benefits. Also, the uncertainties inherent in this kind of modeling, including the omissions of many important impacts categories, present problems for approaches attempting to identify an economically efficient level of GHG reductions and to positive net benefit criteria in general, and point to the importance of considering factors beyond monetized benefits and costs. In uncertain situations such as that associated with climate, EPA typically recommends that analysis consider a range of benefit and cost estimates, and the potential implications of non-monetized and non-quantified benefits.

Economic principles suggest that global benefits should also be considered when evaluating alternative GHG reduction policies.[504] Typically, because the benefits and costs of most environmental regulations are predominantly domestic, EPA focuses on benefits that accrue to the U.S. population when quantifying the impacts of domestic regulation. However, OMB's guidance for economic analysis of federal regulations specifically allows for consideration of international effects.[505] GHGs are global and very long-run public goods, and economic principles suggest that the full costs to society of emissions should be considered in order to identify the policy that maximizes the net benefits to society, i.e., achieves an efficient outcome (Nordhaus, 2006).[506] As such, estimates of global benefits capture more of the full value to society than domestic estimates and will result in higher global net benefits for GHG reductions when considered.[507]

Furthermore, international effects of climate change may also affect domestic benefits directly and indirectly to the extent U.S. citizens value international impacts (e.g., for tourism reasons, concerns for the existence of ecosystems, and/or concern for others); U.S. international interests are affected (e.g., risks to U.S. national security, or the U.S. economy from potential disruptions in other nations); and/or domestic mitigation decisions affect the level of mitigation and emissions changes in general in other countries (i.e., the benefits realized in the U.S. will depend on emissions changes in the U.S. and internationally). The economics literature also suggests that policies based on direct domestic benefits will result in little appreciable reduction in global GHGs (e.g., Nordhaus, 1995).[508] While these marginal benefits estimates are not comprehensive or economically optimal, the global estimates in Table IX.C.2–1 internalize a larger portion of the global and intergenerational externalities of reducing a unit of emissions.

A key challenge facing EPA is the appropriate discount rate over the longer timeframe relevant for GHGs. With the benefits of GHG emissions reductions distributed over a very long time horizon, benefit and cost estimations are likely to be very sensitive to the discount rate. When considering climate change investments, they should be compared to similar alternative investments (via the discount rate). Changes in GHG emissions—both increases and reductions—are essentially long-run investments in changes in climate and the potential impacts from climate change, which includes the potential for significant impacts from climate change, where the exact timing and magnitude of these impacts are unknown.

When there are important benefits or costs that affect multiple generations of the population, EPA and OMB allow for low but positive discount rates (e.g., 0.5–3% noted by U.S. EPA, 1–3% by OMB).[509] In this multi-generation context, the three percent discount rate is consistent with observed interest rates from long-term investments available to current generations (net of risk premiums) as well as current estimates of the impacts of climate change that reflect potential impacts on consumers. In addition, rates of three percent or lower are consistent with long-run uncertainty in economic growth and interest rates, considerations of issues associated with the transfer of wealth between generations, and the risk of high impact climate damages. Given the uncertain environment, analysis could also consider evaluating uncertainty in the discount rate (e.g., Newell and Pizer, 2001, 2003).[510]

For the final rulemaking, we will be developing and updating the FUND model as best as possible based on the latest research and peer reviewing the estimates. To improve upon our estimates, we hope to evaluate several factors not currently captured in the proposed estimates due to time constraints. For example, we will quantify additional impact categories as is possible and provide a qualitative evaluation of the implications of what is not monetized. We also plan to conduct an uncertainty analysis, consider complementary bottom-up analyses, and develop estimates of the marginal benefits associated with non-CO_2 GHGs relevant to the rule (e.g., CH_4, N_2O, and HFC–134a).[511]

EPA solicits comment on the appropriateness of using U.S. and global values in quantifying the benefits of GHG reductions and the appropriate application of benefits estimates given the state of the art and overall uncertainties. We also seek comment on our estimates of the global and U.S. marginal benefits of GHG emissions reductions that EPA has developed, including the scientific and economic foundations, the methods employed in developing the estimates, the discount

increase at a much faster rate, rather than increasing gradually or smoothly, different approaches are necessary for quantifying the benefits of ''large'' (non-incremental) versus ''small'' (incremental) reductions in global GHGs. Marginal benefits estimates, like those presented above, can be useful for estimating benefits for small changes in emissions. *See* the DRIA for additional discussion of this point. Note that even small reductions in global GHG emissions are expected to reduce climate change risks, including catastrophic risks.

504 Recently, the National Highway Traffic Safety Administration (NHTSA) issued the final Environmental Impact Statement for their proposed rulemaking for average fuel economy standards for passenger cars and light trucks in which the preferred alternative is based upon a domestic marginal benefit estimate for carbon dioxide reductions. See Average Fuel Economy Standards, Passenger Cars and Light Trucks, MY 2011–2015, Final Environmental Impact Statement *http://www.nhtsa.dot.gov/portal/site/nhtsa/menuitem.43ac99aefa80569eea57529cdba046a0/*.

505 OMB (2003), page 15.

506 Nordhaus, W., 2006, ''Paul Samuelson and Global Public Goods,'' in M. Szenberg, L. Ramrattan, and A. Gottesman (eds), Samuelsonian Economics, Oxford.

507 Both the United Kingdom and the European Commission following these economic principles in consideration of the global social cost of carbon (SCC) for valuing the benefits of GHG emission reductions in regulatory impact assessments and cost-benefit analyses (Watkiss *et al.* 2006).

508 Nordhaus, William D. (1995). ''Locational Competition and the Environment: Should Countries Harmonize Their Environmental Policies?'' in Locational Competition in the World Economy, Symposium 1994, ed., Horst Siebert, J. C. B. Mohr (Paul Siebeck), Tuebingen, 1995.

509 EPA (U.S. Environmental Protection Agency), 2000. Guidelines for Preparing Economic Analyses. EPA 240–R–00–003. *See* also OMB (U.S. Office of Management and Budget), 2003. Circular A–4. September 17, 2003. These documents are the guidance used when preparing economic analyses for all EPA rulemakings.

510 Newell, R. and W. Pizer, 2001. Discounting the benefits of climate change mitigation: How much do uncertain rates increase valuations? PEW Center on Global Climate Change, Washington, DC. Newell, R. and W. Pizer, 2003. Discounting the distant future: how much do uncertain rates increase valuations? Journal of Environmental Economics and Management 46:52–71.

511 Due to differences in atmospheric lifetime and radiative forcing, the marginal benefit values of non-CO_2 GHG reductions and their growth rates over time will not be the same as the marginal benefits of CO_2 emissions reductions (IPCC WGII, 2007).

rates considered, current and proposed future consideration of uncertainty in the estimates, marginal benefits estimates for non-CO_2 GHG emissions reductions, and potential opportunities for improving the estimates. We are also interested in comments on methods for quantifying benefits for non-incremental reductions in global GHG emissions.

Because the literature on SCC and our understanding of that literature continues to evolve, EPA will continue to assess the best available information on the social cost of carbon and climate benefits, and may adjust its approaches to quantifying and presenting information on these areas in future rulemakings.

4. Total Monetized GHG Benefits Estimates

As described in Section VI.F, annualized equivalent GHG emissions reductions associated with the RFS2 proposal in 2022 would be 160 million metric tons of CO_2 equivalent ($MMTCO_2eq$) with a 2% discount rate, and 155 and 136 $MMCO_2eq$ with discount rates of 3% and 7%, respectively. This section provides the monetized total GHG benefits estimates associated with the proposal in 2022. As discussed above in Section IX.C.3, these estimates do not include significant impacts that have yet to be monetized. Total monetized benefits in 2022 are calculated by multiplying the marginal benefits per metric ton of CO_2 in that year by the annualized equivalent emissions reductions. For the final rulemaking, we plan to separate the emissions reductions by gas and use CO_2 and non-CO_2 marginal benefits estimates. Non-CO_2 GHGs have different climate and atmospheric implications and therefore different marginal climate impacts.

Table IX.C.4–1 provides the estimated monetized GHG benefits of the proposal for 2022. The large range of values in the Table reflects some of the uncertainty captured in the range of monetized marginal benefits estimates presented in Table IX.C.2–1.[512] All values in this section are presented in 2006 real dollars.

TABLE IX.C.4–1—MONETIZED GHG BENEFITS OF THE PROPOSED RULE IN 2022

[Billion 2006$]

Marginal benefit		2%	3%	7%
Meta global	Low	−$0.3	−$0.3	n/a
	Central	16.8	9.6	n/a
	High	39.4	25.5	n/a
FUND global	Low	−0.6	−0.6	−0.3
	Central	21.7	4.0	−0.1
	High	172.8	31.9	1.2
FUND domestic	Low	0.0	0.0	0.0
	Central	1.1	0.3	0.0
	High	4.1	1.4	0.0

D. Co-pollutant Health and Environmental Impacts

This section describes EPA's analysis of the co-pollutant health and environmental impacts that can be expected to occur as a result of this renewable fuels proposal throughout the period from initial implementation through 2030. GHG emissions are predominantly the byproduct of fossil fuel combustion processes that also produce criteria and hazardous air pollutants. The fuels that are subject to the proposed standard are also significant sources of mobile source air pollution such as direct PM, NO_X, VOCs and air toxics. The proposed standard would affect exhaust and evaporative emissions of these pollutants from vehicles and equipment. They would also affect emissions from upstream sources such as fuel production, storage, and distribution and agricultural emissions. Any decrease or increase in ambient ozone, $PM_{2.5}$, and air toxics associated with the proposal would impact human health in the form of avoided or incurred premature deaths and other serious human health effects, as well as other important public health and welfare effects.

As can be seen in Section II.B, we estimate that the proposal would lead to both increased and decreased criteria and air toxic pollutant emissions. Making predictions about human health and welfare impacts based solely on emissions changes, however, is extremely difficult. Full-scale photochemical modeling is necessary to provide the needed spatial and temporal detail to more completely and accurately estimate the changes in ambient levels of these pollutants. EPA typically quantifies and monetizes the PM- and ozone-related health and environmental impacts in its regulatory impact analyses (RIAs) when possible. However, we were unable to do so in time for this proposal. EPA attempts to make emissions and air quality modeling decisions early in the analytical process so that we can complete the photochemical air quality modeling and use that data to inform the health and environmental impacts analysis. Resource and time constraints precluded the Agency from completing this work in time for the proposal. EPA will, however, provide a complete characterization of the health and environmental impacts, both in terms of incidence and valuation, for the final rulemaking.

This section explains what PM- and ozone-related health and environmental impacts EPA will quantify and monetize in the analysis for the final rules. EPA will base its analysis on peer-reviewed studies of air quality and health and welfare effects and peer-reviewed studies of the monetary values of public health and welfare improvements, and will be consistent with benefits analyses performed for the recent analysis of the proposed Ozone NAAQS and the final PM NAAQS analysis.[513] [514] These methods will be described in detail in the DRIA prepared for the final rule.

Though EPA is characterizing the changes in emissions associated with toxic pollutants, we will not be able to

[512] EPA notes, however, that the Ninth Circuit recently rejected an approach of assigning no monetized value to greenhouse gas reductions resulting from vehicular fuel economy. *Center for Biodiversity* v. *NHTSA,* F. 3d, (9th Cir. 2007).

[513] U.S. Environmental Protection Agency. July 2007. Regulatory Impact Analysis of the Proposed Revisions to the National Ambient Air Quality Standards for Ground-Level Ozone. Prepared by: Office of Air and Radiation. EPA–452/R–07–008.

[514] U.S. Environmental Protection Agency. October 2006. Final Regulatory Impact Analysis (RIA) for the Proposed National Ambient Air Quality Standards for Particulate Matter. Prepared by: Office of Air and Radiation.

quantify or monetize the human health effects associated with air toxic pollutants for either the proposal or the final rule analyses. This is primarily because available tools and methods to assess air toxics risk from mobile sources at the national scale are not adequate for extrapolation to benefits assessment. In addition to inherent limitations in the tools for national-scale modeling of air quality and exposure, there is a lack of epidemiology data for air toxics in the general population. For a more comprehensive discussion of these limitations, please refer to the final Mobile Source Air Toxics rule.[515] Please refer to Section VII for more information about the air toxics emissions impacts associated with the proposed standard.

1. Human Health and Environmental Impacts

To model the ozone and PM air quality benefits of the final rules, EPA will use the Community Multiscale Air Quality (CMAQ) model (see Section VII.D.2 for a description of the CMAQ model). The modeled ambient air quality data will serve as an input to the Environmental Benefits Mapping and Analysis Program (BenMAP).[516] BenMAP is a computer program developed by EPA that integrates a number of the modeling elements used in previous DRIAs (e.g., interpolation functions, population projections, health impact functions, valuation functions, analysis and pooling methods) to translate modeled air concentration estimates into health effects incidence estimates and monetized benefits estimates.

Table IX.D.1–1 lists the co-pollutant health effect exposure-response functions ($PM_{2.5}$ and ozone) we will use to quantify the co-pollutant incidence impacts associated with the proposal.

TABLE IX.D.1–1—HEALTH IMPACT FUNCTIONS USED IN BENMAP TO ESTIMATE IMPACTS OF $PM_{2.5}$ AND OZONE REDUCTIONS

Endpoint	Pollutant	Study	Study population
Premature Mortality:			
Premature mortality—daily time series	O3	Multi-city	All ages.
		Bell et al. (2004)—Non-accidental	
		Huang et al. (2005)—Cardiopulmonary.	
		Schwartz (2005)—Non-accidental.	
		Meta-analyses:	
		Bell et al. (2005)—All cause.	
		Ito et al. (2005)—Non-accidental.	
		Levy et al. (2005)—All cause.	
Premature mortality—cohort study, all-cause	$PM_{2.5}$	Pope et al. (2002)	>29 years.
		Laden et al. (2006)	>25 years.
Premature mortality, total exposures	$PM_{2.5}$	Expert Elicitation (IEc, 2006)	>24 years.
Premature mortality—all-cause	$PM_{2.5}$	Woodruff et al. (1997)	Infant (<1 year).
Chronic Illness:			
Chronic Bronchitis	$PM_{2.5}$	Abbey et al. (1995)	>26 years.
Nonfatal heart attacks	$PM_{2.5}$	Peters et al. (2001)	Adults (>18 years).
Hospital Admissions:			
Respiratory	O3	Pooled estimate	>64 years.
		Schwartz (1995)—ICD 460–519 (all resp).	
		Schwartz (1994a; 1994b)—ICD 480–486 (pneumonia).	
		Moolgavkar et al. (1997)—ICD 480–487 (pneumonia).	
		Schwartz (1994b)—ICD 491–492, 494–496 (COPD).	
		Moolgavkar et al. (1997)—ICD 490–496 (COPD).	
		Burnett et al. (2001)	<2 years.
	$PM_{2.5}$	Pooled estimate	>64 years.
		Moolgavkar (2003)—ICD 490–496 (COPD).	
		Ito (2003)—ICD 490–496 (COPD).	
	$PM_{2.5}$	Moolgavkar (2000)—ICD 490–496 (COPD)	20–64 years.
	$PM_{2.5}$	Ito (2003)—ICD 480–486 (pneumonia)	>64 years.
	$PM_{2.5}$	Sheppard (2003)—ICD 493 (asthma)	<65 years.
Cardiovascular	$PM_{2.5}$	Pooled estimate	>64 years.
		Moolgavkar (2003)—ICD 390–429 (all Cardiovascular).	
		Ito (2003)—ICD 410–414, 427–428 (ischemic heart disease, dysrhythmia, heart failure).	
	$PM_{2.5}$	Moolgavkar (2000)—ICD 390–429 (all Cardiovascular).	20–64 years.
Asthma-related ER visits	O3	Pooled estimate	5–34 years.
		Jaffe et al. (2003)	All ages.
		Peel et al. (2005)	All ages.
		Wilson et al. (2005).	
	$PM_{2.5}$	Norris et al. (1999)	0–18 years.
Other Health Endpoints:			

[515] U.S. Environmental Protection Agency. February 2007. Control of Hazardous Air Pollutants from Mobile Sources: Final Regulatory Impact Analysis. Office of Air and Radiation. Office of Transportation and Air Quality. EPA420–R–07–002.

[516] Information on BenMAP, including downloads of the software, can be found at *http://www.epa.gov/ttn/ecas/benmodels.html*.

TABLE IX.D.1–1—HEALTH IMPACT FUNCTIONS USED IN BENMAP TO ESTIMATE IMPACTS OF $PM_{2.5}$ AND OZONE REDUCTIONS—Continued

Endpoint	Pollutant	Study	Study population
Acute bronchitis	$PM_{2.5}$	Dockery et al. (1996)	8–12 years.
Upper respiratory symptoms	$PM_{2.5}$	Pope et al. (1991)	Asthmatics, 9–11 years.
Lower respiratory symptoms	$PM_{2.5}$	Schwartz and Neas (2000)	7–14 years.
Asthma exacerbations	$PM_{2.5}$	Pooled estimate	6–18 years.
		Ostro et al. (2001) (cough, wheeze and shortness of breath).	
		Vedal et al. (1998) (cough).	
Work loss days	$PM_{2.5}$	Ostro (1987)	18–65 years.
School absence days	O3	Pooled estimate	5–17 years.
		Gilliland et al. (2001).	
		Chen et al. (2000).	
Minor Restricted Activity Days (MRADs)	O3	Ostro and Rothschild (1989)	18–65 years.
	$PM_{2.5}$	Ostro and Rothschild (1989)	18–65 years.

2. Monetized Impacts

Table IX.D.2–1 presents the monetary values we will apply to changes in the incidence of health and welfare effects associated with the RFS2 standard.

TABLE IX.D.2–1—VALUATION METRICS USED IN BENMAP TO ESTIMATE MONETARY BENEFITS

Endpoint	Valuation method	Valuation (2000$)
Premature mortality	Assumed Mean VSL	$5,500,000
Chronic Illness		
Chronic Bronchitis	WTP: Average Severity	340,482
Myocardial Infarctions, Nonfatal	Medical Costs Over 5 Years. Varies by age and discount rate. Russell (1998)	
	Medical Costs Over 5 Years. Varies by age and discount rate. Wittels (1990)	
Hospital Admissions		
Respiratory, Age 65+	COI: Medical Costs + Wage Lost	18,353
Respiratory, Ages 0–2	COI: Medical Costs	7,741
Chronic Lung Disease (less Asthma).	COI: Medical Costs + Wage Lost	12,378
Pneumonia	COI: Medical Costs + Wage Lost	14,693
Asthma	COI: Medical Costs + Wage Lost	6,634
Cardiovascular	COI: Medical Costs + Wage Lost (20–64)	22,778
	COI: Medical Costs + Wage Lost (65–99)	21,191
ER Visits, Asthma	COI: Smith et al. (1997)	312
	COI: Standford et al. (1999)	261
Other Health Endpoints		
Acute Bronchitis	WTP: 6 Day Illness, CV Studies	356
Upper Respiratory Symptoms	WTP: 1 Day, CV Studies	25
Lower Respiratory Symptoms	WTP: 1 Day, CV Studies	16
Asthma Exacerbation	WTP: Bad Asthma Day, Rowe and Chestnut (1986)	43
Work Loss Days	Median Daily Wage, County-Specific	
Minor Restricted Activity Days	WTP: 1 Day, CV Studies	51
School Absence Days	Median Daily Wage, Women 25+	75
Worker Productivity	Median Daily Wage, Outdoor Workers, County-Specific, Crocker and Horst (1981).	
Environmental Endpoints Recreational Visibility.	WTP: 86 Class I Areas	

Source: Dollar amounts for each valuation method were extracted from BenMAP version 2.4.5.

3. Other Unquantified Health and Environmental Impacts

In addition to the co-pollutant health and environmental impacts we will quantify for the analysis of the RFS2 standard, there are a number of other health and human welfare endpoints that we will not be able to quantify because of current limitations in the methods or available data. These impacts are associated with emissions of air toxics (including benzene, 1,3-butadiene, formaldehyde, acetaldehyde, acrolein, and ethanol), ambient ozone, and ambient $PM_{2.5}$ exposures. For example, we have not quantified a number of known or suspected health effects linked with ozone and PM for which appropriate health impact functions are not available or which do not provide easily interpretable outcomes (i.e., changes in heart rate variability). Additionally, we are currently unable to quantify a number of known welfare effects, including reduced acid and particulate deposition damage to cultural monuments and other materials, and environmental benefits due to reductions of impacts of eutrophication in coastal areas. For air toxics, the available tools and methods to assess risk from mobile sources at the national scale are not adequate for extrapolation to benefits assessment. In addition to inherent limitations in the tools for national-scale modeling of air toxics and exposure, there is a lack of epidemiology data for air toxics in the general population. Table IX.D.3–1 lists these unquantified health and environmental impacts.

TABLE IX.D.3–1—UNQUANTIFIED AND NON-MONETIZED POTENTIAL EFFECTS

Pollutant/Effects	Effects not included in analysis—changes in:
Ozone Health [a]	Chronic respiratory damage.
	Premature aging of the lungs.
	Non-asthma respiratory emergency room visits.
	Exposure to UVb (±) [d].
Ozone Welfare	Yields for:
	—commercial forests.
	—some fruits and vegetables.
	—non-commercial crops.
	Damage to urban ornamental plants.
	Impacts on recreational demand from damaged forest aesthetics.
	Ecosystem functions.
	Exposure to UVb (±).
PM Health [b]	Premature mortality—short term exposures.[c]
	Low birth weight.
	Pulmonary function.
	Chronic respiratory diseases other than chronic bronchitis.
	Non-asthma respiratory emergency room visits.
	Exposure to UVb (±).
PM Welfare	Residential and recreational visibility in non-Class I areas.
	Soiling and materials damage.
	Damage to ecosystem functions.
	Exposure to UVb (±).
Nitrogen and Sulfate Deposition Welfare.	Commercial forests due to acidic sulfate and nitrate deposition.
	Commercial freshwater fishing due to acidic deposition.
	Recreation in terrestrial ecosystems due to acidic deposition.
	Existence values for currently healthy ecosystems.
	Commercial fishing, agriculture, and forests due to nitrogen deposition.
	Recreation in estuarine ecosystems due to nitrogen deposition.
	Ecosystem functions.
	Passive fertilization.
CO Health	Behavioral effects.
Hydrocarbon (HC)/Toxics Health [e].	Cancer (benzene, 1,3-butadiene, formaldehyde, acetaldehyde, ethanol).
	Anemia (benzene).
	Disruption of production of blood components (benzene).
	Reduction in the number of blood platelets (benzene).
	Excessive bone marrow formation (benzene).
	Depression of lymphocyte counts (benzene).
	Reproductive and developmental effects (1,3-butadiene, ethanol).
	Irritation of eyes and mucus membranes (formaldehyde).
	Respiratory irritation (formaldehyde).
	Asthma attacks in asthmatics (formaldehyde).
	Asthma-like symptoms in non-asthmatics (formaldehyde).
	Irritation of the eyes, skin, and respiratory tract (acetaldehyde).
	Upper respiratory tract irritation and congestion (acrolein).
HC/Toxics Welfare [f].	Direct toxic effects to animals.
	Bioaccumulation in the food chain.
	Damage to ecosystem function.
	Odor.

[a] In addition to primary economic endpoints, there are a number of biological responses that have been associated with ozone health effects including increased airway responsiveness to stimuli, inflammation in the lung, acute inflammation and respiratory cell damage, and increased susceptibility to respiratory infection. The public health impact of these biological responses may be partly represented by our quantified endpoints.

[b] In addition to primary economic endpoints, there are a number of biological responses that have been associated with PM health effects including morphological changes and altered host defense mechanisms. The public health impact of these biological responses may be partly represented by our quantified endpoints.

[c] While some of the effects of short-term exposures are likely to be captured in the estimates, there may be premature mortality due to short-term exposure to PM not captured in the cohort studies used in this analysis. However, the PM mortality results derived from the expert elicitation do take into account premature mortality effects of short term exposures.

[d] May result in benefits or disbenefits.

[e] Many of the key hydrocarbons related to this rule are also hazardous air pollutants listed in the Clean Air Act. Please refer to Section VII.E.4 for additional information on the health effects of air toxics.

[f] Please refer to Section VII.E for additional information on the welfare effects of air toxics.

While there will be impacts associated with air toxic pollutant emission changes that result from the RFS2 standard, we will not attempt to monetize those impacts. This is primarily because currently available tools and methods to assess air toxics risk from mobile sources at the national scale are not adequate for extrapolation to incidence estimations or benefits assessment. The best suite of tools and methods currently available for assessment at the national scale are those used in the National-Scale Air Toxics Assessment (NATA). The EPA Science Advisory Board specifically commented in their review of the 1996 NATA that these tools were not yet ready for use in a national-scale benefits analysis, because they did not consider the full distribution of exposure and risk, or address sub-chronic health effects.[517] While EPA has since improved the tools, there remain critical limitations for estimating incidence and assessing benefits of reducing mobile source air toxics. EPA continues to work to address these limitations; however, we do not anticipate having methods and tools available for national-scale application in time for the analysis of the final rules. Please refer to the final Mobile Source Air Toxics Rule RIA for more discussion.[518]

E. Economy-Wide Impacts

It is anticipated that this proposed rulemaking will have impacts on the U.S. economy that extend beyond the two sectors most directly affected—the transportation and agriculture sectors. Consider how the proposed rulemaking will affect the overall U.S. economy. By requiring 36 billion gallons of renewable transportation fuels in the U.S. transportation sector by 2022, it is anticipated that the cost of motor vehicle fuels will increase. This cost increase will impact all sectors of the economy that use motor vehicles fuels, as intermediate inputs to production. For example, manufacturing firms will see an increase in their shipping costs. Households will also be impacted as consumers of these goods, and directly as consumers of motor vehicle fuels. Additionally, it is anticipated that the production of renewable fuels will increase the demand for U.S. farm

[517] Science Advisory Board. 2001. NATA—Evaluating the National-Scale Air Toxics Assessment for 1996—an SAB Advisory. *http://www.epa.gov/ttn/atw/sab/sabrev.html.*

[518] U.S. EPA. 2007. Control of Hazardous Air Pollutants From Mobile Sources—Regulatory Impact Analysis. Assessment and Standards Division. Office of Transportation and Air Quality. EPA420R–07–002. February.

products, and increase farm incomes. This will have ripple effects for sectors that supply inputs to the U.S. farm sector (e.g. tractors), and sectors that demand outputs from the farm sector. The sum of all of these impacts will affect the total levels of output and consumption in the U.S. economy. Because multiple markets beyond the transportation sector will be affected by the proposed rulemaking, a general equilibrium analysis is required to provide a more accurate picture of the social cost of the policy than a partial equilibrium analysis. (A partial equilibrium analysis looks at the impacts in one market of the economy but does not attempt to capture the full interaction of a policy change in all markets simultaneously, as a general equilibrium model does).

In order to estimate the impacts of the RFS2 rule on U.S. gross domestic product (GDP) and consumption, EPA intends to use an economy-wide, computable general equilibrium (CGE) model between proposal and the final rule. This model will use detailed fuel sector cost estimates provided in Section VIII as inputs to determine the economy-wide impacts of the rulemaking. The economy-wide model to be utilized for this analysis is the Intertemporal General Equilibrium Model (IGEM). IGEM is a model of the U.S. economy with an emphasis on the energy and environmental aspects. It is a dynamic model, which depicts growth of the economy due to capital accumulation, technical change and population change. It is a detailed multi-sector model covering thirty-five industries of the U.S. economy. It also depicts changes in consumption patterns due to demographic changes, price and income effects. The substitution possibilities for both producers and consumers in IGEM are driven by model parameters that are based on observed market behavior revealed over the past forty to fifty years. EPA seeks comment on the modeling approach to be utilized to estimate the economy-wide impacts of the RFS2 proposal.

An additional issue that arises is how biofuel subsidies are considered from an economy-wide perspective. The Renewable Fuels Standard, by encouraging the use of biofuels, will result in an expansion of subsidy payments by the U.S. For example, each gallon of corn-based ethanol sold in the U.S. qualifies for a $0.45/gallon subsidy. One assumption that could be made is that biofuel subsidies, which are a loss in revenue to the U.S. government, are offset by an increase in taxes by the U.S. In this case, the Renewable Fuels Standard program becomes revenue neutral. If taxes are raised to offset the revenue loss from the subsidies, the taxes could have a distortionary impact on the economy. For example, if taxes are raised on labor and capital, then there will less output. To account for the potential distortionary impacts of increased taxes, as a rule of thumb, it is sometimes assumed that for each dollar of tax revenue raised, there is a $0.25 loss in output in the economy. We intend to consider the impact of the expansion of biofuel subsidies from the RFS2 in the context of the economy-wide modeling.

X. Impacts on Water

A. Background

As the production and price of corn and other biofuel feedstocks increase, there may be substantial impacts to both water quality and water quantity. To analyze the potential water-related impacts, EPA focused on agricultural corn production for several reasons. Corn acres have increased dramatically, 20% in 2007. Although corn acres declined seven percent in 2008, total corn acres remained the second highest since 1946.[519] Corn has the highest fertilizer and pesticide use per acre and accounts for the largest share of nitrogen fertilizer use among all crops.[520] Corn generally utilizes only 40 to 60% of the applied nitrogen fertilizer. The remaining nitrogen is available to leave the field and runoff to surface waters, leach into ground water, or volatilize to the air where it can return to water through depositional processes.

There are three major pathways for contaminants to reach water from agricultural lands: run off from the land's surface, subsurface tile drains, or leaching to ground water. A variety of management factors influence the potential for contaminants such as fertilizers, sediment, and pesticides to reach water from agricultural lands. These factors include nutrient and pesticide application rates and application methods, use of conservation practices and crop rotations by farmers, and acreage and intensity of tile drained lands.

Historically, corn has been grown in rotation with other crops, especially soybeans. As corn prices increase relative to prices for other crops, more farmers are choosing to grow corn every year (continuous corn). Continuous corn production results in significantly greater nitrogen losses annually than a corn-soybean rotation and lower yields per acre. In response, farmers may add higher rates of nitrogen fertilizer to try to match yields of corn grown in rotation. Growing continuous corn also increases the viability of pests such as corn rootworm. Farmers may increase use of pesticides to control these pests. As corn acres increase, use of the common herbicides like atrazine and glyphosate (e.g. Roundup) may also increase.

High corn prices may encourage farmers to grow corn on lands that are marginal for row production such as hay land or pasture. Typically, agricultural producers apply far less fertilizer and pesticide on pasture land than land in row crops. Corn yield on these marginal lands will be lower and may require higher fertilizer rates. However since nitrogen fertilizer prices are tied to oil prices, fertilizer costs have increased significantly recently. It is unclear how agricultural producers have responded to these increases in both corn and fertilizer prices. EPA solicits comments on the impact of corn and fertilizer prices on nitrogen fertilizer use.

Tile drainage is another important factor in determining the losses of fertilizer from cropland. Tile drainage consists of subsurface tiles or pipes that move water from wet soils to surface waters quickly so crops can be planted. Tile drainage has transformed large expanses of historic wetland soils into productive agriculture lands. However, the tile drains also move fertilizers and pesticides more quickly to surface waters without any of the attenuation that would occur if these contaminants moved through soils or wetlands. The highest proportion of tile drainage occurs in the Upper Mississippi and the Ohio-Tennessee River basins.[521]

The increase in corn production and prices may also have significant impacts on voluntary conservation programs funded by the U.S. Department of Agriculture (USDA) that are important to protect water quality. As land values increase due to higher crop prices, USDA payments may not keep up with the need for farmers and tenant farmers, to make an adequate return. For example, farmland in Iowa increased an

[519] U.S. Department of Agriculture, National Agricultural Statistics Service, ''Acreage'', 2008, available online at: *http://usda.mannlib.cornell.edu/usda/current/Acre/Acre-06–30–2008.pdf.*

[520] Committee on Water Implications of Biofuels Production in the United States, National Research Council, 2008, Water implications of biofuels production in the United States, The National Academies Press, Washington, DC, 88 p.

[521] U.S. Environmental Protection Agency, EPA Science Advisory Board, Hypoxia in the northern Gulf of Mexico, EPA–SAB–08–003, 275 p, available online at: *http://yosemite.epa.gov/sab/sabproduct.nsf/C3D2F27094E03F90852573B800601D93/$File/EPA–SAB–08–003complete.unsigned.pdf.*

average of 18% in 2007 from 2006 prices.

Both land retirement programs like the Conservation Reserve Program (CRP) and working land programs like the Environmental Quality Incentives Program (EQIP) can be affected. Under CRP, USDA contracts with farmers to take land out of agricultural production and plant grasses or trees. Generally farmers put land into CRP because it is not as productive and has other characteristics that make the cropland more environmentally sensitive, such as high erosion rates. CRP provides valuable environmental benefits both for water quality and for wildlife habitat. Midwestern states, where much of U.S. corn is grown, tend to have lower CRP reenrollment rates than the national average. Under EQIP, USDA makes cost-share payments to farmers to implement conservation practices. Some of the most cost-effective practices include: Riparian buffers; crop rotation; appropriate rate, timing, and method of fertilizer application; cover crops; and, on tile-drained lands, treatment wetlands and controlled drainage. Producers may be less willing to participate and require higher payments to offset perceived loss of profits through implementation of conservation practices.

1. Ecological Impacts

Nitrogen and phosphorus enrichment due to human activities is one of the leading problems facing our nation's lakes, reservoirs, and estuaries. Nutrient enrichment also has negative impacts on aquatic life in streams; adverse health effects on humans and domestic animals; and impairs aesthetic and recreational use. Excess nutrients can lead to excessive growth of algae in rivers and streams, and aquatic plants in all waters. For example, declines in invertebrate community structure have been correlated directly with increases in phosphorus concentration. High concentrations of nitrogen in the form of ammonia are known to be toxic to aquatic animals. Excessive levels of algae have also been shown to be damaging to invertebrates. Finally, fish and invertebrates will experience growth problems and can even die if either oxygen is depleted or pH increases are severe; both of these conditions are symptomatic of eutrophication. As a biologic system becomes more enriched by nutrients, different species of algae may spread and species composition can shift.

Nutrient pollution is widespread. The most widely known examples of significant nutrient impacts include the Gulf of Mexico and the Chesapeake Bay. There are also known impacts in over 80 estuaries/bays, and thousands of rivers, streams, and lakes. Waterbodies in virtually every state and territory in the U.S. are impacted by nutrient-related degradation. Reducing nutrient pollution is a priority for EPA. The combustion of transportation fuels results in significant loadings of nitrogen from air deposition to waterbodies around the country, including the Chesapeake Bay, Long Island Sound, and Lake Tahoe.

2. Gulf of Mexico

Production of corn for ethanol may exacerbate existing serious water quality problems in the Gulf of Mexico. Nitrogen fertilizer applications to corn are already the major source of total nitrogen loadings to the Mississippi River. A large area of low oxygen, or hypoxia, forms in the Gulf of Mexico every year, often called the "dead zone." The primary cause of the hypoxia is excess nutrients (nitrogen and phosphorus) from the Upper Midwest flowing into the Mississippi River to the Gulf. These nutrients trigger excessive algal growth (or eutrophication) resulting in reduced sunlight, loss of aquatic habitat, and a decrease in oxygen dissolved in the water. Hypoxia threatens commercial and recreational fisheries in the Gulf because fish and other aquatic species cannot live in the low oxygen waters.

In 2008, the hypoxic zone was the second largest since measurements began in 1985—8,000 square miles, an area larger than the state of Massachusetts, and slightly larger than the 2007 measurement.[522] The Mississippi River/Gulf of Mexico Watershed Nutrient Task Force's "Gulf Hypoxia Action Plan 2008" calls for a 45% reduction in both nitrogen and phosphorus reaching the Gulf to reduce the size of the zone.[523] An additional reduction in nitrogen and phosphorus reduction would be necessary as a result of increased corn production for ethanol and climate change impacts.

Alexander, et al.[524] modeled the sources of nutrient loadings to the Gulf of Mexico using the USGS SPARROW model. They estimated that agricultural sources contribute more than 70% of the delivered nitrogen and phosphorus. Corn and soybean production accounted for 52% of nitrogen delivery and 25% of the phosphorus.

Several recent scientific reports have estimated the impact of increasing corn acres for ethanol in the Gulf of Mexico watershed. Donner and Kucharik's[525] study showed increases in nitrogen export to the Gulf as a result of increasing corn ethanol production from 2007 levels to 15 billion gallons in 2022. They concluded that the expansion of corn-based ethanol production could make it almost impossible to meet the Gulf of Mexico nitrogen reduction goals without a "radical shift" in feed production, livestock diet, and management of agricultural lands. The study estimated a mean dissolved inorganic nitrogen load increase of 10 to 18% from 2007 to 2022 to meet the 15 billion gallon corn ethanol goal. EPA's Science Advisory Board report to the Mississippi River/Gulf of Mexico Watershed Task Force estimated that corn grown for ethanol will result in an additional national annual loading of almost 300 million pounds of nitrogen. An estimated 80% of that nitrogen loading or 238 million pounds will occur in the Mississippi-Atchafalaya River basin and contribute nitrogen to the hypoxia in the Gulf of Mexico.[526]

B. Upper Mississippi River Basin Analysis

To provide a quantitative estimate of the impact of this proposal and production of corn ethanol generally on water quality, EPA conducted an analysis that modeled the changes in loadings of nitrogen, phosphorus, and sediment from agricultural production in the Upper Mississippi River Basin (UMRB). The UMRB drains approximately 189,000 square miles, including large parts of the states of Illinois, Iowa, Minnesota, Missouri, and Wisconsin. Small portions of Indiana, Michigan, and South Dakota are also within the basin. EPA selected the UMRB because it is representative of the many potential issues associated with ethanol production, including its connection to major water quality

[522] Louisiana Universities Marine Consortium, 2008, 'Dead zone' again rivals record size, available online at: *http://www.gulfhypoxia.net/research/shelfwidecruises/2008/PressRelease08.pdf.*

[523] Mississippi River/Gulf of Mexico Watershed Nutrient Task Force, 2008, Gulf hypoxia action plan 2008 for reducing, mitigating, and controlling hypoxia in the northern Gulf of Mexico and improving water quality in the Mississippi River basin, 61 p., Washington, DC, available online at: *http://www.epa.gov/msbasin/actionplan.htm.*

[524] Alexander, R.B., Smith, R.A., Schwarz, G.E., Boyer, E.W., Nolan, J.V., and Brakebill, J.W., 2008, Differences in phosphorus and nitrogen delivery to the Gulf of Mexico from the Mississippi River basin, Environmental Science and Technology, v. 42, no. 3, p. 822–830, available online at: *http://pubs.acs.org/cgi-bin/abstract.cgi/esthag/2008/42/i03/abs/es0716103.html.*

[525] Donner, S. D. and Kucharik, C. J., 2008, Corn-based ethanol production compromises goal of reducing nitrogen export by the Mississippi River, PNAS, v. 105, no. 11, p. 4513–4518, available online at: *http://www.pnas.org/content/105/11/4513.full.*

[526] U.S. EPA, supra note 4.

concerns such as Gulf of Mexico hypoxia, large corn production, and numerous ethanol production plants. For more details on the analysis, see Chapter 6 in the DRIA.

On average the UMRB contributes about 39% of the total nitrogen loads and 26% of the total phosphorus loads to the Gulf of Mexico.[527] The high percentage of nitrogen from the UMRB is primarily due to the large inputs of fertilizer for agriculture and the 60% of cropland that is tile drained. Although nitrogen inputs to the UMRB in recent years is fairly level, there is a 21% decline in net inputs from humans. The Science Advisory Board report attributes this decline to higher amount of nitrogen removed during harvest, due to higher crop yields. For the same time period, phosphorus inputs increased 12%.

1. SWAT Model

EPA selected the SWAT (Soil and Water Assessment Tool) model to assess nutrient loads from changes in agricultural production in the UMRB. Models are the primary tool that can be used to predict future impacts based on alternative scenarios. SWAT is a physical process model developed to quantify the impact of land management practices in large, complex watersheds.[528]

2. Baseline Model Scenario

In order to assess alternative potential future conditions within the UMRB, EPA developed a SWAT model of a Baseline Scenario against which to analyze the impact of increased corn production for biofuel. For simplicity's sake, we refer to the baseline as 2005, but like most water quality modeling, we had to use a range of data sets for the inputs. As noted above corn acres did not increase significantly until the 2007 crop year. While this baseline does not directly quantify the impacts of this proposal on water quality, it is useful in understanding the magnitude of the impacts of corn production for biofuels. EPA plans to conduct additional analyses for the final rule that will compare the reference case biofuel volumes to the RFS2 volumes.

The SWAT model was applied (i.e., calibrated) to the UMRB using 1960 to 2001 weather data and flow and water quality data from 13 USGS gages on the mainstem of the Mississippi River. The 42-year SWAT model runs were performed and the results analyzed to establish runoff, sediment, nitrogen, and phosphorous loadings from each of the 131 8-digit HUC subwatersheds and the larger 4-digit subbasins, along with the total outflow from the UMRB and at the various USGS gage sites along the Mississippi River. These results provided the Baseline Scenario model values to which the future alternatives are compared.

3. Alternative Scenarios

SWAT scenario analyses were performed for the years 2010, 2015, 2020, and 2022 with corn ethanol volumes of 12 billion gallons a year (BGY) for 2010, and 15 BGY for 2015 to 2022. These volumes were adjusted for the UMRB based on a 42.3% ratio of ethanol production capacity within the UMRB compared to national capacity. The resulting UMRB ethanol production goals were converted into the corresponding required corn production acreage, i.e. the extent of corn acreage needed to meet those ethanol production goals. Annual increases in corn yield of 1.23% were built into the future scenarios. Fewer corn acres were needed to meet ethanol production goals after the 2015 scenario due to those yield increases.

Table X.B.3–1 and Table X.B.3–2 summarize the model outputs both within the UMRB and at the outlet of the UMRB in the Mississippi River at Grafton, Illinois for each of the four scenario years: 2010, 2015, 2020, and 2022. It is important to note that these results only estimate loadings from the Upper Mississippi River basin, not the entire Mississippi River watershed. As noted earlier, the UMRB contributes about 39% of the total nitrogen loads and 26% of total phosphorus loads to the Gulf of Mexico. Due to the timing of this proposal, we were not able to assess the local impact in smaller watersheds within the UMRB. Those impacts may be significantly different. The decreasing nitrogen load over time is likely attributed to the increased corn yield production, resulting in greater plant uptake of nitrogen.

TABLE X.B.3–1—CHANGES IN NUTRIENT LOADINGS WITHIN THE UPPER MISSISSIPPI RIVER BASIN FROM THE 2005 BASELINE SCENARIO

	2005 Baseline	2010	2015	2020	2022
Nitrogen	1897.0 million lbs	+5.1%	+4.2%	+2.2%	+1.6%
Phosphorus	176.6 million lbs	+2.3%	+1.1%	+0.6%	+0.4%

About 24% of nitrogen and 25% of phosphorus leaving agricultural fields was assimilated (taken by aquatic plants or volatilized) before reaching the outlet of the UMRB. The assimilated nitrogen is not necessarily eliminated as an environmental concern. Five percent or more of the nitrogen can be converted to nitrous gas, a powerful greenhouse gas that has 300 times the climate-warming potential of carbon dioxide, the major greenhouse. Thus, a water pollutant becomes an air pollutant until it is either captured through biological sequestration or converted fully to elemental nitrogen.

Total sediment outflow showed very little change over all scenarios. This is likely due to the corn being modeled as well-managed crop in terms of sediment loss, primarily due to the corn stover remaining on the fields following harvest.

TABLE X.B.3–2—CHANGES FROM THE 2005 BASELINE TO THE MISSISSIPPI RIVER AT GRAFTON, ILLINOIS FROM THE UPPER MISSISSIPPI RIVER BASIN

	2005 Baseline	2010	2015	2020	2022
Average corn yield (bushels/acre)	141	150	158	168	171

[527] Mississippi River/Gulf of Mexico Watershed Nutrient Task Force, supra note 6.

[528] Gassman, P.W., Reyes, M.R., Green, C.H., Arnold, J.G., 2007, The soil and water assessment tool: Historical development, applications, and future research directions. Transactions of the American Society of Agricultural and Biological Engineers, v. 50, no. 4, p. 1211–1240. *http://www.card.iastate.edu/environment/items/asabe_swat.pdf.*

TABLE X.B.3–2—CHANGES FROM THE 2005 BASELINE TO THE MISSISSIPPI RIVER AT GRAFTON, ILLINOIS FROM THE UPPER MISSISSIPPI RIVER BASIN—Continued

	2005 Baseline	2010	2015	2020	2022
Nitrogen	1,433.5 million lbs	+5.5%	+4.7%	+2.5%	+1.8%
Phosphorus	132.4 million lbs	+2.8%	+1.7%	+0.98%	+0.8%
Sediment	6.4 million tons	+0.5%	+0.3%	+0.2%	+0.1%

After evaluating comments on this proposal, if time and resources permit, EPA may conduct additional water quality analyses using the SWAT model in the UMRB. Potential future analyses could include: (1) Determination of the most sensitive assumptions in the model, (2) water quality impacts from the changes in ethanol volumes between the reference case and this proposal, (3) removing corn stover for cellulosic ethanol, and (4) a case study of a smaller watershed to evaluate local water quality impacts that are impossible to ascertain at the scale of the UMRB.

EPA solicits comments on the scenarios developed for this proposal and additional future analyses. At this time, we are not able to assess the impact of these additional loadings on the size of the Gulf of Mexico hypoxia zone or water quality within the UMRB. EPA also solicits comments on the significance of the modeled increases in nitrogen and phosphorus loads.

C. Additional Water Issues

Water quality and quantity impacts resulting from corn ethanol production go beyond our ability to model. The following issues are summarized to provide additional context about the broader range of potential impacts. *See* Chapter 6 in the DRIA for more discussion of these issues.

1. Chesapeake Bay Watershed

Agricultural lands contribute more nutrients to the Chesapeake Bay than any other land use. Chesapeake Bay Program partners have pledged to significantly reduce nutrients to the Bay to meet water quality goals. To estimate the increase in nutrient loads to the Bay from changes to agricultural crop production from 2005 to 2008, the Chesapeake Bay Program Watershed Model Phase 4.3 and Vortex models were utilized. Total nitrogen loads increased by almost 2.4 million pounds from an increase of almost 66,000 corn acres. As agriculture land use shifts from hay and pasture to more intensively fertilized row crops, this analysis estimates that nitrogen loads increase by 8.8 million pounds.

2. Ethanol Production

There are three principal sources of discharges to water from ethanol plants: Reject water from water purification, cooling water blowdown, and off-batch ethanol. Most ethanol facilities use on-site wells to produce the process water for the ethanol process. Groundwater sources are generally not suitable for process water because of their mineral content. Therefore, the water must be treated, commonly by reverse osmosis. For every two gallons of pure water produced, about a gallon of brine is discharged as reject water from this process. Most estimates of water consumption in ethanol production are based on the use of clean process water and neglect the water discharged as reject water.

The largest source of wastewater discharge is reverse osmosis reject water from process water purification. The reverse osmosis process concentrates groundwater minerals to levels where they can have water quality impacts. There is really no means of ''treating'' these ions to reduce toxicity, other than further concentration and disposal, or use of instream dilution. Some facilities have had to construct long pipelines to get access to dilution so they can meet water quality standards. Ethanol plants also discharge cooling water blowdown, where some water is discharged to avoid the buildup of minerals in the cooling system. These brines are similar to the reject water described above. In addition, if off-batch ethanol product or process water is discharged, the waste stream can have high Biochemical Oxygen Demand (BOD) levels. BOD directly affects the amount of dissolved oxygen in rivers and streams. The greater the BOD, the more rapidly oxygen is depleted in the stream. The consequences of high BOD are the same as those for low dissolved oxygen: Aquatic organisms become stressed, suffocate, and die.

Older generation production facilities used four to six gallons of process water to produce a gallon of ethanol, but newer facilities use less than three gallons of water in the production process. Most of this water savings is gained through improved recycling of water and heat in the process. Water supply is a local issue, and there have been concerns with water consumption as new plants go online. Some facilities are tapping into deeper aquifers as a source of water. These deeper water resources tend to contain higher levels of minerals and this can further increase the concentration of minerals in reverse osmosis reject water. Geographic impacts of water use vary. A typical plant producing 50 million gallons of ethanol per year uses a minimum of 175 million gallons of water annually. In Iowa, water consumption from ethanol refining accounts for about seven percent of all industrial water use, and is projected to be 14% by 2012—or about 50 million gallons per day.

a. Distillers Grain with Solubles

Distillers grain with solubles (DGS) is an important co-product of ethanol production. About one-third of the corn processed into ethanol is converted into DGS. DGS has become an increasingly important feed component for confined livestock. DGS are higher in crude protein (nitrogen) and three to four times higher in phosphorus relative to traditional feeds. When nitrogen and phosphorus are fed in excess of the animal's needs, these nutrients are excreted in the manure. When manure is applied to crops at rates above their nutrient needs or at times the crop can not use the nutrients, the nutrients can runoff to surface waters or leach into ground waters.

Livestock producers can limit the potential pollution from manure applications to crops by implementing comprehensive nutrient management. Due to the substantially higher phosphorus content of manure from livestock fed DGS, producers will potentially need significantly more acres to apply the manure so that phosphorus will not be applied at rates above the needs of the crops. This is a particularly important concern in areas where concentrated livestock production already produces more phosphorus in the manure than can be taken up by crops or pasture land in the vicinity.

Several recent studies have indicated that DGS may have an impact on food safety. Cattle fed DGS have a higher prevalence of a major food-borne pathogen, E. coli O157, than cattle without DGS in their diets.[529] More research is needed to confirm these studies and devise methods to eliminate the potential risks.

b. Ethanol Leaks and Spills

The potential for exposure to fuel components and/or additives can occur when underground fuel storage tanks leak fuel into ground water that is used for drinking water supplies or when spills occur that contaminate surface drinking water supplies. Ethanol biodegrades quickly and is not necessarily the pollutant of greatest concern in these occurrences. Instead, ethanol's high biodegradability can cause the plume of BTEX (benzene, toluene, ethylbenzene and xylenes) compounds in fuel to extend farther (by as much as 70%)[530] and persist longer in ground water, thereby increasing potential exposures to these compounds.

With the increasing use of ethanol in the fuel supply nationwide, it is important to understand the impact of ethanol on the existing tank infrastructure. Given the corrosivity of ethanol, there is concern regarding the increased potential for leaks from existing gas stations and subsequent impacts on drinking water supplies. In 2007, there were 7,500 reported releases from underground storage tanks. Therefore, EPA is undertaking analyses designed to assess the potential impacts of ethanol blends on tank infrastructure and leak detection systems and determine the resulting water quality impacts.

3. Biodiesel Plants

Biodiesel plants use much less water than ethanol plants. Water is used for washing impurities from the finished product. Water use is variable, but is usually less than one gallon of water for each gallon of biodiesel produced. Larger well-designed plants use water more sparingly, while smaller producers use more water. Some facilities recycle washwater, which reduces water consumption. The strength of process wastewater from biodiesel plants is highly variable. Most production processes produce washwater that has very high BOD levels. The high strength of these wastes can overload and disrupt municipal treatment plants.

Crude glycerin is an important side product from the biodiesel process and is about 10% of the final product. The rapid development of the biodiesel industry has caused a glut of glycerin production and many facilities dispose of glycerin. Poor handling of crude glycerin has resulted in upset of sewage treatment plants and fish kills.

4. Water Quantity

Water demand for crop production for ethanol could potentially be much larger than biorefinery demand. According to the National Research Council, the demand for water to irrigate crops for biofuels will not have an impact on national water use, but it is likely to have significant local and regional impacts.[531] The impact is crop and region specific, but could be especially great in areas where new acres are irrigated.

5. Drinking Water

Increased corn production for ethanol may increase the occurrence of nitrate, nitrite, and the herbicide atrazine in sources of drinking water. Under the Safe Drinking Water Act, EPA has established enforceable standards for these contaminants to protect public health. Increases in occurrence of these contaminants may raise costs to public water systems through increased treatment needs or increased pumping costs where ethanol production is accelerating the long running depletion of aquifers. There is also a risk of decreased supplies of drinking water in communities where aquifers are being depleted and potential contamination due to leaks from gasoline stations using higher blends of ethanol.

D. Request for Comment on Options for Reducing Water Quality Impacts

EPA is seeking comment on how best to reduce the impacts of biofuels on water quality. EPA is seeking comment on the use of section 211(c) of the Clean Air Act, as amended by EISA, to address these water quality issues. Section 211(c) gives the EPA administrator the discretion to ''control'' the manufacture and sale of a motor vehicle transportation fuel based on a finding that the fuel, or its emission product, ''causes or contributes'' to air pollution or water pollution that may reasonably be anticipated to endanger the public health or welfare.

In evaluating this option, EPA is seeking comment on whether it would be appropriate to find that emission products from such transportation fuels, including renewable fuels, are ''causing or contributing'' to ''water pollution'' and that this water pollution ''may reasonably be anticipated to endanger the public health or welfare.'' EPA is also seeking comment on whether it would be allowable and appropriate to ''control or prohibit the manufacture * * * '' of a fuel by requiring that manufacturers of such fuels, such as manufacturers of a biofuel, use, or certify that they used, only corn feedstocks grown using farming practices designed to reduce nutrient water pollution. For example, is this a reasonable way to ''offset'' water pollution caused, in part, by air deposition of nitrogen to water from combustion of transportation fuels with reductions of nitrogen runoff to water from corn feedstock by means of such ''controls'' on the manufacture of biofuels adopted pursuant to section 211(c). In the alternative, would this be a reasonable way to attempt to offset water pollution caused by the production of the feedstock associated with the production of the biofuel based on section 211(c).

EPA is seeking comment and suggestions on how biofuel manufacturers might establish that their biofuel feedstock was grown with appropriate practices to control nutrient runoff (e.g., require a program similar to the one used for compliance with the restrictions in the definition of renewable biomass on previously cleared agricultural land). Finally, EPA is seeking comments on other approaches, mechanisms, or authorities that might be adopted in the renewable fuels rule that are likely to have the effect of reducing the water quality impacts of biofuels.

XI. Public Participation

We request comment on all aspects of this proposal. This section describes how you can participate in this process.

A. How Do I Submit Comments?

We are opening a formal comment period by publishing this document. We will accept comments during the period indicated under **DATES** in the first part of this proposal. If you have an interest in the proposed program described in this document, we encourage you to comment on any aspect of this rulemaking. We also request comment on specific topics identified throughout this proposal.

Your comments will be most useful if you include appropriate and detailed

[529] Jacob, M. D., Fox, J. T., Drouillard, J. S., Renter, D. G., Nagaraja, T. G., 2008, Effects of dried distillers' grain on fecal prevalence and growth of *Escherichia coli* O157 in batch culture fermentations from cattle, Applied and Environmental Microbiology, v. 74, no. 1, p. 38–43, available online at: *http://aem.asm.org/cgi/content/abstract/74/1/38*

[530] Ruiz-Aguilar, G. M. L.; O'Reilly, K.; Alvarez, P. J. J., 2003, Forum: A comparison of benzene and toluene plume lengths for sites contaminated with regular vs. ethanol-amended gasoline, Ground Water Monitoring and Remediation, v. 23, p. 48–53.

[531] Committee on Water Implications of Biofuels Production in the United States, supra note 2.

supporting rationale, data, and analysis. Commenters are especially encouraged to provide specific suggestions for any changes to any aspect of the regulations that they believe need to be modified or improved. You should send all comments, except those containing proprietary information, to our Air Docket (*see* **ADDRESSES** in the first part of this proposal) before the end of the comment period.

You may submit comments electronically, by mail, or through hand delivery/courier. To ensure proper receipt by EPA, identify the appropriate docket identification number in the subject line on the first page of your comment. Please ensure that your comments are submitted within the specified comment period. Comments received after the close of the comment period will be marked ''late.'' EPA is not required to consider these late comments. If you wish to submit Confidential Business Information (CBI) or information that is otherwise protected by statute, please follow the instructions in Section XI.B.

B. How Should I Submit CBI to the Agency?

Do not submit information that you consider to be CBI electronically through the electronic public docket, www.regulations.gov, or by e-mail. Send or deliver information identified as CBI only to the following address: U.S. Environmental Protection Agency, Assessment and Standards Division, 2000 Traverwood Drive, Ann Arbor, MI, 48105, Attention Docket ID EPA–HQ–OAR–2005–0161. You may claim information that you submit to EPA as CBI by marking any part or all of that information as CBI (if you submit CBI on disk or CD–ROM, 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 CBI). Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

In addition to one complete version of the comments that include any information claimed as CBI, a copy of the comments that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. If you submit the copy that does not contain CBI on disk orCD–ROM, mark the outside of the disk or CD–ROM clearly that it does not contain CBI. Information not marked as CBI will be included in the public docket without prior notice. If you have any questions about CBI or the procedures for claiming CBI, please consult the person identified in the **FOR FURTHER INFORMATION CONTACT** section.

C. Will There Be a Public Hearing?

We will hold a public hearing in Washington DC on June 9, 2009 at the location shown below. The hearing will start at 10 a.m. local time and continue until everyone has had a chance to speak.

The Dupont Hotel, 1500 New Hampshire Avenue, NW., Washington, DC 20036, Phone# 202–483–6000.

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** in the first part of this proposal at least 8 days before the hearing. 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 make a tentative schedule for the order of testimony based on the notifications we receive. This schedule will be available on the morning of the hearing. In addition, we will reserve a block of time for anyone else in the audience who wants to give testimony.

We will conduct the hearing informally, and technical rules of evidence will not apply. We will arrange for a written transcript of the hearing and keep the official record of the hearing open for 30 days to allow you to submit supplementary information. You may make arrangements for copies of the transcript directly with the court reporter.

D. Comment Period

The comment period for this rule will end on July 27, 2009.

E. What Should I Consider as I Prepare My Comments for EPA?

You may find the following suggestions helpful for preparing your comments:

- Explain your views as clearly as possible.
- Describe any assumptions that you used.
- Provide any technical information and/or data you used that support your views.
- If you estimate potential burden or costs, explain how you arrived at your estimate.
- Provide specific examples to illustrate your concerns.
- Offer alternatives.
- Make sure to submit your comments by the comment period deadline identified.
- To ensure proper receipt by EPA, identify the appropriate docket identification number in the subject line on the first page of your response. It would also be helpful if you provided the name, date, and **Federal Register** citation related to your comments.

XII. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under section 3(f)(1) of Executive Order (EO) 12866 (58 FR 51735, October 4, 1993), this action is an ''economically significant regulatory action'' because it is likely to have an annual effect on the economy of $100 million or more. 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.

In addition, EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis is contained in the Draft Regulatory Impact Analysis, which is available in the docket for this rulemaking and at the docket internet address listed under **ADDRESSES** in the first part of this proposal. A more complete assessment of the costs and benefits associated with this Action will be completed for the Final Rule.

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 Act, 44 U.S.C. 3501 *et seq.* The Information Collection Request (ICR) document prepared by EPA has been assigned EPA ICR number 2333.01. A draft Supporting Statement has been placed in the docket for public comment.

The Agency proposes to collect information to ensure compliance with the provisions in this rule. This includes a variety of requirements for transportation fuel refiners, blenders, marketers, distributors, importers, and exporters. The types of information proposed to be collected includes, but is not limited to: registrations, periodic compliance reports, product transfer documentation, transactional information involving RINs and associated volumes of renewable fuel, and attest engagements. We invite comment on the proposed collection of information associated with this proposed rule.

Section 208(a) of the Clean Air Act requires that fuel producers 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.

As shown in Table XII.B–1, the total annual burden associated with this proposal is about 323,922 hours and $27,073,827, based on a projection of 20,216 respondents. The estimated burden for fuel producers is a total estimate for both new and existing reporting requirements. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

TABLE XII.B–1—ESTIMATED BURDEN FOR REPORTING AND RECORDKEEPING REQUIREMENTS

Industry sector	Number of respondents	Annual burden hours	Annual costs ($)
Fuels:			
Producers of renewable fuels	5,472	112,461	8,893,531
Importers of renewable fuels[a]	1,131	22,503	1,824,913
Obligated parties, exporters[b]	1,410	36,796	2,868,116
RIN owners[c]	12,083	148,542	13,102,447
Foreign refiners[d]	65	3,460	364,940
Foreign RIN owners	30	135	18,105
Retail stations (pump label)	25	25	1,775
Total	20,216	323,922	27,073,827

[a] Includes foreign producers.
[b] Refiners, exporters fall under this category.
[c] Includes blenders, brokers, marketers, etc. Anyone can own RINs.
[d] Includes small foreign refiners.

In addition to the estimates shown above, we have separately estimated the costs of potential third party disclosure that is associated with the proposed registration requirements explained in this notice of proposed rulemaking. Potentially affected parties include farmers, private forest owners, and other biofuel feedstock producers. We estimate a total of 43,466 respondents, 83,633 annual burden hours, and $5,937,943 in annual burden cost associated with the proposed third party disclosure. These estimates are explained in an addendum to the draft Supporting Statement, which has also been placed in the public docket.

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 proposed ICR, under Docket ID number EPA–HQ–OAR–2005–0161. Submit any comments related to the ICR for this proposed rule to EPA and OMB. See **ADDRESSES** 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 May 26, 2009, a comment to OMB is best assured of having its full effect if OMB receives it by June 25, 2009. 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[a]	Defined as small entity by SBA if:	NAICS[a] codes
Gasoline and diesel fuel refiners	≤1,500 employees	324110

[a] North American Industrial Classification System.

2. Background

Section 1501 of the Energy Policy Act of 2005 (EPAct) amended section 211 of the Clean Air Act (CAA) by adding section 211(o) which required the Environmental Protection Agency (EPA) to promulgate regulations implementing a renewable fuel program. EPAct specified that the regulations must ensure a specific volume of renewable fuel to be used in gasoline sold in the U.S. each year, with the total volume increasing over time. The goal of the program was to reduce dependence on foreign sources of petroleum, increase domestic sources of energy, and help transition to alternatives to petroleum in the transportation sector.

The final Renewable Fuels Standard (RFS1) program rule was published on May 1, 2007, and the program began on September 1, 2007. Per EPAct, the RFS1 program created a specific annual level for minimum renewable fuel use that increases over time—resulting in a requirement that 7.5 billion gallons of renewable fuel be blended into gasoline (for highway use only) by 2012. Under the RFS1 program, compliance is based on meeting the required annual renewable fuel volume percent standard (published annually in the **Federal Register** by EPA) through the use of Renewable Identification Numbers, or RINs, 38-digit serial numbers assigned to each batch of renewable fuel produced. For obligated parties (those who must meet the annual volume percent standard), RINs must be acquired to show compliance.

The Energy Independence and Security Act of 2007 (EISA) amended section 211(o), and the RFS program, by requiring higher volumes of renewable fuels, to result in 36 billion gallons of renewable fuel by 2022. EISA also expanded the purview of the RFS1 program by requiring that these renewable fuels be blended into gasoline and diesel fuel (both highway and nonroad). This expanded the pool of regulated entities, so the obligated parties under this RFS2 NPRM will now include certain refiners, importers, and blenders of these fuels that were not previously covered by the RFS1 program. In addition to the total renewable fuel standard required by EPAct, EISA added standards for three additional types of renewable fuels to the program (advanced biofuel, cellulosic biofuel, and biomass-based diesel) and requires compliance with all four standards.

Pursuant to section 603 of the RFA, EPA prepared an initial regulatory flexibility analysis (IRFA) that examines the impact of the proposed rule on small entities along with regulatory alternatives that could reduce that impact. The IRFA is available for review in the docket (in Chapter 7 of the Draft Regulatory Impact Analysis) and is summarized below.

As required by section 609(b) of the RFA, as amended by SBREFA, EPA also conducted outreach to small entities and convened a Small Business Advocacy Review Panel to obtain advice and recommendations of representatives of the small entities that potentially would be subject to the rule's requirements.

Consistent with the RFA/SBREFA requirements, the Panel evaluated the assembled materials and small-entity comments on issues related to elements of the IRFA. A copy of the Panel Report is included in the docket for this proposed rule, and a summary of the Panel process, and subsequent Panel recommendations, is summarized below.

3. Summary of Potentially Affected Small Entities

The small entities that will potentially be subject to the renewable fuel standard include: Domestic refiners that produce gasoline and/or diesel and importers of gasoline and/or diesel into the United States. Based on 2007 data, EPA believes that there are about 95 refiners of gasoline and diesel fuel. Of these, EPA believes that there are currently 21 refiners producing gasoline and/or diesel fuel that meet the SBA small entity definition of having 1,500 employees or less. Further, we believe that three of these refiners own refineries that do not meet the Congressional ''small refinery'' definition.[532] It should be noted that because of the dynamics in the refining industry (i.e., mergers and acquisitions), the actual number of refiners that ultimately qualify for small refiner status under the RFS2 program could be different than this initial estimate.

4. Potential Reporting, Recordkeeping, and Compliance

For any fuel control program, EPA must have assurance that any fuel produced meets all applicable standards and requirements, and that the fuel continues to meet those standards and requirements as it passes downstream through the distribution system to the ultimate end user. Registration, reporting, and recordkeeping are necessary to track compliance with the RFS2 requirements and transactions involving RINs. As discussed above in Sections III.J and IV.E, the proposed compliance requirements under the RFS2 program are in many ways similar to those required under the RFS1 program, with some modifications to account for the new requirements of EISA.

5. Related Federal Rules

We are aware of a few other current or proposed Federal rules that are related to the upcoming proposed rule. The primary federal rules that are related to the proposed RFS2 rule under consideration are the first Renewable Fuel Standard (RFS1) rule (72 FR 23900, May 1, 2007) and the RFS1 Technical Amendment Direct Final Rulemaking (73 FR 57248, October 2, 2008).[533]

6. Summary of SBREFA Panel Process and Panel Outreach

a. Significant Panel Findings

The Small Business Advocacy Review Panel (SBAR Panel, or the Panel) considered regulatory options and flexibilities to help mitigate potential adverse effects on small businesses as a result of this rule. During the SBREFA Panel process, the Panel sought out and received comments on the regulatory options and flexibilities that were presented to SERs and Panel members. The recommendations of the Panel are described below and are also located in Section 9 of the SBREFA Final Panel Report, which is available in the public docket.

b. Panel Process

As required by section 609(b) of the RFA, as amended by SBREFA, we also conducted outreach to small entities and convened an SBAR Panel to obtain advice and recommendations of representatives of the small entities that potentially would be subject to the rule's requirements. On July 9, 2008, EPA's Small Business Advocacy Chairperson convened a Panel under Section 609(b) of the RFA. In addition to the Chair, the Panel consisted of the Division Director of the Assessment and Standards Division of EPA's Office of Transportation and Air Quality, the Chief Counsel for Advocacy of the Small Business Administration, and the

[532] EPAct defined a ''small refinery'' as a refinery with a crude throughput of no more than 75,000 barrels of crude per day (at CAA section 211(o)(1)(K)). This definition is based on facility size and is different than SBA's small refiner definition (which is based on company size). A small refinery could be owned by a larger refiner that exceeds SBA's small entity standards. SBA's size standards were established to set apart those businesses which are most likely to be at an inherent economic disadvantage relative to larger businesses.

[533] This Direct Final Rule corrects minor typographical errors and provides clarification on existing provisions in the RFS1 regulations.

Administrator of the Office of Information and Regulatory Affairs within the Office of Management and Budget. As part of the SBAR Panel process, we conducted outreach with representatives from representatives of small businesses that would potentially be affected by the proposed rulemaking. We met with these Small Entity Representatives (SERs) to discuss the potential rulemaking approaches and potential options to decrease the impact of the rulemaking on their industries. We distributed outreach materials to the SERs; these materials included background on the rulemaking, possible regulatory approaches, and possible rulemaking alternatives. The Panel met with SERs from the industries that would be directly affected by the RFS2 rule on July 30, 2008 to discuss the outreach materials and receive feedback on the approaches and alternatives detailed in the outreach packet (the Panel also met with SERs on June 3, 2008 for an initial outreach meeting). The Panel received written comments from the SERs following the meeting in response to discussions had at the meeting and the questions posed to the SERs by the Agency. The SERs were specifically asked to provide comment on regulatory alternatives that could help to minimize the rule's impact on small businesses.

In general, SERs stated that they believed that small refiners would face challenges in meeting the new standards. More specifically, they voiced concerns with respect to the RIN program itself, uncertainty (with the required renewable fuel volumes, RIN availability, and cost), and the desire for a RIN system review.

The Panel's findings and discussions were based on the information that was available during the term of the Panel and issues that were raised by the SERs during the outreach meetings and in their comments. One concern that was raised by EPA with regard to provisions for small refiners in the RFS2 rule is that this rule presents a very different issue than the small refinery versus small refiner concept from RFS1. This issue deals with whether EPA has the authority to provide small refineries that are operated by a small refiner with an extension of time that would be different from (and more than) the temporary exemption specified by Congress in section 211(o)(9) for small refineries. For those small refiners who are covered by the small refinery provisions, Congress has specifically adopted a relief provision aimed at their refineries. This provides a temporary extension through December 31, 2010 and allows for further extensions only if certain criteria are met. EPA believes that providing small refineries (and thus, small refiners who own small refineries) with an additional exemption different from that provided by section 211(o)(9) raises concerns about inconsistency with the intent of Congress. Congress spoke directly to the relief that EPA may provide for small refineries, including those small refineries operated by small refiners, and limited it to a blanket exemption through December 31, 2010, with additional extensions if the criteria specified by Congress were met. An additional or different extension, relying on a more general provision in section 211(o)(3), would raise questions about consistency with the intent of Congress.

It was agreed that EPA should consider the issues raised by the SERs and discussions had by the Panel itself, and that EPA should consider comments on flexibility alternatives that would help to mitigate negative impacts on small businesses to the extent legally allowable by the Clean Air Act. Alternatives discussed throughout the Panel process included those offered in previous or current EPA rulemakings, as well as alternatives suggested by SERs and Panel members. A summary of these recommendations is detailed below, and a full discussion of the regulatory alternatives and hardship provisions discussed and recommended by the Panel can be found in the SBREFA Final Panel Report. A complete discussion of the provisions for which we are requesting comment and/or proposing in this action can be found in Section IV.B of this preamble. Also, the Panel Report includes all comments received from SERs (Appendix B of the Report) and summaries of the two outreach meetings that were held with the SERs. In accordance with the RFA/SBREFA requirements, the Panel evaluated the aforementioned materials and SER comments on issues related to the IRFA. The Panel's recommendations from the Final Panel Report are discussed below.

c. Panel Recommendations

The purpose of the Panel process is to solicit information as well as suggested flexibility options from the SERs, and the Panel recommended that EPA continue to do so during the development of the RFS2 rule. Recognizing the concerns about EPA's authority to provide extensions to a subset of small refineries (i.e., those that are owned by small refiners) different from that provided to small refineries in section 211(o)(9), the Panel recommended that EPA continue to evaluate this issue, and that EPA request comment on its authority and the appropriateness of providing extensions beyond those authorized by section 211(o)(9) for small refineries operated by a small refiner. The Panel also recommended that EPA propose to provide the same extension provision of 211(o)(9) to small refiners who do not own small refineries as is provided for small refiners who do own small refineries.

i. Delay in Standards

The RFS1 program regulations provide small refiners who operate small refineries as well as small refiners who do not operate small refineries with a temporary exemption from the standard through December 31, 2010. Small refiner SERs suggested that an additional temporary exemption for the RFS2 program would be beneficial to them in meeting the standards. EPA evaluated a temporary exemption for at least some of the four required RFS2 standards for small refiners. The Panel recommended that EPA propose a delay in the effective date of the standards until 2014 for small entities, to the maximum extent allowed by the statute. However, the Panel recognized that EPA has serious concerns about its authority to provide an extension of the temporary exemption for small refineries that is different from that provided in CAA section 211(o)(9), since Congress specifically addressed an extension for small refineries in that provision.

The Panel did recommend that EPA propose other avenues through which small refineries and small refiners could receive extensions of the temporary exemption. These avenues, as discussed in greater detail in Sections XII.C.6.c.v and vi below, are a possible extension of the temporary exemption for an additional two years following a study of small refineries by the Department of Energy (DOE) and provisions for case-by-case economic hardship relief.

ii. Phase-in

Small refiner SERs' suggested that a phase-in of the obligations applicable to small refiners would be beneficial for compliance, such that small refiners would comply by gradually meeting the standards on an incremental basis over a period of time, after which point they would comply fully with the RFS2 standards, EPA has serious concerns about its authority to allow for such a phase-in of the standards. CAA section 211(o)(3)(B) states that the renewable fuel obligation shall ''consist of a single applicable percentage that applies to all categories of persons specified'' as obligated parties. This kind of phase-in approach would result in different applicable percentages being applied to different obligated parties. Further, as discussed above, such a phase-in approach would provide more relief to small refineries operated by small refiners than that provided under the small refinery provision. Thus the Panel recommended that EPA should invite comment on a phase-in, but not propose such a provision.

iii. RIN-Related Flexibilities

The small refiner SERs requested that the proposed rule contain provisions for small refiners related to the RIN system, such as flexibilities in the RIN rollover cap percentage and allowing all small refiners to use RINs interchangeably. Currently in the RFS1 program, EPA allows for 20% of a previous year's RINs to be ''rolled over'' and used for compliance in the following year. A provision to allow for flexibilities in the rollover cap could include a higher RIN rollover cap for small refiners for some period of time or for at least some of the four standards. Since the concept of a rollover cap was not mandated by section 211(o), EPA believes that there may be an opportunity to provide appropriate flexibility in this area to small refiners under the RFS2 program but only if it is determined in the DOE small refinery study that there is a disproportionate effect warranting relief. The Panel recommended that EPA request comment on increasing the RIN rollover cap percentage for small refiners, and further that EPA should request comment on an appropriate level of that percentage.

The Panel recommended that EPA invite comment on allowing RINs to be used interchangeably for small refiners, but not propose this concept because under this approach small refiners would arguably be subject to a different applicable percentage than other obligated parties. This concept would also fail to require the four different standards mandated by Congress (e.g., conventional biofuel could not be used instead of cellulosic biofuel or biomass-based diesel).

iv. Program Review

With regard to the suggested program review, EPA raised the concern that this could lead to some redundancy since EPA is required to publish a notice of the applicable RFS standards in the Federal Register annually, and that this annual process will inevitably include an evaluation of the projected availability of renewable fuels. Nevertheless, the SBA and OMB Panel members stated that they believe that a program review could be helpful to small entities in providing them some insight to the RFS program's progress and alleviate some uncertainty regarding the RIN system. As EPA will be publishing a **Federal Register** notice annually, the Panel recommended that EPA include an update of RIN system progress (e.g., RIN trading, RIN availability, etc.) in this notice and that the results of this evaluation be considered in any request for case-by-case hardship relief.

v. Extensions of the Temporary Exemption Based on a Study of Small Refinery Impacts

The Panel recommended that EPA propose in the RFS2 program the provision at 40 CFR 80.1141(e) extending the RFS1 temporary exemption for at least two years for any small refinery that DOE determines would be subject to disproportionate economic hardship if required to comply with the RFS2 requirements.

Section 211(o)(9)(A)(ii) required that by December 31, 2008, DOE was to perform a study of the economic impacts of the RFS requirements on small refineries to assess and determine whether the RFS requirements would impose a disproportionate economic hardship on small refineries, and submit this study to EPA. Section 211(o)(9) also provided that small refineries found to be in a disproportionate economic hardship situation would receive an extension of the temporary exemption for at least two years.

The Panel also recommended that EPA work with DOE in the development of the small refinery study, specifically to communicate the comments that SERs raised during the Panel process.

vi. Extensions of the Temporary Exemption Based on Disproportionate Economic Hardship

While SERs did not specifically comment on the concept of hardship provisions for the upcoming proposal, the Panel noted that under CAA section 211(o)(9)(B) small refineries may petition EPA for case-by-case extensions of the small refinery temporary exemption on the basis of disproportionate economic hardship. Refiners may petition EPA for this case-by-case hardship relief at any time.

The Panel recommended that EPA propose in the RFS2 program a case-by-case hardship provision for small refineries similar to that provided at 40 CFR 80.1141(e)(1). The Panel also recommended that EPA propose a case-by-case hardship provision for small refiners that do not operate small refineries that is comparable to that provided for small refineries under section 211(o)(9)(B), using its discretion under CAA section 211(o)(3)(B). This would apply if EPA does not adopt an automatic extension for small refiners, and would allow those small refiners that do not operate small refineries to apply for the same kind of extension as a small refinery. The Panel recommended that EPA take into consideration the results of the annual update of RIN system progress and the DOE small refinery study in assessing such hardship applications.

We invite comments on all aspects of the proposal and its impacts on small entities.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), P.L. 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.

Today's proposal contains no Federal mandates (under the regulatory provisions of Title II of the UMRA) for

State, local, or tribal governments. The rule imposes no enforceable duty on any State, local or tribal governments. EPA has determined that this rule contains no regulatory requirements that might significantly or uniquely affect small governments. EPA has determined that this proposal contains a Federal mandate that may result in expenditures of $100 million or more for the private sector in any one year. EPA believes that the proposal represents the least costly, most cost-effective approach to achieve the statutory requirements of the rule. The costs and benefits associated with the proposal are discussed above and in the Draft Regulatory Impact Analysis, as required by the UMRA.

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 will be implemented at the Federal level and impose compliance costs only on transportation fuel refiners, blenders, marketers, distributors, importers, and exporters. Tribal governments would 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 Risks and Safety Risks

EPA interprets EO 13045 (62 FR 19885, April 23, 1997) as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the EO has the potential to influence the regulation. This action is not subject to EO 13045 because it does not establish an environmental standard intended to mitigate health or safety risks and because it implements specific standards established by Congress in statutes.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This rule is not a ''significant energy action'' as defined in Executive Order 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'' (66 FR 28355 (May 22, 2001)) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. In fact, this rule has a positive effect on energy supply and use. By promoting the diversification of transportation fuels, this rule enhances energy supply. Therefore, we have concluded that this rule is not likely to have any adverse energy effects. Our energy effects analysis is described above in Section IX.

I. National Technology Transfer Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (''NTTAA''), Public Law No. 104–113, 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This rulemaking proposes changes to the Renewable Fuel Standard (RFS) program at Title 40 of the Code of Federal Regulations, Subpart K which already contains voluntary consensus standard ASTM D6751–06a ''Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels''. This standard was developed by ASTM International (originally known as the American Society for Testing and Materials), Subcommittee D02.E0, and was approved in August 2006. The standard may be obtained through the ASTM Web site (*www.astm.org*) or by calling ASTM at (610) 832–9585.

This proposed rulemaking does not propose to change this voluntary consensus standard, and does not involve any other technical standards. Therefore, EPA is not considering the use of any voluntary consensus standards other than that described above.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States. EPA lacks the discretionary authority to address environmental justice in this proposed rulemaking since the Agency is implementing specific standards established by Congress in statutes. Although EPA lacks authority to modify today's regulatory decision on the basis of environmental justice considerations, EPA nevertheless determined that this proposed rule does not have a disproportionately high and adverse human health or environmental impact on minority or low-income populations.

XIII. Statutory Authority

Statutory authority for this action comes from 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 Clean Air Act, 42 U.S.C. 7414, 7542, and 7601(a).

List of Subjects in 40 CFR Part 80

Environmental protection, Air pollution control, Diesel fuel, Fuel additives, Gasoline, Imports, Incorporation by reference, Labeling, Motor vehicle pollution, Penalties, Reporting and recordkeeping requirements.

Dated: May 5, 2009.

Lisa P. Jackson,

Administrator.

For the reasons set forth in the preamble, 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. A new Subpart M is added to part 80 to read as follows:

Subpart M—Renewable Fuel Standard

Sec.

Subpart M—Renewable Fuel Standard

§ 80.1400 Applicability.

The provisions of this Subpart M shall apply for all renewable fuel produced on or after January 1, 2010, for all RINs generated after January 1, 2010, and for all renewable volume obligations and compliance periods starting with January 1, 2010. Except as provided otherwise in this Subpart M, the provisions of Subpart K of this Part 80 shall not apply for such renewable fuel, RINs, renewable volume obligations, or compliance periods.

§ 80.1401 Definitions.

The definitions of § 80.2 and of this section apply for the purposes of this subpart M. The definitions of this section do not apply to other subparts unless otherwise noted. Note that many terms defined here are common terms that have specific meanings under this subpart M (such as the terms ''co-processed,'' ''cropland,'' and ''yard waste''). The definitions follow:

Actual peak capacity means the maximum annual volume of renewable fuels produced from a specific renewable fuel production facility on an annual basis.

(1) For facilities that commenced construction prior to December 19, 2007 the maximum annual volume is for any year prior to 2008.

(2) For facilities that commenced construction after December 19, 2007, and are fired with natural gas, biomass, or a combination thereof, the maximum annual volume may be for any year after startup over the first three years of operation.

Advanced biofuel means renewable fuel, other than ethanol derived from cornstarch, that qualifies for a D code of 3 pursuant to § 80.1426(d).

Areas at risk of wildfire are areas located within, or within one mile of, forestland, tree plantation, or any other generally undeveloped tract of land that is at least one acre in size with substantial vegetative cover.

Baseline volume means the greater of nameplate capacity or actual peak capacity of a specific renewable fuel production facility.

(1) For facilities that commenced construction on or before December 19, 2007, the actual peak capacity may be for any year prior to 2008.

(2) For facilities that commenced construction after December 19, 2007, and are fired with natural gas, biomass, or a combination thereof, the actual peak capacity may be for any year after startup for the facility over the first three years of operation.

Biomass-based diesel means a renewable fuel which meets the requirements in paragraph (1) or (2) of this definition:

(1) A transportation fuel or fuel additive which is all of the following:

(i) Registered as a motor vehicle fuel or fuel additive under 40 CFR part 79.

(ii) A mono-alkyl ester and meets ASTM D–6751–07, entitled ''Standard Specification for Biodiesel Fuel Blendstock (B100) for Middle Distillate Fuels.'' ASTM D–6751–07 is incorporated by reference. This incorporation by reference was approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR Part 51. A copy may be obtained from the American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, Pennsylvania. A copy may be inspected at the EPA Docket Center, Docket No. EPA–HQ–OAR–2005–0161, EPA/DC, EPA West, Room 3334, 1301

Constitution Ave., NW., Washington, DC, or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 866–272–6272, or go to: *http://www.archives.gov/federal-register/cfr/ibr-locations.html.*

(iii) Intended for use in engines that are designed to run on conventional diesel fuel.

(iv) Qualifies for a D code of 2 pursuant to § 80.1426(d).

(2) A non-ester renewable diesel.

(3) Renewable fuel that is co-processed is not biomass-based diesel.

Carbon Capture and Storage (CCS) is the process of capturing carbon dioxide from an emission source, (typically) converting it to a supercritical state, transporting it to an injection site, and injecting it into deep subsurface rock formations for long-term storage.

Cellulosic biofuel means renewable fuel derived from any cellulose, hemi-cellulose, or lignin that is derived from renewable biomass and that qualifies for a D code of 1 pursuant to § 80.1426(d).

Combined heat and power (CHP), also known as cogeneration, refers to industrial processes in which byproduct heat that would otherwise be released into the environment is used for process heating and/or electricity production.

Commence construction, as applied to facilities that produce renewable fuel, means that the owner or operator has all necessary preconstruction approvals or permits (as defined at 40 CFR 52.21(a)(10)), that for multi-phased projects, the commencement of construction of one phase does not constitute commencement of construction of any later phase, unless each phase is mutually dependent for physical and chemical reasons only, and has satisfied either of the following:

(1) Begun, or caused to begin, a continuous program of actual construction on-site (as defined in 40 CFR 52.21(a)(11)) of the facility to be completed within a reasonable time.

(2) Entered into binding agreements or contractual obligations, which cannot be cancelled or modified without substantial loss to the owner or operator, to undertake a program of actual construction of the facility to be completed within a reasonable time.

Co-processed means that renewable biomass was simultaneously processed with petroleum feedstock in the same unit or units to produce a fuel that is partially renewable.

Crop residue is the residue left over from the harvesting of planted crops.

Cropland is land used for production of crops for harvest and includes cultivated cropland, such as for row crops or close-grown crops, and non-cultivated cropland, such as for horticultural crops.

Diesel refers to any and all of the products specified at § 80.1407(f).

Ecologically sensitive forestland means forestland that is:

(1) An ecological community listed in a document entitled ''Listing of Forest Ecological Communities Pursuant to 40 CFR 80.1401,'' (available in public docket EPA–HQ–OAR–2005–0161); or

(2) Old growth or late successional, characterized by trees at least 200 years in age.

Existing agricultural land is cropland, pastureland, or land enrolled in the Conservation Reserve Program (administered by the U.S. Department of Agriculture's Farm Service Agency) that was cleared or cultivated prior to December 19, 2007, and that, since December 19, 2007, has been continuously:

(1) Nonforested; and

(2) Actively managed as agricultural land or fallow, as evidenced by any of the following:

(i) Records of sales of planted crops, crop residue, or livestock, or records of purchases for land treatments such as fertilizer, weed control, or reseeding.

(ii) A written management plan for agricultural purposes.

(iii) Documented participation in an agricultural management program administered by a Federal, state, or local government agency.

(iv) Documented management in accordance with a certification program for agricultural products.

Export of renewable fuel means:

(1) Transfer of any renewable fuel to a location outside the contiguous 48 states and Hawaii; and

(2) Transfer of any renewable fuel from a location in the contiguous 48 states to Alaska 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 § 80.1443.

Facility means all of the activities and equipment associated with the production of renewable fuel starting from the point of delivery of feedstock material to the point of final storage of the end product, which are located on one property, and are under the control of the same party (or parties under common control).

Fallow means cropland, pastureland, or land enrolled in the Conservation Reserve Program (administered by the U.S. Department of Agriculture's Farm Service Agency) that is intentionally left idle to regenerate for future agricultural purposes with no seeding or planting, harvesting, mowing, or treatment during the fallow period.

Forestland is generally undeveloped land covering a minimum area of 1 acre upon which the primary vegetative species are trees, including land that formerly had such tree cover and that will be regenerated. Forestland does not include tree plantations.

Gasoline refers to any and all of the products specified at § 80.1407(c).

Importers. An importer of transportation fuel or renewable fuel is:

(1) Any party who brings transportation fuel or renewable fuel into the 48 contiguous states of the United States and Hawaii, from a foreign country or from an area that has not opted in to the program requirements of this subpart pursuant to § 80.1443; and

(2) Any party who brings transportation fuel or renewable fuel into an area that has opted in to the program requirements of this subpart pursuant to § 80.1443.

Motor vehicle has the meaning given in Section 216(2) of the Clean Air Act (42 U.S.C. 7550(2)).

Nameplate capacity means:

(1) The maximum rated annual volume output of renewable fuel produced by a renewable fuel production facility under specific conditions as indicated in applicable air permits issued by the U.S. Environmental Protection Agency, state, or local air pollution control agencies and that govern the construction and/or operation of the renewable fuel facility.

(2) If the maximum rated annual volume output of renewable fuel is not specified in any applicable air permits issued by the U.S. Environmental Protection Agency, state, or local air pollution control agencies, then nameplate capacity is the actual peak capacity of the facility.

Neat renewable fuel is a renewable fuel to which only a de minimis amount of gasoline (as defined in Section 211(k)(10)(F) of the Clean Air Act (42 U.S.C. 7550)) or diesel fuel has been added.

Non-ester renewable diesel means renewable fuel which is all the following:

(1) Registered as a motor vehicle fuel or fuel additive under 40 CFR Part 79.

(2) Not a mono-alkyl ester.

(3) Intended for use in engines that are designed to run on conventional diesel fuel.

(4) Derived from nonpetroleum renewable resources.

(5) Qualifies for a D code of 3 as defined in § 80.1426(d).

Nonforested land means land that is not forestland.

Nonpetroleum renewable resources include, but are not limited to the following:

(1) Plant oils.

(2) Animal fats and animal wastes, including poultry fats and poultry wastes, and other waste materials.

Nonroad vehicle has the meaning given in Section 216(11) of the Clean Air Act (42 U.S.C. 7550(11)).

Ocean-going vessel means, for this subpart only, a vessel propelled by a Category 3 (C3) (as defined in 40 CFR 1042.901) marine engine that uses residual fuel (as defined at § 80.2(bbb)) or operates internationally. Note that ocean-going vessels may also include smaller engines such as Category 2 auxiliary engines.

Pastureland is land managed for the production of indigenous or introduced forage plants for livestock grazing or hay production, and to prevent succession to other plant types.

Planted crops are all annual or perennial agricultural crops that may be used as feedstocks for renewable fuel, such as grains, oilseeds, sugarcane, switchgrass, prairie grass, and other species providing that they were intentionally applied to the ground by humans either by direct application as seed or nursery stock, or through intentional natural seeding by mature plants left undisturbed for that purpose.

Planted trees are trees planted by humans from nursery stock or by seed either through direct application to the ground or by intentional natural seeding by mature trees left undisturbed for that purpose.

Pre-commercial thinnings are trees, including unhealthy or diseased trees, primarily removed to reduce stocking to concentrate growth on more desirable, healthy trees.

Renewable biomass means each of the following:

(1) Planted crops and crop residue harvested from existing agricultural land.

(2) Planted trees and slash from a tree plantation located on non-federal land (including land belonging to an Indian tribe or an Indian individual that is held in trust by the U.S. or subject to a restriction against alienation imposed by the U.S.) that was cleared at any time prior to December 19, 2007, and has been continuously actively managed since December 19, 2007. Active management is evidenced by any of the following:

(i) Records of sales of planted trees or slash, or records of purchases of seeds, seedlings, or other nursery stock.

(ii) A written management plan for silvicultural purposes.

(iii) Documented participation in a silvicultural program administered by a Federal, state, or local government agency.

(iv) Documented management in accordance with a certification program for silvicultural products.

(3) Animal waste material and animal byproducts.

(4) Slash and pre-commercial thinnings from non-federal forestland (including forestland belonging to an Indian tribe or an Indian individual, that are held in trust by the United States or subject to a restriction against alienation imposed by the United States) that is not ecologically sensitive forestland.

(5) Biomass (organic matter that is available on a renewable or recurring basis) obtained from within 200 feet of buildings, campgrounds, and other areas regularly occupied by people, or of public infrastructure, such as utility corridors, bridges, and roadways, in areas at risk of wildfire.

(6) Algae.

(7) Separated yard waste or food waste, including recycled cooking and trap grease.

Renewable fuel means a fuel which meets all of the following:

(1) Fuel that is produced from renewable biomass.

(2) Fuel that is used to replace or reduce the quantity of fossil fuel present in a transportation fuel, home heating oil, or jet fuel.

(3) Ethanol covered by this definition shall be denatured as required and defined in 27 CFR parts 19 through 21. Any volume of denaturant added to the undenatured ethanol by a producer or importer in excess of 5 volume percent shall not be included in the volume of ethanol for purposes of determining compliance with the requirements under this subpart.

Renewable Identification Number (RIN), is a unique number generated to represent a volume of renewable fuel pursuant to §§ 80.1425 and 80.1426.

(1) *Gallon-RIN* is a RIN that represents an individual gallon of renewable fuel; and

(2) *Batch-RIN* is a RIN that represents multiple gallon-RINs.

Slash is the residue, including treetops, branches, and bark, left on the ground after logging or accumulating as a result of a storm, fire, delimbing, or other similar disturbance.

Small refinery means a refinery for which the average aggregate daily crude oil throughput for calendar year 2006 (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.

Transportation fuel means fuel for use in motor vehicles, motor vehicle engines, nonroad vehicles, or nonroad engines (except for ocean-going vessels).

Tree plantation is a stand of no fewer than 100 planted trees of similar age comprising one or two tree species or an area managed for growth of such trees covering a minimum of 1 acre.

Yard waste is leaves, sticks, pine needles, grass and hedge clippings, and similar waste from residential, commercial, or industrial areas.

§ 80.1402 [Reserved]

§ 80.1403 Which fuels are not subject to the 20% GHG thresholds?

(a) Pursuant to the definition of baseline volume in § 80.1401, the baseline volume of renewable fuel that is produced from facilities which commenced construction on or before December 19, 2007, shall not be subject to the 20 percent reduction in GHG emissions and shall be deemed grandfathered for purposes of generating RINs pursuant to § 80.1426(d)(7)(ii) if the owner or operator:

(1) Did not discontinue construction for a period of 18 months or more after December 19, 2007; and

(2) Completed construction within 36 months of December 19, 2007.

(b) The volume of ethanol that is produced from facilities which commenced construction after December 19, 2007 and on or before December 31, 2009, shall not be subject to the 20 percent reduction in GHG emissions and shall be deemed grandfathered for purposes of generating RINs pursuant to § 80.1426(d)(7)(ii) only if such facilities are fired with natural gas, biomass, or a combination thereof.

(c) The annual volume of renewable fuel during a calendar year from facilities described in paragraph (a) of this section that is beyond the baseline volume shall be subject to the 20 percent reduction in GHG emissions and such volume shall not be deemed grandfathered for purposes of generating RINs pursuant to § 80.1426(d)(7)(ii).

(d) For those facilities described in paragraph (a) of this section which produce ethanol and are fired with natural gas, biomass, or a combination thereof, increases in the annual volume of ethanol above the baseline volume during a calendar year shall not be subject to the 20 percent reduction in GHG emissions and shall be deemed grandfathered for purposes of generating RINs pursuant to § 80.1426(d)(7)(ii), provided that:

(1) The facility continues to be fired only with natural gas, biomass, or a combination thereof; and

(2) If the increases in volume at the facility are due to new construction, such new construction must have commenced on or before December 31, 2009.

(e) If there are any changes in the mix of renewable fuels produced by those facilities described in paragraph (d) of this section, only the ethanol volume will not be subject to the 20 percent reduction in GHG emissions and shall be deemed grandfathered for purposes of generating RINs pursuant to § 80.1426(d)(7)(ii).

§ 80.1404 [Reserved]

§ 80.1405 What are the Renewable Fuel Standards?

(a) *Renewable Fuel Standards for 2010.* (1) The value of the cellulosic biofuel standard for 2010 shall be 0.06 percent.

(2) The value of the biomass-based diesel standard for 2010 shall be 0.71 percent.

(3) The value of the advanced biofuel standard for 2010 shall be 0.59 percent.

(4) The value of the renewable fuel standard for 2010 shall be 8.01 percent.

(b) Beginning with the 2011 compliance period, EPA will calculate the value of the annual standards and publish these values in the **Federal Register** by November 30 of the year preceding the compliance period.

(c) EPA will base the calculation of the standards on information provided by the Energy Information Administration regarding projected gasoline and diesel volumes and projected volumes of renewable fuels expected to be used in gasoline and diesel blending for the upcoming year.

(d) EPA will calculate the annual renewable fuel standards using the following equations:

$$\mathrm{Std}_{\mathrm{CB,\,i}} = 100\% * \frac{\mathrm{RFV}_{\mathrm{CB,\,i}}}{(G_i - RG_i) + (GS_i - RGS_i) - GE_i + (D_i - RD_i) + (DS_i - RDS_i) - DE_i}$$

$$\mathrm{Std}_{\mathrm{BBD,\,i}} = 100\% * \frac{\mathrm{RFV}_{\mathrm{BBD,\,i}}}{(G_i - RG_i) + (GS_i - RGS_i) - GE_i + (D_i - RD_i) + (DS_i - RDS_i) - DE_i}$$

$$\mathrm{Std}_{\mathrm{AB,\,i}} = 100\% * \frac{\mathrm{RFV}_{\mathrm{AB,\,i}}}{(G_i - RG_i) + (GS_i - RGS_i) - GE_i + (D_i - RD_i) + (DS_i - RDS_i) - DE_i}$$

$$\mathrm{Std}_{\mathrm{RF,\,i}} = 100\% * \frac{\mathrm{RFV}_{\mathrm{RF,\,i}}}{(G_i - RG_i) + (GS_i - RGS_i) - GE_i + (D_i - RD_i) + (DS_i - RDS_i) - DE_i}$$

Where:

$Std_{CB,i}$ = The cellulosic biofuel standard for year i, in percent.

$Std_{BBD,i}$ = The biomass-based diesel standard for year i, in percent.

$Std_{AB,i}$ = The advanced biofuel standard for year i, in percent.

$Std_{RF,i}$ = The renewable fuel standard for year i, in percent.

$RFV_{CB,i}$ = Annual volume of cellulosic biofuel required by section 211(o)(2)(B) of the Clean Air Act for year i, in gallons.

$RFV_{BBD,i}$ = Annual volume of biomass-based diesel required by section 211(o)(2)(B) of the Clean Air Act for year i, in gallons.

$RFV_{AB,i}$ = Annual volume of advanced biofuel required by section 211(o)(2)(B) of the Clean Air Act for year i, in gallons.

$RFV_{RF,i}$ = Annual volume of renewable fuel required by section 211(o)(2)(B) of the Clean Air Act for year i, in gallons.

G_i = Amount of gasoline projected to be used in the 48 contiguous states and Hawaii, in year i, in gallons.

D_i = Amount of diesel projected to be used in the 48 contiguous states and Hawaii, in year i, in gallons.

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

RD_i = Amount of renewable fuel blended into diesel that is projected to be consumed in the 48 contiguous states and Hawaii, in year i, in gallons.

GS_i = Amount of gasoline projected to be used in Alaska or a U.S. territory, in year i, if the state or territory has opted-in or opts-in, in gallons.

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

DS_i = Amount of diesel projected to be used in Alaska or a U.S. territory, in year i, if the state or territory has opted-in or opts-in, in gallons.

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

GE_i = The amount of gasoline projected to be produced by exempt small refineries and small refiners, in year i, in gallons in any year they are exempt per §§ 80.1441 and 80.1442, respectively. Assumed to equal $0.119 * (G_i - RG_i)$.

DE_i = The amount of diesel fuel projected to be produced by exempt small refineries and small refiners in year i, in gallons, in any year they are exempt per §§ 80.1441 and 80.1442, respectively. Assumed to equal $0.152 * (D_i - RD_i)$.

§ 80.1406 To whom do the Renewable Volume Obligations apply?

(a)(1) An obligated party is any refiner that produces gasoline or diesel fuel within the 48 contiguous states or Hawaii, or any importer that imports gasoline or diesel fuel into the 48 contiguous states or Hawaii. A party that simply adds renewable fuel to gasoline or diesel fuel, as defined in § 80.1407(c) or (f), is not an obligated party.

(2) If the Administrator approves a petition of Alaska or a United States territory to opt-in to the renewable fuel program under the provisions in § 80.1443, then ''obligated party'' shall also include any refiner that produces gasoline or diesel fuel within that state or territory, or any importer that imports gasoline or diesel fuel into that state or territory.

(b) For each compliance period starting with 2010, an obligated party is required to demonstrate, pursuant to § 80.1427, that it has satisfied the Renewable Volume Obligations for that compliance period, as specified in § 80.1407(a).

(c) An obligated party may comply with the requirements of paragraph (b) of this section for all of its refineries in the aggregate, or for each refinery individually.

(d) An obligated party must comply with the requirements of paragraph (b) of this section for all of its imported gasoline or diesel fuel in the aggregate.

(e) An obligated party that is both a refiner and importer must comply with the requirements of paragraph (b) of this section for its imported gasoline or diesel fuel separately from gasoline or diesel fuel produced by its refinery or refineries.

(f) Where a refinery or import facility is jointly owned by two or more parties, the requirements of paragraph (b) of this section may be met by one of the joint owners for all of the gasoline or diesel fuel produced/imported at the facility, or each party may meet the requirements of paragraph (b) of this section for the portion of the gasoline or diesel fuel that it owns, as long as all of the gasoline or diesel fuel produced/imported at the facility is accounted for in determining the Renewable Volume Obligations under § 80.1407.

(g) The requirements in paragraph (b) of this section apply to the following compliance periods: Beginning in 2010, and every year thereafter, the compliance period is January 1 through December 31.

(h) A party that exports renewable fuel (pursuant to the definition of an exporter of renewable fuel in § 80.1401) shall demonstrate, pursuant to § 80.1427, that it has satisfied the Renewable Volume Obligations for each compliance period as specified in § 80.1430(b).

§ 80.1407 How are the Renewable Volume Obligations calculated?

(a) The Renewable Volume Obligations for an obligated party are determined according to the following formulas:

(1) *Cellulosic biofuel.*

$RVO_{CB,i} = (RFStd_{CB,i} * (GV_i + DV_i)) + D_{CB,i-1}$

Where:

$RVO_{CB,i}$ = The Renewable Volume Obligation for cellulosic biofuel for an obligated party for calendar year i, in gallons.

$RFStd_{CB,i}$ = The standard for cellulosic biofuel for calendar year i, determined by EPA pursuant to § 80.1405, in percent.

GV_i = The non-renewable gasoline volume, determined in accordance with paragraphs (b), (c), and (d) of this section, which is produced in or imported into the 48 contiguous states or Hawaii by an obligated party in calendar year i, in gallons.

DV_i = The diesel non-renewable volume, determined in accordance with paragraphs (e) and (f) of this section, produced in or imported into the 48 contiguous states or Hawaii by an obligated party in calendar year i, in gallons.

$D_{CB,i-1}$ = Deficit carryover from the previous year for cellulosic biofuel, in gallons.

(2) *Biomass-based diesel.*

$RVO_{BBD,i} = (RFStd_{BBD,i} * (GV_i + DV_i)) + D_{BBD,i-1}$

Where:

$RVO_{BBD,i}$ = The Renewable Volume Obligation for biomass-based diesel for an obligated party for calendar year i, in gallons.

$RFStd_{BBD,i}$ = The standard for biomass-based diesel for calendar year i, determined by EPA pursuant to § 80.1405, in percent.

GV_i = The non-renewable gasoline volume, determined in accordance with paragraphs (b), (c), and (d) of this section, which is produced in or imported into the 48 contiguous states or Hawaii by an obligated party in calendar year i, in gallons.

DV_i = The diesel non-renewable volume, determined in accordance with paragraphs (e) and (f) of this section, produced in or imported into the 48 contiguous states or Hawaii by an obligated party in calendar year i, in gallons.

$D_{BBD,i-1}$ = Deficit carryover from the previous year for biomass-based diesel, in gallons.

(3) *Advanced biofuel.*

$RVO_{AB,i} = (RFStd_{AB,i} * (GV_i + DV_i)) + D_{AB,i-1}$

Where:

$RVO_{AB,i}$ = The Renewable Volume Obligation for advanced biofuel for an obligated party for calendar year i, in gallons.

$RFStd_{AB,i}$ = The standard for advanced biofuel for calendar year i, determined by EPA pursuant to § 80.1405, in percent.

GV_i = The non-renewable gasoline volume, determined in accordance with paragraphs (b), (c), and (d) of this section, which is produced in or imported into the 48 contiguous states or Hawaii by an obligated party in calendar year i, in gallons.

DV_i = The diesel non-renewable volume, determined in accordance with paragraphs (e) and (f) of this section, produced in or imported into the 48 contiguous states or Hawaii by an obligated party in calendar year i, in gallons.

$D_{AB,i-1}$ = Deficit carryover from the previous year for advanced biofuel, in gallons.

(4) *Renewable fuel.*

$RVO_{RF,i} = (RFStd_{RF,i} * (GV_i + DV_i)) + D_{RF,i-1}$

Where:

$RVO_{RF,i}$ = The Renewable Volume Obligation for renewable fuel for an obligated party for calendar year i, in gallons.

$RFStd_{RF,i}$ = The standard for renewable fuel for calendar year i, determined by EPA pursuant to § 80.1405, in percent.

GV_i = The non-renewable gasoline volume, determined in accordance with paragraphs (b), (c), and (d) of this section, which is produced in or imported into the 48 contiguous states or Hawaii by an obligated party in calendar year i, in gallons.

DV_i = The diesel non-renewable volume, determined in accordance with paragraphs (e) and (f) of this section, produced in or imported into the 48 contiguous states or Hawaii by an obligated party in calendar year i, in gallons.

$D_{RF,i-1}$ = Deficit carryover from the previous year for renewable fuel, in gallons.

(b) The non-renewable gasoline volume for an obligated party for a given year, GV_i, specified in paragraph (a) of this section is calculated as follows:

$$GV_i = \sum_{x=1}^{n} G_x - \sum_{y=1}^{m} RBG_y$$

Where:

x = Individual batch of gasoline produced or imported in calendar year i.

n = Total number of batches of gasoline produced or imported in calendar year i.

G_x = Volume of batch x of gasoline produced or imported, as defined in paragraph (c) of this section, in gallons.

y = Individual batch of renewable fuel blended into gasoline in calendar year i.

m = Total number of batches of renewable fuel blended into gasoline in calendar year i.

RBG_y = Volume of batch y of renewable fuel blended into gasoline, in gallons.

(c) All of the following products that are produced or imported during a compliance period, collectively called ‘‘gasoline’’ for the purposes of this section (unless otherwise specified), are to be included (but not double-counted) in the volume used to calculate a party’s Renewable Volume Obligations under paragraph (a) of this section, except as provided in paragraph (d) of this section:

(1) Reformulated gasoline, whether or not renewable fuel is later added to it.

(2) Conventional gasoline, whether or not renewable fuel is later added to it.

(3) Reformulated gasoline blendstock that becomes finished reformulated gasoline upon the addition of oxygenate (RBOB).

(4) Conventional gasoline blendstock that becomes finished conventional gasoline upon the addition of oxygenate (CBOB).

(5) Blendstock (including butane and gasoline treated as blendstock (GTAB)) that has been combined with other blendstock and/or finished gasoline to produce gasoline.

(6) Any gasoline, or any unfinished gasoline that becomes finished gasoline upon the addition of oxygenate, that is

produced or imported to comply with a state or local fuels program.

(d) The following products are not included in the volume of gasoline produced or imported used to calculate a party's renewable volume obligation under paragraph (a) of this section:

(1) Any renewable fuel as defined in § 80.1401.

(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, 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 § 80.1443.

(4) Gasoline produced by a small refinery that has an exemption under § 80.1441 or an approved small refiner that has an exemption under § 80.1442 until January 1, 2011 (or later, for small refineries, if their exemption is extended pursuant to § 80.1441(h)).

(5) Gasoline exported for use outside the 48 United States and Hawaii, and gasoline exported for use outside Alaska, the Commonwealth of Puerto Rico, the U.S. Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Marianas, if the area has opted into the RFS program under § 80.1443.

(6) For blenders, the volume of finished gasoline, RBOB, or CBOB to which a blender adds blendstocks.

(7) The gasoline portion of transmix produced by a transmix processor, or the transmix blended into gasoline by a transmix blender, under § 80.84.

(e) The diesel non-renewable volume for an obligated party for a given year, DV_i, specified in paragraph (a) of this section is calculated as follows:

$$DV_i = \sum_{x=1}^{n} D_x - \sum_{y=1}^{m} RBD_y$$

Where:

x = Individual batch of diesel produced or imported in calendar year i.

n = Total number of batches of diesel produced or imported in calendar year i.

D_x = Volume of batch x of diesel produced or imported, as defined in paragraph (f) of this section, in gallons.

y = Individual batch of renewable fuel blended into diesel in calendar year i.

m = Total number of batches of renewable fuel blended into diesel in calendar year i.

RBD_y = Volume of batch y of renewable fuel blended into diesel, in gallons.

(f) All products meeting the definition of *MVNRLM diesel fuel* at § 80.2(qqq) that are produced or imported during a compliance period, collectively called ''diesel fuel'' for the purposes of this section (unless otherwise specified), are to be included (but not double-counted) in the volume used to calculate a party's Renewable Volume Obligations under paragraph (a) of this section.

§§ 80.1408–80.1414 [Reserved]

§ 80.1415 How are equivalence values assigned to renewable fuel?

(a)(1) Each gallon of a renewable fuel, or gallon equivalent pursuant to paragraph (c) of this section, shall be assigned an equivalence value by the producer or importer pursuant to paragraph (b) or (c) of this section.

(2) The equivalence value is a number that is used to determine how many gallon–RINs can be generated for a batch of renewable fuel according to § 80.1426.

(b) All renewable fuels shall have an equivalence value of 1.0.

(c) A gallon of renewable fuel is a physically measured unit of volume for any fuel that exists as a liquid at 60 °F and 1 atm, but represents 77,930 Btu (lower heating value) for any fuel that exists as a gas at 60 °F and 1 atm.

§ 80.1416 Treatment of parties who produce or import new renewable fuels and pathways.

(a)(1) Each renewable fuel producer or importer that produces or imports a new renewable fuel, or uses a new pathway that can not qualify for a D code as defined in § 80.1426(d), must apply to use a D code as specified in paragraph (b) of this section.

(2) EPA will review the application and may allow the use of an appropriate D code for the combination of fuel type, feedstock, and production process.

(3) Except as provided in paragraph (c) of this section, parties that must apply to use a D code pursuant to paragraph (b) of this section may not generate RINs for that new fuel or new combination fuel type, feedstock, and production process until the Agency has reviewed the application and updated Table 1 to § 80.1426.

(b)(1) The application for a new renewable fuel or pathway shall include all the following:

(i) A completed facility registration under § 80.1450(b).

(ii) A technical justification that includes a description of the renewable fuel, feedstock(s) used to make it, and the production process.

(iii) Any additional information that the Agency needs to complete a lifecycle Greenhouse Gas assessment of the new fuel or pathway.

(2) A company may only submit one application per pathway. If EPA determines the application to be incomplete, per paragraph (b)(4) of this section, then the company may resubmit.

(3) The application must be signed and certified as meeting all the applicable requirements of this subpart by a responsible corporate officer of the applicant organization.

(4) If EPA determines that the application is incomplete then EPA will notify the applicant in writing that the application is incomplete and will not be reviewed further. However, an amended application that corrects the omission may be re-submitted for EPA review.

(5) If the fuel or pathway described in the application does not meet the definition of renewable fuel in § 80.1401, then EPA will notify the applicant in writing that the application is denied and will not be reviewed further.

(c)(1) A producer may use a temporary D code pending EPA review of an application under paragraph (b) of this section if the producer is producing renewable fuel from a fuel type and feedstock combination listed in Table 1 to § 80.1426, but where the renewable fuel producer's production process is not listed. A producer using a temporary D code, must do all the following:

(i) Provide information necessary under paragraph (b) of this section and register under 40 CFR part 79 before introducing the fuel into commerce.

(ii) Generate RINs using the temporary D code for all renewable fuel produced using this combination fuel type, feedstock, and production process.

(iii) When Table 1 to § 80.1426 has been updated to include the new fuel pathway, cease to use the temporary D code and use the applicable D code in the table.

(iv) For existing fuel type and feedstock combinations that apply to more than one D code, the producer must use the highest numerical value from the applicable D codes as the temporary D code.

(2) Except if the application is deemed incomplete or denied pursuant to paragraph (b)(3) or (b)(4) of this section, if Table 1 to § 80.1426 is not updated within 5 years of the initial receipt of a company's application, the company must stop using the temporary D code.

(3) A producer whose fuel pathway is ethanol made from starches in a process that uses natural gas or coal for process heat may not use a temporary D code for their fuel pathway.

(4) EPA may revoke the authority provided by this section for use of a temporary D code at any time if any of the following occur:

(i) EPA determines that the fuel or pathway described in the application does not meet the definition of renewable fuel in § 80.1401.

(ii) EPA discovers adverse health effects unique to the fuel or pathway.

(iii) The information provided by the applicant on the pathway in paragraph (b) of this section is deemed false or incorrect.

(d) The application under this section shall be submitted on forms and following procedures as prescribed by EPA.

§§ 80.1417–80.1424 [Reserved]

§ 80.1425 Renewable Identification Numbers (RINs).

Each RIN is a 38-character numeric code of the following form:

KYYYYCCCCFFFFFBBBBBRRDSSSSSSSSEEEEEEEE

(a) K is a number identifying the type of RIN as follows:

(1) K has the value of 1 when the RIN is assigned to a volume of renewable fuel pursuant to §§ 80.1426(e) and 80.1428(a).

(2) K has the value of 2 when the RIN has been separated from a volume of renewable fuel pursuant to § 80.1429.

(b) YYYY is the calendar year in which the batch of renewable fuel was produced or imported. YYYY also represents the year in which the RIN was originally generated.

(c) CCCC is the registration number assigned, according to § 80.1450, to the producer or importer of the batch of renewable fuel.

(d) FFFFF is the registration number assigned, according to § 80.1450, to the facility at which the batch of renewable fuel was produced or imported.

(e) BBBBB is a serial number assigned to the batch which is chosen by the producer or importer of the batch such that no two batches have the same value in a given calendar year.

(f) RR is a number representing 10 times the equivalence value of the renewable fuel as specified in § 80.1415.

(g) D is a number determined according to § 80.1426(d) and identifying the type of renewable fuel, as follows:

(1) D has the value of 1 to denote fuel categorized as cellulosic biofuel.

(2) D has the value of 2 to denote fuel categorized as biomass-based diesel.

(3) D has the value of 3 to denote fuel categorized as advanced biofuel.

(4) D has the value of 4 to denote fuel categorized as renewable fuel.

(h) SSSSSSSS is a number representing the first gallon-RIN associated with a batch of renewable fuel.

(i) EEEEEEEE is a number representing the last gallon-RIN associated with a batch of renewable fuel. EEEEEEEE will be identical to SSSSSSSS if the batch-RIN represents a single gallon-RIN. Assign the value of EEEEEEEE as described in § 80.1426.

§ 80.1426 How are RINs generated and assigned to batches of renewable fuel by renewable fuel producers or importers?

(a) *Regional applicability.* (1) Except as provided in paragraph (b) of this section, a RIN must be generated by a renewable fuel producer or importer for every batch of fuel that meets the definition of renewable fuel that is produced or imported for use as transportation fuel, home heating oil, or jet fuel in the 48 contiguous states or Hawaii.

(2) If the Administrator approves a petition of Alaska or a United States territory to opt-in to the renewable fuel program under the provisions in § 80.1443, then the requirements of paragraph (a)(1) of this section shall also apply to renewable fuel produced or imported for use as transportation fuel, home heating oil, or jet fuel in that state or territory beginning in the next calendar year.

(b) *Cases in which RINs are not generated.* (1) *Volume threshold.* Renewable fuel producers 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 §§ 80.1450 through 80.1452, and the attest engagement requirements of § 80.1464. However, for those producers and importers that own RINs or voluntarily generate and assign RINs, all the requirements of this subpart apply.

(2) Fuel producers and importers shall not generate RINs for fuel that they produce or import for which they have made a demonstration under § 80.1451(c) that the feedstocks used to produce the fuel are not renewable biomass (as defined in § 80.1401).

(3) Fuel producers and importers may not generate RINs for fuel that is not renewable fuel.

(4) Importers shall not import or generate RINs for fuel imported from a foreign producer that is not registered with EPA as required in § 80.1450.

(5) Importers shall not generate RINs for renewable fuel that has already been assigned RINs by a foreign producer.

(c) *Definition of batch.* For the purposes of this section and § 80.1425, a ''batch of renewable fuel'' is a volume of renewable fuel that has been assigned a unique RIN code BBBBB within a calendar year by the producer or importer of the renewable fuel in accordance with the provisions of this section and § 80.1425.

(1) The number of gallon-RINs generated for a batch of renewable fuel may not exceed 99,999,999.

(2) A batch of renewable fuel cannot represent renewable fuel produced or imported in excess of one calendar month.

(d) *Generation of RINs.* (1) Producers and importers of fuel made from renewable feedstocks must determine for each batch of fuel produced or imported whether or not the fuel is renewable fuel (as defined in § 80.1401), including a determination of whether or not the feedstock used to make the fuel is renewable biomass (as defined § 80.1401). Except as provided in paragraph (b) of this section, the producer or importer of a batch of renewable fuel must generate a RIN for that batch.

(i) Domestic producers must generate RINs for all renewable fuel that they produce.

(ii) Importers must generate RINs for all renewable fuel that they import that has not been assigned RINs by a foreign producer, including any renewable fuel contained in imported transportation fuel.

(iii) Foreign producers may generate RINs for any renewable fuel that they export to the 48 contiguous states of the United States or Hawaii.

(2) A party generating a RIN shall specify the appropriate numerical values for each component of the RIN in accordance with the provisions of § 80.1425(a) and this paragraph (d).

(3) *Applicable pathways.* D codes shall be used in RINs generated by producers or importers of renewable fuel according to the pathways listed in Table 1 to this section.

TABLE 1 TO § 80.1426—APPLICABLE D CODES FOR EACH FUEL PATHWAY FOR USE IN GENERATING RINS

Fuel type	Feedstock	Production process requirements	D code
Ethanol	Starch from corn, wheat, barley, oats, rice, or sorghum	—Process heat derived from biomass	4
Ethanol	Starch from corn, wheat, barley, oats, rice, or sorghum	—Dry mill plant —Process heat derived from natural gas —Combined heat and power (CHP) —Fractionation of feedstocks —Some or all distillers grains are dried	4
Ethanol	Starch from corn, wheat, barley, oats, rice, or sorghum	—Dry mill plant —Process heat derived from natural gas —All distillers grains are wet	4
Ethanol	Starch from corn, wheat, barley, oats, rice, or sorghum	—Dry mill plant —Process heat derived from coal —Combined heat and power (CHP) —Fractionation of feedstocks —Membrane separation of ethanol —Raw starch hydrolysis —Some or all distillers grains are dried	4
Ethanol	Starch from corn, wheat, barley, oats, rice, or sorghum	—Dry mill plant —Process heat derived from coal —Combined heat and power (CHP) —Fractionation of feedstocks —Membrane separation of ethanol —All distillers grains are wet	4
Ethanol	Cellulose and hemicellulose from corn stover, switchgrass, miscanthus, wheat straw, rice straw, sugarcane bagasse, slash, pre-commercial thinnings, yard waste, or planted trees.	—Enzymatic hydrolysis of cellulose —Fermentation of sugars —Process heat derived from lignin	1
Ethanol	Cellulose and hemicellulose from corn stover, switchgrass, miscanthus, wheat straw, rice straw, sugarcane bagasse, slash, pre-commercial thinnings, yard waste, or planted trees.	—Thermochemical gasification of biomass. —Fischer-Tropsch process	1
Ethanol	Sugarcane sugar	—Process heat derived from sugarcane bagasse	3
Biodiesel (mono alkyl ester).	Waste grease, waste oils, tallow, chicken fat, or non-food-grade corn oil	—Transesterification	2
Biodiesel (mono alkyl ester).	Soybean oil and other virgin plant oils	—Transesterification	4
Cellulosic diesel	Cellulose and hemicellulose from corn stover, switchgrass, miscanthus, wheat straw, rice straw, sugarcane bagasse, slash, pre-commercial thinnings, yard waste, or planted trees.	—Thermochemical gasification of biomass. —Fischer-Tropsch process —Catalytic depolymerization	1 or 2
Non-ester renewable diesel.	Waste grease, waste oils, tallow, chicken fat, or non-food-grade corn oil	—Hydrotreating —Dedicated facility that processes only renewable biomass.	2
Non-ester renewable diesel.	Waste grease, waste oils, tallow, chicken fat, or non-food-grade corn oil	—Hydrotreating —Co-processing facility that also processes petroleum feedstocks.	3
Non-ester renewable diesel.	Soybean oil and other virgin plant oils	—Hydrotreating	4
Cellulosic gasoline	Cellulose and hemicellulose from corn stover, switchgrass, miscanthus, wheat straw, rice straw, sugarcane bagasse, slash, pre-commercial thinnings, yard waste, or planted trees.	—Thermochemical gasification of biomass. —Fischer-Tropsch process —Catalytic depolymerization	1

(4) *Producers whose operations can be described by a single pathway.*

(i) The number of gallon-RINs that shall be generated for a given batch of renewable fuel shall be equal to a volume calculated according to the following formula:

$V_{RIN} = EV * V_s$

Where:

V_{RIN} = RIN volume, in gallons, for use in determining the number of gallon-RINs that shall be generated.

EV = Equivalence value for the renewable fuel per § 80.1415.

V_s = Standardized volume of the batch of renewable fuel at 60 °F, in gallons, calculated in accordance with paragraph (d)(10) of this section.

(ii) The D code that shall be used in the RINs generated shall be the D code specified in Table 1 to this section which corresponds to the pathway that describes the producer's operations.

(5) *Producers whose operations can be described by two or more pathways.* (i) The D codes that shall be used in the RINs generated within a calendar year shall be the D codes specified in Table 1 to this section which correspond to the pathways that describe the producer's operations throughout that calendar year.

(ii) If all the pathways describing the producer's operations have the same D code, then that D code shall be used in all the RINs generated. The number of gallon-RINs that shall be generated for a given batch of renewable fuel in this case shall be equal to a volume calculated according to the following formula:

$V_{RIN} = EV * V_s$

Where:

V_{RIN} = RIN volume, in gallons, for use in determining the number of gallon-RINs that shall be generated.

EV = Equivalence value for the renewable fuel per § 80.1415.

V_s = Standardized volume of the batch of renewable fuel at 60 °F, in gallons, calculated in accordance with paragraph (d)(10) of this section.

(iii) If the pathway applicable to a producer changes on a specific date, such that one pathway applies before the date and another pathway applies on and after the date, then the applicable D code used in generating RINs must change on the date that the change in pathway occurs. The number of gallon-RINs that shall be generated for a given batch of renewable fuel in this case shall be equal to a volume calculated according to the following formula:

$V_{RIN} = EV * V_s$

Where:

V_{RIN} = RIN volume, in gallons, for use in determining the number of gallon-RINs that shall be generated for a batch with a single applicable D code.

EV = Equivalence value for the renewable fuel per § 80.1415.

V_s = Standardized volume of the batch of renewable fuel at 60 °F, in gallons, calculated in accordance with paragraph (d)(10) of this section.

(iv) If a producer produces two or more different types of renewable fuel whose volumes can be measured separately, then separate values for V_{RIN} shall be calculated for each batch of each type of renewable fuel according to formulas in Table 2 to this section:

TABLE 2 TO § 80.1426—NUMBER OF GALLON-RINS TO ASSIGN TO BATCH-RINS WITH D CODES DEPENDENT ON FUEL TYPE

D code to use in batch-RIN	Number of gallon-RINs
D = 1	$V_{RIN,\ CB} = EV * V_{s,\ CB}$
D = 2	$V_{RIN,\ BBD} = EV * V_{s,\ BBD}$
D = 3	$V_{RIN,\ AB} = EV * V_{s,\ RF}$
D = 4	$V_{RIN,\ RF} = EV * V_{s,\ RF}$

Where:

$V_{RIN,CB}$ = RIN volume, in gallons, for use determining the number of gallon-RINs that shall be generated for a batch of cellulosic biofuel with a D code of 1.

$V_{RIN,BBD}$ = RIN volume, in gallons, for use determining the number of gallon-RINs that shall be generated for a batch of biomass-based diesel with a D code of 2.

$V_{RIN,AB}$ = RIN volume, in gallons, for use determining the number of gallon-RINs that shall be generated for a batch of advanced biofuel with a D code of 3.

$V_{RIN,RF}$ = RIN volume, in gallons, for use determining the number of gallon-RINs that shall be generated for a batch of renewable fuel with a D code of 4.

EV = Equivalence value for the renewable fuel per § 80.1415.

$V_{s,CB}$ = Standardized volume of the batch of renewable fuel at 60 °F that must be assigned a D code of 1 based on its fuel type, in gallons, calculated in accordance with paragraph (d)(10) of this section.

$V_{s,BBD}$ = Standardized volume of the batch of renewable fuel at 60 °F that must be assigned a D code of 2 based on its fuel type, in gallons, calculated in accordance with paragraph (d)(10) of this section.

$V_{s,AB}$ = Standardized volume of the batch of renewable fuel at 60 °F that must be assigned a D code of 3 based on its fuel type, in gallons, calculated in accordance with paragraph (d)(10) of this section.

$V_{s,RF}$ = Standardized volume of the batch of renewable fuel at 60 °F that must be assigned a D code of 4 based on its fuel type, in gallons, calculated in accordance with paragraph (d)(10) of this section.

(v) If a producer produces a single type of renewable fuel using two or more different feedstocks which are processed simultaneously, then the number of gallon-RINs that shall be generated for each batch of renewable fuel and assigned a particular D code shall be determined according to the formulas in Table 3 to this section.

Table 3 to §80.1426

Number of gallon-RINs to assign to batch-RINs with D codes dependent on feedstock

D code to use in batch-RIN	Number of gallon-RINs
D = 1	$V_{RIN,CB} = EV * V_s * \left(\frac{FE_1}{FE_1 + FE_2 + FE_3 + FE_4} \right)$
D = 2	$V_{RIN,BBD} = EV * V_s * \left(\frac{FE_2}{FE_1 + FE_2 + FE_3 + FE_4} \right)$
D = 3	$V_{RIN,AB} = EV * V_s * \left(\frac{FE_3}{FE_1 + FE_2 + FE_3 + FE_4} \right)$
D = 4	$V_{RIN,RF} = EV * V_s * \left(\frac{FE_4}{FE_1 + FE_2 + FE_3 + FE_4} \right)$

Where:

$V_{RIN,CB}$ = RIN volume, in gallons, for use in determining the number of gallon-RINs that shall be generated for a batch of cellulosic biofuel with a D code of 1.

$V_{RIN,BBD}$ = RIN volume, in gallons, for use in determining the number of gallon-RINs that shall be generated for a batch of biomass-based diesel with a D code of 2.

$V_{RIN,AB}$ = RIN volume, in gallons, for use in determining the number of gallon-RINs that shall be generated for a batch of advanced biofuel with a D code of 3.

$V_{RIN,RF}$ = RIN volume, in gallons, for use in determining the number of gallon-RINs that shall be generated for a batch of renewable fuel with a D code of 4.

EV = Equivalence value for the renewable fuel per § 80.1415.

V_s = Standardized volume of the batch of renewable fuel at 60 °F, in gallons, calculated in accordance with paragraph (d)(10) of this section.

FE_1 = Feedstock energy from all feedstocks whose pathways have been assigned a D code of 1 under Table 1 to this section, in Btu.

FE_2 = Feedstock energy from all feedstocks whose pathways have been assigned a D code of 2 under Table 1 to this section, in Btu.

FE_3 = Feedstock energy from all feedstocks whose pathways have been assigned a D code of 3 under Table 1 to this section, in Btu.

FE_4 = Feedstock energy from all feedstocks whose pathways have been assigned a D code of 4 under Table 1 to this section, in Btu.

Feedstock energy values, FE, shall be calculated according to the following formula:

$FE = M * CF * E$

Where:

FE = Feedstock energy, in Btu.
M = Mass of feedstock, in pounds.
CF = Converted Fraction in annual average mass percent, representing that portion of the feedstock that is estimated to be converted into renewable fuel by the producer.
E = Energy content of the fuel precursor fraction for the feedstock in annual average Btu/lb.

(6) *Producers who co-process renewable biomass and fossil fuels simultaneously to produce a transportation fuel that is partially renewable.* (i) The number of gallon-RINs that shall be generated for a given batch of partially renewable transportation fuel shall be equal to a volume calculated according to the following formula:

$V_{RIN} = EV * V_s * FE_R/(FE_R + FE_F)$

Where:

V_{RIN} = RIN volume, in gallons, for use in determining the number of gallon-RINs that shall be generated.
EV = Equivalence value for the renewable fuel per § 80.1415.
V_s = Standardized volume of the batch of renewable fuel at 60 °F, in gallons, calculated in accordance with paragraph (d)(10) of this section.
FE_R = Feedstock energy from renewable biomass used to make the transportation fuel, in Btu.
FE_F = Feedstock energy from fossil fuel used to make the transportation fuel, in Btu.

(ii) The value of FE for use in paragraph (d)(6)(i) of this section shall be calculated from the following formula:

$FE = M * CF * E$

Where:

FE = Feedstock energy, in Btu.
M = Mass of feedstock, in pounds.
CF = Converted Fraction in annual average mass percent, representing that portion of the feedstock that is estimated to be converted into transportation fuel by the producer.
E = Energy content of the fuel precursor fraction for the feedstock, in annual average Btu/lb.

(iii) The D code that shall be used in the RINs generated to represent partially renewable transportation fuel shall be the D code specified in Table 1 to this section which corresponds to the pathway that describes a producer's operations. In determining the appropriate pathway, the contribution of fossil fuel feedstocks to the production of partially renewable fuel shall be ignored.

(7) *Producers without an applicable pathway.* (i) If none of the pathways described in Table 1 to this section apply to a producer's operations, a party generating a RIN may nevertheless use a pathway in Table 1 to this section if EPA allows the use of a temporary D code pursuant to § 80.1416(c).

(ii) If none of the pathways described in Table 1 to this section apply to a producer's operations and the party generating the RIN does not qualify to use a temporary D code according to the provisions of § 80.1416(c), the party must generate RINs if the fuel from its facility qualifies for grandfathering as provided in § 80.1403.

(A) The number of gallon-RINs that shall be generated for a given batch of grandfathered renewable fuel shall be equal to a volume calculated according to the following formula:

$V_{RIN} = EV * V_s$

Where:

V_{RIN} = RIN volume, in gallons, for use in determining the number of gallon-RINs that shall be generated.
EV = Equivalence value for the renewable fuel per § 80.1415.
V_s = Standardized volume of the batch of renewable fuel at 60°F, in gallons, calculated in accordance with paragraph (d)(10) of this section.

(B) A D code of 4 shall be used in the RINs generated under paragraph (d)(7)(ii)(A) of this section.

(8) *Provisions for importers of renewable fuel.* (i) The number of gallon-RINs that shall be generated for a given batch of renewable fuel shall be equal to a volume calculated according to the following formula:

$V_{RIN} = EV * V_s$

Where:

V_{RIN} = RIN volume, in gallons, for use in determining the number of gallon-RINs that shall be generated.
EV = Equivalence value for the renewable fuel per § 80.1415.
V_s = Standardized volume of the batch of renewable fuel at 60 °F, in gallons, calculated in accordance with paragraph (d)(10) of this section.

(ii) The D code that shall be used in the RINs generated by an importer of renewable fuel shall be determined from information provided by the foreign producer specifying the applicable pathway or pathways for the renewable fuel and the provisions of this paragraph (d).

(9) Multiple gallon-RINs generated to represent a given volume of renewable fuel can be represented by a single batch-RIN through the appropriate designation of the RIN volume codes SSSSSSSS and EEEEEEEE.

(i) The value of SSSSSSSS in the batch-RIN shall be 00000001 to represent the first gallon-RIN associated with the volume of renewable fuel.

(ii) The value of EEEEEEEE in the batch-RIN shall represent the last gallon-RIN associated with the volume of renewable fuel, based on the RIN volume determined pursuant to paragraph (d)(4) of this section.

(10) *Standardization of volumes.* In determining the standardized volume of a batch of renewable fuel for purposes of generating RINs under this paragraph (d), the batch volumes shall be adjusted to a standard temperature of 60 °F.

(i) For ethanol, the following formula shall be used:

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

Where:

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

(ii) For biodiesel (mono-alkyl esters), the following formula shall be used:

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

Where:

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

(iii) For other renewable fuels, an appropriate formula commonly accepted by the industry shall be used to standardize the actual volume to 60 °F. Formulas used must be reported to EPA, and may be reviewed for appropriateness.

(11)(i) A party is prohibited from generating RINs for a volume of fuel that it produces if:

(A) The fuel has been produced from a chemical conversion process that uses another renewable fuel as a feedstock, and the renewable fuel used as a feedstock was produced by another party; or

(B) The fuel is not produced from renewable biomass.

(ii) Parties who produce renewable fuel made from a feedstock which itself was a renewable fuel with RINs, shall assign the original RINs to the new renewable fuel.

(e) *Assignment of RINs to batches.* (1) The producer or importer of renewable fuel must assign all RINs generated to volumes of renewable fuel.

(2) A RIN is assigned to a volume of renewable fuel when ownership of the RIN is transferred along with the transfer of ownership of the volume of renewable fuel, pursuant to § 80.1428(a).

(3) All assigned RINs shall have a K code value of 1.

(4) Any RINs generated but not assigned to a volume of renewable fuel must be counted with assigned RINs in

the quarterly RIN and volume inventory balance check calculation required in § 80.1428.

§ 80.1427 How are RINs used to demonstrate compliance?

(a) *Renewable Volume Obligations.* (1) Except as specified in paragraph (b) of this section or § 80.1455, each party that is obligated to meet the Renewable Volume Obligations under § 80.1407, or each party that is an exporter of renewable fuels that is obligated to meet Renewable Volume Obligations under § 80.1430, must demonstrate pursuant to § 80.1452(a)(1) that it owns sufficient RINs to satisfy the following equations:

(i) *Cellulosic biofuel.*

$$(\Sigma RINNUM)_{CB,i} + (\Sigma RINNUM)_{CB,i-1} = RVO_{CB,i}$$

Where:

$(\Sigma RINNUM)_{CB,i}$ = Sum of all owned gallon-RINs that are valid for use in complying with the cellulosic biofuel RVO, were generated in year i, and are being applied towards the $RVO_{CB,i}$, in gallons.

$(\Sigma RINNUM)_{CB,i-1}$ = Sum of all owned gallon-RINs that are valid for use in complying with the cellulosic biofuel RVO, were generated in year i − 1, and are being applied towards the $RVO_{CB,i}$, in gallons.

$RVO_{CB,i}$ = The Renewable Volume Obligation for cellulosic biofuel for the obligated party or renewable fuel exporter for calendar year i, in gallons, pursuant to § 80.1407 or § 80.1430.

(ii) *Biomass-based diesel.*

$$(\Sigma RINNUM)_{BBD,i} + (\Sigma RINNUM)_{BBD,i-1} = RVO_{BBD,i}$$

Where:

$(\Sigma RINNUM)_{BBD,i}$ = Sum of all owned gallon-RINs that are valid for use in complying with the biomass-based diesel RVO, were generated in year i, and are being applied towards the $RVO_{BBD,i}$, in gallons.

$(\Sigma RINNUM)_{BBD,i-1}$ = Sum of all owned gallon-RINs that are valid for use in complying with the biomass-based diesel RVO, were generated in year i − 1, and are being applied towards the $RVO_{BBD,i}$, in gallons.

$RVO_{BBD,i}$ = The Renewable Volume Obligation for biomass-based diesel for the obligated party or renewable fuel exporter for calendar year i after 2010, in gallons, pursuant to § 80.1407 or § 80.1430.

(iii) *Advanced biofuel.*

$$(\Sigma RINNUM)_{AB,i} + (\Sigma RINNUM)_{AB,i-1} = RVO_{AB,i}$$

Where:

$(\Sigma RINNUM)_{AB,i}$ = Sum of all owned gallon-RINs that are valid for use in complying with the advanced biofuel RVO, were generated in year i, and are being applied towards the $RVO_{AB,i}$, in gallons.

$(\Sigma RINNUM)_{AB,i-1}$ = Sum of all owned gallon-RINs that are valid for use in complying with the advanced biofuel RVO, were generated in year i − 1, and are being applied towards the $RVO_{AB,i}$, in gallons.

$RVO_{AB,i}$ = The Renewable Volume Obligation for advanced biofuel for the obligated party or renewable fuel exporter for calendar year i, in gallons, pursuant to § 80.1407 or § 80.1430.

(iv) *Renewable fuel.*

$$(\Sigma RINNUM)_{RF,i} + (\Sigma RINNUM)_{RF,i-1} = RVO_{RF,i}$$

Where:

$(\Sigma RINNUM)_{RF,i}$ = Sum of all owned gallon-RINs that are valid for use in complying with the renewable fuel RVO, were generated in year i, and are being applied towards the $RVO_{RF,i}$, in gallons.

$(\Sigma RINNUM)_{RF,i-1}$ = Sum of all owned gallon-RINs that are valid for use in complying with the renewable fuel RVO, were generated in year i − 1, and are being applied towards the $RVO_{RF,i}$, in gallons.

$RVO_{RF,i}$ = The Renewable Volume Obligation for renewable fuel for the obligated party or renewable fuel exporter for calendar year i, in gallons, pursuant to § 80.1407 or § 80.1430.

(2) Except as described in paragraph (a)(3) of this section, RINs that are valid for use in complying with each Renewable Volume Obligation are determined by their D codes.

(i) RINs with a D code of 1 are valid for compliance with the cellulosic biofuel RVO.

(ii) RINs with a D code of 2 are valid for compliance with the biomass-based diesel RVO.

(iii) RINs with a D code of 1, 2, or 3 are valid for compliance with the advanced biofuel RVO.

(iv) RINs with a D code of 1, 2, 3, or 4 are valid for compliance with the renewable fuel RVO.

(3) For purposes of demonstrating compliance for calendar year 2010, RINs generated in 2009 pursuant to § 80.1126 that are not used for compliance purposes for calendar year 2009 may be used for compliance in 2010, insofar as permissible pursuant to paragraphs (a)(5) and (a)(7)(iv) of this section, as follows:

(i) A 2009 RIN with an RR code of 15 or 17 is deemed equivalent to a RIN generated pursuant to § 80.1426 having a D code of 2.

(ii) A 2009 RIN with a D code of 1 is deemed equivalent to a RIN generated pursuant to § 80.1426 having a D code of 1.

(iii) All other 2009 RINs are deemed equivalent to RINs generated pursuant to § 80.1426 having D codes of 4.

(iv) A 2009 RIN that is retired pursuant to § 80.1129(e) because the associated volume of fuel is not used as motor vehicle fuel may be reinstated pursuant to § 80.1429(f)(1).

(4) A party may use the same RIN to demonstrate compliance with more than one RVO so long as it is valid for compliance with all RVOs to which it is applied.

(5) Except as provided in paragraph (a)(7)(iv) of this section, the value of $(\Sigma RINNUM)_{i-1}$ may not exceed values determined by the following inequalities:

$$(\Sigma RINNUM)_{CB,i-1} \leq 0.20 * RVO_{CB,i}$$

$$(\Sigma RINNUM)_{BBD,i-1} \leq 0.20 * RVO_{BBD,i}$$

$$(\Sigma RINNUM)_{AB,i-1} \leq 0.20 * RVO_{AB,i}$$

$$(\Sigma RINNUM)_{RF,i-1} \leq 0.20 * RVO_{RF,i}$$

(6) Except as provided in paragraphs (a)(7)(ii) and (iii) of this section, RINs may only be used to demonstrate compliance with the RVOs 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.

(7) *Biomass-based diesel in 2010.* (i) Prior to determining compliance with the 2010 biomass-based diesel RVO, obligated parties may reduce the value of $RVO_{BBD,2010}$ by an amount equal to the sum of all 2008 and 2009 RINs used for compliance purposes for calendar year 2009 which have an RR code of 15 or 17.

(ii) For calendar year 2010 only, the following equation shall be used to determine compliance with the biomass-based diesel RVO instead of the equation in paragraph (a)(1)(ii) of this section:

$$(\Sigma RINNUM)_{BBD,2010} + (\Sigma RINNUM)_{BBD,2009} + (\Sigma RINNUM)_{BBD,2008} = RVO_{BBD,2010}$$

Where:

$(\Sigma RINNUM)_{BBD,2010}$ = Sum of all owned gallon-RINs that are valid for use in complying with the biomass-based diesel RVO, were generated in year 2010, and are being applied towards the $RVO_{BBD,2010}$, in gallons.

$(\Sigma RINNUM)_{BBD,2009}$ = Sum of all owned gallon-RINs that are valid for use in complying with the biomass-based diesel RVO, were generated in year 2009, have not previously been used for compliance purposes, and are being applied towards the $RVO_{BBD,2010}$, in gallons.

$(\Sigma RINNUM)_{BBD,2008}$ = Sum of all owned gallon-RINs that are valid for use in complying with the biomass-based diesel RVO, were generated in year 2008, have not previously been used for compliance purposes, and are being applied towards the $RVO_{BBD,2010}$, in gallons.

$RVO_{BBD,2010}$ = The Renewable Volume Obligation for biomass-based diesel for the obligated party or renewable fuel exporter for calendar year 2010, in gallons, pursuant to § 80.1407 or § 80.1430, as adjusted by paragraph (a)(7)(i) of this section.

(iii) RINs generated in 2008 or 2009 which have not been used for compliance purposes for calendar years 2008 or 2009 and which have an RR code of 15 or 17 may be used to demonstrate compliance with the 2010 biomass-based diesel RVO.

(iv) For compliance with the biomass-based diesel RVO in calendar year 2010 only, the values of $(\Sigma RINNUM)_{2008}$ and $(\Sigma RINNUM)_{2009}$ may not exceed values determined by both of the following inequalities:

$$(\Sigma RINNUM)_{BBD,2008} \leq 0.087 * RVO_{BBD,2010}$$

$$(\Sigma RINNUM)_{BBD,2008} + (\Sigma RINNUM)_{BBD,2009} \leq 0.20 * RVO_{BBD,2010}$$

(8) A party may only use a RIN for purposes of meeting the requirements of paragraph (a)(1) of this section if that RIN is a separated RIN with a K code of 2 obtained in accordance with §§ 80.1428 and 80.1429.

(9) The number of gallon-RINs associated with a given batch-RIN that can be used for compliance with the RVOs shall be calculated from the following formula:

$$RINNUM = EEEEEEEE - SSSSSSSS + 1$$

Where:

RINNUM = Number of gallon-RINs associated with a batch-RIN, where each gallon-RIN represents one gallon of renewable fuel for compliance purposes.

EEEEEEEE = Batch-RIN component identifying the last gallon-RIN associated with the batch-RIN.

SSSSSSSS = Batch-RIN component identifying the first gallon-RIN associated with the batch-RIN.

(b) *Deficit carryovers.* (1) An obligated party or an exporter of renewable fuel that fails to meet the requirements of paragraph (a)(1) or (a)(5) 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 for the same RVO.

(ii) The party subsequently meets the requirements of paragraph (a)(1) of this section for calendar year i+1 and carries no deficit into year i+2 for the same RVO.

(iii) For compliance with the biomass-based diesel RVO in calendar year 2011, the deficit which is carried over from 2010 is no larger than 57% of the party's 2010 biomass-based diesel RVO as determined prior to any adjustment applied pursuant to paragraph (a)(7)(i) of this section.

(2) A deficit is calculated according to the following formula:

$$D_i = RVO_i - [(\Sigma RINNUM)_i + (\Sigma RINNUM)_{i-1}]$$

Where:

D_i = The deficit, in gallons, generated in calendar year i that must be carried over to year i+1 if allowed to do so pursuant to paragraph (b)(1) of this section.

RVO_i = The Renewable Volume Obligation for the obligated party or renewable fuel exporter for calendar year i, in gallons.

$(\Sigma RINNUM)_i$ = Sum of all acquired gallon-RINs that were generated in year i and are being applied towards the RVO_i, in gallons.

$(\Sigma RINNUM)_{i-1}$ = Sum of all acquired gallon-RINs that were generated in year i-1 and are being applied towards the RVO_i, in gallons.

§ 80.1428 General requirements for RIN distribution.

(a) *RINs assigned to volumes of renewable fuel and RINs generated, but not assigned.* (1) *Definitions.* (i) *Assigned RIN,* for the purposes of this subpart, means a RIN assigned to a volume of renewable fuel pursuant to § 80.1426(e) with a K code of 1.

(ii) *RINS generated, but not assigned* are those RINs that have been generated pursuant to 80.1426(a), but have not been assigned to a volume of renewable fuel pursuant to 80.1426(e).

(2) Except as provided in § 80.1429, no party can separate a RIN that has been assigned to a batch pursuant to § 80.1426(e).

(3) An assigned RIN cannot be transferred to another party without simultaneously transferring a volume of renewable fuel to that same party.

(4) No more than 2.5 assigned gallon-RINs with a K code of 1 can be transferred to another party with every gallon of renewable fuel transferred to that same party.

(5)(i) On each of the dates listed in paragraph (a)(5)(ii) of this section in any calendar year, the following equation must be satisfied for assigned RINs and volumes of renewable fuel owned by a party:

$$\Sigma(RIN)_D \leq \Sigma(V_{si} * 2.5)_D$$

Where:

D = Applicable date.

$\Sigma(RIN)_D$ = Sum of all assigned gallon-RINs with a K code of 1 and all RINs generated, but not assigned that are owned on date D.

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

$\Sigma(V_{si} * 2.5)_D$ = Sum of all volumes of renewable fuel owned on date D, multiplied by an equivalence value of 2.5.

(ii) The applicable dates are March 31, June 30, September 30, and December 31.

(6) Any transfer of ownership of assigned RINs must be documented on product transfer documents generated pursuant to § 80.1453.

(i) The RIN must be recorded on the product transfer document used to transfer ownership of the volume of renewable fuel to another party; or

(ii) The RIN must be recorded on a separate product transfer document transferred to the same party on the same day as the product transfer document used to transfer ownership of the volume of renewable fuel.

(b) *RINs separated from volumes of renewable fuel.* (1) *Separated RIN,* for the purposes of this subpart, means a RIN with a K code of 2 that has been separated from a volume of renewable fuel pursuant to § 80.1429.

(2) Any party that has registered pursuant to § 80.1450 can hold title to a separated RIN.

(3) Separated RINs can be transferred from one party to another any number of times.

(c) *RIN expiration.* A RIN is valid for compliance during the year in which it was generated, or the following year. Any RIN that is not used for compliance purposes during the year that it was generated, or during the following year, will be considered an expired RIN. Pursuant to § 80.1431(a)(3), an expired RIN that is used for compliance will be considered an invalid RIN.

(d) Any batch-RIN can be divided by its owner into multiple batch-RINs, each representing a smaller number of gallon-RINs, if all of the following conditions are met:

(1) All RIN components other than SSSSSSSS and EEEEEEEE are identical for the original parent and newly formed daughter RINs.

(2) The sum of the gallon-RINs associated with the multiple daughter batch-RINs is equal to the gallon-RINs associated with the parent batch-RIN.

§ 80.1429 Requirements for separating RINs from volumes of renewable fuel.

(a)(1) Separation of a RIN from a volume of renewable fuel means termination of the assignment of the RIN to a volume of renewable fuel.

(2) RINs that have been separated from volumes of renewable fuel become separated RINs subject to the provisions of § 80.1428(b).

(b) A RIN that is assigned to a volume of renewable fuel is separated from that volume only under one of the following conditions:

(1) Except as provided in paragraph (b)(6) of this section, a party that is an obligated party according to § 80.1406 must separate any RINs that have been assigned to a volume of renewable fuel if they own that volume.

(2) Except as provided in paragraph (b)(5) of this section, any party that owns a volume of renewable fuel must separate any RINs that have been assigned to that volume once the volume is blended with gasoline or diesel to produce a transportation fuel,

home heating oil, or jet fuel. A party may separate up to 2.5 RINs per gallon of renewable fuel.

(3) Any party that exports a volume of renewable fuel must separate any RINs that have been assigned to the exported volume.

(4) Any party that produces, imports, owns, sells, or uses a volume of neat renewable fuel, or a blend of renewable fuel and diesel fuel, must separate any RINs that have been assigned to that volume of neat renewable fuel or that blend if:

(i) The party designates the neat renewable fuel or blend as transportation fuel, home heating oil, or jet fuel: and

(ii) The neat renewable fuel or blend is used without further blending, in the designated form, as transportation fuel, home heating oil, or jet fuel.

(5) RINs assigned to a volume of biodiesel (mono-alkyl ester) can only be separated from that volume pursuant to paragraph (b)(2) of this section if such biodiesel is blended into diesel fuel at a concentration of 80 volume percent biodiesel (mono-alkyl ester) or less.

(i) This paragraph (b)(5) shall not apply to obligated parties or exporters of renewable fuel.

(ii) This paragraph (b)(5) shall not apply to parties meeting the requirements of paragraph (b)(4) of this section.

(6) For RINs that an obligated party generates for renewable fuel that has not been blended into gasoline or diesel to produce a transportation fuel, the obligated party can only separate such RINs from volumes of renewable fuel if the number of gallon-RINs separated in a calendar year is less than or equal to a limit set as follows:

(i) For RINs with a D code of 1, the limit shall be equal to RVO_{CB}.

(ii) For RINs with a D code of 2, the limit shall be equal to RVO_{BBD}.

(iii) For RINs with a D code of 3, the limit shall be equal to RVO_{AB} — RVO_{CB}—RVO_{BBD}.

(iv) For RINs with a D code of 4, the limit shall be equal to RVO_{RF} — RVO_{AB}.

(7) For a party that has received a small refinery exemption under § 80.1441 or a small refiner exemption under § 80.1442, and is not otherwise an obligated party, during the period of time that the small refinery or small refiner exemptions are in effect, the party may only separate RINs that have been assigned to volumes of renewable fuel that the party blends into gasoline or diesel to produce transportation fuel, or that the party used as home heating oil or jet fuel.

(c) The party responsible for separating a RIN from a volume of renewable fuel shall change the K code in the RIN from a value of 1 to a value of 2 prior to transferring the RIN to any other party.

(d) Upon and after separation of a RIN from its associated volume of renewable fuel, the separated RIN must be accompanied by documentation when transferred.

(1) When transferred, the separated RIN shall appear on documentation that includes all the following information:

(i) The name and address of the transferor and transferee.

(ii) The transferor's and transferee's EPA company registration numbers.

(iii) The date of the transfer.

(iv) A list of separated RINs transferred.

(2) [Reserved]

(e) Upon and after separation of a RIN from its associated volume of renewable fuel, product transfer documents used to transfer ownership of the volume must continue to meet the requirements of § 80.1453(a)(5)(iii).

(f) Any party that uses a renewable fuel in a commercial or industrial boiler or ocean-going vessel (as defined in § 80.1401), or designates a renewable fuel for use in a boiler or ocean-going vessel, must retire any RINs received with that renewable fuel and report the retired RINs in the applicable reports under § 80.1452. Any 2009 RINs retired pursuant to § 80.1129(e) may be reinstated by the retiring party for sale or use to demonstrate compliance with a 2010 RVO.

§ 80.1430 Requirements for exporters of renewable fuels.

(a) Any party that owns any amount of renewable fuel, whether in its neat form or blended with gasoline or diesel, that is exported from any of the regions described in § 80.1426(a) shall acquire sufficient RINs to offset all applicable Renewable Volume Obligations representing the exported renewable fuel.

(b) *Renewable Volume Obligations.* An exporter of renewable fuel shall determine its Renewable Volume Obligations from the volumes of the renewable fuel exported.

(1) For exported volumes of biodiesel (mono-alkyl ester) or non-ester renewable diesel, a renewable fuel exporter's Renewable Volume Obligation for biomass-based diesel shall be calculated according to the following formula:

$$RVO_{BBD,i} = \Sigma(VOL_k * EV_k)_i + D_{BBD,i-1}$$

Where:

$RVO_{BBD,i}$ = The Renewable Volume Obligation for biomass-based diesel for the exporter for calendar year i, in gallons.

k = A discrete volume of biodiesel (mono-alkyl ester) or non-ester renewable diesel fuel.

VOL_k = The standardized volume of discrete volume k of exported biodiesel (mono-alkyl ester) or non-ester renewable diesel, in gallons, calculated in accordance with § 80.1426(d)(10).

EV_k = The equivalence value associated with discrete volume k.

Σ = Sum involving all volumes of biodiesel (mono-alkyl ester) or non-ester renewable diesel exported.

$D_{BBD,i-1}$ = Deficit carryover from the previous year for biomass-based diesel, in gallons.

(2) For exported volumes of all renewable fuels, a renewable fuel exporter's Renewable Volume Obligation for total renewable fuel shall be calculated according to the following formula:

$$RVO_{RF,i} = \Sigma(VOL_k * EV_k)_i + D_{RF,i-1}$$

Where:

$RVO_{RF,i}$ = The Renewable Volume Obligation for renewable fuel for the exporter for calendar year i, in gallons of renewable fuel.

k = A discrete volume of renewable fuel.

VOL_k = The standardized volume of discrete volume k of exported renewable fuel, in gallons, calculated in accordance with § 80.1426(d)(10).

EV_k = The equivalence value associated with discrete volume k.

Σ = Sum involving all volumes of renewable fuel exported.

$D_{RF,i-1}$ = Deficit carryover from the previous year for renewable fuel, in gallons.

(3)(i) If the equivalence value for a volume of renewable fuel can be determined pursuant to § 80.1415 based on its composition, then the appropriate equivalence value shall be used in the calculation of the exporter's Renewable Volume Obligations.

(ii) If the equivalence value for a volume of renewable fuel cannot be determined, the value of EV_k shall be 1.0.

(c) Each exporter of renewable fuel must demonstrate compliance with its RVOs using RINs it has acquired, pursuant to § 80.1427.

§ 80.1431 Treatment of invalid RINs.

(a) *Invalid RINs.* An invalid RIN is a RIN that is any of the following:

(1) Is a duplicate of a valid RIN.

(2) Was based on volumes that have not been standardized to 60 °F.

(3) Has expired, except as provided in § 80.1428(c).

(4) Was based on an incorrect equivalence value.

(5) Is deemed invalid under § 80.1467(g).

(6) Does not represent renewable fuel as defined in § 80.1401.

(7) Was assigned an incorrect ''D'' code value under § 80.1426(d)(3) for the associated volume of fuel.

(8) In the event that the same RIN is transferred to two or more parties, all such RINs are deemed invalid, unless EPA in its sole discretion determines that some portion of these RINs is valid.

(9) Was otherwise improperly generated.

(b) In the case of RINs that are invalid, the following provisions apply:

(1) Upon determination by any party that RINs owned are invalid, the party must adjust its records, reports, and compliance calculations in which the invalid RINs were used as necessary to reflect the deletion of the invalid RINs. The party must retire the invalid RINs in the applicable RIN transaction reports under § 80.1452(c)(2) for the quarter in which the RINs were determined to be invalid.

(2) Invalid RINs cannot be used to achieve compliance with the Renewable Volume Obligations of an obligated party or exporter, regardless of the party's good faith belief that the RINs were valid at the time they were acquired.

(3) Any valid RINs remaining after deleting invalid RINs must first be applied to correct the transfer of invalid RINs to another party before applying the valid RINs to meet the party's Renewable Volume Obligations at the end of the compliance year.

§ 80.1432 Reported spillage or disposal of renewable fuel.

(a) A reported spillage or disposal under this subpart means a spillage or disposal of renewable fuel associated with a requirement by a federal, state, or local authority to report the spillage or disposal.

(b) Except as provided in paragraph (c) of this section, in the event of a reported spillage or disposal of any volume of renewable fuel, the owner of the renewable fuel must retire a number of RINs corresponding to the volume of spilled or disposed of renewable fuel multiplied by its equivalence value.

(1) If the equivalence value for the spilled or disposed of volume may be determined pursuant to § 80.1415 based on its composition, then the appropriate equivalence value shall be used.

(2) If the equivalence value for a spilled or disposed of volume of renewable fuel cannot be determined, the equivalence value shall be 1.0.

(c) If the owner of a volume of renewable fuel that is spilled or disposed of and reported establishes that no RINs were generated to represent the volume, then no RINs shall be retired.

(d) A RIN that is retired under paragraph (b) of this section:

(1) Must be reported as a retired RIN in the applicable reports under § 80.1452.

(2) May not be transferred to another party or used by any obligated party to demonstrate compliance with the party's Renewable Volume Obligations.

§§ 80.1433–80.1439 [Reserved]

§ 80.1440 What are the provisions for blenders who handle and blend less than 125,000 gallons of renewable fuel per year?

(a) Renewable fuel blenders who handle and blend less than 125,000 gallons of renewable fuel per year, and who do not have Renewable Volume Obligations, are permitted to delegate their RIN-related responsibilities to the party directly upstream of them who supplied the renewable fuel for blending.

(b) The RIN-related responsibilities that may be delegated directly upstream include all the following:

(1) The RIN separation requirements of § 80.1429.

(2) The recordkeeping requirements of § 80.1451.

(3) The reporting requirements of § 80.1452.

(4) The attest engagement requirements of § 80.1464.

(c) For upstream delegation of RIN-related responsibilities, both parties must agree on the delegation, and a quarterly written statement signed by both parties must be included with the reporting party's reports under § 80.1452.

(1) If EPA finds that a renewable fuel blender improperly delegated its RIN-related responsibilities under this subpart M, the blender will be held accountable for any RINs separated and will be subject to all RIN-related responsibilities under this subpart.

(2) [Reserved]

(d) Renewable fuel blenders who handle and blend less than 125,000 gallons of renewable fuel per year and who do not opt to delegate their RIN-related responsibilities will be subject to all requirements stated in paragraph (b) of this section, and all other applicable requirements of this subpart M.

§ 80.1441 Small refinery exemption.

(a)(1) Transportation fuel produced at a refinery by a refiner, or foreign refiner (as defined at § 80.1465(a)), is exempt through December 31, 2010 from the renewable fuel standards of § 80.1405; and the refinery, or foreign refinery, is exempt from the requirements that apply to obligated parties under this subpart M if that refinery meets the definition of a small refinery under § 80.1401 for calendar year 2006.

(2) This exemption shall apply unless a refiner chooses to waive this exemption (as described in paragraph (f) of this section), or the exemption is extended (as described in paragraph (e) of this section).

(3) For the purposes of this section, the term ''refiner'' shall include foreign refiners.

(4) This exemption shall only apply to refineries that process crude oil through refinery processing units.

(5) The small refinery exemption is effective immediately, except as specified in paragraph (b)(3) of this section.

(b)(1) A refiner owning a small refinery must submit a verification letter to EPA containing all of the following information:

(i) The annual average aggregate daily crude oil throughput for the period January 1, 2006 through December 31, 2006 (as determined by dividing the aggregate throughput for the calendar year by the number 365).

(ii) A letter signed by the president, chief operating or chief executive officer of the company, or his/her designee, stating that the information contained in the letter is true to the best of his/her knowledge, and that the refinery was small as of December 31, 2006.

(iii) Name, address, phone number, facsimile number, and e-mail address of a corporate contact person.

(2) Verification letters must be submitted by January 1, 2010 to one of the addresses listed in paragraph (h) of this section.

(3) For foreign refiners the small refinery exemption shall be effective upon approval, by EPA, of a small refinery application. The application must contain all of the elements required for small refinery verification letters (as specified in paragraph (b)(1) of this section), must satisfy the provisions of § 80.1465(f) through (h) and (o), and must be submitted by January 1, 2010 to one of the addresses listed in paragraph (h) of this section.

(4) Small refinery verification letters are not required for those refiners who have already submitted a verification letter under subpart K of this Part 80.

(c) If EPA finds that a refiner provided false or inaccurate information regarding a refinery's crude throughput (pursuant to paragraph (b)(1)(i) of this section) in its small refinery verification letter, the exemption will be void as of the effective date of these regulations.

(d) If a refiner is complying on an aggregate basis for multiple refineries, any such refiner may exclude from the calculation of its Renewable Volume Obligations (under § 80.1407) transportation fuel from any refinery receiving the small refinery exemption under paragraph (a) of this section.

(e)(1) The exemption period in paragraph (a) of this section shall be extended by the Administrator for a period of not less than two additional years if a study by the Secretary of Energy determines that compliance with the requirements of this subpart would impose a disproportionate economic hardship on a small refinery.

(2) A refiner may petition the Administrator for an extension of its small refinery exemption, based on disproportionate economic hardship, at any time.

(i) 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 hardship the refinery would face in producing transportation fuel meeting the requirements of § 80.1405 and the date the refiner anticipates that compliance with the requirements can reasonably be achieved at the small refinery.

(ii) The Administrator shall act on such a petition not later than 90 days after the date of receipt of the petition.

(f) At any time, a refiner with an approved small refinery exemption under paragraph (a) of this section may waive that exemption upon notification to EPA.

(1) A refiner's notice to EPA that it intends to waive its small refinery exemption must be received by November 1 to be effective in the next compliance year.

(2) The waiver will be effective beginning on January 1 of the following calendar year, at which point the gasoline produced at that refinery will be subject to the renewable fuels standard of § 80.1405 and all other requirements that apply to obligated parties under this Subpart M.

(3) The waiver must be sent to EPA at one of the addresses listed in paragraph (h) of this section.

(g) A refiner that acquires a refinery from either an approved small refiner (as defined under § 80.1442(a)) or another refiner with an approved small refinery exemption under paragraph (a) of this section shall notify EPA in writing no later than 20 days following the acquisition.

(h) Verification letters under paragraph (b) of this section, petitions for small refinery hardship extensions under paragraph (e) of this section, and small refinery exemption waivers under paragraph (f) of this section shall be sent to one of the following addresses:

(1) *For US mail:* U.S. EPA, Attn: RFS2 Program, 6406J, 1200 Pennsylvania Avenue, NW., Washington, DC 20460.

(2) *For overnight or courier services:* U.S. EPA, Attn: RFS2 Program, 6406J, 1310 L Street, NW, 6th floor, Washington, DC 20005. (202) 343–9038.

§ 80.1442 What are the provisions for small refiners under the RFS program?

(a)(1) To qualify as a small refiner under this section, a refiner must meet all of the following criteria:

(i) The refiner produced transportation fuel at its refineries by processing crude oil through refinery processing units from January 1, 2006 through December 31, 2006.

(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 2006 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 2006.

(2) For the purposes of this section, the term "refiner" shall include foreign refiners.

(b) *Applications for small refiner status.* (1) Applications for small refiner status under this section must be submitted to EPA by January 1, 2010.

(2) Small refiner status applications under this section must include all 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:

(i) A listing of the name and address of each company location where any employee worked for the period January 1, 2006 through December 31, 2006.

(ii) The average number of employees at each location based on the number of employees for each pay period for the period January 1, 2006 through December 31, 2006.

(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.

(vi) 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, 2006 through December 31, 2006. 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.

(vii) 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.

(viii) Name, address, phone number, facsimile number, and e-mail address of a corporate contact person.

(3) In the case of a refiner who acquires or reactivates a refinery that was shut down or non-operational between January 1, 2005 and January 1, 2006, the information required in paragraph (b)(2) of this section must be provided for the time period since the refiner acquired or reactivated the refinery.

(4) EPA will notify a refiner of its approval or disapproval of the application for small refiner status by letter.

(5) For foreign refiners the small refiner exemption shall be effective upon approval, by EPA, of a small refiner application. The application must contain all of the elements required for small refiner status applications (as specified in paragraph (b)(2) of this section), must satisfy the provisions of § 80.1465(f) through (h) and (o), must demonstrate compliance with the crude oil capacity criterion of paragraph (a)(1)(iii) of this section, and must be submitted by January 1, 2010 to one of the addresses listed in paragraph (i) of this section.

(c) *Small refiner temporary exemption.* (1) Transportation fuel produced by a refiner, or foreign refiner (as defined at § 80.1465(a)), is exempt through December 31, 2010 from the renewable fuel standards of § 80.1405 and the requirements that apply to obligated parties under this subpart if the refiner or foreign refiner meets all of the following criteria:

(i) The refiner produced transportation fuel at its refineries by processing crude oil through refinery processing units from January 1, 2006 through December 31, 2006.

(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 2006 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 2006.

(2) The small refiner exemption shall apply to an approved small refiner unless that refiner chooses to waive this exemption (as described in paragraph (d) of this section).

(d)(1) A refiner with approved small refiner status may, at any time, waive the small refiner exemption under paragraph (c) of this section upon notification to EPA.

(2) A refiner's notice to EPA that it intends to waive the small refiner exemption must be received by November 1 of a given year in order for the waiver to be effective for the following calendar year. The waiver will be effective beginning on January 1 of the following calendar year, at which point the refiner will be subject to the renewable fuel standards of § 80.1405 and the requirements that apply to obligated parties under this subpart.

(3) The waiver must be sent to EPA at one of the addresses listed in paragraph (j) of this section.

(e) Refiners who qualify as small refiners under this section and subsequently fail to meet all of the qualifying criteria as set out in paragraph (a) of this section are disqualified as small refiners as of the effective date of this subpart, except as provided under paragraphs (d) and (e)(2) of this section.

(1) In the event such disqualification occurs, the refiner shall notify EPA in writing no later than 20 days following the disqualifying event.

(2) Disqualification under this paragraph (e) shall not apply in the case of a merger between two approved small refiners.

(f) If EPA finds that a refiner provided false or inaccurate information in its application for small refiner status under this subpart M, the refiner will be disqualified as a small refiner as of the effective date of this subpart.

(g) Any refiner that acquires a refinery from another refiner with approved small refiner status under paragraph (a) of this section shall notify EPA in writing no later than 20 days following the acquisition.

(h) *Extensions of the small refiner temporary exemption.* (1) A small refiner may apply for an extension of the temporary exemption of paragraph (c)(1) of this section based on a showing of all the following:

(i) Circumstances exist that impose disproportionate economic hardship on the refiner and significantly affect the refiner's ability to comply with the RFS standards.

(ii) The refiner has made best efforts to comply with the requirements of this subpart.

(2) A refiner must apply, and be approved, for small refiner status under this section.

(3) A small refiner's hardship application must include all the following information:

(i) A plan demonstrating how the refiner will comply with the requirements of § 80.1405 (and all other requirements of this subpart applicable to obligated parties), as expeditiously as possible.

(ii) A detailed description of the refinery configuration and operations including, at a minimum, all the following information:

(A) The refinery's total crude capacity.

(B) Total crude capacity of any other refineries owned by the same entity.

(C) Total volume of gasoline and diesel produced at the refinery.

(D) Detailed descriptions of efforts to comply.

(E) Bond rating of the entity that owns the refinery.

(F) Estimated investment needed to comply with the requirements of this subpart.

(4) A small refiner shall notify EPA in writing of any changes to its situation between approval of the extension application and the end of its approved extension period.

(5) EPA may impose reasonable conditions on extensions of the temporary exemption, including reducing the length of such an extension, if conditions or situations change between approval of the application and the end of the approved extension period.

(i) Applications for small refiner status, small refiner exemption waivers, or extensions of the small refiner temporary exemption under this section must be sent to one of the following addresses:

(1) *For US Mail:* U.S. EPA, *Attn:* RFS2 Program, 6406J, 1200 Pennsylvania Avenue, NW., Washington, DC 20460.

(2) *For overnight or courier services:* U.S. EPA, *Attn:* RFS2 Program, 6406J, 1310 L Street, NW., 6th floor, Washington, DC 20005. (202) 343–9038.

§ 80.1443 What are the opt-in provisions for noncontiguous states and territories?

(a) Alaska or a United States territory may petition the Administrator to opt-in to the program requirements of this subpart.

(b) The Administrator will approve the petition if it meets the provisions of paragraphs (c) and (d) of this section.

(c) The petition must be signed by the Governor of the state or his authorized representative (or the equivalent official of the territory).

(d)(1) A petition submitted under this section must be received by EPA by November 1 for the state or territory to be included in the RFS program in the next calendar year.

(2) A petition submitted under this section should be sent to either of the following addresses:

(i) *For US Mail:* U.S. EPA, *Attn:* RFS Program, 6406J, 1200 Pennsylvania Avenue, NW., Washington, DC 20460.

(ii) *For overnight or courier services:* U.S. EPA, *Attn:* RFS Program, 6406J, 1310 L Street, NW., 6th floor, Washington, DC 20005. (202) 343–9038.

(e) Upon approval of the petition by the Administrator:

(1) EPA shall calculate the standards for the following year, including the total gasoline and diesel fuel volume for the state or territory in question.

(2) Beginning on January 1 of the next calendar year, all gasoline and diesel fuel refiners and importers in the state or territory for which a petition has been approved shall be obligated parties as defined in § 80.1406.

(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 § 80.1426(a)(2), be required to generate RINs and comply with other requirements of this subpart M that are applicable to producers of renewable fuel.

§ 80.1444–80.1448 [Reserved]

§ 80.1449 What are the Production Outlook Report requirements?

(a) A renewable fuel producer or importer, for each of its facilities, must submit all the following information, as applicable, to EPA annually beginning February 28, 2010:

(1) The type, or types, of renewable fuel expected to be produced or imported at each facility owned by the renewable fuel producer or importer.

(2) The volume of each type of renewable fuel expected to be produced or imported at each facility.

(3) The number of RINs expected to be generated by the renewable fuel producer or importer for each type of renewable fuel.

(4) Information about all the following:

(i) Existing and planned production capacity.

(ii) Long-range plans.

(iii) Feedstocks and production processes to be used at each production facility.

(iv) Changes to the facility that would raise or lower emissions of any greenhouse gases from the facility.

(5) For expanded production capacity that is planned or underway at each existing facility, or new production facilities that are planned or underway, information on all the following:

(i) Strategic planning.

(ii) Planning and front-end engineering.

(iii) Detailed engineering and permitting.

(iv) Procurement and construction.

(v) Commissioning and startup.

(6) Whether capital commitments have been made or are projected to be made.

(b) The information listed in paragraph (a) of this section shall include the reporting party's best estimates for the five following calendar years.

(c) Production outlook reports must provide an update of the progress in each of the areas listed in paragraph (a)(5) of this section.

(d) Production outlook reports shall be sent to one of the following addresses:

(1) *For US Mail:* U.S. EPA, Attn: RFS2 Program-Production Outlook Reports, 6406J, 1200 Pennsylvania Avenue, NW., Washington, DC 20460.

(2) *For overnight or courier services:* U.S. EPA, Attn: RFS2 Program-Production Outlook Reports, 6406J, 1310 L Street, NW., 6th floor, Washington, DC 20005. (202) 343–9038.

§ 80.1450 What are the registration requirements under the RFS program?

(a) *Obligated Parties and Exporters.* Any obligated party described in § 80.1406, and any exporter of renewable fuel described in § 80.1430, must provide EPA with the information specified for registration under § 80.76, if such information has not already been provided under the provisions of this part. An obligated party or an exporter of renewable fuel must receive EPA-issued identification numbers prior to engaging in any transaction involving RINs. Registration information must be submitted to EPA by January 1, 2010 or 60 days prior to engaging in any transaction involving RINs, whichever is later.

(b) *Producers.* Except as provided in § 80.1426(b)(1), any foreign or domestic producer of renewable fuel, regardless of whether RINs will be generated for that renewable fuel, must provide EPA the information specified under § 80.76 if such information has not already been provided under the provisions of this part, and must receive EPA-issued company and facility identification numbers prior to generating or assigning any RINs. All the following registration information must be submitted to EPA by January 1, 2010 or 60 days prior to the production of any renewable fuel subject to this subpart, whichever is later:

(1) A description of the types of renewable fuels and co-products produced at the facility and all the following for each product type:

(i) A list of the feedstocks capable of being utilized by the facility.

(ii) A description of the facility's renewable fuel production processes.

(iii) The facility's renewable fuel production capacity.

(iv) A list of the facility's process energy sources.

(v) For a producer of renewable fuel with a facility that commenced construction on or before December 19, 2007 per § 80.1403:

(A) The location of the facility.

(B) Record of costs of additions, replacements, and repairs inclusive of labor costs conducted at the facility since December 19, 2007.

(C) The estimated life of the facility.

(D) A discussion of any economic or technical limitations the facility may have in using a fuel production pathway that will achieve a 20 percent reduction in GHG as compared to baseline fuel.

(2) An independent third party engineering review and written verification of the descriptions made pursuant to paragraph (b)(1) of this section.

(i) The verifications required under this section must be conducted by a licensed Professional Engineer who works in the chemical engineering field and who is licensed by the appropriate state agency.

(ii) To be considered an independent third party under this paragraph (b)(2):

(A) The third party shall not be operated by the renewable fuel producer or any subsidiary or employee of the renewable fuel producer.

(B) The third party shall be free from any interest in the renewable fuel producer's business.

(C) The renewable fuel producer shall be free from any interest in the third party's business.

(D) Use of a third party that is debarred, suspended, or proposed for debarment pursuant to the Government-wide Debarment and Suspension regulations, 40 CFR part 32, or the Debarment, Suspension and Ineligibility provisions of the Federal Acquisition Regulations, 48 CFR, part 9, subpart 9.4, shall be deemed noncompliance with the requirements of this section.

(iii) The independent third party shall retain all records pertaining to the verification required under this section for a period of five years from the date of creation and shall deliver such records to the Administrator upon request.

(iv) The renewable fuel producer must retain records of the review and verification, as required in § 80.1451(b)(7).

(c) *Importers.* Importers of renewable fuel must provide EPA the information specified under § 80.76, if such information has not already been provided under the provisions of this part and must receive an EPA-issued company identification number prior to owning any RINs. Registration information may be submitted to EPA by January 1, 2010 or 60 days prior to engaging in any transaction involving RINs, whichever is later.

(d) *Registration updates.* Except as provided in § 80.1426(b)(1):

(1) Any producer of renewable fuel who makes changes to his facility that will qualify his renewable fuel for a renewable fuel category or D code as defined in § 80.1425(g) that is not reflected in the producer's registration information on file with EPA must update his registration information and submit a copy of an updated independent engineering review at least 60 days prior to producing the new type of renewable fuel.

(2) Any producer of renewable fuel who makes any other changes to a facility not affecting the renewable fuel category for which the producer is registered must update his registration information within 7 days of the change.

(e) *Parties who own RINs or who intend to own RINs.* Any party who owns or intends to own RINs, but who is not covered by paragraphs (a), (b), or (d) of this section, must provide EPA the information specified under § 80.76, if such information has not already been provided under the provisions of this part and must receive an EPA-issued company identification number prior to owning any RINs. Registration information must be submitted to EPA by January 1, 2010 or 60 days prior to engaging in any transaction involving RINs, whichever is later.

(f) Registration shall be on forms, and following policies, established by the Administrator.

§ 80.1451 What are the recordkeeping requirements under the RFS program?

(a) Beginning January 1, 2010, any obligated party (as described at § 80.1406) or exporter of renewable fuel (as described at § 80.1430) must keep all of the following records:

(1) Product transfer documents consistent with § 80.1453 and associated with the obligated party's activity, if any, as transferor or transferee of renewable fuel.

(2) Copies of all reports submitted to EPA under §§ 80.1449 and 80.1452(a).

(3) Records related to each RIN transaction, including all the following:

(i) A list of the RINs owned, purchased, sold, retired, or reinstated.

(ii) The parties involved in each RIN transaction including the transferor, transferee, and any broker or agent.

(iii) The date of the transfer of the RIN(s).

(iv) Additional information related to details of the transaction and its terms.

(4) Records related to the use of RINs (by facility, if applicable) for compliance, including all the following:

(i) Methods and variables used to calculate the Renewable Volume Obligations pursuant to § 80.1407 or § 80.1430.

(ii) List of RINs used to demonstrate compliance.

(iii) Additional information related to details of RIN use for compliance.

(b) Beginning January 1, 2010, any foreign or domestic producer of a renewable fuel as defined in § 80.1401 must keep all of the following records:

(1) Product transfer documents consistent with § 80.1453 and associated with the renewable fuel producer's activity, if any, as transferor or transferee of renewable fuel.

(2) Copies of all reports submitted to EPA under §§ 80.1449 and 80.1452(b).

(3) Records related to the generation and assignment of RINs for each facility, including all of the following:

(i) Batch volume in gallons.

(ii) Batch number.

(iii) RIN as assigned under § 80.1426.

(iv) Identification of batches by renewable category.

(v) Date of production.

(vi) Results of any laboratory analysis of batch chemical composition or physical properties.

(vii) Additional information related to details of RIN generation.

(4) Records related to each RIN transaction, including all of the following:

(i) A list of the RINs owned, purchased, sold, retired, or reinstated.

(ii) The parties involved in each transaction including the transferor, transferee, and any broker or agent.

(iii) The date of the transfer of the RIN(s).

(iv) Additional information related to details of the transaction and its terms.

(5) Records related to the production, importation, ownership, sale or use of any volume of renewable fuel or blend of renewable fuel and gasoline or diesel fuel that any party designates for use as transportation fuel, jet fuel, or home heating oil and the use of the fuel or blend as transportation fuel, jet fuel, or home heating oil without further blending, in the designated form.

(6) Documents associated with feedstock purchases and transfers that identify where the feedstocks were produced and are sufficient to verify that feedstocks used are renewable biomass (as defined in § 80.1401) if RINs are generated, or sufficient to verify that feedstocks used are not renewable biomass if no RINs are generated.

(i) Renewable fuel producers who use planted crops or crop residue from existing agricultural land, or who use planted trees or slash from actively managed tree plantations must keep records that serve as evidence that the land from which the feedstock was obtained was continuously actively managed or fallow, and nonforested, since December 19, 2007. The records must be provided by the feedstock producer and consist of at least one of the following documents: Sales records for planted crops or trees, crop residue, livestock, or slash; purchasing records for fertilizer, weed control, or reseeding, including seeds, seedlings, or other nursery stock; a written management plan for agricultural or silvicultural purposes; documentation of participation in an agricultural, or silvicultural program sponsored by a Federal, state or local government agency; or documentation of land management in accordance with an agricultural or silvicultural product certification program.

(ii) Renewable fuel producers who use any other type of renewable biomass must have written certification from their feedstock supplier that the feedstock qualifies as renewable biomass.

(iii) Renewable fuel producers who do not use renewable biomass must have written certification from their feedstock supplier that the feedstock does not qualify as renewable biomass.

(7) Copies of registration documents required under § 80.1450, including information on fuels and products, feedstocks, facility production processes and capacity, energy sources, and independent third party engineering review.

(c) Beginning January 1, 2010, any importer of a renewable fuel (as defined in § 80.1401) must keep all of the following records:

(1) Product transfer documents consistent with § 80.1453 and associated with the renewable fuel importer's activity, if any, as transferor or transferee of renewable fuel.

(2) Copies of all reports submitted to EPA under §§ 80.1449 and 80.1452(b); however, duplicate records are not required.

(3) Records related to the generation and assignment of RINs for each facility, including all of the following:

(i) Batch volume in gallons.

(ii) Batch number.

(iii) RIN as assigned under § 80.1426.

(iv) Identification of batches by renewable category.

(v) Date of import.

(vi) Results of any laboratory analysis of batch chemical composition or physical properties.

(vii) Additional information related to details of RIN generation.

(4) Records related to each RIN transaction, including all of the following:

(i) A list of the RINs owned, purchased, sold, retired, or reinstated.

(ii) The parties involved in each transaction including the transferor, transferee, and any broker or agent.

(iii) The date of the transfer of the RIN(s).

(iv) Additional information related to details of the transaction and its terms.

(5) Documents associated with feedstock purchases and transfers, sufficient to verify that feedstocks used are renewable biomass (as defined in § 80.1401) if the importer generates RINs.

(6) Documents associated with feedstock purchases and transfers, sufficient to verify that feedstocks used are not renewable biomass as defined in § 80.1401 if the importer does not generate RINs.

(7) Copies of registration documents required under § 80.1450.

(8) Records related to the import of any volume of renewable fuel that the importer designates for use as transportation fuel, jet fuel, or home heating oil.

(d) Beginning January 1, 2010, any production facility with a baseline volume of fuel that is not subject to the 20% GHG threshold, pursuant to § 80.1403(a), must keep all of the following:

(1) Detailed engineering plans for the facility.

(2) Federal, State, and local preconstruction approvals and permitting.

(3) Procurement and construction contracts and agreements.

(4) Records of electricity consumption and energy use.

(5) Records showing costs of additions, replacements, and repairs inclusive of labor costs conducted at the facility since December 19, 2007.

(6) Records estimating the life of the existing facility.

(e) Beginning January 1, 2010, any party, other than those parties covered in paragraphs (a) and (b) of this section, that owns RINs must keep all of the following records:

(1) Product transfer documents consistent with § 80.1453 and associated with the party's activity, if any, as transferor or transferee of renewable fuel.

(2) Copies of all reports submitted to EPA under § 80.1452(c).

(3) Records related to each RIN transaction by renewable fuel category, including all of the following:

(i) A list of the RINs owned, purchased, sold, retired, or reinstated.

(ii) The parties involved in each RIN transaction including the transferor, transferee, and any broker or agent.

(iii) The date of the transfer of the RIN(s).

(iv) Additional information related to details of the transaction and its terms.

(4) Records related to any volume of renewable fuel that the party designated for use as transportation fuel, jet fuel, or home heating oil and from which RINs were separated pursuant to § 80.1429(b)(4).

(f) The records required under paragraphs (a) through (c) of this section and under § 80.1453 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.

(g) The records required under paragraph (d) of this section shall be kept through calendar year 2022.

(h) On request by EPA, the records required under this section and under § 80.1453 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.

(i) The records required in paragraphs (b)(6) and (b)(7) of this section must be provided to the importer of the renewable fuel by any foreign producer not generating RINs for his renewable fuel.

§ 80.1452 What are the reporting requirements under the RFS program?

(a) *Obligated parties and exporters.* Any obligated party described in § 80.1406 or exporter of renewable fuel described in § 80.1430 must submit to EPA reports according to the schedule, and containing all the information, that is set forth in this paragraph (a).

(1) Annual compliance demonstration reports for the previous compliance period shall be submitted on February 28 of each year and shall include all of the following information:

(i) The obligated party's name.

(ii) The EPA company registration number.

(iii) Whether the party is complying on a corporate (aggregate) or facility-by-facility basis.

(iv) The EPA facility registration number, if complying on a facility-by-facility basis.

(v) The production volume of all of the products listed in § 80.1407(c) and (f) for the reporting year.

(vi) The RVOs, as defined in § 80.1427(a) for obligated parties and § 80.1430(b) for exporters of renewable fuel, for the reporting year.

(vii) Any deficit RVOs carried over from the previous year.

(viii) The total current-year RINs by type of renewable fuel, as those fuels are defined in § 80.1401 (i.e., cellulosic biofuel, biomass-based diesel, advanced biofuels, and renewable fuels), used for compliance.

(ix) The total prior-year RINs by renewable fuel type, as those fuels are defined in § 80.1401, used for compliance.

(x) A list of all RINs used for compliance in the reporting year.

(A) For the 2010 reporting year only (January 1—December 31, 2010), a list of all 38-digit RINs used to demonstrate compliance.

(B) Starting January 1, 2011, RINs used to meet compliance will be conveyed via the EPA Moderated Transaction System (EMTS) as set forth in paragraph (e) of this section.

(xi) Any deficit RVO(s) carried into the subsequent year.

(xii) Any additional information that the Administrator may require.

(2) The RIN transaction reports required under paragraph (c)(1) of this section.

(3) The quarterly RIN activity reports required under paragraph (c)(2) of this section.

(4) Reports required under this paragraph (a) must be signed and certified as meeting all the applicable requirements of this subpart by the owner or a responsible corporate officer of the obligated party.

(b) *Renewable fuel producers (domestic and foreign) and importers.* Any domestic producer or importer of renewable fuel, or foreign renewable fuel producer who generates RINs, must submit to EPA reports according to the schedule, and containing all the information, that is set forth in this paragraph (b).

(1)(i) Until December 31, 2010, renewable fuel production reports for each facility owned by the renewable fuel producer or importer shall be submitted monthly, according to the schedule specified in paragraph (d)(1) of this section.

(ii) Starting January 1, 2011, renewable fuel production reports for each facility owned by the renewable fuel producer or importer shall be submitted in accordance with paragraph (e)(2) of this section.

(iii) The renewable fuel production reports shall include all the following information for each batch of renewable fuel produced, where "batch" means a discrete quantity of renewable fuel produced and either assigned or not assigned a unique batch-RIN per § 80.1426(b)(2):

(A) The renewable fuel producer's name.

(B) The EPA company registration number.

(C) The EPA facility registration number.

(D) The applicable monthly reporting period.

(E) Whether RINs were generated for each batch according to § 80.1426.

(F) The production date of each batch.

(G) The type of renewable fuel of each batch, as defined in § 80.1401.

(H) Information related to the volume of denaturant and applicable equivalence value of each batch.

(I) The volume of each batch produced.

(J) The process(es) and feedstock(s) used and proportion of renewable volume attributable to each process and feedstock.

(K) The type and volume of co-products produced with each batch of renewable fuel.

(L) In the case that RINs were generated for the batch, a list of the RINs generated and a certification that the feedstock(s) used for each batch meets the definition of renewable biomass as defined in § 80.1401.

(M) In the case that RINs were not generated for the batch, an explanation as to the reason for not generating RINs.

(N) Any additional information the Administrator may require.

(2) The RIN transaction reports required under paragraph (c)(1) of this section.

(3) The quarterly RIN activity reports required under paragraph (c)(2) of this section.

(4) Reports required under this paragraph (b) must be signed and certified as meeting all the applicable requirements of this subpart by the owner or a responsible corporate officer of the renewable fuel producer.

(c) *All RIN-owning parties.* Any party, including any party specified in paragraphs (a) and (b) of this section, that owns RINs during a reporting period, must submit reports to EPA according to the schedule, and containing all the information, that is set forth in this paragraph (c).

(1)(i) Until December 31, 2010, RIN transaction reports listing each RIN transaction shall be submitted monthly according to the schedule in paragraph (d)(1) of this section.

(ii) Starting January 1, 2011, RIN transaction reports listing each RIN transaction shall be submitted in accordance with paragraph (e)(3) of this section.

(iii) Each report required by paragraph (c)(1)(i) of this section shall include all of the following information:

(A) The submitting party's name.

(B) The party's EPA company registration number.

(C) [Reserved]

(D) The applicable monthly reporting period.

(E) Transaction type (i.e., RIN purchase, RIN sale, retired RIN, reinstated 2009 RIN).

(F) Transaction date.

(G) For a RIN purchase or sale, the trading partner's name.

(H) For a RIN purchase or sale, the trading partner's EPA company registration number. For all other transactions, the submitting party's EPA company registration number.

(I) RIN subject to the transaction.

(J) For a RIN purchase or sale, the per gallon RIN price and/or the per gallon renewable price if the RIN price is included.

(K) For a retired RIN, the reason for retiring the RIN (e.g., invalid RIN under § 80.1431, reportable spill under § 80.1432, foreign producer volume correction under § 80.1466(e), renewable fuel used in a boiler or ocean-going vessel under § 80.1429(f), enforcement obligation, or use for compliance (per paragraph (a)(1)(x) of this section), etc.).

(L) Any additional information that the Administrator may require.

(2) Quarterly RIN activity reports shall be submitted to EPA according to the schedule specified in paragraph (d)(2) of this section. Each report shall summarize RIN activities for the reporting period, separately for RINs separated from a renewable fuel volume and the sum of both RINs assigned to a renewable fuel volume and RINs generated, but not assigned to a renewable fuel volume. The quarterly RIN activity reports shall include all of the following information:

(i) The submitting party's name.

(ii) The party's EPA company registration number.

(iii) The number of current-year RINs owned at the start of the month.

(iv) The number of prior-year RINs owned at the start of the month.

(v) The total current-year RINs purchased.

(vi) The total prior-year RINs purchased.

(vii) The total current-year RINs sold.

(viii) The total prior-year RINs sold.

(ix) The total current-year RINs retired.

(x) The total prior-year RINs retired.

(xi) The number of current-year RINs owned at the end of the quarter.

(xii) The number of prior-year RINs owned at the end of the quarter.

(xiii) For parties reporting RIN activity under this paragraph for RINs generated, but not assigned to a renewable fuel volume and/or RINs assigned to a volume of renewable fuel, and the volume of renewable fuel (in gallons) owned at the end of the quarter.

(xiv) The total 2009 retired RINs reinstated.

(xv) Any additional information that the Administrator may require.

(3) All reports required under this paragraph (c) must be signed and certified as meeting all the applicable requirements of this subpart by the RIN owner or a responsible corporate officer of the RIN owner.

(d) *Report submission deadlines.* The submission deadlines for monthly and quarterly reports shall be as follows:

(1) Monthly reports shall be submitted to EPA by the last day of the next calendar month following the compliance period (i.e., the report covering January would be due by February 28th, the report covering February would be due by March 31st, etc.).

(2) Quarterly reports shall be submitted to EPA by the last day of the second month following the compliance period (i.e., the report covering January–March would be due by May 31st, the report covering April–June would be due by August 31st, the report covering July–September would be due by November 30th and the report covering October–December would be due by February 28th).

(e) *EPA Moderated Transaction System (EMTS).* (1) Each party required to report under this section must establish an account with EMTS by October 1, 2010 or sixty (60) days prior to engaging in any transaction involving RINs, whichever is later.

(2) Starting January 1, 2011, each time a domestic producer or importer of renewable fuel, or foreign renewable fuel producer who generates RINs, produces or imports a batch of renewable fuel, all the following information must be submitted to EPA within three (3) business days:

(i) The renewable fuel producer's or importer's name.

(ii) The EPA company registration number.

(iii) The EPA facility registration number.

(iv) Whether RINs were generated for the batch, according to § 80.1426.

(v) The production date of the batch.

(vi) The type of renewable fuel of the batch, as defined in § 80.1401.

(vii) Information related to the volume of denaturant and applicable equivalence value of each batch.

(viii) The volume of the batch.

(ix) The process(es) and feedstock(s) used and proportion of renewable volume attributable to each process and feedstock.

(x) A certification that the feedstock(s) used for each batch meets the definition of renewable biomass as defined in § 80.1401.

(xi) The type and volume of co-products produced with the batch of renewable fuel.

(xii) In the case that RINs were generated for the batch, a list of the RINs generated and a certification that the feedstock(s) used for each batch meets the definition of renewable biomass as defined in § 80.1401.

(xiii) In the case that RINs were not generated for the batch, an explanation as to the reason for not generating RINs.

(xiv) Any additional information the Administrator may require.

(3) Starting January 1, 2011, each time any party engages in a transaction involving RINs, all the following information must be submitted to EPA within three (3) business days:

(i) The submitting party's name.

(ii) The party's EPA company registration number.

(iii) [Reserved]

(iv) The applicable monthly reporting period.

(v) Transaction type (i.e., RIN purchase, RIN sale, retired RIN).

(vi) Transaction date.

(vii) For a RIN purchase or sale, the trading partner's name.

(viii) For a RIN purchase or sale, the trading partner's EPA company registration number. For all other transactions, the submitting party's EPA company registration number.

(ix) RIN subject to the transaction.

(x) For a RIN purchase or sale, the per gallon RIN price and/or the per gallon renewable price if the RIN price is included.

(xi) For a retired RIN, the reason for retiring the RIN (e.g., reportable spill under § 80.1432, foreign producer volume correction under § 80.1466(e), renewable fuel used in a boiler or ocean-going vessel under § 80.1429(f), enforcement obligation, or use for compliance (per paragraph (a)(1)(x) of this section), etc.).

(xii) Any additional information that the Administrator may require.

(f) All reports required under this section shall be submitted on forms and following procedures prescribed by the Administrator.

§ 80.1453 What are the product transfer document (PTD) requirements for the RFS program?

(a) On each occasion when any party transfers ownership of renewable fuels subject to this subpart, the transferor must provide to the transferee documents identifying the renewable fuel and any assigned RINs which include all of the following information, as applicable:

(1) The name and address of the transferor and transferee.

(2) The transferor's and transferee's EPA company registration number.

(3) The volume of renewable fuel that is being transferred.

(4) The date of the transfer.

(5) Whether any RINs are assigned to the volume, as follows:

(i) If the assigned RINs are being transferred on the same PTD used to transfer ownership of the renewable fuel, then the assigned RINs shall be listed on the PTD.

(ii) If the assigned RINs are being transferred on a separate PTD from that which is used to transfer ownership of the renewable fuel, then the PTD which is used to transfer ownership of the renewable fuel shall state the number of gallon-RINs being transferred as well as a unique reference to the PTD which is transferring the assigned RINs.

(iii) If no assigned RINs are being transferred with the renewable fuel, the PTD which is used to transfer ownership of the renewable fuel shall state ''No assigned RINs transferred''.

(iv) If RINs have been separated from the renewable fuel or blend pursuant to § 80.1129(b)(4), then all PTDs which are at any time used to transfer ownership of the renewable fuel or blend shall state, ''This volume of fuel must be used in the designated form, without further blending.''.

(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.

(c) The RIN number required under paragraph (a)(5) of this section must always appear in its entirety.

(d) If a RIN is traded in the EPA–Moderated Trading System (EMTS) as described in § 80.1452(e), the transferor must provide to the transferee documents that include all information as described in paragraphs (a) and (b) of this section and the number of RINs transferred identified by all the following:

(1) Assignment (Assigned or Separated).

(2) Type and/or D code (cellulosic biofuel D=1, biomass-based diesel D=2, advanced biofuel D=3, renewable fuel D=4).

(3) RIN generation year.

§ 80.1454 What are the provisions for renewable fuel production facilities 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. Except as stated in paragraph (b) of this section, such production facilities and importers that do not generate and/or assign RINs to batches of renewable fuel are also exempt from all the following requirements of this subpart:

(1) The recordkeeping requirements of § 80.1451.

(2) The reporting requirements of § 80.1452.

(3) The attest engagement requirements of § 80.1464.

(4) The production outlook report requirements of § 80.1449.

(b)(1) Renewable fuel production facilities 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 §§ 80.1449 through 80.1452, and 80.1464.

(2) Renewable fuel production facilities and importers who produce or import less than 10,000 gallons of renewable fuel each year but wish to own RINs will be subject to all requirements stated in paragraphs (a)(1) through (a)(4) of this section, and all other applicable requirements of this subpart M.

§ 80.1455 What are the provisions for cellulosic biofuel allowances?

(a) If EPA reduces the applicable volume of cellulosic biofuel pursuant to section 211(o)(7)(D)(i) of the Clean Air Act (42 U.S.C. 7545(o)(7)(D)(i)) for any given compliance year, then EPA will provide cellulosic biofuel allowances for purchase for that compliance year.

(1) The price of these allowances will be set by EPA on an annual basis in accordance with paragraph (d) of this section.

(2) The total allowances available will be equal to the reduced cellulosic biofuel volume established by EPA for the compliance year.

(b) *Use of allowances.* (1) Allowances are only valid for use in the compliance year that they are made available.

(2) Allowances are nonrefundable.

(3) Allowances are nontransferable except if forfeiting the allowances to EPA.

(c) *Purchase of allowances.* (1) Only parties with an RVO for cellulosic biofuel may purchase cellulosic biofuel allowances.

(2) Allowances shall be purchased from EPA at the time that a party submits its annual compliance report to EPA pursuant to § 80.1452(a)(1).

(3) Parties may not purchase more allowances than their cellulosic biofuel RVO minus cellulosic biofuel RINs with a D code of 1 that they own.

(4) Allowances may be used to meet an obligated party's RVOs for the advanced biofuel and total renewable fuel standards.

(d) *Setting the price of allowances.* (1) The price for allowances shall be set equal to the greater of:

(i) $0.25 per allowance, adjusted for inflation in comparison to calendar year 2008; or

(ii) $3.00 less the wholesale price of gasoline per allowance, adjusted for inflation in comparison to calendar year 2008.

(2) The wholesale price of gasoline will be calculated by averaging the most recent twelve monthly values for U.S. Total Gasoline Bulk Sales (Price) by All Sellers as provided by the Energy Information Administration that are available as of September 30 of the year preceding the compliance period.

(3) The inflation adjustment will be calculated by comparing the most recent Consumer Price Index for All Urban Consumers (CPI–U) for All Items expenditure category as provided by the Bureau of Labor Statistics that is available as of September 30 of the year preceding the compliance period to the most recent comparable value reported prior to December 31, 2008. When EPA must set the price of allowances for a compliance year, EPA will calculate the new amounts for paragraphs (d)(1)(i) and (ii) of this section for each year after 2008 and every month where data is available for the year preceding the compliance period.

(e) Cellulosic biofuel allowances under this section will only be able to be purchased on forms and following procedures prescribed by EPA.

§§ 80.1456–80.1459 [Reserved]

§ 80.1460 What acts are prohibited under the RFS program?

(a) *Renewable fuels producer or importer violation.* Except as provided in § 80.1454, no party shall produce or import a renewable fuel without assigning the proper number of gallon-RINs or identifying it by a batch-RIN as required under § 80.1426.

(b) *RIN generation and transfer violations.* No party shall do any of the following:

(1) Generate a RIN for a fuel that is not a renewable fuel, or for which the applicable renewable fuel volume was not produced.

(2) Create or transfer to any party a RIN that is invalid under § 80.1431.

(3) Transfer to any party a RIN that is not properly identified as required under § 80.1425.

(4) Transfer to any party a RIN with a K code of 1 without transferring an appropriate volume of renewable fuel to the same party on the same day.

(5) Introduce into commerce any renewable fuel produced from a feedstock or through a process that is not described in the party's registration information.

(c) *RIN use violations.* No party shall do any of the following:

(1) Fail to acquire sufficient RINs, or use invalid RINs, to meet the party's RVOs under § 80.1427.

(2) Fail to acquire sufficient RINs to meet the party's RVOs under § 80.1430.

(3) Use a validly generated RIN to meet the party's RVOs under § 80.1427, or separate and transfer a validly generated RIN, where the party ultimately uses the renewable fuel volume associated with the RIN in an application other than for use as transportation fuel (as defined in § 80.1401).

(d) *RIN retention violation.* No party shall retain RINs in violation of the requirements in § 80.1428(a)(5).

(e) *Causing a violation.* No party shall cause another party to commit an act in violation of any prohibited act under this section.

(f) *Failure to meet a requirement.* No party shall fail to meet any requirement that applies to that party under this subpart.

§ 80.1461 Who is liable for violations under the RFS program?

(a) *Parties liable for violations of prohibited acts.* (1) Any party who violates a prohibition under § 80.1460(a) through (d) is liable for the violation of that prohibition.

(2) Any party who causes another person to violate a prohibition under § 80.1460(a) through (d) is liable for a violation of § 80.1460(e).

(b) *Parties liable for failure to meet other provisions of this subpart.* (1) Any party who fails to meet a requirement of any provision of this subpart is liable for a violation of that provision.

(2) Any party who causes another party 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.

§ 80.1462 [Reserved]

§ 80.1463 What penalties apply under the RFS program?

(a) Any party who is liable for a violation under § 80.1461 is subject a to 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 party liable under § 80.1461(a) for a violation of § 80.1460(c) for failure to meet its RVOs, or § 80.1460(e) for causing another party to fail to meet their RVOs, during any averaging period, is subject to a separate day of violation for each day in the averaging period.

(c) Any party liable under § 80.1461(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.

§ 80.1464 What are the attest engagement requirements under the RFS program?

The requirements regarding annual attest engagements in §§ 80.125 through 80.127, and 80.130, also apply to any attest engagement procedures required under this subpart M. In addition to any other applicable attest engagement procedures, such as the requirements in § 80.1465, the following annual attest engagement procedures are required under this subpart.

(a) *Obligated parties and exporters.* The following attest procedures shall be completed for any obligated party as stated in § 80.1406(a) or exporter of renewable fuel that is subject to the renewable fuel standard under § 80.1405:

(1) *Annual compliance demonstration report.* (i) Obtain and read a copy of the annual compliance demonstration report required under § 80.1452(a)(1) which contains information regarding all the following:

(A) The obligated party's volume of finished gasoline, reformulated gasoline blendstock for oxygenate blending (RBOB), and conventional gasoline blendstock that becomes finished conventional gasoline upon the addition of oxygenate (CBOB) produced or imported during the reporting year.

(B) RVOs.

(C) RINs used for compliance.

(ii) Obtain documentation of any volumes of renewable fuel used in gasoline at the refinery or import facility or exported during the reporting year; compute and report as a finding the total volumes of renewable fuel represented in these documents.

(iii) Compare the volumes of gasoline reported to EPA in the report required under § 80.1452(a)(1) with the volumes, excluding any renewable fuel volumes, contained in the inventory reconciliation analysis under § 80.133, and verify that the volumes reported to EPA agree with the volumes in the inventory reconciliation analysis.

(iv) Compute and report as a finding the obligated party's or exporter's RVOs, and any deficit RVOs carried over from the previous year or carried into the subsequent year, and verify that the values agree with the values reported to EPA.

(v) Obtain the database, spreadsheet, or other documentation for all RINs used for compliance during the year being reviewed; calculate the total number of RINs used for compliance by year of generation represented in these documents; state whether this information agrees with the report to EPA and report as a finding any exceptions.

(2) *RIN transaction reports.* (i) Obtain and read copies of a representative sample, selected in accordance with the guidelines in § 80.127, of each RIN transaction type (RINs purchased, RINs sold, RINs retired, RINs reinstated) included in the RIN transaction reports required under § 80.1452(a)(2) for the compliance year.

(ii) Obtain contracts, invoices, or other documentation for the representative samples of RIN transactions; compute the transaction types, transaction dates, and RINs traded; state whether the information agrees with the party's reports to EPA and report as a finding any exceptions.

(3) *RIN activity reports.* (i) Obtain and read copies of all quarterly RIN activity reports required under § 80.1452(a)(3) for the compliance year.

(ii) Obtain the database, spreadsheet, or other documentation used to generate the information in the RIN activity reports; compare the RIN transaction samples reviewed under paragraph (a)(2) of this section with the corresponding entries in the database or spreadsheet and report as a finding any discrepancies; compute the total number of current-year and prior-year RINs owned at the start and end of the quarter, purchased, sold, retired, and reinstated, and for parties that reported RIN activity for RINs assigned to a volume of renewable fuel, the volume of renewable fuel owned at the end of the quarter; as represented in these documents; and state whether this information agrees with the party's reports to EPA.

(b) *Renewable fuel producers and RIN-generating importers.* The following attest procedures shall be completed for any renewable fuel producer or RIN-generating importer:

(1) *Renewable fuel production reports.* (i) Obtain and read copies of the renewable fuel production reports required under §§ 80.1452(b)(1) and (e)(2) for the compliance year.

(ii) Obtain production data for each renewable fuel batch produced or imported during the year being reviewed; compute the RIN numbers, production dates, types, volumes of denaturant and applicable equivalence values, and production volumes for each batch; state whether this information agrees with the party's reports to EPA and report as a finding any exceptions.

(iii) Verify that the proper number of RINs were generated and assigned for each batch of renewable fuel produced or imported, as required under § 80.1426.

(iv) Obtain product transfer documents for a representative sample, selected in accordance with the guidelines in § 80.127, of renewable fuel batches produced or imported during the year being reviewed; verify that the product transfer documents contain the applicable information required under § 80.1453; verify the accuracy of the information contained in the product transfer documents; report as a finding any product transfer document that does not contain the applicable information required under § 80.1453.

(v) Obtain documentation, as required under § 80.1451(b)(6), associated with feedstock purchases and transfers for a representative sample, selected in accordance with the guidelines in § 80.127, of renewable fuel batches produced or imported during the year being reviewed.

(A) If RINs were generated for a given batch of renewable fuel, verify that feedstocks used meet the definition of renewable biomass in § 80.1401.

(B) If no RINs were generated for a given batch of renewable fuel, verify that feedstocks used do not meet the definition of renewable biomass in § 80.1401 or that there was another reason that the fuel produced without RINs was not renewable fuel.

(2) *RIN transaction reports.* (i) Obtain and read copies of a representative sample, selected in accordance with the guidelines in § 80.127, of each transaction type (RINs purchased, RINs sold, RINs retired, RINs reinstated) included in the RIN transaction reports required under § 80.1452(b)(2) for the compliance year.

(ii) Obtain contracts, invoices, or other documentation for the representative samples of RIN transactions; compute the transaction types, transaction dates, and the RINs traded; state whether this information agrees with the party's reports to EPA and report as a finding any exceptions.

(3) *RIN activity reports.* (i) Obtain and read copies of the quarterly RIN activity reports required under § 80.1452(b)(3) for the compliance year.

(ii) Obtain the database, spreadsheet, or other documentation used to generate the information in the RIN activity reports; compare the RIN transaction samples reviewed under paragraph (b)(2) of this section with the corresponding entries in the database or spreadsheet and report as a finding any discrepancies; compute the total number of current-year and prior-year RINs owned at the start and end of the quarter, purchased, sold, retired, and reinstated, and for parties that reported RIN activity for RINs assigned to a volume of renewable fuel, the volume of renewable fuel owned at the end of the quarter, as represented in these documents; and state whether this information agrees with the party's reports to EPA.

(4) *Independent Third Party Engineering Review.* (i) Obtain documentation of independent third party engineering review required under § 80.1450(b)(2).

(ii) Review and verify the written verification and records generated as part of the independent third party engineering review.

(c) *Other parties owning RINs.* The following attest procedures shall be completed for any party other than an obligated party or renewable fuel producer or importer that owns any RINs during a calendar year:

(1) *RIN transaction reports.* (i) Obtain and read copies of a representative sample, selected in accordance with the guidelines in § 80.127, of each RIN transaction type (RINs purchased, RINs sold, RINs retired, RINs reinstated) included in the RIN transaction reports required under § 80.1452(c)(1) for the compliance year.

(ii) Obtain contracts, invoices, or other documentation for the representative samples of RIN transactions; compute the transaction types, transaction dates, and the RINs traded; state whether this information agrees with the party's reports to EPA and report as a finding any exceptions.

(2) *RIN activity reports.* (i) Obtain and read copies of the quarterly RIN activity reports required under § 80.1452(c)(2) for the compliance year.

(ii) Obtain the database, spreadsheet, or other documentation used to generate the information in the RIN activity reports; compare the RIN transaction samples reviewed under paragraph (c)(1) of this section with the corresponding entries in the database or spreadsheet and report as a finding any discrepancies; compute the total number of current-year and prior-year RINs owned at the start and end of the quarter, purchased, sold, retired, and reinstated, and for parties that reported RIN activity for RINs assigned to a volume of renewable fuel, the volume of renewable fuel owned at the end of the quarter, as represented in these documents; and state whether this information agrees with the party's reports to EPA.

(d) The following submission dates apply to the attest engagements required under this section:

(1) For each compliance year, each party subject to the attest engagement requirements under this section shall cause the reports required under this section to be submitted to EPA by May 31 of the year following the compliance year.

(2) [Reserved]

(e) The party conducting the procedures under this section shall obtain a written representation from a company representative that the copies of the reports required under this section are complete and accurate copies of the reports filed with EPA.

(f) The party conducting the procedures under this section shall identify and report as a finding the commercial computer program used by the party to track the data required by the regulations in this subpart, if any.

§ 80.1465 What are the additional requirements under this subpart for foreign small refiners, foreign small refineries, and importers of RFS–FRFUEL?

(a) *Definitions.* The following additional definitions apply for this subpart:

(1) *Foreign refinery* is a refinery that is located outside the United States, the Commonwealth of Puerto Rico, the U.S. Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Mariana Islands (collectively referred to in this section as ''the United States'').

(2) *Foreign refiner* is a party that meets the definition of refiner under § 80.2(i) for a foreign refinery.

(3) *Foreign small refiner* is a foreign refiner that has received a small refinery exemption under § 80.1441 for one or more of its refineries or a foreign refiner that has received a small refiner exemption under § 80.1442.

(4) *RFS–FRFUEL* is transportation fuel produced at a foreign refinery that has received a small refinery exemption under § 80.1441 or by a foreign refiner with a small refiner exemption under § 80.1442.

(5) *Non-RFS–FRFUEL* is one of the following:

(i) Transportation fuel produced at a foreign refinery that has received a small refinery exemption under § 80.1441 or by a foreign refiner with a small refiner exemption under § 80.1442.

(ii) Transportation fuel produced at a foreign refinery that has not received a small refinery exemption under § 80.1441 or by a foreign refiner that has not received a small refiner exemption under § 80.1442.

(b) *General requirements for RFS–FRFUEL for foreign small refineries and small refiners.* A foreign refiner must do all the following:

(1) Designate, at the time of production, each batch of transportation fuel produced at the foreign refinery that is exported for use in the United States as RFS–FRFUEL.

(2) Meet all requirements that apply to refiners who have received a small refinery or small refiner exemption under this subpart.

(c) *Designation, foreign small refiner certification, and product transfer documents.*

(1) Any foreign small refiner must designate each batch of RFS–FRFUEL as such at the time the transportation fuel is produced.

(2) On each occasion when RFS–FRFUEL is loaded onto a vessel or other transportation mode for transport to the United States, the foreign small refiner shall prepare a certification for each batch of RFS–FRFUEL that meets all the following requirements:

(i) The certification shall include the report of the independent third party under paragraph (d) of this section, and all the following additional information:

(A) The name and EPA registration number of the refinery that produced the RFS–FRFUEL.

(B) [Reserved]

(ii) The identification of the transportation fuel as RFS–FRFUEL.

(iii) The volume of RFS–FRFUEL being transported, in gallons.

(3) On each occasion when any party transfers custody or title to any RFS–FRFUEL prior to its being imported into the United States, it must include all the following information as part of the product transfer document information:

(i) Designation of the transportation fuel as RFS–FRFUEL.

(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–FRFUEL is loaded onto a vessel for transport to the United States the foreign small refiner shall have an independent third party do all the following:

(i) Inspect the vessel prior to loading and determine the volume of any tank bottoms.

(ii) Determine the volume of RFS–FRFUEL 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–FRFUEL to the United States.

(v) Determine the date and time the vessel departs the port serving the foreign refinery.

(vi) Review original documents that reflect movement and storage of the RFS–FRFUEL from the foreign refinery to the load port, and from this review determine:

(A) The refinery at which the RFS–FRFUEL was produced; and

(B) That the RFS–FRFUEL remained segregated from Non-RFS–FRFUEL and other RFS–FRFUEL produced at a different refinery.

(2) The independent third party shall submit a report to all the following:

(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.

(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 transportation fuel was produced, assurance that the transportation fuel remained segregated as specified in paragraph (j)(1) of this section, and a description of the transportation fuel's movement and storage between production at the source refinery and vessel loading.

(3) The independent third party must do all the following:

(i) Be approved in advance by EPA, based on a demonstration of ability to perform the procedures required in this paragraph (d).

(ii) Be independent under the criteria specified in § 80.65(f)(2)(iii).

(iii) Sign a commitment that contains the provisions specified in paragraph (f) of this section with regard to activities, facilities, and documents relevant to compliance with the requirements of this paragraph (d).

(e) *Comparison of load port and port of entry testing.* (1)(i) Any foreign small refiner or foreign small refinery and any United States importer of RFS–FRFUEL shall compare the results from the load port testing under paragraph (d) of this section, with the port of entry testing as reported under paragraph (k) of this section, for the volume of transportation fuel, except as specified in paragraph (e)(1)(ii) of this section.

(ii) Where a vessel transporting RFS–FRFUEL off loads this transportation fuel 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 transportation fuel or blendstock between the first United States port of entry and the subsequent port of entry.

(2) If the temperature-corrected volumes determined at the port of entry and at the load port differ by more than one percent, the United States importer and the foreign small refiner or foreign small refinery shall not treat the transportation fuel as RFS–FRFUEL and the importer shall include the volume of transportation fuel in 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) Transportation fuel is produced;

(B) Documents related to refinery operations are kept; and

(C) RFS–FRFUEL is stored or transported between the foreign refinery and the United States, including storage tanks, vessels and pipelines.

(iii) Inspections and audits may be by EPA employees or contractors to EPA.

(iv) Any documents requested that are related to matters covered by inspections and audits must be provided to an EPA inspector or auditor on request.

(v) Inspections and audits by EPA may include review and copying of any documents related to all the following:

(A) The volume of RFS–FRFUEL.

(B) The proper classification of transportation fuel as being RFS–FRFUEL or as not being RFS–FRFUEL.

(C) Transfers of title or custody to RFS–FRFUEL.

(D) Testing of RFS–FRFUEL.

(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 transportation fuel 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–FRFUEL produced at a foreign refinery is stored or transported by another company between the refinery and the vessel that transports the RFS–FRFUEL 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 transportation fuel to the United States under such exemption, the foreign refiner, and its agents and employees, without exception, become subject to the full operation of the administrative and judicial enforcement powers and provisions of the United States without limitation based on sovereign immunity, with respect to actions instituted against the foreign refiner, its agents and employees in any court or other tribunal in the United States for conduct that violates the requirements applicable to the foreign refiner under this subpart, including conduct that violates the False Statements Accountability Act of 1996 (18 U.S.C. 1001) and section 113(c)(2) of the Clean Air Act (42 U.S.C. 7413).

(h) *Bond posting.* Any foreign refiner shall meet the requirements of this paragraph (h) as a condition to approval of a small foreign refinery or small foreign refiner exemption under this subpart.

(1) The foreign refiner shall post a bond of the amount calculated using the following equation:

$$\text{Bond} = G * \$\ 0.01$$

Where:

Bond = amount of the bond in United States dollars.

G = the largest volume of transportation fuel 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 or refiner'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 transportation fuel 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, or shall include an English language translation.

(j) *Prohibitions.* (1) No party may combine RFS–FRFUEL with any Non-RFS–FRFUEL, and no party may combine RFS–FRFUEL with any RFS–FRFUEL 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 party may cause another party 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–FRFUEL shall meet the following requirements:

(1) Each batch of imported RFS–FRFUEL shall be classified by the importer as being RFS–FRFUEL.

(2) Transportation fuel shall be classified as RFS–FRFUEL 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 transportation fuel batch classified as RFS–FRFUEL, any United States importer shall have an independent third party do all the following:

(i) Determine the volume of transportation fuel in the vessel.

(ii) Use the foreign refiner's RFS–FRFUEL certification to determine the name and EPA-assigned registration number of the foreign refinery that produced the RFS–FRFUEL.

(iii) Determine the name and country of registration of the vessel used to transport the RFS–FRFUEL to the United States.

(iv) Determine the date and time the vessel arrives at the United States port of entry.

(4) Any importer shall submit reports within 30 days following the date any vessel transporting RFS–FRFUEL 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 transportation fuel that is not classified as RFS–FRFUEL under paragraph (k)(2) of this section.

(l) *Truck imports of RFS–FRFUEL produced at a foreign refinery.* (1) Any refiner whose RFS–FRFUEL is transported into the United States by truck may petition EPA to use alternative procedures to meet all the following requirements:

(i) Certification under paragraph (c)(2) of this section.

(ii) Load port and port of entry testing requirements under paragraphs (d) and (e) of this section.

(iii) Importer testing requirements under paragraph (k)(3) of this section.

(2) These alternative procedures must ensure RFS–FRFUEL remains segregated from Non-RFS–FRFUEL until it is imported into the United States. The petition will be evaluated based on whether it adequately addresses all the following:

(i) Provisions for monitoring pipeline shipments, if applicable, from the refinery, that ensure segregation of RFS–FRFUEL from that refinery from all other transportation fuel.

(ii) Contracts with any terminals and/or pipelines that receive and/or transport RFS–FRFUEL that prohibit the commingling of RFS–FRFUEL with Non-RFS–FRFUEL or RFS–FRFUEL 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–FRFUEL remains segregated throughout the distribution system.

(3) The petition described in this section must be submitted to EPA along with the application for a small refinery or small refiner exemption under this subpart.

(m) *Additional attest requirements for importers of RFS–FRFUEL.* The following additional procedures shall be carried out by any importer of RFS–FRFUEL as part of the attest engagement required for importers under this subpart M.

(1) Obtain listings of all tenders of RFS–FRFUEL. Agree the total volume of tenders from the listings to the transportation fuel inventory reconciliation analysis required in § 80.133(b), and to the volumes determined by the third party under paragraph (d) of this section.

(2) For each tender under paragraph (m)(1) of this section, where the transportation fuel is loaded onto a marine vessel, report as a finding the name and country of registration of each vessel, and the volumes of RFS–FRFUEL loaded onto each vessel.

(3) Select a sample from the list of vessels identified per paragraph (m)(2) of this section used to transport RFS–FRFUEL, in accordance with the guidelines in § 80.127, and for each vessel selected perform all the following:

(i) Obtain the report of the independent third party, under paragraph (d) of this section.

(A) Agree the information in these reports with regard to vessel identification and transportation fuel volume.

(B) Identify, and report as a finding, each occasion the load port and port of entry volume results differ by more than the amount allowed in paragraph (e)(2) of this section, and determine whether all of the requirements of paragraph (e)(2) of this section have been met.

(ii) Obtain the documents used by the independent third party to determine transportation and storage of the RFS–FRFUEL from the refinery to the load port, under paragraph (d) of this section. Obtain tank activity records for any storage tank where the RFS–FRFUEL is stored, and pipeline activity records for any pipeline used to transport the RFS–FRFUEL prior to being loaded onto the vessel. Use these records to determine whether the RFS–FRFUEL was produced at the refinery that is the subject of the attest engagement, and whether the RFS–FRFUEL was mixed with any Non-RFS–FRFUEL or any RFS–FRFUEL produced at a different refinery.

(4) Select a sample from the list of vessels identified per paragraph (m)(2) of this section used to transport RFS–FRFUEL, in accordance with the guidelines in § 80.127, and for each vessel selected perform all 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–FRFUEL, and perform all the following:

(i) Agree the volume of tenders from the listings to the transportation fuel inventory reconciliation analysis in § 80.133(b).

(ii) Obtain a separate listing of the tenders under this paragraph (m)(5) where the transportation fuel 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 transportation fuel was off loaded for the selected vessels. Determine and report as a finding the country where the transportation fuel was off loaded for each vessel selected.

(6) In order to complete the requirements of this paragraph (m), an auditor shall do all the following:

(i) Be independent of the foreign refiner or importer.

(ii) Be licensed as a Certified Public Accountant in the United States and a citizen of the United States, or be approved in advance by EPA based on a demonstration of ability to perform the procedures required in §§ 80.125 through 80.127, 80.130, 80.1464, and this paragraph (m).

(iii) Sign a commitment that contains the provisions specified in paragraph (f) of this section with regard to activities and documents relevant to compliance with the requirements of §§ 80.125 through 80.127, 80.130, 80.1464, and this paragraph (m).

(n) *Withdrawal or suspension of foreign small refiner or foreign small refinery status.* EPA may withdraw or suspend a foreign refiner's small refinery or small refiner exemption where:

(1) A foreign refiner fails to meet any requirement of this section;

(2) A foreign government fails to allow EPA inspections as provided in paragraph (f)(1) of this section;

(3) A foreign refiner asserts a claim of, or a right to claim, sovereign immunity in an action to enforce the requirements in this subpart; or

(4) A foreign refiner fails to pay a civil or criminal penalty that is not satisfied using the foreign refiner bond specified in paragraph (h) of this section.

(o) *Additional requirements for applications, reports and certificates.* Any application for a small refinery or small refiner exemption, alternative procedures under paragraph (l) of this section, any report, certification, or other submission required under this section shall be:

(1) Submitted in accordance with procedures specified by the Administrator, including use of any forms that may be specified by the Administrator.

(2) Signed by the president or owner of the foreign refiner company, or by that party's immediate designee, and shall contain the following declaration:

"I hereby certify: (1) That I have actual authority to sign on behalf of and to bind [insert name of foreign 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 M, 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 M, including 40 CFR 80.1465 apply to [INSERT NAME OF FOREIGN REFINER]. Pursuant to Clean Air Act section 113(c) and 18 U.S.C. 1001, the penalty for furnishing false, incomplete or misleading information in this certification or submission is a fine of up to $10,000 U.S., and/or imprisonment for up to five years.".

§ 80.1466 What are the additional requirements under this subpart for foreign producers and importers of renewable fuels?

(a) *Foreign producer of renewable fuel.* For purposes of this subpart, a foreign producer of renewable fuel is a party located outside the United States, the Commonwealth of Puerto Rico, the Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Mariana Islands (collectively referred to in this section as "the United States") that has been approved by EPA to assign RINs to renewable fuel that the foreign producer produces and exports to the United States, hereinafter referred to as a "foreign producer" under this section.

(b) *General requirements.* An approved foreign producer under this section must meet all requirements that apply to renewable fuel producers under this subpart.

(c) *Designation, foreign producer certification, and product transfer documents.* (1) Any approved foreign producer under this section must designate each batch of renewable fuel as "RFS–FRRF" at the time the renewable fuel is produced.

(2) On each occasion when RFS–FRRF is loaded onto a vessel or other transportation mode for transport to the United States, the foreign producer shall prepare a certification for each batch of RFS–FRRF; the certification shall include the report of the independent third party under paragraph (d) of this section, and all the following additional information:

(i) The name and EPA registration number of the company that produced the RFS–FRRF.

(ii) The identification of the renewable fuel as RFS–FRRF.

(iii) The volume of RFS–FRRF being transported, in gallons.

(3) On each occasion when any party transfers custody or title to any RFS–FRRF prior to its being imported into the United States, it must include all the following information as part of the product transfer document information:

(i) Designation of the renewable fuel as RFS–FRRF.

(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–FRRF is loaded onto a vessel for transport to the United States the foreign producer shall have an independent third party do all the following:

(i) Inspect the vessel prior to loading and determine the volume of any tank bottoms.

(ii) Determine the volume of RFS–FRRF loaded onto the vessel (exclusive of any tank bottoms before loading).

(iii) Obtain the EPA-assigned registration number of the foreign producer.

(iv) Determine the name and country of registration of the vessel used to transport the RFS–FRRF to the United States.

(v) Determine the date and time the vessel departs the port serving the foreign producer.

(vi) Review original documents that reflect movement and storage of the RFS–FRRF from the foreign producer to the load port, and from this review determine all the following:

(A) The facility at which the RFS–FRRF was produced.

(B) That the RFS–FRRF remained segregated from Non-RFS–FRRF and other RFS–FRRF produced by a different foreign producer.

(2) The independent third party shall submit a report to the following:

(i) The foreign producer, containing the information required under paragraph (d)(1) of this section, to accompany the product transfer documents for the vessel.

(ii) The Administrator, containing the information required under paragraph (d)(1) of this section, within thirty days following the date of the independent third party's inspection. This report shall include a description of the method used to determine the identity of the foreign producer facility at which the renewable fuel was produced, assurance that the renewable fuel remained segregated as specified in paragraph (j)(1) of this section, and a description of the renewable fuel's movement and storage between production at the source facility and vessel loading.

(3) The independent third party must:

(i) Be approved in advance by EPA, based on a demonstration of ability to perform the procedures required in this paragraph (d);

(ii) Be independent under the criteria specified in § 80.65(e)(2)(iii); and

(iii) Sign a commitment that contains the provisions specified in paragraph (f) of this section with regard to activities, facilities and documents relevant to compliance with the requirements of this paragraph (d).

(e) *Comparison of load port and port of entry testing.* (1)(i) Any foreign producer and any United States importer of RFS–FRRF shall compare the results from the load port testing under paragraph (d) of this section, with the port of entry testing as reported under paragraph (k) of this section, for the volume of renewable fuel, except as specified in paragraph (e)(1)(ii) of this section.

(ii) Where a vessel transporting RFS–FRRF off loads the renewable fuel 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 renewable fuel between the first United States port of entry and the subsequent port of entry.

(2)(i) If the temperature-corrected volumes determined at the port of entry and at the load port differ by more than one percent, the number of RINs associated with the renewable fuel shall be calculated based on the lesser of the two volumes in paragraph (e)(1)(i) of this section.

(ii) Where the port of entry volume is the lesser of the two volumes in paragraph (e)(1)(i) of this section, the importer shall calculate the difference between the number of RINs originally assigned by the foreign producer and the number of RINs calculated under § 80.1426 for the volume of renewable fuel as measured at the port of entry, and retire that amount of RINs in accordance with paragraph (k)(4) of this section.

(f) *Foreign producer commitments.* Any foreign producer shall commit to and comply with the provisions contained in this paragraph (f) as a condition to being approved as a foreign producer under this subpart.

(1) Any United States Environmental Protection Agency inspector or auditor must be given full, complete, and immediate access to conduct inspections and audits of the foreign producer facility.

(i) Inspections and audits may be either announced in advance by EPA, or unannounced.

(ii) Access will be provided to any location where:

(A) Renewable fuel is produced;

(B) Documents related to renewable fuel producer operations are kept; and

(C) RFS–FRRF is stored or transported between the foreign producer and the United States, including storage tanks, vessels and pipelines.

(iii) Inspections and audits may be by EPA employees or contractors to EPA.

(iv) Any documents requested that are related to matters covered by inspections and audits must be provided to an EPA inspector or auditor on request.

(v) Inspections and audits by EPA may include review and copying of any documents related to the following:

(A) The volume of RFS–FRRF.

(B) The proper classification of gasoline as being RFS–FRRF.

(C) Transfers of title or custody to RFS–FRRF.

(D) Work performed and reports prepared by independent third parties and by independent auditors under the requirements of this section, including work papers.

(vi) Inspections and audits by EPA may include interviewing employees.

(vii) Any employee of the foreign producer must be made available for interview by the EPA inspector or auditor, on request, within a reasonable time period.

(viii) English language translations of any documents must be provided to an EPA inspector or auditor, on request, within 10 working days.

(ix) English language interpreters must be provided to accompany EPA inspectors and auditors, on request.

(2) An agent for service of process located in the District of Columbia shall be named, and service on this agent constitutes service on the foreign producer or any employee of the foreign producer for any action by EPA or otherwise by the United States related to the requirements of this subpart.

(3) The forum for any civil or criminal enforcement action related to the provisions of this section for violations of the Clean Air Act or regulations promulgated thereunder shall be governed by the Clean Air Act, including the EPA administrative forum where allowed under the Clean Air Act.

(4) United States substantive and procedural laws shall apply to any civil or criminal enforcement action against the foreign producer or any employee of the foreign producer related to the provisions of this section.

(5) Applying to be an approved foreign producer under this section, or producing or exporting renewable fuel under such approval, and all other actions to comply with the requirements of this subpart relating to such approval constitute actions or activities covered by and within the meaning of the provisions of 28 U.S.C. 1605(a)(2), but solely with respect to actions instituted against the foreign producer, its agents and employees in any court or other tribunal in the United States for conduct that violates the requirements applicable to the foreign producer under this subpart, including conduct that violates the False Statements Accountability Act of 1996 (18 U.S.C. 1001) and section 113(c)(2) of the Clean Air Act (42 U.S.C. 7413).

(6) The foreign producer, or its agents or employees, will not seek to detain or to impose civil or criminal remedies against EPA inspectors or auditors, whether EPA employees or EPA contractors, for actions performed within the scope of EPA employment related to the provisions of this section.

(7) The commitment required by this paragraph (f) shall be signed by the owner or president of the foreign producer company.

(8) In any case where RFS–FRRF produced at a foreign producer facility is stored or transported by another company between the refinery and the vessel that transports the RFS–FRRF to the United States, the foreign producer shall obtain from each such other company a commitment that meets the requirements specified in paragraphs (f)(1) through (7) of this section, and these commitments shall be included in the foreign producer's application to be an approved foreign producer under this subpart.

(g) *Sovereign immunity.* By submitting an application to be an approved foreign producer under this subpart, or by producing and exporting renewable fuel to the United States under such approval, the foreign producer, and its agents and employees, without exception, become subject to the full operation of the administrative and judicial enforcement powers and provisions of the United States without limitation based on sovereign immunity, with respect to actions instituted against the foreign producer, its agents and employees in any court or other tribunal in the United States for conduct that violates the requirements applicable to the foreign producer under this subpart, including conduct that violates the False Statements Accountability Act of 1996 (18 U.S.C. 1001) and section 113(c)(2) of the Clean Air Act (42 U.S.C. 7413).

(h) *Bond posting.* Any foreign producer shall meet the requirements of this paragraph (h) as a condition to approval as a foreign producer under this subpart.

(1) The foreign producer shall post a bond of the amount calculated using the following equation:

Bond = G * $ 0.01

Where:

Bond = amount of the bond in U.S. dollars.

G = the largest volume of renewable fuel produced at the foreign producer's facility and exported to the United States, in gallons, during a single calendar year among the most recent of the following calendar years, up to a maximum of five calendar years: the calendar year immediately preceding the date the refinery's application is submitted, the calendar year the application is submitted, and each succeeding calendar year.

(2) Bonds shall be posted by any of the following methods:

(i) Paying the amount of the bond to the Treasurer of the United States.

(ii) Obtaining a bond in the proper amount from a third party surety agent that is payable to satisfy United States administrative or judicial judgments against the foreign producer, provided EPA agrees in advance as to the third party and the nature of the surety agreement.

(iii) An alternative commitment that results in assets of an appropriate liquidity and value being readily available to the United States provided EPA agrees in advance as to the alternative commitment.

(3) Bonds posted under this paragraph (h) shall:

(i) Be used to satisfy any judicial judgment that results from an administrative or judicial enforcement action for conduct in violation of this subpart, including where such conduct violates the False Statements Accountability Act of 1996 (18 U.S.C. 1001) and section 113(c)(2) of the Clean Air Act (42 U.S.C. 7413);

(ii) Be provided by a corporate surety that is listed in the United States Department of Treasury Circular 570 ''Companies Holding Certificates of Authority as Acceptable Sureties on Federal Bonds''; and

(iii) Include a commitment that the bond will remain in effect for at least five years following the end of latest annual reporting period that the foreign producer produces renewable fuel pursuant to the requirements of this subpart.

(4) On any occasion a foreign producer bond is used to satisfy any judgment, the foreign producer shall increase the bond to cover the amount used within 90 days of the date the bond is used.

(5) If the bond amount for a foreign producer increases, the foreign producer shall increase the bond to cover the shortfall within 90 days of the date the bond amount changes. If the bond amount decreases, the foreign refiner may reduce the amount of the bond beginning 90 days after the date the bond amount changes.

(i) *English language reports.* Any document submitted to EPA by a foreign producer shall be in English, or shall include an English language translation.

(j) *Prohibitions.* (1) No party may combine RFS–FRRF with any Non-RFS–FRRF, and no party may combine RFS–FRRF with any RFS–FRRF produced at a different refinery, until the importer has met all the requirements of paragraph (k) of this section.

(2) No foreign producer or other party may cause another party to commit an action prohibited in paragraph (j)(1) of this section, or that otherwise violates the requirements of this section.

(k) *Requirements for United States importers of RFS–FRRF.* Any United States importer shall meet all the following requirements:

(1) Each batch of imported RFS–FRRF shall be classified by the importer as being RFS–FRRF.

(2) Renewable fuel shall be classified as RFS–FRRF according to the designation by the foreign producer if this designation is supported by product transfer documents prepared by the foreign producer as required in paragraph (c) of this section.

(3) For each renewable fuel batch classified as RFS–FRRF, any United States importer shall have an independent third party do all the following:

(i) Determine the volume of gasoline in the vessel.

(ii) Use the foreign producer's RFS–FRRF certification to determine the name and EPA-assigned registration number of the foreign producer that produced the RFS–FRRF.

(iii) Determine the name and country of registration of the vessel used to transport the RFS–FRRF to the United States.

(iv) Determine the date and time the vessel arrives at the United States port of entry.

(4) Where the importer is required to retire RINs under paragraph (e)(2) of this section, the importer must report the retired RINs in the applicable reports under § 80.1452.

(5) Any importer shall submit reports within 30 days following the date any vessel transporting RFS–FRRF arrives at the United States port of entry to all the following:

(i) The Administrator, containing the information determined under paragraph (k)(3) of this section.

(ii) The foreign producer, containing the information determined under paragraph (k)(3)(i) of this section, and including identification of the port at which the product was off loaded, and any RINs retired under paragraph (e)(2) of this section.

(6) Any United States importer shall meet all other requirements of this subpart for any imported ethanol or other renewable fuel that is not classified as RFS–FRRF under paragraph (k)(2) of this section.

(l) *Truck imports of RFS–FRRF produced by a foreign producer.* (1) Any foreign producer whose RFS–FRRF is transported into the United States by truck may petition EPA to use alternative procedures to meet all the following requirements:

(i) Certification under paragraph (c)(2) of this section.

(ii) Load port and port of entry testing under paragraphs (d) and (e) of this section.

(iii) Importer testing under paragraph (k)(3) of this section.

(2) These alternative procedures must ensure RFS–FRRF remains segregated from Non-RFS–FRRF until it is imported into the United States. The petition will be evaluated based on whether it adequately addresses the following:

(i) Contracts with any facilities that receive and/or transport RFS–FRRF that prohibit the commingling of RFS–FRRF with Non-RFS–FRRF or RFS–FRRF from other foreign producers.

(ii) Attest procedures to be conducted annually by an independent third party that review loading records and import documents based on volume reconciliation to confirm that all RFS–FRRF remains segregated.

(3) The petition described in this section must be submitted to EPA along with the application for approval as a foreign producer under this subpart.

(m) *Additional attest requirements for producers of RFS–FRRF.* The following additional procedures shall be carried out by any producer of RFS–FRRF as part of the attest engagement required for renewable fuel producers under this subpart M.

(1) Obtain listings of all tenders of RFS–FRRF. Agree the total volume of tenders from the listings to the volumes determined by the third party under paragraph (d) of this section.

(2) For each tender under paragraph (m)(1) of this section, where the renewable fuel is loaded onto a marine vessel, report as a finding the name and country of registration of each vessel, and the volumes of RFS–FRRF 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–FRRF, in accordance with the guidelines in § 80.127, and for each vessel selected perform all 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 renewable fuel volume.

(B) Identify, and report as a finding, each occasion the load port and port of entry volume results differ by more than the amount allowed in paragraph (e) of this section, and determine whether the importer retired the appropriate amount of RINs as required under paragraph (e)(2) of this section, and submitted the applicable reports under § 80.1452 in accordance with paragraph (k)(4) of this section.

(ii) Obtain the documents used by the independent third party to determine transportation and storage of the RFS–FRRF from the foreign producer's facility to the load port, under paragraph (d) of this section. Obtain tank activity records for any storage tank where the RFS–FRRF is stored, and activity records for any mode of transportation used to transport the RFS–FRFUEL prior to being loaded onto the vessel. Use these records to determine whether the RFS–FRRF was produced at the foreign producer's facility that is the subject of the attest engagement, and whether the RFS–FRRF was mixed with any Non-RFS–FRRF or any RFS–FRRF produced at a different facility.

(4) Select a sample from the list of vessels identified in paragraph (m)(2) of this section used to transport RFS–FRRF, in accordance with the guidelines in § 80.127, and for each vessel selected perform the following:

(i) Obtain a commercial document of general circulation that lists vessel arrivals and departures, and that includes the port and date of departure of the vessel, and the port of entry and date of arrival of the vessel.

(ii) Agree the vessel's departure and arrival locations and dates from the independent third party and United States importer reports to the information contained in the commercial document.

(5) Obtain a separate listing of the tenders under this paragraph (m)(5) where the RFS–FRRF 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 renewable fuel was off loaded for the selected vessels. Determine and report as a finding the country where the renewable fuel was off loaded for each vessel selected.

(6) In order to complete the requirements of this paragraph (m) an auditor shall:

(i) Be independent of the foreign producer;

(ii) Be licensed as a Certified Public Accountant in the United States and a citizen of the United States, or be approved in advance by EPA based on a demonstration of ability to perform the procedures required in §§ 80.125 through 80.127, 80.130, 80.1464, and this paragraph (m); and

(iii) Sign a commitment that contains the provisions specified in paragraph (f) of this section with regard to activities and documents relevant to compliance with the requirements of §§ 80.125 through 80.127, 80.130, 80.1464, and this paragraph (m).

(n) *Withdrawal or suspension of foreign producer approval.* EPA may withdraw or suspend a foreign producer's approval where any of the following occur:

(1) A foreign producer fails to meet any requirement of this section.

(2) A foreign government fails to allow EPA inspections as provided in paragraph (f)(1) of this section.

(3) A foreign producer asserts a claim of, or a right to claim, sovereign immunity in an action to enforce the requirements in this subpart.

(4) A foreign producer fails to pay a civil or criminal penalty that is not satisfied using the foreign producer bond specified in paragraph (g) of this section.

(o) *Additional requirements for applications, reports and certificates.* Any application for approval as a foreign producer, alternative procedures under paragraph (l) of this section, any report, certification, or other submission required under this section shall be:

(1) Submitted in accordance with procedures specified by the Administrator, including use of any forms that may be specified by the Administrator.

(2) Signed by the president or owner of the foreign producer company, or by that party's immediate designee, and shall contain the following declaration:

''I hereby certify: 1) That I have actual authority to sign on behalf of and to bind [insert name of foreign producer] with regard to all statements contained herein; 2) that I am aware that the information contained herein is being Certified, or submitted to the United States Environmental Protection Agency, under the requirements of 40 CFR part 80, subpart M, 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 M, including 40 CFR 80.1465 apply to [insert name of foreign producer]. Pursuant to Clean Air Act section 113(c) and 18 U.S.C. 1001, the penalty for furnishing false, incomplete or misleading information in this certification or submission is a fine of up to $10,000 U.S., and/or imprisonment for up to five years.''.

§ 80.1467 What are the additional requirements under this subpart for a foreign RIN owner?

(a) *Foreign RIN owner.* For purposes of this subpart, a foreign RIN owner is a party located outside the United States, the Commonwealth of Puerto Rico, the Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Mariana Islands (collectively referred to in this section as ''the United States'') that has been approved by EPA to own RINs.

(b) *General requirement.* An approved foreign RIN owner must meet all requirements that apply to parties who own RINs under this subpart.

(c) *Foreign RIN owner commitments*. Any party shall commit to and comply with the provisions contained in this paragraph (c) as a condition to being approved as a foreign RIN owner under this subpart.

(1) Any United States Environmental Protection Agency inspector or auditor must be given full, complete, and immediate access to conduct inspections and audits of the foreign RIN owner's place of business.

(i) Inspections and audits may be either announced in advance by EPA, or unannounced.

(ii) Access will be provided to any location where documents related to RINs the foreign RIN owner has obtained, sold, transferred or held are kept.

(iii) Inspections and audits may be by EPA employees or contractors to EPA.

(iv) Any documents requested that are related to matters covered by inspections and audits must be provided to an EPA inspector or auditor on request.

(v) Inspections and audits by EPA may include review and copying of any documents related to the following:

(A) Transfers of title to RINs.

(B) Work performed and reports prepared by independent auditors under the requirements of this section, including work papers.

(vi) Inspections and audits by EPA may include interviewing employees.

(vii) Any employee of the foreign RIN owner must be made available for interview by the EPA inspector or auditor, on request, within a reasonable time period.

(viii) English language translations of any documents must be provided to an EPA inspector or auditor, on request, within 10 working days.

(ix) English language interpreters must be provided to accompany EPA inspectors and auditors, on request.

(2) An agent for service of process located in the District of Columbia shall be named, and service on this agent constitutes service on the foreign RIN owner or any employee of the foreign RIN owner for any action by EPA or otherwise by the United States related to the requirements of this subpart.

(3) The forum for any civil or criminal enforcement action related to the provisions of this section for violations of the Clean Air Act or regulations promulgated thereunder shall be governed by the Clean Air Act, including the EPA administrative forum where allowed under the Clean Air Act.

(4) United States substantive and procedural laws shall apply to any civil or criminal enforcement action against the foreign RIN owner or any employee of the foreign RIN owner related to the provisions of this section.

(5) Submitting an application to be a foreign RIN owner, and all other actions to comply with the requirements of this subpart constitute actions or activities covered by and within the meaning of the provisions of 28 U.S.C. 1605(a)(2), but solely with respect to actions instituted against the foreign RIN owner, its agents and employees in any court or other tribunal in the United States for conduct that violates the requirements applicable to the foreign RIN owner under this subpart, including conduct that violates the False Statements Accountability Act of 1996 (18 U.S.C. 1001) and section 113(c)(2) of the Clean Air Act (42 U.S.C. 7413).

(6) The foreign RIN owner, or its agents or employees, will not seek to detain or to impose civil or criminal remedies against EPA inspectors or auditors, whether EPA employees or EPA contractors, for actions performed within the scope of EPA employment related to the provisions of this section.

(7) The commitment required by this paragraph (c) shall be signed by the owner or president of the foreign RIN owner business.

(d) *Sovereign immunity*. By submitting an application to be a foreign RIN owner under this subpart, the foreign entity, and its agents and employees, without exception, become subject to the full operation of the administrative and judicial enforcement powers and provisions of the United States without limitation based on sovereign immunity, with respect to actions instituted against the foreign RIN owner, its agents and employees in any court or other tribunal in the United States for conduct that violates the requirements applicable to the foreign RIN owner under this subpart, including conduct that violates the False Statements Accountability Act of 1996 (18 U.S.C. 1001) and section 113(c)(2) of the Clean Air Act (42 U.S.C. 7413).

(e) *Bond posting*. Any foreign entity shall meet the requirements of this paragraph (e) as a condition to approval as a foreign RIN owner under this subpart.

(1) The foreign entity shall post a bond of the amount calculated using the following equation:

$$\text{Bond} = G * \$\,0.01$$

Where:

Bond = amount of the bond in U.S. dollars.

G = the total of the number of gallon-RINs the foreign entity expects to sell or transfer during the first calendar year that the foreign entity is a RIN owner, plus the number of gallon-RINs the foreign entity expects to sell or transfer during the next four calendar years. After the first calendar year, the bond amount shall be based on the actual number of gallon-RINs sold or transferred during the current calendar year and the number held at the conclusion of the current averaging year, plus the number of gallon-RINs sold or transferred during the four most recent calendar years preceding the current calendar year. For any year for which there were fewer than four preceding years in which the foreign entity sold or transferred RINs, the bond shall be based on the total of the number of gallon-RINs sold or transferred during the current calendar year and the number held at the end of the current calendar year, plus the number of gallon-RINs sold or transferred during any calendar year preceding the current calendar year, plus the number of gallon-RINs expected to be sold or transferred during subsequent calendar years, the total number of years not to exceed four calendar years in addition to the current calendar year.

(2) Bonds shall be posted by doing any of the following:

(i) Paying the amount of the bond to the Treasurer of the United States.

(ii) Obtaining a bond in the proper amount from a third party surety agent that is payable to satisfy United States administrative or judicial judgments against the foreign RIN owner, provided EPA agrees in advance as to the third party and the nature of the surety agreement.

(iii) An alternative commitment that results in assets of an appropriate liquidity and value being readily available to the United States, provided EPA agrees in advance as to the alternative commitment.

(3) All the following shall apply to bonds posted under this paragraph (e); bonds 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''.

(iii) Include a commitment that the bond will remain in effect for at least five years following the end of latest reporting period in which the foreign RIN owner obtains, sells, transfers, or holds RINs.

(4) On any occasion a foreign RIN owner bond is used to satisfy any judgment, the foreign RIN owner shall increase the bond to cover the amount

used within 90 days of the date the bond is used.

(f) *English language reports.* Any document submitted to EPA by a foreign RIN owner shall be in English, or shall include an English language translation.

(g) *Prohibitions.* (1) A foreign RIN owner is prohibited from obtaining, selling, transferring, or holding any RIN that is in excess of the number for which the bond requirements of this section have been satisfied.

(2) Any RIN that is sold, transferred, or held that is in excess of the number for which the bond requirements of this section have been satisfied is an invalid RIN under § 80.1431.

(3) Any RIN that is obtained from a party located outside the United States that is not an approved foreign RIN owner under this section is an invalid RIN under § 80.1431.

(4) No foreign RIN owner or other party may cause another party to commit an action prohibited in this paragraph (g), or that otherwise violates the requirements of this section.

(h) *Additional attest requirements for foreign RIN owners.* The following additional requirements apply to any foreign RIN owner as part of the attest engagement required for RIN owners under this subpart M.

(i) The attest auditor must be independent of the foreign RIN owner.

(ii) The attest auditor must be licensed as a Certified Public Accountant in the United States and a citizen of the United States, or be approved in advance by EPA based on a demonstration of ability to perform the procedures required in §§ 80.125 through 80.127, 80.130, and 80.1464.

(iii) The attest auditor must sign a commitment that contains the provisions specified in paragraph (c) of this section with regard to activities and documents relevant to compliance with the requirements of §§ 80.125 through 80.127, 80.130, and 80.1464.

(i) *Withdrawal or suspension of foreign RIN owner status.* EPA may withdraw or suspend its approval of a foreign RIN owner where any of the following occur:

(1) A foreign RIN owner fails to meet any requirement of this section, including, but not limited to, the bond requirements.

(2) A foreign government fails to allow EPA inspections as provided in paragraph (c)(1) of this section.

(3) A foreign RIN owner asserts a claim of, or a right to claim, sovereign immunity in an action to enforce the requirements in this subpart.

(4) A foreign RIN owner fails to pay a civil or criminal penalty that is not satisfied using the foreign RIN owner bond specified in paragraph (e) of this section.

(j) *Additional requirements for applications, reports and certificates.* Any application for approval as a foreign RIN owner, any report, certification, or other submission required under this section shall be:

(1) Submitted in accordance with procedures specified by the Administrator, including use of any forms that may be specified by the Administrator.

(2) Signed by the president or owner of the foreign RIN owner company, or by that party's immediate designee, and shall contain the following declaration:

''I hereby certify: 1) That I have actual authority to sign on behalf of and to bind [insert name of foreign RIN owner] with regard to all statements contained herein; 2) that I am aware that the information contained herein is being Certified, or submitted to the United States Environmental Protection Agency, under the requirements of 40 CFR part 80, subpart M, 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 M, including 40 CFR 80.1467 apply to [insert name of foreign RIN owner]. Pursuant to Clean Air Act section 113(c) and 18 U.S.C. 1001, the penalty for furnishing false, incomplete or misleading information in this certification or submission is a fine of up to $10,000 U.S., and/or imprisonment for up to five years.''.

§ 80.1468 [Reserved]

§ 80.1469 What are the labeling requirements that apply to retailers and wholesale purchaser-consumers of ethanol fuel blends that contain greater than 10 volume percent ethanol?

(a) Any retailer or wholesale purchaser-consumer who sells, dispenses, or offers for sale or dispensing, ethanol fuel blends that contain greater than 10 volume percent ethanol must prominently and conspicuously display in the immediate area of each pump stand from which such fuel is offered for sale or dispensing, the following legible label in block letters of no less than 24-point bold type in a color contrasting with the background:

CONTAINS MORE THAN 10 VOLUME PERCENT ETHANOL

For use only in flexible-fuel gasoline vehicles.

May damage non-flexible fuel vehicles.

WARNING

Federal law prohibits use in non-flexible fuel vehicles.

(b) Alternative labels to those specified in paragraph (a) of this section may be used as approved by EPA. Requests for approval of alternative labels shall be sent to one of the following addresses:

(1) *For US mail:* U.S. EPA, *Attn:* Alternative fuel dispenser label request, 6406J, 1200 Pennsylvania Avenue, NW., Washington, DC 20460.

(2) *For overnight or courier services:* U.S. EPA, *Attn:* Alternative fuel dispenser label request, 6406J, 1310 L Street, NW., 6th floor, Washington, DC 20005. (202) 343–9038.

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