

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

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

E. Attest Engagements

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

conduct in the creation and transfer of RINs.

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

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

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

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

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

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

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

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

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

VI. Current and Projected Renewable Fuel Production and Use

While the definition of renewable fuel does not limit compliance with the standard to any one particular type of renewable fuel, ethanol is currently the most prevalent renewable fuel blended into gasoline today. Biodiesel represents another renewable fuel which, while not as widespread as ethanol use (in terms of volume), has been increasing in production capacity and use over the last several years. This section provides a brief overview of the ethanol and biodiesel industries today and how they are projected to grow into the future.

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

1. Current Ethanol Production

As of October 2006, there were 110 ethanol production facilities operating in the United States with a combined production capacity of approximately 5.2 billion gallons per year.⁴³ All of the ethanol currently produced comes from grain or starch-based feedstocks that can easily be broken down into ethanol via traditional fermentation processes. The majority of ethanol (almost 92 percent by volume) is produced exclusively from corn. Another 7 percent comes from a blend of corn and/or similarly processed grains (milo, wheat, or barley) and less than 1 percent is produced from waste beverages, cheese whey, and sugars/starches combined. A summary of ethanol production by feedstock is presented in Table VI.A.1-1.

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

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

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

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

^c Includes two facilities processing brewery waste.

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

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

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

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

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

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

or biomass into ethanol. For a more detailed discussion on future cellulosic ethanol plants and production technologies, refer to RIA Sections 1.2.3.6 and 7.1.2, respectively.

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

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

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

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

The majority of domestic ethanol is currently produced in the Midwest within PADD 2—where most of the corn is grown. Of the 110 U.S. ethanol

production facilities, 100 are located in PADD 2. As a region, PADD 2 accounts for 96 percent (or over five billion gallons) of the annual domestic ethanol

production, as shown in Table VI.A.1-3.

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

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

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

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

feedstocks, while others rely on a combination of both.

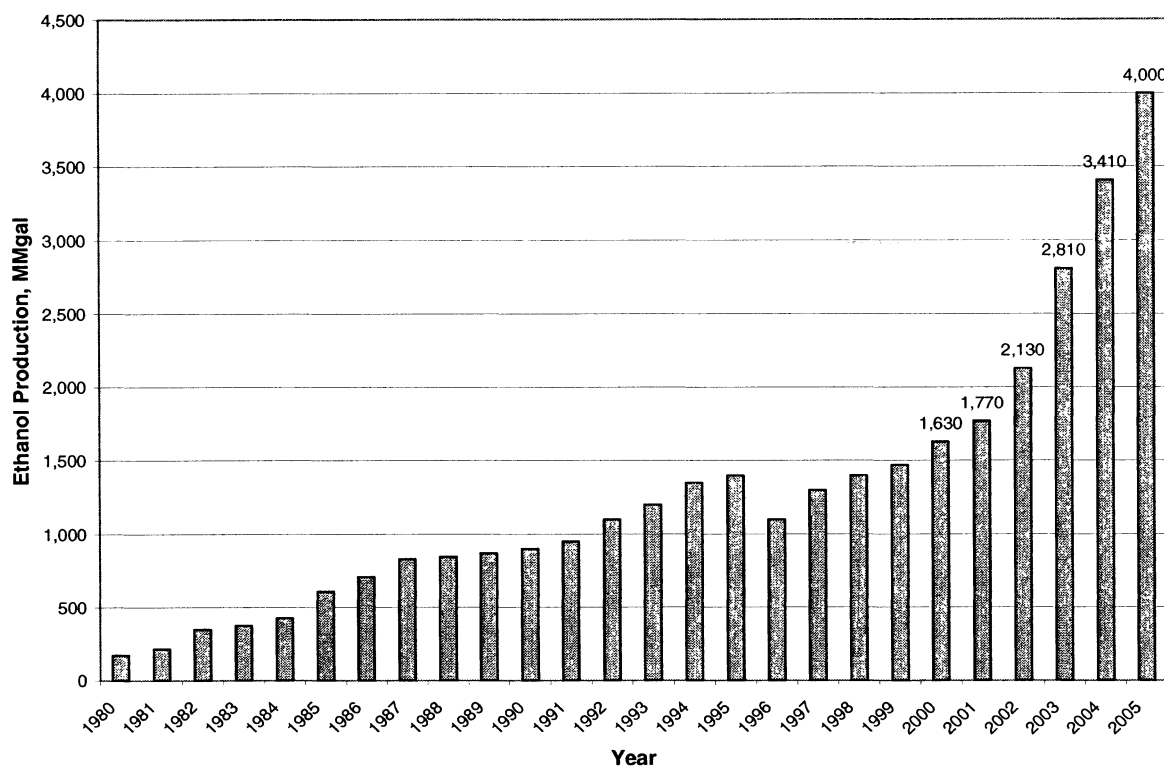
The U.S. ethanol industry is currently comprised of a mixture of corporations and farmer-owned cooperatives (co-ops). More than half (or 60) of today's plants are owned by corporations and, on average, these plants are larger in size than farmer-owned co-ops. Accordingly, company-owned plants account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

2. Expected Growth in Ethanol Production

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

Figure VI.A.2-1

U.S. Ethanol Production versus Time



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

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

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

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

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

⁴⁶ Based on RFA comments received in response to the proposed rulemaking, 71 FR 5552 (September 22, 2006).

ethanol. As a result, the nation is on track to exceed the renewable fuel volume requirements contained in the Act. Today's ethanol production capacity (5.2 billion gallons) is already

exceeding the 2007 renewable fuel requirement (4.7 billion gallons). In addition, there is another 3.4 billion gallons of ethanol production capacity currently under construction.⁴⁷ A

summary of the new construction and plant expansion projects currently underway (as of October 2006) is found in Table VI.A.2-1.

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

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

^a Includes plant expansions.

A select group of builders, technology providers, and construction contractors are completing the majority of the

construction projects described in Table VI.A.2-1. As such, the completion dates of these projects are staggered over

approximately 18 months, resulting in the gradual phase-in of ethanol production shown in Figure VI.A.2-2.⁴⁸

⁴⁷ Under construction plant locations, capacities, feedstocks, and energy sources as well as planned/proposed plant locations and capacities were derived from a variety of data sources including Renewable Fuels Association (RFA), Ethanol Biorefinery Locations (updated October 16, 2006); Ethanol Producer Magazine (EPM), under

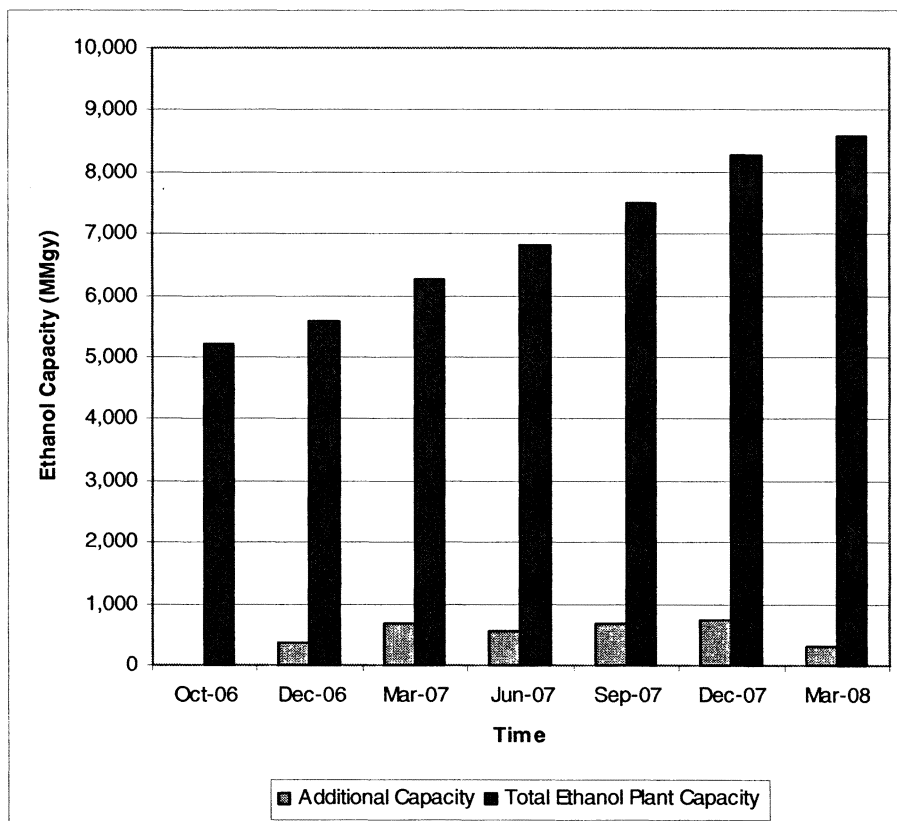
construction plant list (downloaded October 18, 2006) and monthly publications (June 2006 through October 2006); ICF International, Ethanol Industry Profile (September 30, 2006); BioFuels Journal, News & Information for the Ethanol and BioFuels Industries (breaking news posted June 16, 2006 through October 18, 2006); and ethanol producer

Web sites. This analysis does not consider ethanol plants under construction or planned for the Virgin Islands or U.S. territories.

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

Figure VI.A.2-2

Estimated Phase-In of Under Construction Plant Capacity



As shown in Table VI.A.2-1 and Figure VI.A.2-2, once all the construction projects currently underway are complete (estimated by March 2008), the resulting U.S. ethanol production capacity would be about 8.6 billion gallons. Without even considering forecasted biodiesel production (described below in Section

VI.B.1), this would be more than enough renewable fuel to satisfy the 2012 RFS requirements (7.5 billion gallons). However, ethanol production is expected to continue to grow. There are more and more ethanol projects being announced each day. These potential projects are at various stages of planning from conducting feasibility studies to

gaining local approval to applying for permits to financing/fundraising to obtaining contractor agreements. Together these potential projects could result in an additional 21 billion gallons of ethanol production capacity as shown in Table VI.A.2-2.

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

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

^a Includes plant expansions.

^b Total including existing plus under construction plants.

Although there is clearly a great potential for ethanol production growth, it is highly unlikely that all the

announced projects would actually reach completion in a reasonable amount of time, or at all, considering

the large number of projects moving forward. Since there is no precise way to know exactly which plants will come

to fruition in the future, we have chosen to focus our subsequent discussion on forecasted ethanol production on plants which are likely to be online by 2012.⁴⁹ This includes existing plants as well as projects which are under construction

(refer to Table VI.A.2-1) or in the final planning stages (denoted as “planned” in Table VI.A.2-2). The distinction between “planned” versus “proposed” is that as of October 2006 planned projects had completed permitting,

fundraising/financing, and had builders assigned with definitive construction timelines whereas proposed projects did not.

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

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

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

According to a current report by F.O. Licht, U.S. net import demand is estimated to be around 300 million gallons per year by 2012, being supplied primarily through the Caribbean Basin Initiative (CBI), with some direct imports from Brazil during times of shortfall or high price. For more information on ethanol imports, refer to RIA Section 1.5.

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

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

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

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

^a Facilities plan to start off processing corn.

⁴⁹ A more detailed summary of the plants we considered is found in a March 5, 2007 note to the

docket titled: RFS Industry Characterization—Ethanol Production.

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

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

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

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

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

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

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

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

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

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

⁵⁰ We anticipate a ramp-up in cellulosic ethanol production in the years to come so that capacity exists to satisfy the Act’s 2013 requirement (250 million gallons of cellulosic biomass ethanol). Therefore, for subsequent analysis purposes, we have assumed that 250 million gallons of ethanol would come from cellulosic biomass sources by 2012.

3. Current Ethanol and MTBE Consumption

To understand the impact of the increased ethanol production/use on gasoline properties and in turn overall air quality, we first need to gain a better understanding of where ethanol is used today and how the picture is going to change in the future. As such, in addition to the production analysis presented above, we have completed a parallel consumption analysis comparing current ethanol consumption to future predictions.

In the 2004 base case, 3.5 billion gallons of ethanol⁵¹ and 1.9 billion gallons of MTBE⁵² were blended into gasoline to supply the transportation sector with a total of 136 billion gallons of gasoline.⁵³ A breakdown of the 2004

⁵¹ EIA Monthly Energy Review, June 2006 (Table 10.1: Renewable Energy Consumption by Source, Appendix A: Thermal Conversion Factors).

⁵² File containing historical RFG MTBE usage obtained from EIA representative on March 9, 2006.

⁵³ EIA 2004 Petroleum Marketing Annually (Table 48: Prime Supplier Sales Volumes of Motor

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

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

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

^a MTBE blended into RFG.
^b PADD 5 excluding California.

As shown above, nearly half (or about 45 percent) of the ethanol was consumed in PADD 2 gasoline, where the majority of ethanol was produced. The next highest region of use was the State of California which accounted for about 25 percent of domestic ethanol consumption. This is reasonable because California alone accounts for over 10 percent of the nation's total gasoline consumption and all the fuel (both Federal RFG and California Phase 3 RFG) has been assumed to contain ethanol (following their recent MTBE ban) at 5.7 volume percent.⁵⁴ The bulk of the remaining ethanol was used in reformulated gasoline (RFG) and winter oxy-fuel areas requiring oxygenated gasoline. Overall, 62 percent of ethanol was used in RFG, 33 percent was used

in CG, and 5 percent was used in winter oxy-fuel.⁵⁵
 As shown above in Table VI.A.3-1, 99 percent of MTBE use occurred in PADDs 1 and 3. This reflects the high concentration of RFG areas in the northeast (PADD 1) and the local production of MTBE in the gulf coast (PADD 3). PADD 1 receives a large portion of its gasoline from PADD 3 refineries who either produce the fossil-fuel based oxygenate or are closely affiliated with MTBE-producing petrochemical facilities in the area. Overall, 100 percent of MTBE in 2004 was assumed to be used in reformulated gasoline.⁵⁶
 In 2004, total ethanol use exceeded MTBE use. Ethanol's lead oxygenate role is relatively new, however the trend

has been a progression over the past few years. From 2001 to 2004, ethanol consumption more than doubled (from 1.7 to 3.5 billion gallons), while MTBE use (in RFG) was virtually cut in half (from 3.7 to 1.9 billion gallons). A plot of oxygenate use over the past decade is provided below in Figure VI.A.3-1.
 The nation's transition to ethanol is linked to states' responses to recent environmental concerns surrounding MTBE groundwater contamination. Resulting concerns over drinking water quality have prompted several states to significantly restrict or completely ban MTBE use in gasoline. At the time of this analysis, 19 states had adopted MTBE bans. A list of the states with MTBE bans is provided in RIA Table 2.1-4.

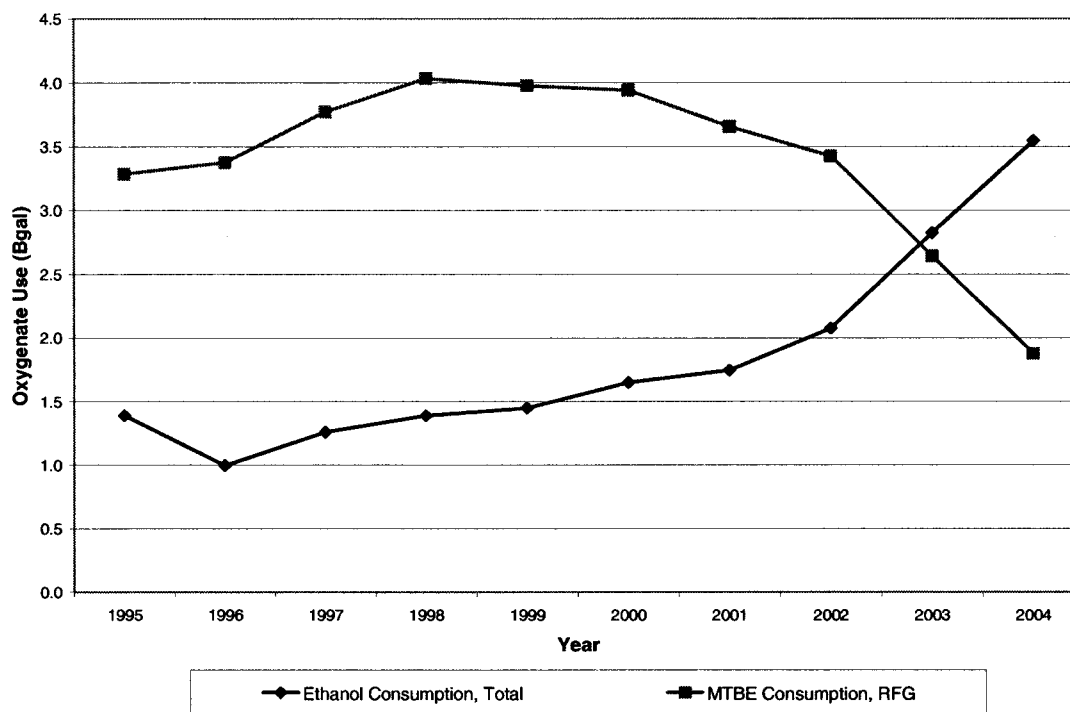
Gasoline by Grade, Formulation, PAD District, and State).
⁵⁴ Current California gasoline regulations make it very difficult to meet the NO_x emissions performance standard with ethanol content higher than about 6 vol%. For our analysis, all California RFG was assumed to contain 5.7 volume percent

ethanol based on a conversation with Dean Simeroth at California Air Resources Board (CARB).
⁵⁵ For the purpose of this analysis, except where noted, the term "RFG" pertains to Federal RFG plus California Phase 3 RFG (CaRFG3) and Arizona Clean Burning Gasoline (CBG).

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

Figure VI.A.3-1

U.S. Oxygenate Use Over Time



Source: Energy Information Administration

4. Expected Growth in Ethanol Consumption

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

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

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

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

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

⁵⁸ Based on discussions with the refining industry.

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

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

To estimate where ethanol would be consumed in 2012, we used a linear

programming (LP) refinery cost model (discussed in more detail in Section VII). For both future ethanol consumption scenarios discussed above, the modeling provided us with a summary of ethanol usage by PADD, fuel type, and season. There was some

post-processing involved to ensure that all state ethanol mandates and winter oxy-fuel requirements were satisfied. The adjusted results for the 6.7 Bgal RFS case and the 9.6 Bgal EIA case are presented below in Tables VI.A.4-1 and VI.A.4-2, respectively.

TABLE VI.A.4-1.—FORECASTED 2012 U.S. ETHANOL CONSUMPTION (MMGAL) 6.7 BGAL RFS CASE

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

^aIncludes Arizona CBG and winter oxy-fuel.
^bFederal RFG and California Phase 3 RFG.
^cPADDs 4 and 5 excluding California.

TABLE VI.A.4-1.—FORECASTED 2012 U.S. ETHANOL CONSUMPTION BY SEASON (MMGAL) 9.6 BGAL EIA CASE

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

^aIncludes Arizona CBG and winter oxy-fuel.
^bFederal RFG and California Phase 3 RFG.
^cPADDs 4 and 5 excluding California.

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

B. Overview of Biodiesel Industry and Future Production/Consumption

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

Historically, the cost to make biodiesel was an inhibiting factor to production in the U.S. The cost to produce biodiesel was high compared to the price of petroleum derived diesel

fuel, even with the subsidies and credits provided by federal and state programs. Much of the demand occurred as a result of mandates from states and local municipalities, that required the use of biodiesel. However, over the past couple of years biodiesel production has been increasing rapidly. The combination of higher crude oil prices and greater federal tax subsidies has created a favorable economic situation. The Biodiesel Blenders Tax Credit programs and the Commodity Credit Commission Bio-energy Program, both subsidize producers and offset production costs. The Energy Policy Act extended the Biodiesel Blenders Tax Credit program to 2008. This credit provides about one dollar per gallon in the form of a federal excise tax credit to biodiesel blenders from virgin vegetable oil feedstocks and 50 cents per gallon to biodiesel produced from recycled grease and animal fats. The program was started in 2004 under the American Jobs Act, spurring the expansion of biodiesel production and demand. Historical estimates and future forecasts of

biodiesel production in the U.S. are presented in Table VI.B.1-1 below.

TABLE VI.B.1-1.—ESTIMATED BIODIESEL PRODUCTION

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

Source: Historical data from 2001-2004 obtained from estimates from John Baize "The Outlook and Impact of Biodiesel on the Oil-seeds Sector" USDA Outlook Conference 06. Year 2005 data from USDA Bioenergy Program <http://www.fsa.usda.gov/daco/bioenergy/2005/FY2005ProductPayments>, Year 2006 data from verbal quote based on projection by NBB in June of 2006. Production data for years 2007 and higher are from EIA's AEO 2006.

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

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

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

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

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

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

^aCapacity Data based on surveys conducted around the month of September for most years, though the 2006 information is based on a survey conducted in January 2006.⁶¹

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

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

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

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

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

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

For cost and emission analysis purposes, three biodiesel usage cases were considered: A 2004 base case, a 2012 reference case, and a 2012 control case. The 2004 base case was formed based on historical biodiesel usage (25 million gallons as summarized in Table VI.B.1.1). The reference case was computed by taking the 2004 base case and growing it out to 2012 by applying the 2004–2012 EIA diesel fuel growth rate.⁶² The resulting 2012 reference case consisted of 30 million gallons of biodiesel. Finally, for the 2012 control case, forecasted biodiesel use was assumed to be 300 million gallons based on EIA’s AEO 2006 report (rounded value from Table VI.B.1.1). Unlike forecasted ethanol use, biodiesel use was assumed to be constant at 300 million gallons under both the statutory and higher projected renewable fuel consumption scenarios described in VI.A.4. EIA’s projection is based on the assumption that the blender’s tax credit is not renewed beyond 2008. If the tax credit is renewed, the projection for biodiesel demand would increase.

C. Feasibility of the RFS Program Volume Obligations

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

1. Production Capacity of Ethanol and Biodiesel

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

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

2. Technology Available To Produce Cellulosic Ethanol

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

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

⁶⁰NBB Survey September 13, 2006 “U.S. Biodiesel Production Capacity”.

⁶¹From Presentation “Biodiesel Production Capacity,” by Leland Tong, National Biodiesel Conference and Expo, February 7, 2006.

⁶²EIA Annual Energy Outlook 2006, Table 1.

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

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

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

a. Sugar Platform

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

i. Pretreatment

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

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

ii. Dilute Acid Hydrolysis

Dilute acid hydrolysis is the oldest technology for converting cellulose biomass to ethanol. The dilute acid process uses a 1-percent sulfuric acid in a continuous flow reactor at about 420 °F; reaction times are measured in seconds and minutes, which facilitates continuous processing. The process involves two reactions with a sugar conversion efficiency of about 50 percent. The process conditions at which the cellulosic molecules are converted into sugar are also those at which the sugar is almost immediately converted into other chemicals, principally furfural. The rapid conversion to furfural reduces the sugar yield, which along with other by-products inhibits the fermentation process. One way to decrease sugar degradation is to use a two-stage process which takes advantage of the fact that hemicellulose (5-carbon) sugars degrade more rapidly than cellulose (6-carbon) sugars. The first stage is conducted under mild process conditions to recover the 5-carbon sugars, while the second stage is conducted under harsher conditions to recover the 6-carbon sugars. Both hydrolyzed solutions are then fermented to ethanol. Lime is used to neutralize the residual acid before the fermentation stage. Regardless, some sugar degrades to furfural, which naturally limits the net yield of ethanol. The residual cellulose and lignin are used as boiler fuel for electricity or steam production.⁶⁵

iii. Concentrated acid hydrolysis

Concentrated acid hydrolysis uses a 70-percent sulfuric acid solution, followed by water hydrolysis to convert the cellulose into sugar. The process rapidly, and nearly completely, converts

cellulose to glucose (6-carbon) and hemicellulose to xylose (5-carbon) sugar, with little degradation to furfural; the reaction times are typically slower than those of the dilute acid process. The critical factors needed to make this process economically viable are to optimize sugar recovery and cost effectively recover the acid for recycling. The concentrated acid process is somewhat more complicated and requires more time, but it has the primary advantage of yielding up to about 90% of both hemicellulosic and cellulosic sugars.⁶⁶ In addition, a significant advantage of the concentrated acid process is that it is carried out at relatively low temperatures, about 212 °F, and low pressure, such that fiberglass reactors and piping can be used.

iv. Enzymatic hydrolysis

Enzymatic hydrolysis is not necessarily a recent discovery. We found reports of research conducted by a variety of companies and government agencies going back to at least 1991.^{67 68 69} The enzymatic hydrolysis of cellulose was reportedly discovered when a fungus, *trichoderma reesei*, was identified which produced cellulase enzymes that broke down cotton clothing and tents in the South Pacific during World War II. Since then, generations of cellulases have been developed through genetic modifications of the fungus strain. As in acid hydrolysis, the hydrolyzing enzymes must have access to the cellulose and hemicellulose in order to work efficiently. Although enzymatic hydrolysis requires some kind of pretreatment, purely physical pretreatments are typically not adequate. Furthermore, the chemical method uses dilute sulfuric acid, which is poisonous to the fermentation

⁶⁶ Ibid.

⁶⁷ Technical and Economic Analysis Of An Enzymatic Hydrolysis Based Ethanol Plant, Fuels and Chemicals Research and Engineering Division, Solar Energy Research Institute, Golden CO, 80401, June 1991 • DRAFT • SERI Protected Proprietary Information • Do Not Copy.

⁶⁸ Biomass to Ethanol Process Evaluation, A report prepared for National Renewable Energy Laboratory, December 1994; Chem Systems Inc. 303 South Broadway, Tarrytown, New York, 10591.

⁶⁹ Lignocellulosic Biomass to Ethanol Process Design and Economics Utilizing Co-Current Dilute Acid Prehydrolysis and Enzymatic Hydrolysis Current and Futuristic Scenarios, July 1999 • NREL/TP-580-26157; Robert Wooley, Mark Ruth, John Sheehan, and Kelly Ibsen, Biotechnology Center for Fuels and Chemicals; Henry Majdeski and Adrian Galvez, Delta-T Corporation; National Renewable Energy Laboratory, 1617 Cole Boulevard, Golden, Colorado 80401-3393; NREL is a U.S. Department of Energy Laboratory Operated by Midwest Research Institute • Battelle • Bechtel; Contract No. DE-AC36-98-GO10337.

⁶⁴ Appendix B, Overview of Cellulose-Ethanol Production Technology; OREGON CELLULOSE-ETHANOL STUDY, *An evaluation of the potential for ethanol production in Oregon using cellulose-based feedstocks*; Prepared by: Angela Graf, Bryan & Bryan Inc., 5015 Red Gulch, Cotopaxi, Colorado 81223; Tom Koehler, Celilo Group, 2208 S.W. First Ave., #320, Portland, Oregon 97204; For submission to: The Oregon Office of Energy.

⁶⁵ Ibid.

microorganisms and must be detoxified. While original enzymatic hydrolysis processes used separate hydrolysis and fermentation steps, recent process improvements integrate saccharification and fermentation by combining the cellulase enzymes and fermenting microbes in one vessel. This results in a one-step process of sugar production and fermentation, referred to as the simultaneous saccharification and fermentation (SSF) process. One disadvantage is that the cellulase enzyme and fermentation organism must operate under the same process conditions, which could decrease the sugar and, ultimately, the ethanol yields. An alternative to the SSF technology is the sequential hydrolysis and fermentation (SHF) process. The separation of hydrolysis and fermentation enables enzymes to operate at higher temperatures in the hydrolysis step to increase sugar production and more moderate temperatures in the fermentation step to optimize the conversion of sugar into ethanol.

Cost-effective cellulase enzymes must also be developed for this technology to be completely successful.⁷⁰ Several companies are using variations of these technologies to develop processes for converting cellulosic biomass into ethanol by way of fermentation. A few groups, using recently developed genome modifying technology, have been able to produce a variety of new or modified enzymes and microbes that show promise for use in weak- or dilute-acid enzymatic-prehydrolysis. Another problem with cellulosic feedstocks is, as previously described, that the hydrolysis reactions produce both glucose, the six-carbon sugar, and xylose, the five-carbon sugar (pentose sugar, C₅H₁₀O₅; sometimes called "wood sugar"). Early conversion technology required different microbes to ferment each sugar. Recent research has developed better fermenting organisms. Now, glucose and xylose can be co-fermented—hence, the present-day terminology: Weak-acid enzymatic hydrolysis and co-fermentation.

b. Syngas Platform

The second platform for producing cellulosic ethanol is to convert the biomass into a syngas which is then converted into ethanol. A "generic" syngas process is essentially a "steam reformer," which "gasifies" biomass and other carbon based substances including wastes, in a reduced-oxygen environment and reacts them with steam to produce a synthesis gas or

"syngas" consisting primarily of carbon monoxide and hydrogen. The syngas is then passed over in a Fischer-Tropsch catalyst to produce ethanol.

The biomass feedstock is dried to about 15% moisture content and ground small enough to be efficiently burned and reacted in the reformer. The reformer, an important upstream element of the process, is essentially a common solid-fuel gasifier, which with some modification and steam injection becomes what is sometimes referred to as the "primary reformer."

When any fuel is completely burned, all of its potential energy is released as heat which can be recovered for immediate use. In a common gasification process, the partially burned fuel (wood or coal) releases a small amount of heat, but leaves some uncombusted, gaseous products. Ordinarily, the hot product gases are fed directly to a nearby boiler or gas turbine, to do work; it has been reported that for a well-designed system, the overall efficiency may approach that of a solid fuel boiler. However, when steam is injected into the gasifier, it reacts with the burning solid fuel to produce more gaseous product. The primary reaction is between carbon and water which produces hydrogen and carbon monoxide and an inorganic ash. The ash and heavy hydrocarbon-tars are removed from the raw syngas before it is compressed and passed over Fischer-Tropsch catalyst to produce ethanol. Fisher-Tropsch technology has been used for many years in the chemical and refining industries, most notably to produce gasoline and diesel fuel from syngas produced by coal gasification. Whether the Fischer-Tropsch reaction produces diesel or ethanol is primarily the result of changes to process pressure, temperature and in some cases the use of custom catalysts. In most cases, the Fischer-Tropsch process did not produce pure ethanol in the first pass through the system. Rather, a stream of mixed chemicals was produced, including gasoline, diesel, and oxygenated hydrocarbons (alcohol).⁷¹

c. Plasma Technology

The development of another technology, called plasma, is also

underway for creating a syngas from which ethanol is produced. A plasma "reactor," generates an ionized gas (plasma) which serves as an electrical conductor to transfer intense radiant energy to a biomass or waste material. This intense energy is said to actually breakdown the various materials in the biomass or waste into their atomic components. Anything present in the feed-mass that doesn't gasify, is essentially "vitrified." This vitrified stream is reportedly inert and can be used as aggregate in paving materials. Following gasification, the syngas is cooled, impurities are removed, and the gas is sent to ethanol production as with the syngas platform described above.⁷²

d. Feedstock Optimization

Cellulosic biomass can come from a variety of sources. Because the conversion of cellulosic biomass to ethanol has not yet been commercially demonstrated, we cannot say at this time which feedstocks are superior to others. A few of the many resources are: Post-sorted municipal waste, rice and wheat straw,⁷³ soft-woods, hardwood, switch grass, and bagasse. Regardless, each feedstock requires a specific combination of pretreatment methods and enzyme "cocktails" to optimize the operation and maximize the ethanol yield. One of the many challenges for the cellulose-ethanol industry is to find the best feedstocks and then develop the most cost-effective ways for converting them into ethanol.

3. Renewable Fuel Distribution System Capability

Ethanol and biodiesel blended fuels are currently not shipped by petroleum product pipeline due to operational issues and additional cost factors. Hence, a separate distribution system is needed for ethanol and biodiesel up to the point where they are blended into petroleum-based fuel as it is loaded into tank trucks for delivery to retail and fleet operators. In cases where ethanol and biodiesel are produced within 200 miles of a terminal, trucking is often the preferred means of distribution. For longer shipping distances, the preferred

⁷² Ethanol From Tires Via Plasma Converter Plus Fischer Tropsch, March 15, 2006; http://thefraserdomain.typepad.com/energy/2006/03/ethanol_from_ti.html.

⁷³ Wheat Straw for Ethanol Production in Washington: A Resource, Technical, and Economic Assessment, September 2001, WSUCEEP2001084; Prepared by: James D. Kerstetter, Ph.D., John Kim Lyons, Washington State University Cooperative Extension Energy Program, 925 Plum Street, SE., P.O. Box 43165, Olympia, WA 98504-3165; Prepared for: Washington State Office of Trade and Economic Development.

⁷⁰ Ibid.

⁷¹ Gridley Ethanol Demonstration Project Utilizing Biomass Gasification Technology: Pilot Plant Gasifier and Syngas Conversion Testing, August 2002–June 2004; February 2005 • NREL/SR-510-37581; TSS Consultants, For the City of Gridley, California, 1617 Cole Boulevard, Golden, Colorado 80401-3393, 303-275-3000 • <http://www.nrel.gov>; Operated for the U.S. Department of Energy Office of Energy Efficiency and Renewable Energy by Midwest Research Institute • Battelle Contract No. DE-AC36-99-GO10337.

method of bringing renewable fuels to terminals is by rail and barge.

Modifications to the rail, barge, tank truck, and terminal distribution systems will be needed to support the transport of the anticipated increased volumes of renewable fuels. These modifications include the addition of terminal blending systems for ethanol and biodiesel, additional storage tanks at terminals, additional rail delivery systems at terminals for ethanol and biodiesel, and additional rail cars, barges, and tank trucks to distribute ethanol and biodiesel to terminals. Terminal storage tanks for 100 percent biodiesel will also need to be heated during cold months to prevent gelling. The most comprehensive study of the infrastructure requirements for an expanded fuel ethanol industry was conducted for the Department of Energy (DOE) in 2002.⁷⁴ The conclusions reached in that study indicate that the changes needed to handle the anticipated increased volume of ethanol by 2012 will not represent a major obstacle to industry. While some changes have taken place since this report was issued, including an increased reliance on rail over marine transport, we continue to believe that the rail and marine transportation industries can manage the increased growth in demand in an orderly fashion. This belief is supported by the demonstrated ability for the industry to handle the rapid increases and redistribution of ethanol use across the country over the last several years as MTBE was removed. The necessary facility changes at terminals and at retail stations to dispense ethanol containing fuels have been occurring at a record pace. Given that future growth is expected to progress at a steadier pace and with greater advance warning in response to economic drivers, we anticipate that the distribution system will be able to respond appropriately. A discussion of the costs associated making the changes discussed above is contained in Section VII.B of today's preamble.

VII. Impacts on Cost of Renewable Fuels and Gasoline

This section examines the impact on fuel costs resulting from the growth in renewable fuel use between a base year of 2004 and 2012. We note that based on analyses conducted by the Energy Information Administration (EIA), renewable fuels will be used in gasoline and diesel fuel in excess of the RFS

requirements. As such, the changes in the use of renewable fuels and their related cost impacts are not directly attributable to the RFS rule. Rather, our analysis assesses the broader fuels impacts of the growth in renewable fuel use in the context of corresponding changes to the makeup of gasoline. These fuel impacts include the elimination of the reformulated gasoline (RFG) oxygen standard which has resulted in the refiners ceasing to use the gasoline blendstock methyl tertiary butyl ether (MTBE) and replacing it with ethanol. Thus, in this analysis, we are assessing the impact on the cost of gasoline and diesel fuel of increased use of renewable fuels, the cost savings resulting from the phase out of MTBE and the increased cost due to the other changes in fuel quality that result.

As discussed in Section II, we chose to analyze a range of renewable fuel use. In the case of ethanol's use in gasoline, the lower end of this range is based on the minimum renewable fuel volume requirements in the Act, (the RFS case) and the higher end is based on AEO 2006 (the EIA case). At both ends of this range, we assume that biodiesel consumption will be the level estimated in AEO 2006. We analyzed the projected fuel consumption scenario and associated program costs in 2012, the year that the RFS is fully phased-in. The volumes of renewable fuels consumed in 2012 at the two ends of the range are summarized in Table II.A.1–1.

We have estimated an average corn ethanol production cost of \$1.26 per gallon in 2012 (2004 dollars) for the RFS case and \$1.32 per gallon for the EIA case. For cellulosic ethanol, we estimate it will cost approximately \$1.65 in 2012 (2004 dollars) to produce a gallon of ethanol using corn stover as a cellulosic feedstock. In this analysis, however, we assume that the cellulosic requirement will be met by corn-based ethanol produced by energy sourced from biomass (animal and other waste materials as discussed in Section III.B of today's preamble) and costing the same as corn based ethanol produced by conventional means.

We estimated production costs for soy-derived biodiesel of \$2.06 per gallon in 2004 and \$1.89 per gallon in 2012. For yellow grease derived biodiesel, we estimate an average production cost of \$1.19 per gallon in 2004 and \$1.11 in 2012.

For the proposed rule, we estimated the cost of increased use of renewable fuel and other major cost impacts by developing our own cost spreadsheet model. That analysis considered the production cost, distribution cost as well as the cost for balancing the octane

and RVP caused by these fuel changes. That analysis, however, could not properly balance octane and other gasoline qualities. For this final rule, we have therefore used the services of Jacobs Consultancy to run their refinery LP model to estimate the cost impacts of the RFS rule.

The results from the refinery LP model indicate that the impacts on overall gasoline costs from the increased use of ethanol and the corresponding changes to the other aspects of gasoline would be 0.49 cents per gallon for the RFS case. The EIA case would result in increased total cost of 1.03 cents per gallon. The actual cost at the fuel pump, however, will be decreased due to the effect of State and Federal tax subsidies for ethanol. Taking this into consideration results in "at the pump" decreased costs (cost savings) of -0.47 cents per gallon for the RFS case and "at the pump" decreased cost of -0.83 cents per gallon for the EIA case. Section 7 of the RIA contains more detail on the cost analysis used to develop these costs.

A. Renewable Fuel Production and Blending Costs

1. Ethanol Production Costs

a. Corn Ethanol

A significant amount of work has been done in the last decade on surveying and modeling the costs involved in producing ethanol from corn to serve business and investment purposes as well as to try to educate energy policy decisions. Corn ethanol costs for our work were estimated using a model developed by USDA in the 1990s that has been continuously updated by USDA. The most current version was documented in a peer-reviewed journal paper on cost modeling of the dry-grind corn ethanol process, and it produces results that compare well with cost information found in surveys of existing plants.⁷⁵ We made some minor modifications to the USDA model to allow scaling of the plant size, to allow consideration of plant energy sources other than natural gas, and to adjust for energy prices in 2012, the year of our analysis.

The cost of ethanol production is most sensitive to the prices of corn and the primary co-product, DDGS. Utilities, capital, and labor expenses also have an impact, although to a lesser extent. Corn feedstock minus DDGS sale credits

⁷⁵ Kwaitkowski, J.R., McAloon, A., Taylor, F., Johnston, D.B., *Industrial Crops and Products* 23 (2006) 288–296.

⁷⁶ Shapouri, H., Gallagher, P., *USDA's 2002 Ethanol Cost-of-Production Survey* (published July 2005).

⁷⁴ "Infrastructure Requirements for an Expanded Fuel Ethanol Industry," *Downstream Alternatives Inc.*, January 15, 2002.

represents about 48% of the final per-gallon cost, while utilities, capital and labor comprise about 19%, 9%, and 6%, respectively. For this work, we used corn prices of \$2.50/bu and \$2.71/bu for the RFS and EIA cases, respectively, with corresponding DDGS prices at \$83.35/ton and \$85.16/ton (2004 dollars). These estimates are from modeling work done for this rulemaking using the Forestry and Agricultural Sector Optimization Model, which is described in more detail in Chapter 8 of the RIA. Energy prices were derived from historical data and projected to 2012 using EIA's AEO 2006. More details on how the ethanol production cost estimates were made can be found in Chapter 7 of the RIA.

The estimated average corn ethanol production cost of \$1.26 per gallon in 2012 (2004 dollars) in the RFS case and \$1.32 per gallon in the EIA case represents the full cost to the plant operator, including purchase of feedstocks, energy required for operations, capital depreciation, labor, overhead, and denaturant, minus revenue from sale of co-products. It assumes that 86% of new plants will use natural gas as a thermal energy source, at a price of \$6.16/MMBtu (2004 dollars).⁷⁷ It does not account for any subsidies on production or sale of ethanol. Note that the cost figure generated here is independent of the market price of ethanol, which has been related closely to the wholesale price of gasoline for the past decade.^{78 79}

Under the Energy Act, starch-based ethanol can be counted as cellulosic if at least 90% of the process energy is derived from renewable feedstocks, which include plant cellulose, municipal solid waste, and manure biogas.⁸⁰ It is expected that the vast majority of the 250 million gallons per year of cellulosic ethanol production required by 2013 will be made using this provision. While we have been unable to develop a detailed production cost estimate for corn ethanol meeting cellulosic criteria, we assume that the costs will not be significantly different from conventionally produced corn ethanol. We believe this is reasonable because the costs of hauling, storing, and processing this low or zero cost waste material in order to combust it

will be significant, thus making overall production costs at these plants similar to gas-fired ethanol plants. As of the time of this writing, we know of only a few operating plants of this type, and expect the quantity of ethanol produced this way to remain a relatively small fraction of the total ethanol demand. Thus, the sensitivity of the overall analysis to this assumption is also very small.⁸¹ Based on these factors, we have assigned starch ethanol made using this cellulosic criteria the same cost as ethanol produced from corn using conventional means.

b. Cellulosic Ethanol

In 1999, the National Renewable Energy Laboratory (NREL) published a report outlining its work with the USDA to design a computer model of a plant to produce ethanol from hard-wood chips.⁸² Although the model was originally prepared for hardwood chips, it was meant to serve as a modifiable-platform for ongoing research using cellulosic biomass as feedstock to produce ethanol. Their long-term plan was that various indices, costs, technologies, and other factors would be regularly updated.

NREL and USDA used a modified version of the model to compare the cost of using corn-grain with the cost of using corn stover to produce ethanol. We used the corn stover model from the second NREL/USDA study for the analysis for this rule. Because there were no operating plants that could potentially provide real world process design, construction, and operating data for processing cellulosic ethanol, NREL had considered modeling the plant based on assumptions associated with a first-of-a-kind or pioneer plant. The literature indicates that such models often underestimate actual costs since the high performance assumed for pioneer process plants is generally unrealistic.

Instead, the NREL researchers assumed that the corn stover plant was an Nth generation plant, e.g., not a pioneer plant or first-of-its kind, built after the industry had been sufficiently established to provide verified costs. The corn stover plant was normalized to the corn kernel plant, e.g., placed on a

similar basis.⁸³ It is also reasonable to expect that the cost of cellulosic ethanol would be higher than corn ethanol because of the complexity of the cellulose conversion process. Recently, process improvements and advancements in corn production have considerably reduced the cost of producing corn ethanol. We also believe it is realistic to assume that cellulose-derived ethanol process improvements will be made and that one can likewise reasonably expect that, as the industry matures, the cost of producing ethanol from cellulose will also decrease.

We calculated fixed and variable operating costs using percentages of direct labor and total installed capital costs. Following this methodology, we estimate that producing a gallon of ethanol using corn stover as a cellulosic feedstock would cost \$1.65 in 2012 (2004 dollars).

2. Biodiesel Production Costs

We based our estimate for the cost to produce biodiesel on the use of USDA's, NREL's and EIA's biodiesel computer models, along with estimates from engineering vendors that design biodiesel plants. Biodiesel fuel can be made from a wide variety of virgin vegetable oils such as canola, corn oil, cottonseed, etc. though, the operating costs (minus the costs of the feedstock oils) for these virgin vegetable oils are similar to the costs based on using soy oil as a feedstock, according to an analysis by NREL Biodiesel costs are therefore determined based on the use of soy oil, since this is the most commonly used virgin vegetable feedstock oil, and the use of recycled cooking oil (yellow grease) as a feedstock. Production costs are based on the process of continuous transesterification, which converts these feedstock oils to esters, along with the ester finishing processes and glycerol recovery. The models and vendors data are used to estimate the capital, fixed and operating costs associated with the production of biodiesel fuel, considering utility, labor, land and any other process and operating requirements, along with the prices for

⁷⁷ For more details on fuel sources and costs of production, see RIA Chapter 1.2.2 and 7.1.1.2.

⁷⁸ Whims, J., Sparks Companies, Inc. and Kansas State University, "Corn Based Ethanol Costs and Margins, Attachment 1" (Published May 2002).

⁷⁹ Piel, W.J., Tier & Associates, Inc., March 9, 2006 report on costs of ethanol production and alternatives.

⁸⁰ Energy Policy Act of 2005, Section 1501 amending Clean Air Act Section 211(o)(1)(A).

⁸¹ See Table VI.A.1-2 for more details on number of operating ethanol plants and their fuel sources.

⁸² Lignocellulosic Biomass to Ethanol Process Design and Economics Utilizing Co-Current Dilute Acid Prehydrolysis and Enzymatic Hydrolysis Current and Futuristic Scenarios, Robert Wooley, Mark Ruth, John Sheehan, and Kelly Ibsen, Biotechnology Center for Fuels and Chemicals, Henry Majdeski and Adrian Galvez, Delta-T Corporation; National Renewable Energy Laboratory, Golden, CO, July 1999, NREL/TP-580-26157.

⁸³ Determining the Cost of Producing Ethanol from Corn Starch and Lignocellulosic Feedstocks; A Joint Study Sponsored by: USDA and USDOE, October 2000 • NREL/TP-580-28893 • Andrew McAloon, Frank Taylor, Winnie Yee, USDA, Eastern Regional Research Center Agricultural Research Service; Kelly Ibsen, Robert Wooley, National Renewable Energy Laboratory, Biotechnology Center for Fuels and Chemicals, 1617 Cole Boulevard, Golden, CO, 80401-3393; NREL is a USDOE Operated by Midwest Research Institute • Battelle • Bechtel; Contract No. DE-AC36-99-GO10337.

feedstock oils, methanol, chemicals and the byproduct glycerol.

The USDA, NREL and EIA models are based on a medium sized biodiesel plant that was designed to process raw degummed virgin soy oil as the feedstock. Additionally, the EIA model also contains a representation to estimate the biodiesel production cost for a plant that uses yellow grease as a feedstock. In the USDA model, the equipment needs and operating requirements for their biodiesel plant was estimated through the use of process simulation software. This software determines the biodiesel process requirements based on the use of established engineering relationships, process operating conditions and reagent needs. To substantiate the validity and accuracy of their model, USDA solicited feedback from major biodiesel producers. Based on responses, they then made adjustments to their model and updated their input prices to year 2005. The NREL model is also based on process simulation software, though the results are adjusted to reflect NREL's modeling methods, using prices based on year 2002. The output for all of these models was provided in spreadsheet format. We also use engineering vendor estimates as another source to generate soy oil and yellow grease biodiesel production costs. These firms are primarily engaged in the business of designing biodiesel plants.

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

The models and vendor estimates are further modified to use input prices for feedstocks, byproducts and energy that reflect the effects of the fuels provisions in the Energy Act. In order to capture a range of production costs, we generated cost projections from all of the models and vendors. We present the details on these estimates in Chapter 7 of the RIA.

For soy oil biodiesel production, we estimate a production cost ranging from \$1.89 to \$2.15 per gallon in 2012 (in 2004 dollars) using these different

models and sources of information. For yellow grease derived biodiesel, we used the EIA and vendor estimates to generate total production costs which range from \$1.11 to \$1.56 for year 2012.

With the current Biodiesel Blender Tax Credit Program, producers using virgin vegetable oil stocks receive a one dollar per gallon tax subsidy while yellow grease producers receive 50 cents per gallon, reducing the net production cost to a range of 89 to 115 cents per gallon for soy oil and 61 to 106 cents per gallon for yellow greased derived biodiesel fuel in 2012. This compares favorably to the projected wholesale diesel fuel prices of 138 cents per gallon in 2012, signifying that the economics for biodiesel are positive under the effects of the blender credit program, though the tax credit program will expire in 2008 if it is not extended. Congress may later elect to extend the blender credit program following the precedence used for extending the ethanol blending subsidies. Additionally, the Small Biodiesel Blenders Tax credit program and state tax and credit programs offer some additional subsidies and credits, though the benefits are modest in comparison to the Blender's Tax credit.

3. Diesel Fuel Costs

Biodiesel fuel is blended into highway and nonroad diesel fuel, which increases the volume and therefore the supply of diesel fuel and thereby reduces the demand for refinery-produced diesel fuel. In this section, we estimate the overall cost impact, considering how much refinery based diesel fuel is displaced by the forecasted production volume of biodiesel fuel. The cost impacts are evaluated considering the production cost of biodiesel with and without the subsidy from the Biodiesel Blenders Tax credit program. Additionally, the diesel cost impacts are quantified with refinery diesel prices as forecasted by Jacob's which is based on EIA's AEO 2006.

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

transport fuel, neglecting minor uses in the heating oil market.

For RFS cases, the net effect of biodiesel production on diesel fuel costs, including the biodiesel blenders' subsidy, is a reduction in the cost of transport diesel fuel costs by \$114 million per year, which equates to a reduction in fuel cost of about 0.20 cents per gallon.⁸⁴ Without the subsidy, the transport diesel fuel costs are increased by \$91 million per year, or an increase of 0.16 cents per gallon for transport diesel fuel.

B. Distribution Costs

1. Ethanol Distribution Costs

There are two components to the costs associated with distributing the volumes of ethanol necessary to meet the requirements of the Renewable Fuels Standard (RFS): (1) The capital cost of making the necessary upgrades to the fuel distribution infrastructure system, and (2) the ongoing additional freight costs associated with shipping ethanol to terminals. The most comprehensive study of the infrastructure requirements for an expanded fuel ethanol industry was conducted for the Department of Energy (DOE) in 2002.⁸⁵ That study provided the foundation for our estimates of the capital costs associated with upgrading the distribution infrastructure system as well as the freight costs to handle the increased volume of ethanol needed to meet the requirements of the RFS in 2012. Distribution costs are evaluated here for both the RFS case and for the EIA case. The 2012 reference case against which we are estimating the cost of distributing the additional volume of ethanol needed to meet the requirements of the RFS is 3.9 billion gallons.

a. Capital Costs To Upgrade Distribution System for Increased Ethanol Volume

The 2002 DOE study examined two cases regarding the use of renewable fuels for estimating the capital costs for distributing additional ethanol. The first assumed that 5.1 billion gal/yr of ethanol would be used in 2010, and the second assumed that 10 billion gal/yr of ethanol would be used in the 2015 timetable. We interpolated between these two cases to provide the foundation for our estimate of the capital costs to support the use of 6.7 billion gal/yr of ethanol in 2012 for the

⁸⁴ Based on EIA's AEO 2006, 58.9 billion gallons of highway and off-road diesel fuel is projected to be consumed in 2012.

⁸⁵ Infrastructure Requirements for an Expanded Fuel Ethanol Industry, Downstream Alternatives Inc., January 15, 2002.

RFS case.⁸⁶ The 10 billion gal/yr case examined in the DOE study was used as the foundation in estimating the capital costs under the EIA projected case examined in today's rule of 9.6 billion gal/yr of ethanol.⁸⁷ Our estimated capital costs in this final rule differ from those in the proposed rule for several reasons. We adjusted our capital costs from those in the proposal to reflect an increase in the cost of tank cars and barges used to ship ethanol since the DOE study was conducted. In addition, we are assuming an increased reliance on rail transport over that projected in the DOE study.⁸⁸

Table VII.B.1.a-1 contains our estimates of the infrastructure changes and associated capital costs for the two ethanol use scenarios examined in today's rule. Amortized over 15 years with a 7 percent cost of capital, the total capital costs equate to approximately 1.4 cents per gallon of ethanol under the RFS case and 1.2 cents per gallon under the EIA case.⁸⁹

TABLE VII.B.1.A-1.—ESTIMATED ETHANOL DISTRIBUTION INFRASTRUCTURE CAPITAL COSTS (\$M) *

	RFS case 6.7 Bgal/yr	EIA case 9.6 Bgal/yr
<i>Fixed Facilities:</i>		
Retail	20	44
Terminals	115	241
<i>Mobile Facilities:</i>		
Transport		
Trucks	24	50
Barges	21	43
Rail Cars	172	297
Total Capital Costs	352	675

* Relative to a 3.9 billion gal/yr reference case.

b. Ethanol Freight Costs

The Energy Information Administration (EIA) translated the ethanol freight cost estimates in the DOE study to a census division basis.⁹⁰

⁸⁶ See chapter 7.3 of the Regulatory Impact Analysis associated with today's rule for additional discussion of how the results of the DAI study were adjusted to reflect current conditions in estimating the ethanol distribution infrastructure capital costs under today's rule.

⁸⁷ For both the 6.7 bill gal/yr and 9.6 bill gal/yr cases, the baseline from which the DOE study cases were projected was adjusted to reflect a 3.9 bill gal/yr 2012 baseline.

⁸⁸ This increased reliance on rail transport was the subject of a sensitivity analysis conducted for the proposed rule.

⁸⁹ These capital costs will be incurred incrementally during the period of 2007–2012 as ethanol volumes increase. For the purpose of this analysis, we assumed that all capital costs were incurred in 2007.

⁹⁰ Petroleum Market Model of the National Energy Modeling System, Part 2, March 2006, DOE/EIA-

For this final rule, we translated the EIA projections into State-by-State and national average freight costs to align with our State-by-State ethanol use estimates. Not including capital recovery, we estimate that the freight cost to transport ethanol to terminals would range from 4 cents per gallon in the Midwest to 25 cents per gallon to the West Coast. On a national basis, this averages to 11.3 cents per gallon of ethanol under the RFS case and 11.9 cents per gallon under the EIA case.⁹¹ We adjusted the estimated ethanol freight costs from those in the proposal by increasing the cost of shipping ethanol to satellite versus hub terminals, by increasing the cost of gathering ethanol for large volume shipments to hub terminals, and by increasing the percentage of ethanol delivered to large volume terminals versus the volume delivered to lesser volume terminals.⁹²

Including the cost of capital recovery for the necessary distribution facility changes, we estimate the national average cost of distributing ethanol to be 12.7 cents per gallon under the RFS case and 13.1 cents per gallon under the EIA case.⁹³ Thus, we estimate the total cost for producing and distributing ethanol to be between \$1.39 and \$1.45 per gallon of ethanol, on a nationwide average basis. This estimate includes both the capital costs to upgrade the distribution system and freight costs.

2. Biodiesel Distribution Costs

The volume of biodiesel used by 2012 under the RFS is estimated at 300 million gallons per year. The 2012 baseline case against which we are estimating the cost of distributing the additional volume of biodiesel is 30 million gallons.⁹⁴

The capital costs associated with distribution of biodiesel are higher per gallon than those associated with the distribution of ethanol due to the need for storage tanks, blending systems, barges, tanker trucks and rail cars to be insulated and in many cases heated

⁹⁰⁹ (2006), [http://tonto.eia.doe.gov/FTP/ROOT/modeldoc/m059\(2006\)-2.pdf](http://tonto.eia.doe.gov/FTP/ROOT/modeldoc/m059(2006)-2.pdf).

⁹¹ See Chapter 7.3 of the RIA.

⁹² Hub terminals refer to those terminals where ethanol is delivered in large volume shipments such as by unit train (consisting of 70 tank cars or more) or marine barges/tanker. Satellite terminals are those terminals that are either supplied from a hub terminal or receive ethanol shipments in smaller quantities directly from the producer. See Chapter 7 of the RIA regarding how these estimates were adjusted from those in the proposal and the check of our estimates against current ethanol freight rates.

⁹³ All capital costs were assumed to be incurred in 2007 and were amortized over 15 years at a 7 percent cost of capital.

⁹⁴ 2004 baseline of 25 million gallons grown with diesel demand to 2012.

during the winter months.⁹⁵ In the proposal, we estimated that these capital costs would be approximately \$50,000,000. We adjusted our estimate of these capital costs for this final rule based on additional information regarding the cost to install necessary storage and blending equipment at terminals and the need for additional rail tank cars for biodiesel.⁹⁶ As discussed in the RIA, we now estimate that handling the increased biodiesel volume will require a total capital cost investment of \$145,500,000 which equates to about 6 cents per gallon of new biodiesel volume.⁹⁷

In the proposal, we estimated that the freight costs for ethanol may adequately reflect those for biodiesel as well. In response to comments, we sought additional information regarding the freight costs for biodiesel. This information indicates that freight costs for biodiesel are typically 30 percent higher than those for ethanol which translates into an estimate of 15.5 cents per gallon for biodiesel freight costs on a national average basis.⁹⁸

Including the cost of capital recovery for the necessary distribution facility changes, we estimate the cost of distributing biodiesel to be 21.5 cents per gallon. Depending on whether the feedstock is waste grease or virgin oil, we estimate the total cost for producing and distributing biodiesel to be between \$1.33 and \$2.11 per gallon of biodiesel, on a nationwide average basis.⁹⁹ This estimate includes both the capital costs to upgrade the distribution system and freight costs, and the wide range reflects differences in different types of production feedstocks.

C. Estimated Costs to Gasoline

To estimate the cost of increased use of renewable fuels, the cost savings from the phase out of MTBE and the production cost of alkylate, we relied on

⁹⁵ See Chapter 1.3 of the Regulatory Impact Analysis associated with today's rule for a discussion of the special handling requirements for biodiesel under cold conditions.

⁹⁶ Biodiesel rail tank cars typically have a capacity of 25,500 gallons as opposed to 30,000 gallons for an ethanol tank car. Thus, additional tank cars are needed to transport a given volume of biodiesel relative to the same volume of ethanol.

⁹⁷ Capital costs will be incurred incrementally over the period of 2007–2012 as biodiesel volumes increase. For the purpose of this analysis, all capital costs were assumed to be incurred in 2007 and were amortized over 15 years at a 7 percent cost of capital.

⁹⁸ The estimated ethanol freight costs were increased by 30 percent to arrive at the estimate of biodiesel freight costs.

⁹⁹ See Section VII.A.2. of this preamble regarding biodiesel production costs. We estimated 2012 production costs of \$1.89 per gal for soy-derived biodiesel and \$1.11 per gal for yellow grease derived biodiesel.

refinery modeling conducted by Jacob's Consultancy that established baselines based on 2004 volumes, which were then used to project a reference case and 2 control cases for 2012. The contractor developed a five region, U.S. demand model in which specific regional clean product demands are sold at hypothetical regional terminals.

1. Description of Cases Modeled

a. Base Case (2004)

The baseline case was established by modeling fuel volumes for 2004, with data on fuel properties provided to the contractor by EPA. Fuel property data for this base case was built off of 2004 refinery batch reports provided to EPA; however, the base case assumed sulfur standards based on gasoline data in 2004, not with fully phased in Tier 2 gasoline standards at the 30 ppm level. In addition we assumed the phase-in of 15 ppm sulfur standards for highway, nonroad, locomotive and marine diesel fuel. The supply/demand balance for the U.S. was based on gasoline volumes from EIA and the California Air Resources Board (CARB). Our decision to use 2004 rather than 2005 as the baseline year was because of the refinery upset conditions associated with the Gulf Coast hurricanes in 2005.

b. Reference Case (2012)

The reference case was based on modeling the base case, using 2012 fuel prices, and scaling the 2004 fuel volumes to 2012 based on growth in fuel demand. In addition, we scaled MTBE and ethanol upward, in proportion to gasoline growth, and assumed the RFS program would not be in effect. For example, if the PADD 1 gasoline pool MTBE oxygen was 0.5 wt% in 2004, the reference case assumed it should remain at 0.5 wt%. Finally, we assumed the MSAT 1 standards would remain in place as would the RFG oxygen mandate. We assumed the crude slate quality in 2012 is the same as the baseline case.

c. Control Cases (2012)

Two control cases were run for 2012. The assumptions for each of the control cases are summarized below

Control Case 1 (RFS case): 6.7 billion gallons/yr (BGY) of ethanol in gasoline; it reflects the renewable fuel mandate. We have also assumed that 0.3 billion gallons of biodiesel will be consumed as reflected in Table II.A.1-1. In addition,

it is assumed that no MTBE is in gasoline, MSAT1 is in place, the psi waiver for conventional gasoline containing 10 volume percent ethanol is in effect, the RFS is in effect, and there is no RFG oxygenate mandate.

Control Case 2 (EIA case): Same as Control Case 1, except the ethanol volume in gasoline is 9.6 BGY.

2. Overview of Cost Analysis Provided by the Contractor Refinery Model

The estimated cost of increased use of renewable fuels, the cost savings from the phase out of MTBE and the cost of converting some of the former MTBE feedstocks to produce alkylate, isooctane, and isooctene is provided by the output of the refinery model. As described in VII.C.1, the cost analysis was conducted by comparing the 2012 reference case with the two control cases which are assumed to take place in 2012.

The major factors which impact the costs in the refinery model are (1) blending in more ethanol, (2) adjusting the gasoline blending to lower RVP, (3) removing the MTBE, (4) converting MTBE feedstocks to other high quality replacement, and (5) adjusting for the change in gasoline energy density. The first is the addition of ethanol to the gasoline pool. The refinery model estimates the cost impact of increasing the volume of ethanol in the reference case from 3.94 billion gallons to 6.67 and 9.60 billion gallons in the RFS and EIA modeled cases, respectively. The estimated production prices for ethanol for the RFS and EIA cases are provided above in Section VII.A. We also show the results with the federal and state subsidies applied to the production price of ethanol.

The addition of ethanol to wintertime gasoline, and to summertime RFG, will cause an increase of approximately 1 psi in RVP which needs to be offset to maintain constant RVP levels. One method that refiners could choose to offset the increase in RVP is to reduce the butane levels in their gasoline. To some extent, the modeling results showed some occurrences of that, but it also did not report an overall increase in butane sales as a result of the increased use of ethanol.

To convert the captive MTBE over to alkylate, after the rejection of methanol, refiners will need to combine refinery-produced isobutane with the isobutylene that was used as a feedstock for MTBE. The use of the isobutane will

reduce the RVP of the gasoline pool from which it comes, helping to offset the RVP impacts of ethanol. Also, the increased production of alkylate provides a low RVP gasoline blendstock which offsets a portion of the cracked stocks produced by the fluidized catalytic cracker unit. Other means that the refinery model used to offset the high blending RVP of ethanol included purchasing gasoline components with lower RVP, producing more poly gasoline which has low RVP and selling more high-RVP naphtha to petrochemical sales.

3. Overall Impact on Fuel Cost

Based on the refinery modeling conducted for today's rule, we have calculated the costs of these fuel changes that will occur for the RFS and EIA cases. The costs are expressed two different ways. First, we express the cost of the program without the ethanol consumption subsidies in which the costs are based on the total accumulated cost of each of the fuels changes. Second, we express the cost with the ethanol consumption subsidies included since the subsidized portion of the renewable fuels costs will not be represented to the consumer in its fuel costs paid at the pump, but instead by being paid through the state and federal tax revenues. In all cases, the capital costs are amortized at 7 percent return on investment (ROI), and based on 2006 dollars.

a. Cost Without Ethanol Subsidies

Table VII.C.3.a-1 summarizes the costs without ethanol subsidies for each of the two control cases, including the cost for each aspect of the fuel changes, and the aggregated total and the per-gallon costs for all the fuel changes.¹⁰⁰ This estimate of costs reflects the changes in gasoline that are occurring with the expanded use of ethanol, including the corresponding removal of MTBE. These costs include the labor, utility and other operating costs, fixed costs and the capital costs for all the fuel changes expected. The per-gallon costs are derived by dividing the total costs over all U.S. gasoline projected to be consumed in 2012. We excluded federal and state ethanol consumption subsidies which avoids the transfer payments caused by these subsidies that would hide a portion of the program's costs.

¹⁰⁰ EPA typically assesses social benefits and costs of a rulemaking. However, this analysis is more limited in its scope by examining the average

cost of production of ethanol and gasoline without accounting for the effects of farm subsidies that

tend to distort the market price of agricultural commodities.

TABLE VII.C.3.A-1.—ESTIMATED COST WITHOUT ETHANOL CONSUMPTION SUBSIDIES

[Million dollars and cents per gallon; 7% ROI and 2006 dollars]

	RFS case 6.8 billion gals in- cremental to reference case	EIA case 9.6 billion gals in- cremental to reference case	EIA case 9.6 billion gals in- cremental to RFS case
Capital Costs (\$MM)	-5,878	-7,311	-1,433
Amortized Capital Costs (\$MM/yr)	-647	-804	-158
Fixed Operating Cost (\$MM/yr)	-178	-222	-43
Variable Operating Cost (\$MM/yr)	-201	-491	-290
Fuel Economy Cost (\$MM/yr)	1,848	3,255	1407
Total Cost (\$MM/yr)	823	1739	915
Capital Costs (c/gal of gasoline)	-0.40	-0.49	-0.10
Fixed Operating Cost (c/gal of gasoline)	-0.11	-0.14	-0.03
Variable Operating Cost (c/gal of gasoline)	-0.12	-0.30	-0.18
Fuel Economy Cost (c/gal of gasoline)	1.13	1.98	0.86
Total Cost Excluding Subsidies (c/gal of gasoline)	0.50	1.06	0.56

Our analysis shows that when considering all the costs associated with these fuel changes resulting from the expanded use of subsidized ethanol that these various possible gasoline use scenarios will increase fuel costs by \$820 million or \$1,740 million in the year 2012 for the RFS and EIA cases, respectively. Expressed as per-gallon costs, these fuel changes would increase

fuel costs by 0.50 to 1.1 cents per gallon of gasoline.

b. Gasoline Costs Including Ethanol Consumption Tax Subsidies

Table VII.C.3.b-1 expresses the total and per-gallon gasoline costs for the two control scenarios with the federal and state ethanol subsidies included. The federal tax subsidy is 51 cents per gallon for each gallon of new ethanol blended

into gasoline. The state tax subsidies apply in 5 states and range from 1.6 to 29 cents per gallon. The cost reduction to the fuel industry and consumers is estimated by multiplying the subsidy times the volume of new ethanol estimated to be used in the state. The per-gallon costs are derived by dividing the total costs over all U.S. gasoline projected to be consumed in 2012.

TABLE VII.C.3.B-1.—ESTIMATED COST INCLUDING ETHANOL CONSUMPTION SUBSIDIES

[Million dollars and cents per gallon; 7% ROI and 2006 dollars]

	RFS case 6.8 billion gals in- cremental to reference case	EIA case 9.6 billion gals in- cremental to reference case	EIA case 9.6 billion gals in- cremental to RFS case
Total Cost (\$MM/yr)	823	1739	915
Federal Subsidy (\$MM/yr)	-1376	-2865	-1489
State Subsidies (\$MM/yr)	-5	-31	-26
Revised Total Cost (\$MM/yr)	-558	-1158	-600
Per-Gallon Cost Excluding Subsidies (c/gal of gasoline)	0.50	1.06	0.56
Federal Subsidy (c/gal of gasoline)	-0.84	-1.74	-0.90
State Subsidies (c/gal of gasoline)	-0.003	-0.02	-0.02
Total Cost Including Subsidies (c/gal of gasoline)	-0.34	-0.71	-0.37

The cost including subsidies better represents gasoline's production cost as reflected to the fuel industry as a whole and to consumers "at the pump" because the federal and state subsidies tend to hide a portion of the actual costs. Our analysis estimates that the fuel industry and consumers will see a 0.34 and 0.71 cent per gallon decrease in the apparent cost of producing gasoline for the RFS and EIA cases, respectively.

VIII. What Are the Impacts of Increased Ethanol Use on Emissions and Air Quality?

In this section, we evaluate the impact of increased production and use of renewable fuels on emissions and air quality in the U.S., particularly ethanol

and biodiesel. In performing these analyses, we compare the emissions which would have occurred in the future if fuel quality had remained unchanged from pre-Act levels to those which will be either required under the Energy Policy Act of 2005 (Energy Act or the Act) or exist due to market forces.

This approach differs from that traditionally taken in EPA regulatory impact analyses. Traditionally, we would have compared future emissions with and without the requirement of the Energy Act. However, as described in Section II, we expect that total renewable fuel use in the U.S. in 2012 to exceed the Act's requirements even in the absence of the RFS program. Thus, a traditional regulatory impact analysis would have shown no impact on

emissions or air quality. This is because, strictly speaking, if the same volume and types of renewable fuels are produced and used with and without the RFS program, the RFS program has no impact on fuel quality and thus, no impact on emissions or air quality. However, levels of renewable fuel use are increasing dramatically relative to both today and the recent past, with corresponding impacts on emissions and air quality. We believe that it is appropriate to evaluate these changes here, regardless of whether they are occurring due to economic forces or Energy Act requirements.

In the process of estimating the impact of increased renewable fuel use, we also include the impact of reduced use of MTBE in gasoline. It is the

increased production and use of ethanol which is facilitating the continued production of RFG which meets both commercial and EPA regulatory specifications without the use of MTBE. Because of this connection, we found it impractical to isolate the impact of increased ethanol use from the removal of MTBE.

A. Effect of Renewable Fuel Use on Emissions

1. Emissions From Gasoline Fueled Motor Vehicles and Equipment

Several models of the impact of gasoline quality on motor vehicle emissions have been developed since the early 1990's. We evaluated these models and selected those which were based on the most comprehensive set of emissions data and developed using the most advanced statistical tools for this analysis. Still, as will be described below, significant uncertainty exists as to the effect of these gasoline components on emissions from both motor vehicle and nonroad equipment, particularly from the latest vehicle and engine models equipped with the most advanced emission controls. Pending adequate funding, we plan to conduct significant vehicle and equipment testing over the next several years to improve our estimates of the impact of these additives and other gasoline properties on emissions. We hope that the results from these test programs will be available for reference in the future evaluations of the emission and air

quality impacts of U.S. fuel programs required by the Act.¹⁰¹

The remainder of this sub-section is divided into three parts. The first evaluates the impact of increased ethanol use and decreased MTBE use on gasoline quality. The second evaluates the impact of increased ethanol use and decreased MTBE use on motor vehicle emissions. The third evaluates the impact of increased ethanol use and decreased MTBE use on nonroad equipment emissions.

a. Gasoline Fuel Quality

For the final rulemaking, we estimate the impact of increased ethanol use and decreased MTBE use on gasoline quality using refinery modeling conducted specifically for the RFS rulemaking.¹⁰² In general, adding ethanol to gasoline reduces the aromatic content of conventional gasoline and the mid- and high-distillation temperatures (e.g., T50 and T90). RVP increases except in areas where ethanol blends are not provided a 1.0 RVP waiver of the applicable RVP standards in the summer. With the exception of RVP, adding MTBE directionally produces the same impacts. Thus, the effect of removing MTBE results in essentially the opposite impacts. Neither oxygenate is expected to affect sulfur levels, as refiners control sulfur independently in order to meet the Tier 2 sulfur standards.

The impacts of oxygenate use are smaller with respect to RFG. This is due to RFG's VOC and toxics emission

performance specifications, which limit the range of feasible fuel quality values. Thus, oxygenate type or level does not consistently affect the RVP level and aromatic and benzene contents of RFG.

Table VIII.A.1.a-1 shows the fuel quality of a typical summertime, non-oxygenated conventional gasoline and how these qualities change with the addition of 10 volume percent ethanol. Similarly, the table shows the fuel quality of a typical MTBE RFG blend and how fuel quality might change with either ethanol use or simply MTBE removal. All of these fuels are based, in whole or in part, on projections made by Jacobs in their recent refinery modeling performed for EPA and therefore, represent improvements over the projections made for the NPRM. Please see Chapter 2 of the RIA for a detailed description of the methodologies used to determine the specific changes in projected fuel quality. As discussed there, we use the Jacobs model projections of RFG fuel quality directly in our emission modeling. For conventional gasoline, we use the Jacobs modeling described in Section VII to determine the change in fuel quality due to ethanol use and apply this change to base fuel quality estimates contained in EPA's NMIM emission inventory model. Sulfur is not shown in Table VIII.A.1.a-1, as it is held constant at 30 ppm, which is the average Tier 2 sulfur standard applicable to all gasoline sold in the U.S. in the timeframe of our emission analyses.

TABLE VIII.A.1.A-1.—TYPICAL SUMMERTIME FUEL QUALITY

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

^a MTBE blend—Reference Case PADD 1 South, Ethanol blend—RFS Case PADD 1 North, Non-oxy blend. —RFS Case PADD 1 South.

b. Emissions From Motor Vehicles

We use the EPA Predictive Models to estimate the impact of gasoline fuel quality on exhaust VOC and NO_x emissions from motor vehicles. These models were developed in 2000, in

support of EPA's response to California's request for a waiver of the RFG oxygen mandate. These models represent a significant update of the EPA Complex Model. However, they are still based on emission data from Tier 0

vehicles (roughly equivalent to 1990 model year vehicles). We based our estimates of the impact of fuel quality on CO emissions on the EPA MOBILE6.2 model. We base our estimates of the impact of fuel quality

¹⁰¹ Subject to funding.

¹⁰² Refinery modeling performed in support of the original RFG rulemaking is also used to help separate the effects of the two oxygenates.

on exhaust toxic emissions (benzene, formaldehyde, acetaldehyde, and 1,3-butadiene) primarily on the MOBILE6.2 model, updated to reflect the effect of fuel quality on exhaust VOC emissions per the EPA Predictive Models. Very limited data are available on the effect of gasoline quality on PM emissions. Therefore, the effect of increased ethanol use on PM emissions can only be qualitatively discussed.

In responding to California's request for a waiver of the RFG oxygen mandate in 2000, we found that both very limited and conflicting data were available on the effect of fuel quality on exhaust emissions from Tier 1 and later vehicles.¹⁰³ Thus, we assumed at the time that changes to gasoline quality would not affect VOC, CO and NO_x exhaust emissions from these vehicles.¹⁰⁴ Very little additional data have been collected since that time on which to modify this assumption. Consequently, for our primary analysis for today's final rule we have maintained the assumption that changes to gasoline do not affect exhaust emissions from Tier 1 and later technology vehicles.

For the NPRM, we evaluated one recent study by the Coordinating Research Council (CRC) which assessed the impact of ethanol and two other fuel properties on emissions from twelve 2000–2004 model year vehicles (CRC study E–67). Based on comments received on the NPRM, we evaluated four additional studies of the fuel-emission effects of recent model year vehicles. The results of these test

programs indicate that emissions from these late model year vehicles are likely sensitive to changes in fuel properties. However, both the size and direction of the effects are not consistent between the various studies. More testing is still needed before confident predictions of the effect of fuel quality on emissions from these vehicles can be made.

In the NPRM, we developed two sets of assumptions regarding the effect of fuel quality on emissions from Tier 1 and later vehicles to reflect this uncertainty. A primary analysis assumed that exhaust emissions from Tier 1 and later vehicles are not sensitive to fuel quality. This is consistent with our analysis of California's request for a waiver of the RFG oxygen mandate. A sensitivity analysis assumed that the NMHC and NO_x emissions from Tier 1 and later vehicles were as sensitive to fuel quality as Tier 0 vehicles. Only one effect of fuel quality on CO emissions was assumed, that contained in EPA's MOBILE6.2 emission inventory model.

The five available studies of Tier 1 and later vehicles support continuing this approach for exhaust NMHC and NO_x emissions. The assumptions supporting both our primary and sensitivity analyses reasonably bracket the results of the five studies. However, we have decided to perform a sensitivity analysis for CO emissions, as well. In this case, we apply the fuel-emission effects from MOBILE6.2 for Tier 0 vehicles to Tier 1 and later vehicles. This is analogous to the approach taken for exhaust NMHC and NO_x emissions.

We base our estimates of fuel quality on non-exhaust VOC and benzene emissions on the EPA MOBILE6.2 model. The one exception to this is the effect of ethanol on permeation emissions through plastic fuel tanks and elastomers used in fuel line connections. Recent testing has shown that ethanol increases permeation emissions, both by permeating itself and increasing the permeation of other gasoline components. This effect was included in EPA's analysis of California's most recent request for a waiver of the RFG oxygen requirement, but is not in MOBILE6.2.¹⁰⁵ Therefore, we have added the effect of ethanol on permeation emissions to MOBILE6.2's estimate of non-exhaust VOC emissions in assessing the impact of gasoline quality on these emissions.

No models are available which address the impact of gasoline quality on PM emissions. Very limited data indicate that ethanol blending might reduce exhaust PM emissions under very cold weather conditions (e.g., –20 °F to 0 °F). Very limited testing at warmer temperatures (e.g., 20 °F to 75 °F) shows no definite trend in PM emissions with oxygen content. Thus, for now, no quantitative estimates can be made regarding the effect of ethanol use on direct PM emissions.

Table VIII.A.1.b–1 presents the average per vehicle (2012 fleet) emission impacts of three types of RFG: Non-oxygenated, a typical MTBE RFG as has been marketed in the Gulf Coast, and a typical ethanol RFG which has been marketed in the Midwest.

TABLE VIII.A.1.B–1.—EFFECT OF RFG ON PER MILE EMISSIONS FROM TIER 0 VEHICLES RELATIVE TO A TYPICAL 9PSI RVP CONVENTIONAL GASOLINE ^a

Pollutant	Source	Non-Oxy RFG (percent)	11 Volume percent MTBE	10 Volume percent ethanol
Exhaust Emissions				
VOC	EPA Predictive Models	– 13.4	– 15.3	– 9.7
NO _x	– 2.4	– 1.7	7.3
CO	MOBILE6.2	– 22	– 31	– 36
Exhaust Benzene	EPA Predictive and Complex Models	– 21.2	– 29.7	– 38.9
Formaldehyde	– 5.9	19.4	2.3
Acetaldehyde	– 0.2	– 9.5	173.7
1,3-Butadiene	20.9	– 29.2	6.1
Non-Exhaust Emissions				
VOC	MOBILE6.2 & CRC E–65	– 30	– 30	– 18
Benzene	MOBILE6.2 & Complex Models	– 40	– 43	– 32

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

¹⁰³ The one exception was the impact of sulfur on emissions from these later vehicles, which is not an issue here due to the fact that renewable fuel use is not expected to change sulfur levels significantly.

¹⁰⁴ An exception is that MOBILE6.2 applies the effect of oxygenate on CO emissions to Tier 1 and later vehicles which are expected to be high emitters based on their age and mileage.

¹⁰⁵ For more information on California's request for a waiver of the RFG oxygen mandate and the Decision Document for EPA's response, see http://www.epa.gov/otaq/rfg_regs.htm#waveir.

As can be seen, all three types of RFG produce significantly lower emissions of VOC, CO and benzene than conventional gasoline. The impact of ethanol RFG on non-exhaust VOC emissions is lower than the other two types of RFG due to the impact of ethanol on permeation emissions. The impact of RFG on emissions of NO_x and the other air toxics depends on the type of RFG blend. The most notable effect on toxic emissions in percentage terms is the 173 percent increase in acetaldehyde with the use of ethanol. However, as will be seen below, base acetaldehyde emissions are low relative to the other toxics. While not shown, the total mass emissions of the four toxic pollutants always decreases, as benzene is by far the largest constituent.

It should be noted that these comparisons assume that all gasoline blends meet EPA's Tier 2 gasoline sulfur standard of 30 ppm. Prior to the Tier 2 program, RFG contained less sulfur than conventional gasoline and reduced NO_x emissions to a greater degree compared to conventional gasoline.

Historically, no non-oxygenated RFG was sold, due to the requirement that RFG contain at least 2.0 weight percent oxygen. However, with the Energy Act's removal of this requirement, all three types of RFG blends can be sold today. Increased use of ethanol in RFG would therefore either replace MTBE RFG or non-oxygenated RFG. The former has already occurred in many areas, as MTBE was essentially removed from the U.S. gasoline market by the end of 2006. The impact of using ethanol in RFG in

lieu of MTBE or no oxygenate can be seen from comparing the relative impacts of the various RFG blends shown in Table VIII.A.1.b-1.

Blending RFG with ethanol instead of MTBE or no oxygenate will increase VOC and NO_x emissions and decrease CO emissions. Exhaust benzene and formaldehyde emissions will decrease, but non-exhaust benzene, acetaldehyde, and 1,3-butadiene emissions will increase. All of these impacts are on a per vehicle basis and apply to Tier 0 vehicles only. The overall impact of increased ethanol use on total emissions of these various pollutants is described below.

Table VIII.A.1.b-2 presents the effect of blending either MTBE or ethanol into conventional gasoline while matching octane.

TABLE VIII.A.1.B-2.—EFFECT OF MTBE AND ETHANOL IN CONVENTIONAL GASOLINE ON TIER 0 VEHICLE EMISSIONS RELATIVE TO A TYPICAL NON-OXYGENATED CONVENTIONAL GASOLINE ^a

Pollutant	Source	11 Volume percent MTBE	10 Volume percent ethanol ^b
Exhaust VOC	EPA Predictive Models	-9.2	-7.4
NO _x	-2.6	7.7
CO ^c	MOBILE6.2	-6/-11	-11/-19
Exhaust Benzene	EPA Predictive and Complex Models	-22.8	-24.9
Formaldehyde	+21.3	+6.7
Acetaldehyde	+0.8	+156.8
1,3-Butadiene	-3.7	-13.2
Non-Exhaust VOC	MOBILE6.2	Zero	+30
Non-Exhaust Benzene	MOBILE6.2 & Complex Models	-9.5	+15.8

^a Average per vehicle effects for the 2012 fleet during summer conditions.
^b Assumes a 1.0 psi RVP waiver for ethanol blends.
^c The first figure shown applies to normal emitters; the second applies to high emitters.

Use of either oxygenate reduces exhaust VOC and CO emissions, but increases NO_x emissions. The ethanol blend increases non-exhaust VOC emissions due to the commonly granted 1.0 psi waiver of the RVP standard, as well as increased permeation emissions. Both oxygenated blends reduce exhaust benzene and 1,3-butadiene emissions. As above, ethanol increases non-exhaust benzene and acetaldehyde emissions. While small amounts of MTBE may have still been used in CG in 2004, for our reference case we have assumed that all MTBE use was in RFG. Therefore, we are not predicting any emissions impact related to removing MTBE from conventional gasoline. Increased use of conventional ethanol blends will be in lieu of non-oxygenated conventional gasoline. Thus, the more relevant column in Table VII.A.1.b-2 for our modeling is the last column, which shows the emission impact of a 10 volume percent ethanol blend relative to non-oxygenated gasoline.

The exhaust emission effects shown above for VOC and NO_x emissions only apply to Tier 0 vehicles in our primary analysis. For example, MOBILE6.2 estimates that 34 of exhaust VOC emissions and 16 of NO_x emissions from gasoline vehicles in 2012 come from Tier 0 vehicles. In the sensitivity analysis, these effects are extended to all gasoline vehicles. The effect of RVP and permeation on non-exhaust VOC emissions is temperature dependent. The figures shown above are based on the distribution of temperatures occurring across the U.S. in July.

We received several comments related to the effect of ethanol on emissions from onroad vehicles. None of the comments led us to change the basic approach taken to estimating the impact of changing fuel quality described above. Several comments suggested that we expand our discussion of the uncertainty in these fuel effects (as well as the effects of fuel quality on emissions from nonroad equipment and diesels described below). While such an

expanded discussion might be generally desirable, the lack of relevant emission data from late model vehicles and equipment prevents this. We believe that we have adequately described the uncertainty in the emission estimates presented below and our plans to obtain more data in order to improve these estimates in the near future.

c. Nonroad Equipment

To estimate the effect of gasoline quality on emissions from nonroad equipment, we used EPA's NONROAD emission model. We used the 2005 version of this model, NONROAD2005, which includes the effect of ethanol on permeation emissions from most nonroad equipment.

Only sulfur and oxygen content affect exhaust VOC, CO and NO_x emissions in NONROAD. Since sulfur level is assumed to remain constant, the only difference in exhaust emissions between conventional and reformulated gasoline is due to oxygen content. Table VIII.A.1.c-1 shows the effect of adding

11 volume percent MTBE or 10 volume percent ethanol to non-oxygenated gasoline on these emissions.

TABLE VIII.A.1.C-1.—EFFECT MTBE AND ETHANOL ON NONROAD EXHAUST EMISSIONS RELATIVE TO A TYPICAL NON-OXYGENATED GASOLINE

Base fuel	4-Stroke engines		2-Stroke engines	
	11 Volume percent MTBE	10 Volume percent ethanol	11 Volume percent MTBE	10 Volume percent ethanol
Exhaust VOC	-9	-16	-1	-2
Non-Exhaust VOC	0	26	0	26
CO	-13	-22	-13	-23
NO _x	+23	+40	+37	+65

As can be seen, higher oxygen content reduces exhaust VOC and CO emissions significantly, but also increases NO_x emissions. However, NO_x emissions from these engines tend to be fairly low to start with, given the fact that these engines run much richer than stoichiometric. Thus, a large percentage increase of a relative low base value can be a relatively small increase in absolute terms.

Evaporative emissions from nonroad equipment are impacted by only RVP, and permeation by ethanol content. Both the RVP increase due to blending of ethanol and its permeation effect cause non-exhaust VOC emissions to increase with the use of ethanol in nonroad equipment. The 26 percent effect represents the average impact across the U.S. in July for both 2-stroke and 4-stroke equipment. We updated the NONROAD2005 hose permeation emission factors for small spark-ignition engines and recreational marine watercraft to reflect the use of ethanol.

For nonroad toxics emissions, we base our estimates of the impact of fuel quality on the fraction of exhaust VOC emissions represented by each toxic on MOBILE6.2 (i.e., the same effects predicted for onroad vehicles). The National Mobile Inventory Model (NMIM) contains estimates of the fraction of VOC emissions represented by the various air toxics based on

oxygenate type (none, MTBE or ethanol). However, estimates for nonroad gasoline engines running on different fuel types are limited, making it difficult to accurately model the impacts of changes in fuel quality. In the recent final rule addressing mobile air toxic emissions, EPA replaced the toxic-related fuel effects contained in NMIM with those from MOBILE6.2 for onroad vehicles.¹⁰⁶ We follow the same methodology here. Future testing could significantly alter these emission impact estimates.

2. Diesel Fuel Quality: Biodiesel

EPA assessed the impact of biodiesel fuel on emissions in 2002 and published a draft report summarizing the results.¹⁰⁷ This report included a technical analysis of biodiesel effects on regulated and unregulated pollutants from diesel powered vehicles and concluded that biodiesel fuels improved PM, HC and CO emissions of diesel engines while slightly increasing their NO_x emissions.

While the conclusions reached in the 2002 EPA report relative to biodiesel effects on VOC, CO and PM emissions have been generally accepted, the magnitude of the B20 effect on NO_x remains controversial due to conflicting results from different studies. Significant new testing is being planned with broad stakeholder participation and support in order to better estimate

the impact of biodiesel on NO_x and other exhaust emissions from the in-use fleet of diesel engines. We hope to incorporate the data from such additional testing into the analyses for other studies required by the Energy Act in 2008 and 2009, and into a subsequent rule to set the RFS program standard for 2013 and later.

3. Renewable Fuel Production and Distribution

Areas experiencing increased renewable production will experience the corresponding emission increases associated with their production. The primary impact of renewable fuel production and distribution regards ethanol, since it is expected to be the predominant renewable fuel used in the foreseeable future. We approximate the impact of increased ethanol and biodiesel production, including corn and soy farming, on emissions based on DOE's GREET model, version 1.7. In addition, we develop a second estimate of emissions from ethanol production facilities using estimates of emissions from current ethanol plants obtained from the States. We also include emissions effects resulting from the transport of increased volumes of renewable fuels and decreased volumes of gasoline and diesel fuel. These emissions are summarized in Table VIII.A.3-1.

TABLE VIII.A.3-1.—WELL-TO-PUMP EMISSIONS FOR PRODUCING AND DISTRIBUTING RENEWABLE FUELS [Grams per gallon ethanol or biodiesel]^a

Pollutant	GREET1.7		GREET1.7 + state data		Biodiesel—GREET1.7
	Current ethanol plants	Future ethanol plants	Current ethanol plants	Future ethanol plants	
VOC	1.8	1.8	3.6	3.2	37.6
CO	4.0	4.1	4.4	4.3	12.7
NO _x	11.4	11.4	10.8	13.0	25.1
PM10	4.9	4.9	6.1	2.8	4.8

¹⁰⁶ 71, Federal Register, 15804, March 29, 2006.

¹⁰⁷ "A Comprehensive Analysis of Biodiesel Impacts on Exhaust Emissions," Draft Technical

Report, U.S. EPA, EPA420-P-02-001, October 2002. <http://www.epa.gov/otaq/models/biodsl.htm>.

TABLE VIII.A.3-1.—WELL-TO-PUMP EMISSIONS FOR PRODUCING AND DISTRIBUTING RENEWABLE FUELS—Continued
[Grams per gallon ethanol or biodiesel]^a

Pollutant	GREET1.7		GREET1.7 + state data		Biodiesel— GREET1.7
	Current eth- anol plants	Future eth- anol plants	Current eth- anol plants	Future eth- anol plants	
SO _x	6.4	6.4	7.2	9.7	21.8

^a Includes credit for reduced distribution of gasoline and diesel fuel.

At the same time, areas with refineries might experience reduced emissions, not necessarily relative to current emission levels, but relative to those which would have occurred in the future had renewable fuel use not risen. However, to the degree that increased renewable fuel use reduces imports of gasoline and diesel fuel, as opposed to the domestic production of these fuels, these reduced refinery emissions will occur overseas and not in the U.S.

Similarly, areas with MTBE production facilities might experience reduced emissions from these plants as they cease producing MTBE. However, many of these plants may be converted to produce other gasoline blendstocks, such as iso-octane or alkylate. In this case, their emissions are not likely to change substantially.

B. Impact on Emission Inventories

We use the NMIM to estimate emissions under the various ethanol scenarios on a county by county basis. NMIM basically runs MOBILE6.2 and NONROAD2005 with county-specific inputs pertaining to fuel quality, ambient conditions, levels of onroad vehicle VMT and nonroad equipment usage, etc. We ran NMIM for two months, July and January. We estimate annual emission inventories by summing the two monthly inventories and multiplying by six.

As described above, we removed the effect of gasoline fuel quality on exhaust VOC and NO_x emissions from the onroad motor vehicle inventories which are embedded in MOBILE6.2. We then applied the exhaust emission effects from the EPA Predictive Models. In our primary analysis, we only applied these EPA Predictive Model effects to exhaust

VOC and NO_x emissions from Tier 0 vehicles. In a sensitivity case, we applied them to exhaust VOC and NO_x emissions from all vehicles. Regarding the effect of fuel quality on emissions of four air toxics from nonroad equipment (in terms of their fraction of VOC emissions), in all cases we replaced the fuel effects contained in NMIM with those for motor vehicles contained in MOBILE6.2. The projected emission inventories for the primary analysis are presented first, followed by those for the sensitivity analysis.

1. Primary Analysis

The national emission inventories for VOC, CO and NO_x in 2012 with current fuels (i.e., “reference fuel”) are summarized in Table VIII.B.1-1. Also shown are the changes in emissions projected for the two levels of ethanol use (i.e., “control cases”) described in Section VI.

TABLE VIII.B.1-1.—2012 EMISSIONS NATIONWIDE FROM GASOLINE VEHICLES AND EQUIPMENT UNDER SEVERAL ETHANOL USE SCENARIOS—PRIMARY ANALYSIS
[Tons per year]¹⁰⁸

Pollutant	Inventory	Change in inventory in control cases	
	Reference case	RFS case	EIA case
VOC	5,882,000	18,000	43,000
NO _x	2,487,000	23,000	40,000
CO	55,022,000	-483,000	-1,366,000
Benzene	178,000	-3,200	-7,200
Formaldehyde	40,400	-600	-200
Acetaldehyde	19,900	3,400	7,100
1,3-Butadiene	18,900	-200	-300

Both VOC and NO_x emissions are projected to increase with increased use of ethanol. However, the increases are small, generally less than 2 percent. CO emissions are projected to decrease by about 0.9 to 2.5 percent. Benzene emissions are projected to decrease by 1.8 to 4.0 percent. Formaldehyde emissions are projected to decrease slightly, on the order of 0.5 to 1.5 percent. 1,3-butadiene emissions are

projected to decrease by about 1.1 to 1.6 percent. The largest change is in acetaldehyde emissions, an increase of 17.1 to 35.7 percent, as acetaldehyde is a partial combustion product of ethanol.

CO also participates in forming ozone, much like VOCs. Generally, CO is 15–50 times less reactive than typical VOC. Still, the reduction in CO emissions is roughly 27–32 times the increase in VOC emissions in the two scenarios. Thus, the projected reduction in CO emissions is important from an ozone perspective. However, as described above, the methodology for projecting

the effect of ethanol use on CO emissions is inconsistent with that for exhaust VOC and NO_x emissions. Thus, comparisons between changes in VOC and CO emissions are particularly uncertain.

There will also be some increases in emissions due to ethanol and biodiesel production. Table VIII.B.1-2 shows estimates of annual emissions expected to occur nationwide due to increased production of ethanol. These estimates include a reduction in emissions related to the distribution of the displaced gasoline. The table reflects the use of

¹⁰⁸ These emission estimates do not include the impact of the recent mobile source air toxic standards (72 FR 8428, February 26, 2007).

emissions factors from DOE's GREET model, version 1.7, as well as estimates of ethanol plant emissions obtained

from the States. It should be noted that emissions in the base case assume an 80/20 mix of dry mill and wet mill

facilities. New plants (and thus, the emission increases) assume 100% dry mill facilities.

TABLE VIII.B.1-2.—ANNUAL EMISSIONS NATIONWIDE FROM ETHANOL PRODUCTION AND TRANSPORTATION: 2012
[Tons per year]

	GREET1.7			GREET1.7 + State data		
	Base case	RFS case	EIA case	Base case	RFS case	EIA case
	Emissions	Increase in emissions		Emissions	Increase in emissions	
VOC	8,000	5,000	11,000	14,000	10,000	20,000
NO _x	17,000	13,000	26,000	18,000	14,000	27,000
CO	49,000	35,000	72,000	56,000	40,000	81,000
PM ₁₀	21,000	15,000	30,000	12,000	9,000	18,000
SO _x	27,000	20,000	41,000	42,000	30,000	61,000

As can be seen, the potential increases in emissions from ethanol production and transportation are of the same order of magnitude as those from ethanol use, with the exception of CO emissions. The vast majority of these emissions are related to farming and ethanol production. Both farms and ethanol plants are generally located in ozone attainment areas.

Where counties are constructing new ethanol plants, expanding existing plants, or planning construction for future plants, the average increase in VOC and NO_x emissions from plants alone are about 26 tons/month VOC and 35 tons/month NO_x using state data (about 17 tons/month VOC and 25 tons/month NO_x using GREET 1.7 emission factors). Average VOC and NO_x emissions increase to about 61 tons/month and 83 tons/month, respectively, in the 10% of counties expecting largest increases in ethanol production. For both VOC and NO_x, emissions estimates

are about 35% less when using the GREET 1.7 emission factors. Table VIII.B.1-3 shows estimates of annual emissions expected to occur nationwide due to increased production of biodiesel. These estimates include a reduction in emissions related to the distribution of the displaced diesel fuel. Again, these emissions are generally expected to be in ozone attainment areas.

TABLE VIII.B.1-3.—ANNUAL EMISSIONS NATIONWIDE FROM BIODIESEL PRODUCTION AND TRANSPORTATION
[Tons per year]

Pollutant	Reference inventory: 30 mill gal biodiesel per year	2012 Emissions inventory: 300 mill gal biodiesel per year
VOC	1,400	14,000
NO _x	1,500	15,000
CO	800	8,000

TABLE VIII.B.1-3.—ANNUAL EMISSIONS NATIONWIDE FROM BIODIESEL PRODUCTION AND TRANSPORTATION—Continued
[Tons per year]

Pollutant	Reference inventory: 30 mill gal biodiesel per year	2012 Emissions inventory: 300 mill gal biodiesel per year
PM ₁₀	50	500
SO _x	250	2,500

2. Sensitivity Analysis

The national emission inventories for VOC and NO_x in 2012 with current fuels are summarized in Table VIII.B.2-1. Here, the emission effects contained in the EPA Predictive Models are assumed to apply to all vehicles, not just Tier 0 vehicles. Also shown are the changes in emissions projected for the two cases for future ethanol volume.

TABLE VIII.B.2-1.—2012 EMISSIONS NATIONWIDE FROM GASOLINE VEHICLES AND EQUIPMENT UNDER TWO FUTURE ETHANOL USE SCENARIOS—SENSITIVITY ANALYSIS
[Tons per year]

Pollutant	Inventory	Change in inventory in control cases	
	Reference case	RFS case	EIA case
	VOC	5,834,000	-20,000
NO _x	2,519,000	68,000	106,000
CO	54,315,000	-692,000	-1,975,000
Benzene	175,700	-5,000	-9,400
Formaldehyde	39,600	-1,100	-700
Acetaldehyde	19,500	3,000	6,600
1,3-Butadiene	18,600	-400	-600

The overall VOC and NO_x emission impacts of the various ethanol use scenarios change to some degree when all motor vehicles are assumed to be sensitive to fuel ethanol content. The increase in VOC emissions turns into a

net decrease due to a greater reduction in exhaust VOC emissions from onroad vehicles. However, the increase in NO_x emissions gets larger, as more vehicles are assumed to be affected by ethanol. Emissions of the four air toxics

generally decrease slightly, due to the greater reduction in exhaust VOC emissions.

3. Local and Regional VOC and NO_x Emission Impacts in July

We also estimate the percentage change in VOC, NO_x, and CO emissions from gasoline fueled motor vehicles and equipment in those areas which actually experienced a significant change in ethanol use. Specifically, we focused on areas where the market share of ethanol blends was projected to change by 50 percent or more. We also focused on

summertime emissions, as these are most relevant to ozone formation. Finally, we developed separately estimates for: (1) RFG areas, including the state of California and the portions of Arizona where their CBG fuel programs apply, (2) low RVP areas (*i.e.*, RVP standards less than 9.0 RVP, and (3) areas with a 9.0 RVP standard. This set of groupings helps to highlight the emissions impact of increased ethanol

use in those areas where emission control is most important.

Table VIII.B.3–1 presents our primary estimates of the percentage change in VOC, NO_x, and CO emission inventories for these three types of areas. Note that the analyses here are very similar to those described in Section 5.1 of the RIA, with the exception that Table VIII.B.3–1 below reflects 50 states (instead of 37 eastern states) and excludes diesel emissions.

TABLE VIII.B.3–1.—JULY 2015 CHANGE IN EMISSIONS FROM GASOLINE VEHICLES AND EQUIPMENT IN COUNTIES WHERE ETHANOL USE CHANGED SIGNIFICANTLY—PRIMARY ANALYSIS

Ethanol use	RFS case	EIA case
RFG Areas		
Ethanol Use	Down	Up.
VOC	0.8%	2.3%.
NO _x	–3.4%	1.6%.
CO	6.1%	–2.6%.
Low RVP Areas		
Ethanol Use	Up	Up.
VOC	4.2%	4.6%.
NO _x	6.2%	5.7%.
CO	–12.5%	–13.7%.
Other Areas (9.0 RVP)		
Ethanol Use	Up	Up.
VOC	3.6%	4.6%.
NO _x	7.3%	7.0%.
CO	–6.4%	–6.0%.

As expected, increased ethanol use tends to increase NO_x emissions. The increase in low RVP and other areas is greater than in RFG areas, since the RFG in the RFG areas included in this analysis all contained MTBE. Also, increased ethanol use tends to increase VOC emissions, indicating that the

increase in non-exhaust VOC emissions exceeds the reduction in exhaust VOC emissions. This effect is muted with RFG due to the absence of an RVP waiver for ethanol blends. We would expect very similar results for 2012. The reader is referred to Chapter 2 of the RIA

for discussion of how ethanol levels will change at the state-level.

Table VIII.B.3–2 presents the percentage change in VOC, NO_x, and CO emission inventories under our sensitivity case (*i.e.*, when we apply the emission effects of the EPA Predictive Models to all motor vehicles).

TABLE VIII.B.3–2.—JULY 2015 CHANGE IN EMISSIONS FROM GASOLINE VEHICLES AND EQUIPMENT IN COUNTIES WHERE ETHANOL USE CHANGED SIGNIFICANTLY—SENSITIVITY ANALYSIS

Ethanol use	RFS case	EIA case
RFG Areas		
Ethanol Use	Down	Up.
VOC	–1.0%	1.0%.
NO _x	–0.9%	5.6%.
CO	7.3%	–3.0%.
Low RVP Areas		
Ethanol Use	Up	Up.
VOC	3.4%	3.7%.
NO _x	10.4%	10.8%.
CO	–15.0%	–16.4%.
Other Areas (9.0 RVP)		
Ethanol Use	Up	Up.
VOC	3.0%	3.9%.
NO _x	10.8%	11.0%.

TABLE VIII.B.3-2.—JULY 2015 CHANGE IN EMISSIONS FROM GASOLINE VEHICLES AND EQUIPMENT IN COUNTIES WHERE ETHANOL USE CHANGED SIGNIFICANTLY—SENSITIVITY ANALYSIS—Continued

Ethanol use	RFS case	EIA case
CO	-9.0%	-8.9%.

Directionally, the changes in VOC and NO_x emissions in the various areas are consistent with those from our primary analysis. The main difference is that the increases in VOC emissions are smaller, due to more vehicles experiencing a reduction in exhaust VOC emissions, and the increases in NO_x emissions are larger.

C. Impact on Air Quality

We estimate the impact of increased ethanol use on the ambient concentrations of two pollutants: Ozone and PM. Quantitative estimates are made for ozone, while only qualitative estimates can be made currently for ambient PM. These impacts are described below.

1. Impact of Increased Ethanol Use on Ozone

We use a metamodeling tool developed at EPA, the ozone response surface metamodel (Ozone RSM), to estimate the effects of the projected changes in emissions from gasoline

vehicles and equipment for the RFS and EIA cases. We included the estimated changes in emissions from renewable fuel production and distribution. Because of limitations in the Ozone RSM, we could not easily assign these emissions to the specific counties where the plants are or are expected to be located. Instead, we assigned all of the emissions related to renewable fuel production and distribution to the set of states expected to contain most of the production facilities.

The Ozone RSM was created using multiple runs of the Comprehensive Air Quality Model with Extensions (CAM_x). Base and proposed control CAM_x metamodeling was completed for the year 2015 over a modeling domain that includes all or part of 37 Eastern U.S. states, plus the District of Columbia. For more information on the Ozone RSM, please see Chapter 5 of the RIA for this final rule.

The Ozone RSM limits the number of geographically distinct changes in VOC

and NO_x emissions which can be simulated. As a result, we could not apply distinct changes in emissions for each county. Therefore, two separate runs were made with different VOC and NO_x emissions reductions. We then selected the ozone impacts from the various runs which best matched the VOC and NO_x emission reductions for that county. This models the impact of local emissions reasonably well, but loses some accuracy with respect to ozone transport. No ozone impact was assumed for areas which did not experience a significant change in ethanol use. The predicted ozone impacts of increased ethanol use for those areas where ethanol use is projected to change by more than a 50% market share are summarized in Table VIII.C.1-1. As shown in the Table 5.1-2 of the RIA, national average impacts (based on the 37-state area modeled) which include those areas where no change in ethanol use is occurring are considerably smaller.

TABLE VIII.C.1-1.—IMPACT ON 8-HOUR DESIGN VALUE EQUIVALENT OZONE LEVELS (PPB) ^a

	Primary analysis		Sensitivity analysis	
	RFS case	EIA case	RFS case	EIA case
Minimum Change	-0.015	0.000	-0.115	0.028
Maximum Change	0.329	0.337	0.624	0.549
Average Change ^b	0.153	0.181	0.300	0.325
Population-Weighted Change ^b	0.154	0.183	0.272	0.315

^a In comparison to the 80 ppb 8-hour ozone standards.

^b Only for those areas experiencing a change in ethanol blend market share of at least 50 percent.

As can be seen, ozone levels generally increase to a small degree with increased ethanol use. This is likely due to the projected increases in both VOC and NO_x emissions. Some areas do see a small decrease in ozone levels. In our primary analysis, where exhaust emissions from Tier 1 and later onroad vehicles are assumed to be unaffected by ethanol use, the population-weighted increase in ambient ozone levels in those areas where ethanol use changed significantly is 0.154–0.183 ppb. Since the 8-hour ambient ozone standard is 85 ppb, this increase represents about 0.2 percent of the standard, a very small percentage.

In our sensitivity analysis, where exhaust emissions from Tier 1 and later onroad vehicles are assumed to respond

to ethanol like Tier 0 vehicles, the population-weighted increase in ambient ozone levels is slightly less than twice as high, or 0.272–0.315 ppb. This increase represents about 0.35 percent of the standard.

There are a number of important caveats concerning these estimates. First, the emission effects of adding ethanol to gasoline are based on extremely limited data for recent vehicles and equipment. Second, the Ozone RSM does not account for changes in CO emissions. As shown above, ethanol use should reduce CO emissions significantly, directionally reducing ambient ozone levels in those areas where ozone formation is VOC-limited. (Ozone levels in areas which are NO_x-limited are less likely to be

affected by a change in CO emissions.) The Ozone RSM also does not account for changes in VOC reactivity. With additional ethanol use, the ethanol content of VOC should increase. Ethanol is less reactive than the average VOC. Therefore, this change should also reduce ambient ozone levels in a way not addressed by the Ozone RSM, again in those areas where ozone formation is predominantly VOC-limited. Because of these limitations, anyone interested in the impact of increased ethanol use on ozone in any particular area should utilize more comprehensive dispersion modeling which accounts for these and other important factors.

We received several requests in comments on the proposal to quantify the impact of the reduced CO emissions

and VOC reactivity on ozone. As discussed in the S&A document, this is not possible without running more sophisticated ambient dispersion models. The impact of CO emissions and VOC reactivity on ozone vary significantly depending on ambient conditions and the relative amount of VOC and NO_x in the atmosphere. Therefore, general rules of thumb cannot be applied.

Moving to health effects, exposure to ozone has been linked to lung function decrements, respiratory symptoms, aggravation of asthma, increased hospital and emergency room visits, increased asthma medication usage, inflammation of the lungs, and a variety of other respiratory effects and cardiovascular effects including premature mortality. Ozone can also adversely affect the agricultural and forestry sectors by decreasing yields of crops and forests. Although the health and welfare impacts of changes in ambient ozone levels are typically quantified in regulatory impact analyses, we do not evaluate them for this analysis. On average, the changes in ambient ozone levels shown above are small and would be even smaller if changes in CO emissions and VOC reactivity were taken into account. The increase in ozone would likely lead to negligible monetized impacts. We therefore do not estimate and monetize ozone health impacts for the changes in renewable use due to the small magnitude of this change, and the uncertainty present in the air quality modeling conducted here, as well as the uncertainty in the underlying emission effects themselves discussed earlier.

2. Particulate Matter

Ambient PM can come from two distinct sources. First, PM can be directly emitted into the atmosphere. Second, PM can be formed in the atmosphere from gaseous pollutants. Gasoline-fueled vehicles and equipment contribute to ambient PM concentrations in both ways.

As described above, we are not currently able to predict the impact of fuel quality on direct PM emissions from gasoline-fueled vehicles or equipment. Therefore, we are unable at this time to project the effect that increased ethanol use will have on levels of directly emitted PM in the atmosphere.

PM can also be formed in the atmosphere (termed secondary PM here) from several gaseous pollutants emitted by gasoline-fueled vehicles and equipment. Sulfur dioxide emissions contribute to ambient sulfate PM. NO_x emissions contribute to ambient nitrate

PM. VOC emissions contribute to ambient organic PM. Increased ethanol use is not expected to change gasoline sulfur levels, so emissions of sulfur dioxide and any resultant ambient concentrations of sulfate PM are not expected to change. Increased ethanol use is expected to increase NO_x emissions, so the possibility exists that ambient nitrate PM levels could increase. Increased ethanol is generally expected to increase total VOC emissions, which could also impact the formation of secondary organic PM. However, while non-exhaust VOC emissions are expected to increase, exhaust VOC emissions are expected to decrease. Generally, the higher the molecular weight of the specific VOC emitted, the greater the likelihood it will form PM in the atmosphere. Non-exhaust VOC is predominantly low in molecular weight, as much of it is due to fuel evaporating. Thus, emissions of VOCs likely to form PM in the atmosphere are likely decreasing with ethanol use.

The formation of secondary organic PM is very complex, due in part to the wide variety of VOCs emitted into the atmosphere. The degree to which a specific gaseous VOC reacts to form PM in the atmosphere depends on the types of reactions that specific VOC undergoes and the products of those reactions. Both of these factors depend on other pollutants present, such as the hydroxyl radical, ozone, NO_x and other reactive compounds. The relative mass of secondary PM formed per mass of gaseous VOC emitted can also depend on the total concentration of gaseous VOC and organic PM in the atmosphere. Most of the secondary organic PM exists in a continually changing equilibrium between the gaseous and PM phases. Both the rates of these reactions and the gaseous-PM equilibria depend on temperature, so seasonal differences can be expected.

Recent smog chamber studies have indicated that gaseous aromatic VOCs can form secondary PM under certain conditions. These compounds comprise a greater fraction of exhaust VOC emissions than non-exhaust VOC emissions, as non-exhaust VOC emissions are dominated by VOCs with relatively high vapor pressures. Aromatic VOCs tend to have lower vapor pressures. As increased ethanol use is expected to reduce exhaust VOC emissions, emissions of aromatic VOCs should also decrease. In addition, refiners are expected to reduce the aromatic content of gasoline by 5 volume percentage points as ethanol is blended into gasoline. Emissions of aromatic VOCs should decrease with

lower concentrations of aromatics in gasoline. Thus, emissions of gaseous aromatic VOCs could decrease for both reasons.

Overall, we expect that the decrease in secondary organic PM is likely to exceed the increase in secondary nitrate PM. In 1999, NO_x emissions from gasoline-fueled vehicles and equipment comprised about 20% of national NO_x emissions from all sources. In contrast, gasoline-fueled vehicles and equipment comprised over 60% of all national gaseous aromatic VOC emissions. The percentage increase in national NO_x emissions due to increased ethanol use should be smaller than the percentage decrease in national emissions of gaseous aromatics. Finally, in most urban areas, ambient levels of secondary organic PM exceed those of secondary nitrate PM. Thus, directionally, we expect a net reduction in ambient PM levels due to increased ethanol use. However, we are unable to quantify this reduction at this time.

EPA currently utilizes the CMAQ model to predict ambient levels of PM as a function of gaseous and PM emissions. This model includes mechanisms to predict the formation of nitrate PM from NO_x emissions. However, it does not currently include any mechanisms addressing the formation of secondary organic PM. EPA is currently developing a model of secondary organic PM from gaseous toluene emissions. We plan to incorporate this mechanism into the CMAQ model in 2007. The impact of other aromatic compounds will be added as further research clarifies their role in secondary organic PM formation. Therefore, we expect to be able to quantitatively estimate the impact of decreased toluene emissions and increased NO_x emissions due to increased ethanol use as part of future analyses of U.S. fuel requirements required by the Act.

IX. Impacts on Fossil Fuel Consumption and Related Implications

Renewable fuels have been of significant interest for many years due to their potential to displace fossil fuels, which have often been targeted as primary contributors to emissions of greenhouse gases such as carbon dioxide, and national energy concerns primarily due to an increasing dependence on foreign sources of petroleum. In the Notice of Proposed Rulemaking, we provided a preliminary assessment of the greenhouse gas emission and energy impacts of renewable fuel and an initial assessment of the economic value of renewable fuel displacing petroleum-based fuels. We

also indicated that we would be updating an analysis of energy security impacts that had been prepared by analysts at the Oak Ridge National Laboratory (ORNL) of the Department of Energy. We present some discussion of that analysis here.

We also performed a full lifecycle or well-to-wheel analysis for this final rule to estimate the GHG and fossil energy reductions from replacing petroleum based fuels with renewable fuels. Argonne National Laboratory's (ANL) GREET¹⁰⁹ model was utilized for this lifecycle analysis. Table IX-1 summarizes this model's estimated impact that increases in the use of renewable fuels are projected to have on

GHG emissions and fossil fuel consumption for the two renewable fuel volume scenarios considered in this final rulemaking relative to the reference case. As described later in this section, the results in Table IX-1 are based on a number of input assumptions including coal being used as process fuel in 14% of ethanol facilities.

As noted in Section III, although we have chosen to base our lifecycle analyses on Argonne National Laboratory's GREET model there are a variety of other lifecycle models and analyses available. The choice of model inputs and assumptions all have a bearing on the results of lifecycle analyses, and many of these

assumptions remain the subject of debate among researchers. Lifecycle analyses must also contend with the fact that the inputs and assumptions generally represent industry-wide averages even though energy consumed and emissions generated can vary widely from one facility or process to another.

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

TABLE IX-1.—GREET MODEL LIFECYCLE REDUCTIONS FROM INCREASED RENEWABLE FUEL USE RELATIVE TO THE 2012 REFERENCE CASE

	RFS case		EIA case	
	Reduction	% of trans. sector	Reduction	% of trans. sector
Fossil Energy (QBtu)	0.15	0.48	0.27	0.85
Petroleum Energy (Bgal)	2.0	0.82	3.9	1.60
GHG Emissions (MMT CO ₂ -eq.)	8.0	0.36	13.1	0.59
CO ₂ Emissions (MMT CO ₂)	11.0	0.52	19.5	0.93

We used the petroleum energy reductions shown in Table IX-1 to determine implications on imports of petroleum products. Our analysis found that calculated petroleum energy reductions come almost entirely from imports of finished products in this 2012 case and amount to the equivalent of 123,000 barrels of transportation fuel under the RFS case and 240,000 barrels of transportation fuel for the EIA case.

Another effect of increased use of renewable fuels in the U.S. is that it diversifies the energy sources in making transportation fuel. Diverse sources of fuel energy reduce both financial and strategic risks associated with a potential disruption in supply or a spike in cost of a particular energy source. This reduction in risks is a measure of improved energy security. The ORNL report used an "oil premium" approach to identify those energy-security related impacts which are not reflected in the market price of oil, and which are expected to change in response to an incremental change in the level of U.S. oil imports.

The following sections provide a more complete description of our analyses of the GHG emissions, fossil fuel, oil imports, and energy security impacts of this final rule.

A. Impacts on Lifecycle GHG Emissions and Fossil Energy Use

Although the use of renewable fuels in the transportation sector directly displaces some petroleum consumed as motor vehicle fuel, this displacement of petroleum is in fact only one aspect of the overall impact of renewable fuels on fossil fuel use. Fossil fuels are also used in producing and transporting renewable feedstocks such as plants or animal byproducts, in converting the renewable feedstocks into renewable fuel, and in transporting and blending the renewable fuels for consumption as motor vehicle fuel. To estimate the true impacts of increases in renewable fuels on fossil fuel use, modelers attempt to take many or all these steps into account.

Similarly, energy is used and GHGs emitted in the pumping of oil, transporting the oil to the refinery, refining the crude oil into finished transportation fuel, transporting the refined gasoline or diesel fuel to the consumer and then burning the fuel in the vehicle. Such analyses are termed lifecycle or well-to-wheels analyses. We performed a full lifecycle analysis as part of this final rulemaking to determine the GHG and fossil energy

reductions from the increased use of renewable fuels.

This lifecycle assessment approach and rationale were highlighted in the proposal. Comments received focused mainly on improving the process, for example the choice of lifecycle model used and initiating a stakeholder dialogue to build consensus around the assumptions and approach. In general comments were supportive of using a full lifecycle assessment approach, but differed on the appropriate model and associated assumptions EPA should use in its analysis.

1. Time Frame and Volumes Considered

The results presented in this analysis represent a snapshot in time. They represent annual GHG and fossil fuel savings in the year considered, in this case 2012. Consistent with the emissions modeling described in Section VII, our analysis of the GHG and fossil fuel consumption impacts of renewable fuel use was conducted using three volume scenarios. The first scenario was the same reference case used elsewhere in this final rulemaking. The reference case scenario provided the point of comparison for the other two scenarios. The other two renewable fuel scenarios for 2012 represented the

¹⁰⁹ Greenhouse gases, Regulated Emissions, and Energy use in Transportation.

RFS program requirements and the volume projected by EIA.

In both the RFS and EIA scenarios, we assumed that the biodiesel production volume would be 0.303 billion gallons based on EIA AEO2006 projections. Furthermore, for both scenarios we assume that 250 million gallons of ethanol that qualify for cellulosic biomass ethanol credit will be produced in 2012 from corn using biomass as the process energy source. The remaining renewable fuel volumes in each scenario would be ethanol made from corn and imports. The import volume is based on EIA's projections for the percent of total ethanol volume supplied by imports in 2012. The total volumes for all three scenarios are shown in Table II.A.1-1.

For the purposes of calculating this difference or the amount of conventional fuel no longer consumed—that is, displaced—as a result of the use of the replacement renewable fuel, we assumed the ethanol volumes shown in Table II.A.1-1 are 5% denatured. The ethanol volumes were adjusted down to represent pure (100%) ethanol, biodiesel volumes were not adjusted. The adjusted volumes were then converted to total Btu using the appropriate volumetric energy content values (76,000 Btu/gal for ethanol, 115,000 Btu/gal for gasoline, 118,000 Btu/gal for biodiesel, and 130,000 Btu/gal for diesel fuel). We make the assumption that vehicle energy efficiency will not be affected by the presence of renewable fuels (i.e., efficiency of combusting one Btu of ethanol is equal to the efficiency of combusting one Btu of gasoline).

This lifecycle analysis is conducted without any regard to the geographic attributes of where emissions or energy use occurs; the model represents global reductions in GHG emissions and energy use, not just those occurring in the U.S. For example, under a full lifecycle assessment approach, the savings associated with reducing overseas crude oil extraction and refining are included, as are the international emissions associated with producing imported ethanol. There were two exceptions to this, both dealing with secondary impacts that may result internationally due to the expanded use of renewable fuels within the United States.

The first exception is the emissions associated with international land use change. Due to decreasing corn exports some changes to international land use may occur, for example, as more crops are planted in other regions to compensate for the decrease in crop exports from the U.S. While the emissions associated with domestic

land use change are well understood and are included in our lifecycle analysis, we did not include the potential impact on international land use and any emissions that might directly result. Our currently modeling capability does not allow us to assess what international land use changes would occur or how these changes would affect greenhouse gas emissions. For example, we would need to know how international cropping patterns would change as well as farming inputs and practices that might affect emissions assessment.

The second case where we have not quantified the international impacts results from any reduction in world oil prices would tend to result from decreased demand in the U.S. as renewable fuels replace oil. It is commonly presumed in economic analyses that all else being equal quantity demanded of a valuable good (i.e., oil) will increase as price decreases. A world wide reduction of oil price would tend to reduce the cost of producing transportation fuel which in turn would tend to reduce the price consumers internationally would have to pay for this fuel.

To the extent fuel prices are decreased, demand and consumption would tend to increase; this impact of reduced cost of driving is sometimes referred to as a "rebound effect." Such a greater consumption internationally would presumably result in an increase in greenhouse gas emissions as consumers in the rest of the world drive more. These increased emissions would in part offset the emission impacts otherwise described in this preamble. While such international impacts of U.S. actions are important to understand, we have not have fully considered and quantified the international rebound effects of this renewable fuel standard. Nevertheless, such impacts remain an important consideration for future analysis.

2. GREET Model

As in the analyses for the proposal, for this final rulemaking we used the GREET fuel-cycle model. GREET has been under development for several years and has undergone extensive peer review through multiple updates. Of the available sources of information on lifecycle analyses of energy consumed and emissions generated, we believe that GREET offers the most comprehensive treatment of the transportation sector. For this final rule, we used an updated version of the

GREET model¹¹⁰, with a few modifications to its input assumptions. These changes since the NPRM are described below.

The two main comments we received on our lifecycle modeling were that we should initiate a public dialogue on lifecycle analyses, models and assumptions, and that our sole reliance on the GREET model should be avoided, given other models are available. We have begun a public dialogue in that we identify the assumptions in the GREET model that were examined and modified for this final rulemaking. Furthermore, we will be initiating more comprehensive discussions about lifecycle analysis with stakeholders which could lead to an increased use of lifecycle analysis in future actions.

In terms of our sole reliance on the GREET model, several other models have been developed for conducting renewable fuels lifecycle analysis. For example, researchers at the Energy and Resources Group (ERG) of the University of California Berkeley have developed the ERG Biofuel Analysis Meta-Model (EBAMM) and Mark Delucchi at the Institute of Transportation Studies of the University of California Davis has developed the Lifecycle Emissions Model (LEM). Other non-fuel specific lifecycle modeling tools could also be used to perform renewable fuel lifecycle analysis.

Several studies have been released recently making use of these other models and showing different results than we find in the analysis done for this rule. For example, whereas GREET estimates a net GHG reduction of about 22% for corn ethanol compared to gasoline, the previously cited works by Farrell et al. utilizing the EBAMM show around a 13% reduction. The main difference in results is not due to the model used but assumptions on scope and input data.

For example, most studies focus on average or current ethanol production which uses a current mix of wet and dry mill ethanol production and use of coal and natural gas as process energy. In contrast, for this rulemaking we consider future increases in renewable fuel production so we focus on new production capacity which will rely more heavily on more efficient dry mill production than the current mix of wet and dry mill capacities. Other studies also typically base ethanol and farm energy use on historic data while we are assuming future capacity increases will use a state of the art dry milling plant and most current farming energy use

¹¹⁰GREET version 1.7, released November 10, 2006.

data. Varying assumptions concerning how land use change impact CO₂ emissions and agriculture related GHG emissions could also have an impact on overall results. Other studies also differ in the environmental flows considered. For example, GREET uses the internationally accepted set of greenhouse gases while Delucchi uses additional types of greenhouse gases.

We have not had an opportunity to develop comparable analyses of the GHG and energy impacts of this rule using these other models. However, as discussed in chapters 6.1.1 and 6.2.3 of the RIA, we believe the scope of the GREET model and the assumptions we have used in running the model tend toward the middle of the range. Therefore we believe these results provide a reasonable assessment of the energy and GHG impacts of the expanded use of renewable fuels.

a. Renewable Fuel Pathways Considered

The feedstocks and processes used to model renewable fuel production were those which our analysis in Chapter 1 of the RIA shows will primarily be used through 2012. However, other pathways for producing renewable fuels may become popular such as producing cellulosic biomass ethanol from municipal solid waste as well as different process for the feedstocks considered, like gasification of switchgrass and production of "renewable" diesel fuel through hydrotreating vegetable oils.

Furthermore, the lifecycle analysis used for this rulemaking is based on averages of the different renewable fuels modeled. For example, the GHG emission and fossil energy savings associated with increased use of corn ethanol are calculated based on a mix of corn wet and dry milling, assuming a certain projected mix of each process. While this method may not exactly represent the reductions associated with a given gallon of renewable fuel, it is accurate for the purpose of this analysis which is to determine the impact of the total increased volume of renewable fuels used.

We recognize that different feedstocks and processes will each have unique characteristics when it comes to lifecycle GHG emissions and energy use. However, we understand that other feedstocks and processes as well as differences in other parts of the renewable fuel lifecycle will impact the savings associated with their use and this is the focus of ongoing work at the agency.

b. Modifications to GREET

Since the analysis done for the NPRM, we have updated the GREET model with the following changes:

- Included CO₂ emissions from corn farming lime use.
- Updated the corn farming fertilizer use inputs.
- Added cellulosic biomass ethanol production from corn stover and forest waste.
- Modeled biomass as a process fuel source in corn ethanol dry milling.

In addition to the changes listed above we also examined and updated other GREET input assumptions for corn ethanol and biodiesel production.

We also examined several other GREET input values, but determined that the default GREET values should not be changed for a variety of reasons. These included, corn and ethanol transport distances and modes and byproduct allocation methods. Our investigation of these other GREET input values are discussed more fully in Chapter 6 of the RIA. The current GREET default factors for these other inputs were included in the analysis for this final rule.

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

A summary of the GREET input values we investigated and modified for the final rule analysis is given below.

Corn Farming Energy Use: Corn farming energy use was updated based on the most recent USDA Agricultural Resource Management Survey (ARMS) data.

CO₂ from Land Use Change: The GREET model has a default factor for CO₂ from land use change that was included in the NPRM analysis. This factor was updated based on the results of the agricultural sector modeling outlined in Section X. The CO₂ emissions from land use change used in the final rulemaking represents approximately 1% of total corn ethanol lifecycle GHG emissions. However, this value could be more significant if increased amounts of renewable fuels are used in the transportation sector. The issue of CO₂ emissions from land use change associated with converting forest or Conservation Reserve Program

(CRP) land into crop production for use in producing renewable fuels is an important factor to consider when determining the overall sustainability of renewable fuel use. While the analysis described above is indicating that the volumes of renewable fuel analyzed in this rulemaking will not cause a significant change in land use, this is an area we will continue to research for any future analysis.

Corn Ethanol Wet-Mill Versus Dry Mill Plants: For this analysis, we expect most new ethanol plants will be dry mill operations. That has been the trend in the last few years as the demand for ethanol has grown, and our analysis of ethanol plants under construction and planned for the near future has verified this. Our analysis of production plans, as outlined in Section VI, indicates that essentially all new ethanol production will be from dry mill plants (99%).

Corn Ethanol Dry Mill Plant Energy Use and Fuel Mix: Our review of plants under construction and those planned for the near future as outlined in Section VI, indicates that coal will be used as process fuel for approximately 14% of the new under construction and planned ethanol production volume capacity. The energy use at a dry mill plant using natural gas was based on the model developed by USDA and modified by EPA for use in the cost analysis of this rulemaking described in Section VII. For this analysis, we assumed that a coal plant would require 15%¹¹¹ more electricity demand due to coal handling and have a 13% increase in thermal demand for steam dryers as compared to the natural gas fueled plant. We also considered a case where a corn ethanol plant utilized biomass as a fuel source. For this case we assumed the same amount of fuel and purchased electricity energy per gallon as a coal powered plant. This assumption is based on the biomass plant having more fuel handling than a natural gas plant and producing steam for DDGS drying.

Corn Ethanol Dry Mill Plant Production Yield: Modern ethanol plants are now able to produce more than 2.7 gallons of ethanol per bushel of corn compared with less than 2.4 gallons of ethanol per bushel of corn in 1980. The development of new enzymes continues to increase the potential ethanol yield. We used a value of

¹¹¹ Baseline Energy Consumption Estimates for Natural Gas and Coal-based Ethanol Plants—The Potential Impact of Combined Heat and Power (CHP), Prepared for: U.S. Environmental Protection Agency Combined Heat & Power Partnership, Prepared by: Energy and Environmental Analysis, Inc., July 2006.

2.71¹¹² gal/bu in our analysis, which may underestimate actual future yields. For additional information on our yield analysis, see the cost modeling of corn ethanol discussed in Section VII.

Corn Ethanol Co-Products: We based the amount of DDGS produced by an ethanol dry mill plant on the USDA model used in the cost analysis work of this rulemaking, described in Section VII. Based on the agricultural sector modeling outlined in Section X, we assumed that one ton of DDGS displaces 0.5 tons of corn and 0.5 tons of soybean meal. We also assume for corn ethanol wet milling that one ton of corn gluten meal substitutes for one ton of soybean meal, one ton of corn gluten feed substitutes for 0.5 tons of corn, and one ton of corn oil substitutes for one ton of soybean oil.

Biodiesel Production: Two scenarios for biodiesel production were considered, one utilizing soybean oil as a feedstock and one using yellow grease. For the soybean oil scenario, the energy use and inputs for the biodiesel production process were based on a model developed by NREL and used by EPA in the cost modeling of soybean oil biodiesel, as discussed in Section VII. The GREET model does not have a specific case of biodiesel production from yellow grease. Therefore, as a surrogate we used the soybean oil based model with several adjustments. For the yellow grease case, we did not include soybean agriculture emissions or energy use. Soybean crushing was still included as a surrogate for yellow grease processing (purification, water removal, etc.). Also, due to additional processing requirements, the energy use associated with producing biodiesel from yellow grease is higher than for soybean oil biodiesel production. As per the cost modeling of yellow grease biodiesel discussed in Section VII, the energy use for yellow grease biodiesel production

was assumed to be 1.72 times the energy used for soybean oil biodiesel.

Biodiesel Transportation: Biodiesel transportation was based on the distribution infrastructure modeling for this rulemaking which indicates pipelines are not currently used to transport biodiesel and are not projected to play a role in biodiesel transport in the future time frame considered. Therefore, GREET default factors for biodiesel transportation from plant to terminal were modified to remove pipeline transport.

c. Sensitivity Analysis

As mentioned above, the results of lifecycle analysis are highly dependent on the input data assumptions used. Section IX.A.1.b outlined changes made to the GREET model inputs to better represent the scope and purpose of our analysis for this rulemaking. However, we also performed several sensitivity analyses on some key assumptions to see how varying them would impact overall results.

We performed a sensitivity analysis on expanding the lifecycle fuel production system boundaries to include farm equipment production (e.g., emissions and energy use associated with producing steel, rubber, etc. used to make farming equipment). It was found that including farm equipment production energy use and emissions increases ethanol lifecycle energy use and GHG emissions by approximately 1 percent. Therefore, the lifecycle results are not changed significantly due to this expansion of system boundaries.

We also performed a sensitivity analysis on the allocation method used in ethanol production. A number of by-products are made during the production of ethanol. In lifecycle analyses, the energy consumed and emissions generated by an ethanol plant must be allocated not only to ethanol,

but also to each of the by-products. There are a number of methods that can be used to estimate by-product allocations. The displacement method for by-product allocation, described in Section 6.1.2.10 of the RIA, is the default for the GREET model and is the method used by EPA. However, we evaluated another method, the process energy approach, to determine the impact this assumption has on the overall results of the analysis.

Use of the process energy based allocation method reduces ethanol lifecycle energy use and GHG emissions by approximately 30 percent compared to the displacement allocation approach. This indicates that ethanol lifecycle analysis results are extremely sensitive to the choice of allocation method used. (See the RIA, Chapter 6 for more information on these two by-product allocation methods) The displacement allocation method is the method supported by international lifecycle assessment standards¹¹³ and therefore EPA feels that it is the most accurate and preferred method to use. This does however highlight the sensitivity of lifecycle analysis results to choice of input parameters and assumptions.

3. Displacement Indexes (DI)

The displacement index (DI) represents the percent reduction in GHG emissions or fossil fuel energy brought about by the use of a renewable fuel in comparison to the conventional gasoline or diesel that the renewable fuel replaces. The formula for calculating the displacement index depends on which fuel is being displaced (i.e. gasoline or diesel), and which endpoint is of interest (e.g. petroleum energy, GHG). For instance, when investigating the CO₂ impacts of ethanol used in gasoline, the displacement index is calculated as follows:

$$DI_{CO_2} = 1 - \frac{\text{lifecycle CO}_2 \text{ emitted for ethanol in g/Btu}}{\text{lifecycle CO}_2 \text{ emitted for gasoline in g/Btu}}$$

The units of g/Btu ensure that the comparison between the renewable fuel and the conventional fuel is made on a common basis, and that differences in the volumetric energy content of the fuels is taken into account. The denominator includes the CO₂ emitted through combustion of the gasoline itself in addition to all the CO₂ emitted

during its manufacturer and distribution. The numerator, in contrast, includes only the CO₂ emitted during the manufacturer and distribution of ethanol, not the CO₂ emitted during combustion of the ethanol.

The combustion of biomass-based fuels, such as ethanol from corn and woody crops, generates CO₂. However,

in the long run the CO₂ emitted from biomass-based fuels combustion does not increase atmospheric CO₂ concentrations, assuming the biogenic carbon emitted is offset by the uptake of CO₂ resulting from the growth of new biomass. Thus ethanol's carbon can be thought of as cycling from the environment into the plant material

¹¹² All yield values presented represent pure ethanol production (i.e. no denaturant).

¹¹³ ISO 14044:2006(E), "Environmental Management—Life Cycle Assessment—Requirements and Guidelines", International

Organization for Standardization (ISO), First edition, 2006-07-01, Switzerland.

used to make ethanol and, upon combustion of the ethanol, back into the environment from which it came. As a result, CO₂ emissions from biomass-based fuels combustion are not included in their lifecycle emissions results and are not used in the CO₂ displacement

index calculations shown above. Net carbon fluxes from changes in biogenic carbon reservoirs in wooded or crop lands are accounted for separately in the GREET model.

Using GREET, we calculated the lifecycle values for energy consumed

and GHGs produced for corn-ethanol, cellulosic ethanol, and soybean-based biodiesel. These values were in turn used to calculate the displacement indexes. The results are shown in Table IX.A.3–1. Details of these calculations can be found in Chapter 6 of the RIA.

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

[In percent]

	Corn ethanol	Corn ethanol (biomass fuel)	Cellulosic ethanol	Imported ethanol	Biodiesel
DI _{Fossil Fuel}	39.4	76.3	92.7	69.0	61.5
DI _{Petroleum}	91.8	92.0	91.7	92.0	91.2
DI _{GHG}	21.8	54.1	90.9	56.0	67.7
DI _{CO₂}	40.3	72.3	100.1	71.0	69.8

The displacement indexes in this table represent the impact of replacing a Btu of gasoline or diesel with a Btu of renewable fuel. Thus, for instance, for every Btu of gasoline which is replaced by corn ethanol, the total lifecycle GHG emissions that would have been produced from that Btu of gasoline would be reduced by 21.8 percent. For every Btu of diesel which is replaced by biodiesel, the total lifecycle petroleum energy that would have been consumed as a result of burning that Btu of diesel fuel would be reduced by 91.2 percent.

Consistent with the cost modeling done for this rule, for the 2012 cases we assume the “cellulosic” ethanol volume is actually produced from corn utilizing a biomass fuel source at the ethanol production plant. The displacement index for that fuel as shown in Table IX.A.3–1 is used in the calculation of reductions. We have included the column for cellulosic ethanol for comparison, indicating that a move toward cellulosic ethanol will not displace petroleum much differently than other renewable fuels but will have a positive impact on GHG emissions reductions.

For imported ethanol, it is more difficult to estimate the lifecycle energy and GHG displacement indexes since we know much less about how the crops used to make the ethanol are grown and what energy is used in the ethanol production facility. While not exclusively, we anticipate much imported ethanol to be primarily sugarcane based ethanol.

The GHG emissions when producing sugarcane ethanol differs from corn ethanol in that the GHG emissions from growing sugarcane is likely different than for growing an equivalent amount of corn to make a gallon of ethanol. Also, the process of turning sugar into ethanol is easier than when starting with starch and therefore less energy intensive (which typically translates into lower GHG). Importantly, we understand that at least some of the ethanol produced in Brazil uses the bagasse from the sugarcane itself as a process fuel source. We know from our analysis that using a biomass source for process energy greatly improves the GHG benefit of the renewable fuel. These factors would result in sugarcane ethanol having a greater GHG benefit per gallon than corn ethanol, certainly where natural gas or coal is the typical process fuel source used.

Conversely, sugarcane ethanol production does not result in a co-product such as distillers grain as in the case of corn ethanol. In our analyses, accounting for co-products significantly improved the GHG displacement index for corn ethanol. Furthermore, there would be additional transportation emissions associated with transporting the imported ethanol to the U.S. as compared to domestically produced ethanol. Developing a technically rigorous lifecycle estimate for energy needs and GHG impacts for imported ethanol is not a simple task and was not available in the timeframe of this rulemaking.

Considering all of the differences between imported and domestic ethanol, for this rulemaking, we assumed imported ethanol would be predominately from sugarcane and have estimated DI's approximately mid-way between the DI's for corn ethanol and DI's for cellulosic ethanol. We are continuing to develop a better understanding of the lifecycle energy and GHG impacts of producing ethanol from sugarcane and other likely feedstock sources of imported ethanol for any future analysis.

4. Impacts of Increased Renewable Fuel Use

We used the methodology described above to evaluate impacts of increased use of renewable fuels on consumption of petroleum and fossil fuels and also on emissions of CO₂ and GHGs. This section describes our results.

a. Greenhouse Gases and Carbon Dioxide

We estimated the reduction associated with the increased use of renewable fuels on lifecycle emissions of CO₂ and total GHG. Since total GHG emission reductions are lower than CO₂ reductions, this indicates that lifecycle emissions of CH₄ and N₂O are higher for renewable fuels than for the conventional fuels replaced. These values are then compared to the U.S. transportation sector emissions to get a percent reduction. The estimates for the 2012 cases are presented in Table IX.A.4.a–1.

TABLE IX.A.4.A-1.—ESTIMATED CO₂ AND GHG EMISSION IMPACTS OF INCREASED USE OF RENEWABLE FUELS IN THE TRANSPORTATION SECTOR IN 2012, RELATIVE TO THE 2012 REFERENCE CASE

	RFS case	EIA case
CO ₂ Reduction (million metric tons CO ₂)	11.0	19.5
Percent reduction in Transportation Sector CO Emissions	0.52	0.93
GHG Reduction (million metric tons CO ₂ -eq.)	8.0	13.1
Percent reduction in Transportation Sector GHG Emissions	0.36	0.59

b. Fossil Fuel and Petroleum

We estimated the reduction associated with the increased use of renewable

fuels on lifecycle fossil fuels and petroleum. These values are then compared to the U.S. transportation

sector emissions to get a percent reduction. The estimates for the 2012 cases are presented in Table IX.A.4.b-1.

TABLE IX.A.4.B-1.—ESTIMATED FOSSIL FUEL AND PETROLEUM IMPACTS OF INCREASED USE OF RENEWABLE FUELS IN THE TRANSPORTATION SECTOR IN 2012, RELATIVE TO THE 2012 REFERENCE CASE

	RFS case	EIA case
Fossil Fuel Reduction (quadrillion Btu)	0.15	0.27
Percent reduction in Transportation Sector Fossil Fuel Use	0.48	0.85
Petroleum Energy Reduction (billion gal.)	2.0	3.9
Percent reduction in Transportation Sector Petroleum Use	0.82	1.60

B. Implications of Reduced Imports of Petroleum Products

In the proposal, we estimated the impact of expanded renewable fuel use on the importation of oil and finished transportation fuel. No comments were received suggesting alternative methodologies should be used. Therefore, we have incorporated that calculation in this final rule without change.

In 2005, the United States imported almost 60 percent of the oil it consumed. This compares to just over 35 percent of oil from imports in 1975.¹¹⁴ Transportation accounts for 70 percent of the U.S. oil consumption. It is clear that oil imports have a significant impact on the U.S. economy. Expanded production of renewable fuel is expected to contribute to energy diversification and the development of domestic sources of energy. We consider whether the RFS will reduce U.S. dependence on imported oil by calculating avoided expenditures on petroleum imports. Note that we do not calculate whether this reduction is on the net, socially beneficial, which would depend on the scarcity value of domestically produced ethanol versus

that of imported petroleum products. However, the next section does discuss some of the energy security implications unique to petroleum imports.

To assess the impact of the RFS program on petroleum imports, we estimate the fraction of domestic consumption derived from foreign sources using results from the AEO 2006. We compared the levels and mix of imports in the AEO reference case with those in the low macroeconomic growth case and high oil price case. In Section 6.4.1 of the RIA we describe in greater detail how fuel producers may change their levels and mix of imports in response to a decrease in fuel demand. For the purposes of this rulemaking, we show values for the low macroeconomic growth comparison, where import reductions come almost entirely from imports of finished products as shown below in Table IX.B-1. The reductions in imports are compared to the AEO projected levels of net petroleum imports. The range of reductions in net petroleum imports are estimated to be between 0.9 to 1.7 percent, as shown in Table IX.B-1.

TABLE IX.B-1.—NET REDUCTIONS IN IMPORTS IN 2012

	RFS case	EIA case
Reduction in finished products* (barrels per day)	123,000	240,000
Percent reduction** ...	0.89%	1.73%

* Net reductions relative to 2012 reference case.

** Compared to AEO 2006 projections for 2012 reference case.

We also calculate the change in expenditures in both petroleum and ethanol imports and compare these with the U.S. trade position measured as U.S. net exports of all goods and services economy-wide. The decreased expenditures were calculated by multiplying the changes in gasoline, diesel, and ethanol imports by the respective AEO 2006 wholesale gasoline, distillate, and ethanol price forecasts for the specific analysis years. In Table IX.B-2, the net expenditures in reduced petroleum imports, increased ethanol imports, and decreased corn exports are compared to the total value of U.S. net exports of goods and services for the whole economy for 2012. Relative to the 2012 projection, the avoided expenditures due to the RFS would represent 0.4 to 0.7% of economy-wide net exports.

¹¹⁴Davis, Stacy C.; Diegel, Susan W., Transportation Energy Data Book: 25th Edition, Oak Ridge National Laboratory, U.S. Department of Energy, ORNL-6974, 2006.

TABLE IX.B-2.—AVOIDED IMPORT EXPENDITURES (\$2004 BILLION)

Cases	AEO total net exports	Expenditures on petroleum imports	Expenditures on ethanol imports	Decreased corn exports	Net expenditures on imports	Percent of total net exports
RFS Case	-\$383 (year 2012)	-\$2.6	+\$0.7	+\$0.6	-\$1.4	0.4%
EIA Case	-\$5.1	+\$1.0	+\$1.3	-\$2.8	0.7%

C. Energy Security Implications of Increases in Renewable Fuels

One of the effects of increased use of renewable fuels in the U.S. from the RFS is that it diversifies the energy sources in making transportation fuel. A potential disruption in supply reflected in the price volatility of a particular energy source carries with it both financial as well as strategic risks. These risks can be reduced to the extent that diverse sources of fuel energy reduce the dependence on any one source. This reduction in risks is a measure of improved energy security.

At the time of the proposal, EPA stated that an analysis would be completed and estimates provided in support of this rule. In order to understand the energy security implications of the RFS, EPA has worked with Oak Ridge National Laboratory (ORNL), which has developed approaches for evaluating the social costs and energy security implications of oil use. In a new study produced for the RFS, entitled "*The Energy Security Benefits of Reduced Oil Use, 2006–2015*," ORNL has updated and applied the method used in the 1997 report "*Oil Imports: An Assessment of Benefits and Costs*," by Leiby, Jones, Curlee and Lee.^{115 116} While the 1997 report including a description of methodology and results at that time has been used or cited on a number of occasions, this updated analysis and results have not been available for full public consideration. Since energy security will be a key consideration in future actions aimed at reducing our dependence on oil, it is important to assure estimates of energy security impacts have been thoroughly examined in a full and open public forum. Since the updated analysis was only recently available, such a thorough analysis has not been possible. Therefore, EPA has decided to consider

¹¹⁵ Leiby, Paul N., Donald W. Jones, T. Randall Curlee, and Russell Lee, *Oil Imports: An Assessment of Benefits and Costs*, ORNL-6851, Oak Ridge National Laboratory, November, 1997.

¹¹⁶ The 1997 ORNL paper was cited and its results used in DOT/NHTSA's rules establishing CAFE standards for 2008 through 2011 model year light trucks. See DOT/NHTSA, *Final Regulatory Impacts Analysis: Corporate Average Fuel Economy and CAFE Reform MY 2008–2011*, March 2006.

this update as a draft report, include it as part of the record of this rulemaking and invite further public analysis and consideration of both this particular draft report but also other perspectives on how to best quantify energy security benefits. To facilitate that additional consideration, we highlight below some of the key aspects of this particular draft analysis.

The approach developed by ORNL estimates the incremental benefits to society, in dollars per barrel, of reducing U.S. oil imports, called "oil premium." Since the 1997 publication of this report, changes in oil market conditions, both current and projected, suggest that the magnitude of the oil premium has changed. Significant driving factors that have been revised include: Oil prices, current and anticipated levels of OPEC production, U.S. import levels, the estimated responsiveness of regional oil supplies and demands to price, and the likelihood of oil supply disruptions. For this analysis, oil prices from the EIA's AEO 2006 were used. Using the "oil premium" approach, estimates of benefits of improved energy security from reduced U.S. oil imports from increased use of renewable fuels are calculated.

In conducting this analysis, ORNL considered the full economic cost of importing petroleum into the U.S. The full economic cost of importing petroleum into the U.S. is defined for this analysis to include two components in addition to the purchase price of petroleum itself. These are: (1) The higher costs for oil imports resulting from the effect of U.S. import demand on the world oil price and OPEC market power (i.e., the so called "demand" or "monoposony" costs); and (2) the risk of reductions in U.S. economic output and disruption of the U.S. economy caused by sudden disruptions in the supply of imported oil to the U.S. (i.e., macroeconomic disruption/adjustment costs).

1. Effect of Oil Use on Long-Run Oil Price, U.S. Import Costs, and Economic Output

The first component of the full economic costs of importing petroleum into the U.S. follows from the effect of

U.S. import demand on the world oil price over the long-run. Because the U.S. is a sufficiently large purchaser of foreign oil supplies, its purchases can affect the world oil price. This monopsony power means that increases in U.S. petroleum demand can cause the world price of crude oil to rise, and conversely, that reduced U.S. petroleum demand can reduce the world price of crude oil. Thus, one consequence of decreasing U.S. oil purchases due to increased use of renewable fuel is the potential decrease in the crude oil price paid for all crude oil purchased.

2. Short-Run Disruption Premium From Expected Costs of Sudden Supply Disruptions

The second component of the external economic costs resulting from U.S. oil imports arises from the vulnerability of the U.S. economy to oil shocks. The cost of shocks depends on their likelihood, size, and length, the capabilities of the market and U.S. Strategic Petroleum Reserve (SPR), the largest stockpile of government-owned emergency crude oil in the world, to respond, and the sensitivity of the U.S. economy to sudden price increases. While the total vulnerability of the U.S. economy to oil price shocks depends on the levels of both U.S. petroleum consumption and imports, variation in import levels or demand flexibility can affect the magnitude of potential increases in oil price due to supply disruptions. Disruptions are uncertain events, so the costs of alternative possible disruptions are weighted by disruption probabilities. The probabilities used by the ORNL study are based on a 2005 Energy Modeling Forum¹¹⁷ synthesis of expert judgment and are used to determine an expected value of disruption costs, and the change in those expected costs given reduced U.S. oil imports.

3. Costs of Existing U.S. Energy Security Policies

The last often-identified component of the full economic costs of U.S. oil

¹¹⁷ Stanford Energy Modeling Forum, Phillip C. Beccue and Hillard G. Huntington, "An Assessment of Oil Market Disruption Risks," Final Report, EMF SR 8, October, 2005.

imports is the costs to the U.S. taxpayers of existing U.S. energy security policies. The two primary examples are maintaining a military presence to help secure stable oil supply from potentially vulnerable regions of the world and maintaining the SPR to provide buffer supplies and help protect the U.S. economy from the consequences of global oil supply disruptions.

U.S. military costs are excluded from the analysis performed by ORNL because their attribution to particular missions or activities is difficult. Most military forces serve a broad range of security and foreign policy objectives. Attempts to attribute some share of U.S. military costs to oil imports are further challenged by the need to estimate how those costs might vary with incremental variations in U.S. oil imports. Similarly, while the costs for building and maintaining the SPR are more clearly related to U.S. oil use and imports, historically these costs have not varied in response to changes in U.S. oil import levels. Thus, while SPR is factored into the ORNL analysis, the cost of maintaining the SPR is excluded.

As stated earlier, we have placed the draft report in the docket of this rulemaking for the purposes of inviting further consideration. However, the draft results of that report have not been used in quantifying the impacts of this rule.

X. Agricultural Sector Economic Impacts

As described in the Notice of Proposed Rulemaking (NPRM), we used the Forest and Agricultural Sector Optimization Model (FASOM) developed by Professor Bruce McCarl of Texas A&M University and others, to estimate the agricultural sector impacts of increasing renewable fuel volumes required by the RFS and for those volumes anticipated by EIA for 2012. Although current renewable fuel volume predictions are higher than the scenarios described in this rulemaking, we based our analysis on assumptions developed during the NPRM process. Our agricultural sector analysis considered the impacts of the domestic production of renewable fuels. Therefore, when we refer to either the RFS Case or the EIA Case, we include only renewable fuels produced from feedstocks grown in the U.S.¹¹⁸

At the time the NPRM was published, we had not yet finished our analysis of the agricultural impacts associated with the RFS. In the NPRM, we stated our

intent to have the analysis completed in time for the Final Rulemaking (FRM). In the proposal we described our plan to evaluate the effect of increasing renewable fuels volumes on U.S. commodity prices, renewable fuel byproduct prices, livestock feed sources, land use, exports, and farm income. The results of this analysis are summarized in this section. Additional details are included in the Regulatory Impact Analysis (RIA).

FASOM is a long-term economic model of the U.S. agriculture sector that attempts to maximize total revenues for producers while meeting the demands of consumers. Using a number of inputs, FASOM estimates which crops, livestock, and processed agricultural products will be produced in the U.S. The cost of these and other inputs are used to determine the price and level of production of commodities (e.g., field crops, livestock, and biofuel products). FASOM does not capture short-term fluctuations (i.e., month-to-month, annual) in prices and production, however, as it is designed to identify long-term trends (i.e., five to ten years).

FASOM predicts that as renewable fuel volumes increase, corn prices will rise by about 18 cents (RFS Case) and 39 cents (EIA Case) above the Reference Case price of \$2.32 per bushel. For consistency, all of the dollar estimates are presented in 2004 dollars. Soybean prices will rise by about 18 cents (RFS Case) and 21 cents (EIA Case) above the Reference Case price of \$5.26 per bushel by 2012. Since biodiesel volumes will not increase significantly in either the RFS or EIA scenarios, FASOM does not predict significant changes in the soybean related markets with respect to usage changes, or most other variables of interest for this rulemaking. The one exception is U.S. soybean exports, which are affected modestly.

Changes in corn use can be seen by the changing percentage of corn used for ethanol. In 2005, approximately 12 percent of the corn supply was used for ethanol production, however we estimate the amount of corn used for ethanol in 2012 will increase to 20 percent (RFS Case) and 26 percent (EIA Case).

The rising price of corn and soybeans has a direct impact on how corn is used. Higher domestic corn prices lead to lower U.S. exports as the world markets shift to other sources of these products or expand the use of substitute grains. FASOM estimates that U.S. corn exports will drop from about 2 billion bushels in our Reference Case, to 1.6 billion bushels (RFS Case) and 1.3 billion bushels (EIA Case) by 2012. U.S. exports of corn are estimated to drop by about

19 percent by 2012 for the RFS Case and by roughly 38 percent in the EIA Case. In value terms, U.S. exports of corn fall by \$573 million in the RFS Case and by \$1.29 billion in the EIA Case in 2012.

The impact on domestic livestock feed due to higher corn prices and higher U.S. demand for corn in ethanol is also partially offset by decreasing the use of corn for U.S. livestock feed. Substitutes are available for corn as a feedstock, and this market is price sensitive. One alternate feedstock is distillers dried grains with solubles (DDGS), a byproduct associated with the dry milling of ethanol production. Since FASOM predicts relatively flat prices for DDGS across all ethanol volume scenarios, the result is a significant increase in the use of DDGS as a feed source. We estimate DDGS in feed for the RFS case will almost double by 2012, increasing from 8.5 million tons to 15.2 million tons. Under the EIA Case, we expect DDGS to increase to 22.2 million tons by 2012.

The increase in soybean prices is estimated to cause a decline in U.S. soybean exports. In terms of export earnings, U.S. exports of soybeans fall by \$220 million in the RFS Case and by \$194 million in the EIA Case in 2012.

The increase in renewable fuel production provides a significant increase in net farm income to the U.S. agricultural sector. FASOM predicts that in 2012, net U.S. farm income will increase by \$2.6 billion dollars in the RFS renewable fuel volumes case (RFS Case) and \$5.4 billion in the EIA renewable fuel volumes case (EIA Case). The RFS and EIA farm revenue increases represent roughly a 5 and 10 percent increase, respectively, in U.S. net farm income from the sale of farm commodities over the Reference Case of roughly \$53 billion.

Higher corn prices will have a direct impact on the value of U.S. agricultural land. As demand for corn and farm products increases, the price of U.S. farm land will also increase. Our analysis shows that in 2012, higher renewable fuel volumes increase land prices by about 8 percent (RFS Case) and 17 percent (EIA Case). Much of the high quality, suitable land in the U.S. is already being used to produce corn. FASOM estimates an increase of 1.6 million acres (RFS Case) and 2.6 million acres (EIA Case) above the 78.5 million corn acres harvested in the Reference Case in 2012. Due to this higher value of land, we are predicting that farms will withdraw a portion of the land currently in the Conservation Reserve Program (CRP), about 2.3 million acres (RFS Case) and 2.5 million acres (EIA

¹¹⁸ The RIA contains additional information on the renewable fuels volumes analyzed for this rulemaking.

Case) out of the approximately 40 million acres in CRP.¹¹⁹

FASOM estimates U.S. annual wholesale food costs will increase by approximately \$2.2 billion with the RFS renewable volumes and \$3.7 billion with the EIA renewable volumes by 2012. These costs translate to approximately \$7 per person per year (RFS case) and \$12 per person per year (EIA case).

In the proposal, we noted that expansion in the use of renewable fuels also raises the issue of whether water quality and rural ecosystems in general could be affected due to increased production of agricultural feedstocks used to produce greater volumes of renewable fuels. We received one comment from Marathon asserting that our environmental assessment was incomplete and did not address water quality issues. In the time frame to complete this rulemaking, we were not able to conduct a comprehensive assessment of the environmental impacts in the agricultural sector of the wider use of renewable fuels. However, we have considered two indicators—fertilizer use on agricultural crops and Conservation Resource Program (CRP) lands—that may relate to environmental quality and water quality from the production of renewable fuels. The CRP is a voluntary program administered by the U.S. Department of Agriculture that helps defray the costs to farmers of taking agricultural lands out of production and placing them in CRP to provide environmental protection.

As discussed in Section X, FASOM predicts the total amount of nitrogen applied on all farms will increase by 1.2 percent in the RFS Case and by 2 percent in the EIA Case, relative to the Reference Case in 2012. The total amount of phosphorous applied on all farms increases by 0.7 percent in the RFS Case and 1.2 percent in the EIA Case, relative to the Reference Case in 2012. Currently, there are approximately 40 million acres in the CRP. FASOM predicts 2.3 million acres (RFS Case) and 2.5 million acres (EIA Case) of land would be withdrawn from the CRP due to higher land values.

XI. Public Participation

Many interested parties participated in the rulemaking process that culminates with this final rule. This process provided opportunity for submitting written public comments

following the proposal that we published on September 22, 2006 (71 FR 55552). We considered these comments in developing the final rule. In addition, we held a public hearing on the proposed rulemaking on October 13, 2006, and we have considered comments presented at the hearing.

Throughout the rulemaking process, EPA met with stakeholders including representatives from the refining industry, renewable fuels production, and marketers and distributors, and others. The program we are finalizing today was developed as a collaborative effort with these stakeholders.

We have prepared a detailed Summary and Analysis of Comments document, which describes comments we received on the proposal and our response to each of these comments. The Summary and Analysis of Comments is available in the docket for this rule at the Internet address listed under **ADDRESSES**, as well as on the Office of Transportation and Air Quality Web site (<http://www.epa.gov/otaq/renewablefuels/index.htm>). In addition, comments and responses for key issues are included throughout this preamble.

XII. Administrative Requirements

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order (EO) 12866, (58 FR 51735, October 4, 1993) this action is a “significant regulatory action” because of the policy implications of the final rule. Even though EPA has estimated that renewable fuel use through 2012 will be sufficient through the operation of market forces to meet the levels required in the standard, the final rule reflects the first renewable fuel mandate at the federal level. Accordingly, EPA submitted this action to the Office of Management and Budget (OMB) for review under EO 12866 and any changes made in response to OMB recommendations have been documented in the docket for this action.

B. Paperwork Reduction Act

The information collection requirements in this final rule have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* The Information Collection Request (ICR) prepared by EPA has been assigned EPA ICR number 2242.02. The information collection requirements are not enforceable until OMB approves them.

The information is planned to be collected to ensure that the required

amount of renewable fuel is used each year. The credit trading program required by the Energy Policy Act will be satisfied through a program utilizing Renewable Identification Numbers (RINs), which are assigned when renewable fuel is produced in or imported to geographic areas covered by the rule. Production and importation of renewable fuel will serve as a surrogate measure of renewable fuel consumption. Our final RIN-based program will fulfill all the functions of a credit trading program, and thus will meet the Energy Policy Act's requirements. For each calendar year, each obligated party will be required to submit a report to the Agency documenting the RINs it acquired, and showing that the sum of all RINs acquired is equal to or greater than its renewable volume obligation. The Agency could then verify that the RINs used for compliance purposes were valid by simply comparing RINs reported by producers to RINs claimed by obligated parties.

For fuel standards, Section 208(a) of the Clean Air Act requires that manufacturers provide information the Administrator may reasonably require to determine compliance with the regulations; submission of the information is therefore mandatory. We will consider confidential all information meeting the requirements of Section 208(c) of the Clean Air Act.

The annual public reporting and recordkeeping burden for this collection of information is estimated to be 3.3 hours per response. A document entitled “Information Collection Request (ICR); OMB-83 Supporting Statement, Environmental Protection Agency, Office of Air and Radiation,” has been placed in the public docket. The supporting statement provides a detailed explanation of the Agency's estimates by collection activity and explains how comments may be submitted by interested parties. The estimates contained in the docket are briefly summarized here:

Estimated total number of potential respondents: 6,425.

Estimated total number of responses: 13,380.

Estimated total annual burden hours: 43,030.

Estimated total respondent cost (estimated at \$71 per hour): \$3,055,130.

Estimated total non-postage purchased services (estimated at \$142 per hour): \$5,219,920.

EPA received various comments on the rulemaking provisions covered by the proposed ICR. All comments that were submitted to EPA are considered in the Summary and Analysis of Comments, which can be found in the

¹¹⁹ Since much of the CRP land is ill suited for corn or soybean production, it is unlikely this land will go directly into corn or soybean production but instead will more likely be used to replace other agricultural land uses displaced by expanded corn and soybean production.

docket. In response to comments, we have increased the frequency of reporting for transaction and summary reports from annually to quarterly. We have also removed a burden for small refiners that was associated with applying for small-refiner flexibilities. The burdens and costs shown above account for these changes.

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9. When this ICR is approved by OMB, the Agency will publish a technical amendment to 40 CFR part 9 in the **Federal Register** to display the OMB control number for the approved information collection requirements contained in this final rule.

C. Regulatory Flexibility Act

1. Overview

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201 (see table below); (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a

population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field. The following table provides an overview of the primary SBA small business categories potentially affected by this regulation:

Industry	Defined as small entity by SBA if	NAICS codes ^a
Gasoline refiners.	≤1,500 employees. ¹²⁰	324110

^aNorth American Industrial Classification System.

EPA has determined that it is not necessary to prepare a regulatory flexibility analysis in connection with this final rule.

2. Background

Since the vast majority of crude oil produced in or imported into the U.S. is consumed as gasoline or diesel fuel, concerns about our dependence on foreign sources of crude oil has renewed interest in renewable transportation fuels. The passage of the Energy Policy Act of 2005 demonstrated a strong commitment on the part of U.S. policymakers to consider additional means of supporting renewable fuels as a supplement to petroleum-based fuels in the transportation sector. Section 1501 of the Energy Policy Act, which was added to the CAA as Section 211(o), requires EPA to establish the RFS program to ensure that the pool of gasoline sold in the contiguous 48 states contains specific volumes of renewable fuel for each calendar year starting with 2006. The Agency is required to set a standard for each year representing the amount of renewable fuel that obligated parties (e.g., refiners, blenders, and importers) must use as a percentage of gasoline sold or introduced into commerce, and the Agency is required to promulgate a credit trading program for the RFS program.

3. Small Refineries Versus Small Refiners

Title XV (Ethanol and Motor Fuels) of the Energy Policy Act provides, at Section 1501(a)(2) [42 U.S.C. 7545(o)(9)(A)-(D)], special provisions for "small refineries", such as a temporary exemption from the standards until calendar year 2011. The

¹²⁰In the NPRM, we also referred to a 125,000 barrels of crude per day (bpcd) crude capacity limit. This criterion was inadvertently used and is not applicable for this program (as it only applies in cases of government procurement). We note that the number of small entities remains the same whether this criterion is used or not.

Act defines the term "small refinery" as " * * * a refinery for which the average aggregate daily crude oil throughput for a calendar year * * * does not exceed 75,000 barrels." As shown in the table above, this term is different than SBA's small business category for gasoline refiners, which is what the Regulatory Flexibility Act is concerned with. EPA is required under the RFA to consider impacts on small entities meeting SBA's small business definition; these entities are referred to as "small refiners" for our regulatory flexibility analysis under SBREFA.

A small refinery, per the Energy Policy Act, is a refinery where the annual crude throughput is less than or equal to 75,000 barrels (i.e., a small-capacity refinery), and could be owned by a larger refiner that exceeds SBA's small entity size standards. The small business employee criteria were established for SBA's small business definition to set apart those companies which are most likely to be at an inherent economic disadvantage relative to larger businesses.

4. Summary of Potentially Affected Small Entities

The refiners that are potentially affected by this rule are those that produce gasoline. For our recent final rule "Control of Hazardous Air Pollutants From Mobile Sources" (72 FR 8428, February 26, 2007), we performed an industry characterization of potentially affected gasoline refiners. We used that industry characterization to determine which refiners would also meet the SBA definition of a small entity. From that industry characterization, and further analysis following the Notice of Proposed Rulemaking (71 FR 5552, September 22, 2006), we have determined that there are 15 gasoline refiners who own 16 refineries (14 refiners own one refinery each, the remaining refiner owns two refineries) that meet the definition of a small refiner. Of the 16 refineries, 13 also meet the Energy Policy Act's definition of a small refinery.

5. Impact of the Regulations on Small Entities

As previously stated, many aspects of the RFS program, such as the required amount of annual renewable fuel volumes, are specified in the Energy Policy Act. As discussed above in Section II.A.1, the annual projections of ethanol production to satisfy market demand exceed the required annual renewable fuel volumes. When the small refinery exemption ends, it is anticipated that there will be over one

billion gallons in excess RINs available. We believe that this large volume of excess RINs will also lower the costs of this program. Thus, with the short-term relief provided under the Energy Policy Act for small refineries, and the anticipated low cost of RINs when the exemption expires, we believe that this program will not impose a significant economic burden on small refineries, small refiners, or any other obligated party. Therefore, we have determined that this rule will not have a significant economic impact on a substantial number of small entities.

When the Agency certifies that a rule will not have a significant economic impact on a substantial number of small entities, EPA's policy is to make an assessment of the rule's impact on any small entities and to engage the potentially regulated entities in a dialog regarding the rule, and minimize the impact to the extent feasible. The following sections discuss our outreach with the potentially affected small entities and regulatory flexibilities to decrease the burden on these entities in compliance with the requirements of the RFS program.

6. Small Refiner Outreach

We do not believe that the RFS program would have a significant economic impact on a substantial number of small entities, however we have still tried to reduce the impact of this rule on small entities. Prior to issuing the proposed rule, we held meetings with small refiners to discuss the requirements of the RFS program and the special provisions offered by the Energy Policy Act for small refineries.

The Energy Policy Act set out the following provisions for small refineries:

- A temporary exemption from the Renewable Fuels Standard requirement until 2011;
- An extension of the temporary exemption period for at least two years for any small refinery where it is determined that the refinery would be subject to a disproportionate economic hardship if required to comply;
- Any small refinery may petition, at any time, for an exemption based on disproportionate economic hardship; and,
- A small refinery may waive its temporary exemption to participate in the credit generation program, or it may also "opt-in", by waiving its temporary exemption, to be subject to the RFS requirement.

During these meetings with the small refiners we also discussed the impacts of these provisions being offered to small refineries only. Three refiners met

the definition of a small refiner, but their refineries did not meet the Act's definition of a small refinery; which naturally concerned the small refiners. Another concern that the small refiners had was that if this rule were to have a significant economic impact on a substantial number of small entities a lengthy SBREFA process would ensue (which would delay the promulgation of the RFS rulemaking) and thus provide less lead time for these small entities prior to the RFS program start date.

Following our discussions with the small refiners, they provided three suggested regulatory flexibility options that they believed could further assist affected small entities in complying with the RFS program standard: (1) That all small *refiners* be afforded the Act's small *refinery* temporary exemption, (2) that small refiners be allowed to generate credits if they elect to comply with the RFS program standard prior to the 2011 small refinery compliance date, and (3) relieve small refiners who generate blending credits of the RFS program compliance requirements.

We agreed with the small refiners' suggestion that small refiners be afforded the same temporary exemption that the Act specifies for small refineries. This relief would apply to refiners who meet the 1,500 employee count criteria, as well as the crude capacity criteria that we have used in previous fuels programs when providing relief for small refiners. Regarding the small refiners' second and third suggestions regarding credits, we note that the RIN-based program will automatically provide them with credit for any renewables that they blend into their motor fuels. Until 2011, small refiners will essentially be treated as oxygenate blenders and may separate RINs from batches and trade or sell these RINs, unless they choose to opt-in to the program.

7. Reporting, Recordkeeping, and Compliance Requirements

Registration, recordkeeping and reporting are necessary to track compliance with the renewable fuels standard and transactions involving RINs, and these compliance requirements will be similar to those required under our previous and current 40 CFR part 80 fuel compliance programs. We will use the same basic forms for RFS program registration that we use under the reformulated gasoline (RFG) and anti-dumping program, as these forms are well known in the regulated community and are simple to fill out. We will use a simplified method of reporting via the Agency's Central Data Exchange (CDX), which will

reduce the reporting burden on regulated parties. Records related to RIN transactions may be kept in any format and the period of record retention by reporting parties is five years, similar to other fuel programs. Records to be retained include copies of all compliance reports submitted to EPA and copies of product transfer documents (PTDs). Sections IV and V, above, contain more detailed discussions on the registration, recordkeeping, reporting, and compliance requirements of this final rule.

8. Related Federal Rules

We are aware of a few other current or proposed Federal rules that are related to this rule. The primary related federal rules are the Mobile Source Air Toxics (MSAT2) rule (72 FR 8428, February 26, 2007), the Tier 2 Vehicle/Gasoline Sulfur rulemaking (65 FR 6698, February 10, 2000), and the fuel sulfur rules for highway diesel (66 FR 5002, January 18, 2001) and nonroad diesel (69 FR 38958, June 29, 2004).

9. Conclusions

As stated above, based on the statutory relief provided by the Energy Policy Act for small refineries, we are certifying that this rule will not have a significant economic impact on a substantial number of small entities. Additionally, we believe that extending the small refinery exemption to small refiners would further reduce the economic impacts on small entities. We believe that small refiners generally lack the resources available to larger companies, and therefore find it appropriate to extend this exemption to all small refiners. Thus, we are extending the small refinery temporary exemption to all qualified small refiners. Small refiners will also be permitted to separate RINs from batches and trade or sell these RINs prior to 2011 if the small refiner operates as an ethanol blender.

Past fuels rulemakings have included a provision that, for the purposes of the regulatory flexibility provisions for small entities, a refiner must also have an average crude capacity of no more than 155,000 barrels of crude per day (bpcd). To be consistent with these previous rules, we are finalizing in this rule that refiners that meet this criterion (in addition to having no more than 1,500 total corporate employees) will be considered small refiners for the purposes of the regulatory flexibility provisions for this rulemaking.

Since the RFS program would have no significant economic impact on a substantial number of small entities

with only the relief required in the Energy Policy Act for small refineries, it also follows that the rule will have no significant economic impact on a substantial number of small entities with the additional relief this final rule provides for small refiners.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104-4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures to State, local, and tribal governments, in the aggregate, or to the private sector, of \$100 million or more in any one year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted.

Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under Section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory programs with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

EPA has determined that this rule does not contain a Federal mandate that may result in expenditures of \$100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any one year. EPA has estimated that renewable fuel use through 2012 will be sufficient to meet the required levels. Therefore, individual refiners, blenders, and importers are already on track to meet

rule obligations through normal market-driven incentives. Thus, today's rule is not subject to the requirements of Sections 202 and 205 of the UMRA.

EPA has determined that this rule contains no regulatory requirements that might significantly or uniquely affect small governments. Compliance with the mandates of the RFS rule, including the reporting and recordkeeping requirements, are the responsibility of exporters, producers, and importers of renewable fuel and gasoline, and not small governments.

E. Executive Order 13132: Federalism

Executive Order 13132, entitled "Federalism" (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure "meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications." "Policies that have federalism implications" is defined in the Executive Order to include regulations that have "substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government."

This final rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. Thus, Executive Order 13132 does not apply to this rule.

In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicited comment on the proposed rule from State and local officials. A number of states commented on the proposed rule. These comments are available in the rulemaking docket, and are summarized and addressed in the Summary and Analysis document.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

Executive Order 13175, entitled "Consultation and Coordination with Indian Tribal Governments" (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications." This final rule does not have tribal implications, as specified in Executive Order 13175. This rule will be implemented at the Federal level and

will apply to refiners, blenders, and importers. Tribal governments will be affected only to the extent they purchase and use regulated fuels. Thus, Executive Order 13175 does not apply to this rule.

G. Executive Order 13045: Protection of Children From Environmental Health and Safety Risks

Executive Order 13045: "Protection of Children from Environmental Health Risks and Safety Risks" (62 FR 19885, April 23, 1997) applies to any rule that: (1) Is determined to be "economically significant" as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

EPA interprets EO 13045 as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under section 5-501 of the EO has the potential to influence the regulation. This final rule is not subject to EO 13045 because it does not establish an environmental standard intended to mitigate health or safety risks and because it implements specific standards established by Congress in statutes.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This rule is not a "significant energy action" as defined in Executive Order 13211, "Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use" (66 FR 28355 (May 22, 2001)) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy.

EPA expects the provisions to have very little effect on the national fuel supply since normal market forces alone are promoting greater renewable fuel use than required by the RFS mandate. We discuss our analysis of the energy and supply effects of the increased use of renewable fuels in Sections VI and X of this preamble.

I. National Technology Transfer Advancement Act

As noted in the proposed rule, Section 12(d) of the National Technology Transfer and Advancement Act of 1995 ("NTTAA"), Public Law No. 104-113, 12(d) (15 U.S.C. 272 note)

directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. The NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This rulemaking involves technical standards. EPA has decided to use ASTM D6751-06a "Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels". This standard was developed by ASTM International (originally known as the American Society for Testing and Materials), Subcommittee D02.E0, and was approved in August 2006. The standard may be obtained through the ASTM Web site (www.astm.org) or by calling ASTM at (610) 832-9585. ASTM D6751-06a meets the objectives of this final rule because it establishes one of the criteria by which biodiesel is defined.

J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

EPA lacks the discretionary authority to address environmental justice in this final rulemaking since the Agency is implementing specific standards established by Congress in statutes. Although EPA lacks authority to modify today's regulatory decision on the basis of environmental justice considerations, EPA nevertheless determined that this final rule does not have a disproportionately high and adverse human health or environmental impact on minority or low-income populations.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 et seq., as added by the Small Business Regulatory Enforcement

Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A Major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a "major rule" as defined by 5 U.S.C. 804(2). The effective date of the rule is September 1, 2007.

L. Clean Air Act Section 307(d)

This rule is subject to Section 307(d) of the CAA. Section 307(d)(7)(B) provides that "[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review." This section also provides a mechanism for the EPA to convene a proceeding for reconsideration, "[i]f the person raising an objection can demonstrate to the EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule." Any person seeking to make such a demonstration to the EPA should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave., NW., Washington, DC 20460, with a copy to both the person(s) listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Director of the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), U.S. EPA, 1200 Pennsylvania Ave., NW., Washington, DC 20460.

XIII. Statutory Authority

Statutory authority for the rules finalized today can be found in section 211 of the Clean Air Act, 42 U.S.C. 7545. Additional support for the procedural and compliance related aspects of today's rule, including the recordkeeping requirements, come from Sections 114, 208, and 301(a) of the CAA, 42 U.S.C. 7414, 7542, and 7601(a).

List of Subjects in 40 CFR Part 80

Environmental protection, Air pollution control, Fuel additives, Gasoline, Imports, Incorporation by

reference, Labeling, Motor vehicle pollution, Penalties, Reporting and recordkeeping requirements.

Dated: April 10, 2007.

Stephen L. Johnson,
Administrator.

■ 40 CFR part 80 is amended as follows:

PART 80—REGULATION OF FUEL AND FUEL ADDITIVES

■ 1. The authority citation for part 80 continues to read as follows:

Authority: 42 U.S.C. 7414, 7542, 7545, and 7601(a).

■ 2. Section 80.1100 is revised to read as follows:

§ 80.1100 How is the statutory default requirement for 2006 implemented?

(a) *Definitions.* For calendar year 2006, the definitions of section 80.2 and the following additional definitions apply to this section.

(1) *Renewable fuel.* (i) *Renewable fuel* means motor vehicle fuel that is used to replace or reduce the quantity of fossil fuel present in a fuel mixture used to operate a motor vehicle, and which:

(A) Is produced from grain, starch, oil seeds, vegetable, animal, or fish materials including fats, greases, and oils, sugarcane, sugar beets, sugar components, tobacco, potatoes, or other biomass; or

(B) Is natural gas produced from a biogas source, including a landfill, sewage waste treatment plant, feedlot, or other place where decaying organic material is found.

(ii) The term "renewable fuel" includes cellulosic biomass ethanol, waste derived ethanol, biodiesel, and any blending components derived from renewable fuel.

(2) *Cellulosic biomass ethanol* means ethanol derived from any lignocellulosic or hemicellulosic matter that is available on a renewable or recurring basis, including dedicated energy crops and trees, wood and wood residues, plants, grasses, agricultural residues, fibers, animal wastes and other waste materials, and municipal solid waste. The term also includes any ethanol produced in facilities where animal wastes or other waste materials are digested or otherwise used to displace 90 percent or more of the fossil fuel normally used in the production of ethanol.

(3) *Waste derived ethanol* means ethanol derived from animal wastes, including poultry fats and poultry wastes, and other waste materials, or municipal solid waste.

(4) *Small refinery* means a refinery for which the average aggregate daily crude

oil throughput for a calendar year (as determined by dividing the aggregate throughput for the calendar year by the number of days in the calendar year) does not exceed 75,000 barrels.

(5) *Biodiesel* means a diesel fuel substitute produced from nonpetroleum renewable resources that meets the registration requirements for fuels and fuel additives established by the Environmental Protection Agency under section 211 of the Clean Air Act. It includes biodiesel derived from animal wastes (including poultry fats and poultry wastes) and other waste materials, or biodiesel derived from municipal solid waste and sludges and oils derived from wastewater and the treatment of wastewater.

(b) *Renewable Fuel Standard for 2006*. The percentage of renewable fuel in the total volume of gasoline sold or dispensed to consumers in 2006 in the United States shall be a minimum of 2.78 percent on an annual average volume basis.

(c) *Responsible parties*. Parties collectively responsible for attainment of the standard in paragraph (b) of this section are refiners (including blenders) and importers of gasoline. However, a party that is a refiner only because he owns or operates a small refinery is exempt from this responsibility.

(d) *EPA determination of attainment*. EPA will determine after the close of 2006 whether or not the requirement in paragraph (b) of this section has been met. EPA will base this determination on information routinely published by the Energy Information Administration on the annual domestic volume of gasoline sold or dispensed to U.S. consumers and of ethanol produced for use in such gasoline, supplemented by readily available information concerning the use in motor fuel of other renewable fuels such as cellulosic biomass ethanol, waste derived ethanol, biodiesel, and other non-ethanol renewable fuels.

(1) The renewable fuel volume will equal the sum of all renewable fuel volumes used in motor fuel, provided that:

(i) One gallon of cellulosic biomass ethanol or waste derived ethanol shall be considered to be the equivalent of 2.5 gallons of renewable fuel; and

(ii) Only the renewable fuel portion of blending components derived from renewable fuel shall be counted towards the renewable fuel volume.

(2) If the nationwide average volume percent of renewable fuel in gasoline in 2006 is equal to or greater than the standard in paragraph (b) of this section, the standard has been met.

(e) *Consequence of nonattainment in 2006*. In the event that EPA determines that the requirement in paragraph (b) of this section has not been attained in 2006, a deficit carryover volume shall be added to the renewable fuel volume obligation for 2007 for use in calculating the standard applicable to gasoline in 2007.

(1) The deficit carryover volume shall be calculated as follows:

$$DC = V_{\text{gas}} * (R_s - R_a)$$

Where:

DC = Deficit carryover, in gallons, of renewable fuel.

V_{gas} = Volume of gasoline sold or dispensed to U.S. consumers in 2006, in gallons.

R_s = 0.0278.

R_a = Ratio of renewable fuel volume divided by total gasoline volume determined in accordance with paragraph (d)(2) of this section.

(2) There shall be no other consequence of failure to attain the standard in paragraph (b) of this section in 2006 for any of the parties in paragraph (c) of this section.

■ 3. Section 80.1101 is added to read as follows:

§ 80.1101 Definitions.

The definitions of § 80.2 and the following additional definitions apply for the purposes of this subpart. For calendar year 2007 and beyond, the definitions in this section § 80.1101 supplant those in § 80.1100.

(a) *Cellulosic biomass ethanol* means either of the following:

(1) Ethanol derived from any lignocellulosic or hemicellulosic matter that is available on a renewable or recurring basis and includes any of the following:

(i) Dedicated energy crops and trees.

(ii) Wood and wood residues.

(iii) Plants.

(iv) Grasses.

(v) Agricultural residues.

(vi) Animal wastes and other waste materials, the latter of which may include waste materials that are residues (e.g., residual tops, branches, and limbs from a tree farm).

(vii) Municipal solid waste.

(2) Ethanol made at facilities at which animal wastes or other waste materials are digested or otherwise used onsite to displace 90 percent or more of the fossil fuel that is combusted to produce thermal energy integral to the process of making ethanol, by:

(i) The direct combustion of the waste materials or a byproduct resulting from digestion of such waste materials (e.g., methane from animal wastes) to make thermal energy; and/or

(ii) The use of waste heat captured from an off-site combustion process as a source of thermal energy.

(b) *Waste derived ethanol* means ethanol derived from either of the following:

(1) Animal wastes, including poultry fats and poultry wastes, and other waste materials.

(2) Municipal solid waste.

(c) *Biogas* means methane or other hydrocarbon gas produced from decaying organic material, including landfills, sewage waste treatment plants, and animal feedlots.

(d) *Renewable fuel*. (1) *Renewable fuel* is any motor vehicle fuel that is used to replace or reduce the quantity of fossil fuel present in a fuel mixture used to fuel a motor vehicle, and is produced from any of the following:

(i) Grain.

(ii) Starch.

(iii) Oilseeds.

(iv) Vegetable, animal, or fish materials including fats, greases, and oils.

(v) Sugarcane.

(vi) Sugar beets.

(vii) Sugar components.

(viii) Tobacco.

(ix) Potatoes.

(x) Other biomass.

(xi) Natural gas produced from a biogas source, including a landfill, sewage waste treatment plant, feedlot, or other place where there is decaying organic material.

(2) The term "Renewable fuel" includes cellulosic biomass ethanol, waste derived ethanol, biodiesel (mono-alkyl ester), non-ester renewable diesel, and blending components derived from renewable fuel.

(3) Ethanol covered by this definition shall be denatured as required and defined in 27 CFR parts 20 and 21.

(4) Small volume additives (excluding denaturants) less than 1.0 percent of the total volume of a renewable fuel shall be counted as part of the total renewable fuel volume.

(5) A fuel produced by a renewable fuel producer that is used in boilers or heaters is not a motor vehicle fuel and therefore is not a renewable fuel.

(e) *Blending component* has the same meaning as "Gasoline blending stock, blendstock, or component" as defined at § 80.2(s), for which the portion that can be counted as renewable fuel is calculated as set forth in § 80.1115(a).

(f) *Motor vehicle* has the meaning given in Section 216(2) of the Clean Air Act (42 U.S.C. 7550).

(g) *Small refinery* means a refinery for which the average aggregate daily crude oil throughput for the calendar year 2004 (as determined by dividing the

aggregate throughput for the calendar year by the number of days in the calendar year) does not exceed 75,000 barrels.

(h) *Biodiesel (mono-alkyl ester)* means a motor vehicle fuel or fuel additive which is all the following:

(1) Registered as a motor vehicle fuel or fuel additive under 40 CFR part 79.

(2) A mono-alkyl ester.

(3) Meets ASTM D-6751-07, entitled "Standard Specification for Biodiesel Fuel Blendstock (B100) for Middle Distillate Fuels." ASTM D-6751-07 is incorporated by reference. This incorporation by reference was approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. A copy may be obtained from the American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, Pennsylvania. A copy may be inspected at the EPA Docket Center, Docket No. EPA-HQ-OAR-2005-0161, EPA/DC, EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC, or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202-741-6030, or go to: <http://www.archives.gov/federal-register/cfr/ibr-locations.html>.

(4) Intended for use in engines that are designed to run on conventional diesel fuel.

(5) Derived from nonpetroleum renewable resources (as defined in paragraph (m) of this section).

(i) *Non-ester renewable diesel* means a motor vehicle fuel or fuel additive which is all the following:

(1) Registered as a motor vehicle fuel or fuel additive under 40 CFR part 79.

(2) Not a mono-alkyl ester.

(3) Intended for use in engines that are designed to run on conventional diesel fuel.

(4) Derived from nonpetroleum renewable resources (as defined in paragraph (m) of this section).

(j) *Renewable crude* means biologically derived liquid feedstocks including but not limited to poultry fats, poultry wastes, vegetable oil, and greases that are used as feedstocks to

make gasoline or diesel fuels at production units as specified in paragraph (k) of this section.

(k) *Renewable crude-based fuels* are renewable fuels that are gasoline or diesel products resulting from the processing of renewable crudes in production units within refineries or at dedicated facilities within refineries, that process petroleum based feedstocks and which make gasoline and diesel fuel.

(l) *Importers*. For the purposes of this subpart only, an importer of gasoline or renewable fuel is:

(1) Any person who brings gasoline or renewable fuel into the 48 contiguous states of the United States from a foreign country or from an area that has not opted in to the program requirements of this subpart pursuant to § 80.1143; and

(2) Any person who brings gasoline or renewable fuel into an area that has opted in to the program requirements of this subpart pursuant to § 80.1143.

(m) *Nonpetroleum renewable resources* include, but are not limited to the following:

(1) Plant oils.

(2) Animal fats and animal wastes, including poultry fats and poultry wastes, and other waste materials.

(3) Municipal solid waste and sludges and oils derived from wastewater and the treatment of wastewater.

(n) *Export of renewable fuel* means:

(1) Transfer of a batch of renewable fuel to a location outside the United States; and

(2) Transfer of a batch of renewable fuel from a location in the contiguous 48 states to Alaska, Hawaii, or a United States territory, unless that state or territory has received an approval from the Administrator to opt-in to the renewable fuel program pursuant to § 80.1143.

(o) *Renewable Identification Number (RIN)*, is a unique number generated to represent a volume of renewable fuel pursuant to §§ 80.1125 and 80.1126.

(1) *Gallon-RIN* is a RIN that represents an individual gallon of renewable fuel; and

(2) *Batch-RIN* is a RIN that represents multiple gallon-RINs.

(p) *Neat renewable fuel* is a renewable fuel to which only de minimus amounts of conventional gasoline or diesel have been added.

§§ 80.1102 through 80.1103 [Reserved]

■ 4. Sections 80.1102 and 80.1103 are reserved.

■ 5. Sections 80.1104 through 80.1107 are added to read as follows:

Subpart K—Renewable Fuel Standard

* * * * *

Sec.

80.1104 What are the implementation dates for the Renewable Fuel Standard Program?

80.1105 What is the Renewable Fuel Standard?

80.1106 To whom does the Renewable Volume Obligation apply?

80.1107 How is the Renewable Volume Obligation calculated?

* * * * *

§ 80.1104 What are the implementation dates for the Renewable Fuel Standard Program?

The RFS standards and other requirements of § 80.1101 and all sections following are effective beginning on September 1, 2007.

§ 80.1105 What is the Renewable Fuel Standard?

(a) The annual value of the renewable fuel standard for 2007 shall be 4.02 percent.

(b) Beginning with the 2008 compliance period, EPA will calculate the value of the annual standard and publish this value in the **Federal Register** by November 30 of the year preceding the compliance period.

(c) EPA will base the calculation of the standard on information provided by the Energy Information Administration regarding projected gasoline volumes and projected volumes of renewable fuel expected to be used in gasoline blending for the upcoming year.

(d) EPA will calculate the annual renewable fuel standard using the following equation:

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

Where:

RFStd_i = Renewable Fuel Standard, in year i, in percent.

RFV_i = Nationwide annual volume of renewable fuels required by section 211(o)(2)(B) of the Act (42 U.S.C. 7545), for year i, in gallons.

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

R_i = Amount of renewable fuel blended into gasoline that is projected to be used in the 48 contiguous states, in year i, in gallons.

GS_i = Amount of gasoline projected to be used in noncontiguous states or territories (if the state or territory opts-in), in year i, in gallons.

RS_i = Amount of renewable fuel blended into gasoline that is projected to be used in noncontiguous states or territories (if the

state or territory opts-in), in year *i*, in gallons.

GE_i = Amount of gasoline projected to be produced by exempt small refineries and small refiners, in year *i*, in gallons (through 2010 only, except to the extent that a small refinery exemption is extended pursuant to § 80.1141(e)).

$Cell_i$ = Beginning in 2013, the amount of renewable fuel that is required to come from cellulosic sources, in year *i*, in gallons.

(e) Beginning with the 2013 compliance period, EPA will calculate the value of the annual cellulosic standard and publish this value in the **Federal Register** by November 30 of the year preceding the compliance period.

(f) EPA will calculate the annual cellulosic standard using the following equation:

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

Where:

RFC_{Cell_i} = Renewable Fuel Cellulosic Standard in year *i*, in percent.

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

R_i = Amount of renewable fuel blended into gasoline that is projected to be used in the 48 contiguous states, in year *i*, in gallons.

GS_i = Amount of gasoline projected to be used in noncontiguous states or territories (if the state or territory opts-in), in year *i*, in gallons.

RS_i = Amount of renewable fuel blended into gasoline that is projected to be used in noncontiguous states or territories (if the state or territory opts-in), in year *i*, in gallons.

$Cell_i$ = Amount of renewable fuel that is required to come from cellulosic sources, in year *i*, in gallons.

§ 80.1106 To whom does the Renewable Volume Obligation apply?

(a) (1) An obligated party is a refiner that produces gasoline within the 48 contiguous states, or an importer that imports gasoline into the 48 contiguous states. A party that simply adds renewable fuel to gasoline, as defined in § 80.1107(c), is not an obligated party.

(2) If the Administrator approves a petition of Alaska, Hawaii, or a United States territory to opt-in to the renewable fuel program under the provisions in § 80.1143, then "obligated party" shall also include any refiner that produces gasoline within that state or territory, or any importer that imports gasoline into that state or territory.

(3) For the purposes of this section, "gasoline" refers to any and all of the products specified at § 80.1107(c).

(b) For each compliance period starting with 2007, any obligated party is required to demonstrate, pursuant to

§ 80.1127, that it has satisfied the Renewable Volume Obligation for that compliance period, as specified in § 80.1107(a).

(c) An obligated party may comply with the requirements of paragraph (b) of this section for all of its refineries in the aggregate, or for each refinery individually.

(d) An obligated party must comply with the requirements of paragraph (b) of this section for all of its imported gasoline in the aggregate.

(e) An obligated party that is both a refiner and importer must comply with the requirements of paragraph (b) of this section for its imported gasoline separately from gasoline produced by its refinery or refineries.

(f) Where a refinery or importer is jointly owned by two or more parties, the requirements of paragraph (b) of this section may be met by one of the joint owners for all of the gasoline produced at the refinery, or all of the imported gasoline, in the aggregate, or each party may meet the requirements of paragraph (b) of this section for the portion of the gasoline that it owns, as long as all of the gasoline produced at the refinery, or all of the imported gasoline, is accounted for in determining the renewable fuels obligation under § 80.1107.

(g) The requirements in paragraph (b) of this section apply to the following compliance periods:

(1) For 2007, the compliance period is September 1 through December 31.

(2) Beginning in 2008, and every year thereafter, the compliance period is January 1 through December 31.

§ 80.1107 How is the Renewable Volume Obligation calculated?

(a) The Renewable Volume Obligation for an obligated party is determined according to the following formula:

$$RVO_i = (RFStd_i * GV_i) + D_{i-1}$$

Where:

RVO_i = The Renewable Volume Obligation for an obligated party for calendar year *i*, in gallons of renewable fuel.

$RFStd_i$ = The renewable fuel standard for calendar year *i*, determined by EPA pursuant to § 80.1105, in percent.

GV_i = The non-renewable gasoline volume, determined in accordance with paragraphs (b), (c), and (d) of this section, which is produced or imported by the obligated party in calendar year *i*, in gallons.

D_{i-1} = Renewable fuel deficit carryover from the previous year, per § 80.1127(b), in gallons.

(b) The non-renewable gasoline volume for a refiner, blender, or importer for a given year, GV_i , specified in paragraph (a) of this section is calculated as follows:

$$GV_i = \sum_{x=1}^n G_x - \sum_{y=1}^m RB_y$$

Where:

x = Individual batch of gasoline produced or imported in calendar year *i*.

n = Total number of batches of gasoline produced or imported in calendar year *i*.

G_x = Volume of batch *x* of gasoline produced or imported, in gallons.

y = Individual batch of renewable fuel blended into gasoline in calendar year *i*.

m = Total number of batches of renewable fuel blended into gasoline in calendar year *i*.

RB_y = Volume of batch *y* of renewable fuel blended into gasoline, in gallons.

(c) All of the following products that are produced or imported during a compliance period, collectively called "gasoline" for the purposes of this section (unless otherwise specified), are to be included in the volume used to calculate a party's renewable volume obligation under paragraph (a) of this section, except as provided in paragraph (d) of this section:

(1) Reformulated gasoline, whether or not renewable fuel is later added to it.

(2) Conventional gasoline, whether or not renewable fuel is later added to it.

(3) Reformulated gasoline blendstock that becomes finished reformulated gasoline upon the addition of oxygenate ("RBOB").

(4) Conventional gasoline blendstock that becomes finished conventional gasoline upon the addition of oxygenate ("CBOB").

(5) Blendstock (including butane and gasoline treated as blendstock ("GTAB")) that has been combined with other blendstock and/or finished gasoline to produce gasoline.

(6) Any gasoline, or any unfinished gasoline that becomes finished gasoline upon the addition of oxygenate, that is produced or imported to comply with a state or local fuels program.

(d) The following products are not included in the volume of gasoline produced or imported used to calculate a party's renewable volume obligation under paragraph (a) of this section:

(1) Any renewable fuel as defined in § 80.1101(d).

(2) Blendstock that has not been combined with other blendstock or finished gasoline to produce gasoline.

(3) Gasoline produced or imported for use in Alaska, Hawaii, the Commonwealth of Puerto Rico, the U.S. Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Marianas, unless the area has opted into the RFS program under § 80.1143.

(4) Gasoline produced by a small refinery that has an exemption under § 80.1141 or an approved small refiner

that has an exemption under § 80.1142 until January 1, 2011 (or later, for small refineries, if their exemption is extended pursuant to § 80.1141(e)).

(5) Gasoline exported for use outside the 48 United States, and gasoline exported for use outside Alaska, Hawaii, the Commonwealth of Puerto Rico, the U.S. Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Marianas, if the area has opted into the RFS program under § 80.1143.

(6) For blenders, the volume of finished gasoline, RBOB, or CBOB to which a blender adds blendstocks.

(7) The gasoline portion of transmix produced by a transmix processor, or the transmix blended into gasoline by a transmix blender, under 40 CFR 80.84.

§§ 80.1108 through 80.1114 [Reserved]

■ 6. Sections 80.1108 through 80.1114 are reserved.

■ 7. Section 80.1115 is added to read as follows:

§ 80.1115 How are equivalence values assigned to renewable fuel?

(a)(1) Each gallon of a renewable fuel shall be assigned an equivalence value by the producer or importer pursuant to paragraph (b) or (c) of this section.

(2) The equivalence value is a number that is used to determine how many gallon-RINs can be generated for a batch of renewable fuel according to § 80.1126.

(b) Equivalence values shall be assigned for certain renewable fuels as follows:

(1) Cellulosic biomass ethanol and waste derived ethanol produced on or before December 31, 2012 which is denatured shall have an equivalence value of 2.5.

(2) Ethanol other than cellulosic biomass ethanol or waste-derived ethanol which is denatured shall have an equivalence value of 1.0.

(3) Biodiesel (mono-alkyl ester) shall have an equivalence value of 1.5.

(4) Butanol shall have an equivalence value of 1.3.

(5) Non-ester renewable diesel, including that produced from coprocessing a renewable crude with fossil fuels in a hydrotreater, shall have an equivalence value of 1.7.

(6) All other renewable crude-based renewable fuels shall have an equivalence value of 1.0.

(c)(1) For renewable fuels not listed in paragraph (b) of this section, a producer or importer shall submit an application to the Agency for an equivalence value following the provisions of paragraph (d) of this section.

(2) A producer or importer may also submit an application for an alternative

equivalence value pursuant to paragraph (d) of this section if the renewable fuel is listed in paragraph (b) of this section, but the producer or importer has reason to believe that a different equivalence value than that listed in paragraph (b) of this section is warranted.

(d) *Determination of equivalence values.* (1) Except as provided in paragraph (d)(4) of this section, the equivalence value for renewable fuels described in paragraph (c) of this section shall be calculated using the following formula:

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

Where:

EV = Equivalence Value for the renewable fuel, rounded to the nearest tenth.

R = Renewable content of the renewable fuel.

This is a measure of the portion of a renewable fuel that came from a renewable source, expressed as a percent, on an energy basis.

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

(2) The application for an equivalence value shall include a technical justification that includes a description of the renewable fuel, feedstock(s) used to make it, and the production process.

(3) The Agency will review the technical justification and assign an appropriate Equivalence Value to the renewable fuel based on the procedure in this paragraph (d).

(4) For biogas, the Equivalence Value is 1.0, and 77,550 Btu of biogas is equivalent to 1 gallon of renewable fuel.

§§ 80.1116 through 80.1124 [Reserved]

■ 8. Sections 80.1116 through 80.1124 are reserved.

■ 9. Sections 80.1125 through 80.1132 are added to read as follows:

Subpart K—Renewable Fuel Standard

*	*	*	*	*
Sec.				
80.1125	Renewable Identification Numbers (RINs).			
80.1126	How are RINs generated and assigned to batches of renewable fuel by renewable fuel producers or importers?			
80.1127	How are RINs used to demonstrate compliance?			
80.1128	General requirements for RIN distribution.			
80.1129	Requirements for separating RINs from volumes of renewable fuel.			
80.1130	Requirements for exporters of renewable fuels.			
80.1131	Treatment of invalid RINs.			
80.1132	Reported spillage of renewable fuel.			
*	*	*	*	*

§ 80.1125 Renewable Identification Numbers (RINs).

Each RIN is a 38 character numeric code of the following form:

KYYYYCCCCFFFFFBBBBBRRDSSSSSSSEEEEEEEEE

(a) K is a number identifying the type of RIN as follows:

(1) K has the value of 1 when the RIN is assigned to a volume of renewable fuel pursuant to §§ 80.1126(e) and 80.1128(a).

(2) K has the value of 2 when the RIN has been separated from a volume of renewable fuel pursuant to § 80.1126(e)(4) or § 80.1129.

(b) YYYY is the calendar year in which the batch of renewable fuel was produced or imported. YYYY also represents the year in which the RIN was originally generated.

(c) CCCC is the registration number assigned according to § 80.1150 to the producer or importer of the batch of renewable fuel.

(d) FFFFF is the registration number assigned according to § 80.1150 to the facility at which the batch of renewable fuel was produced or imported.

(e) BBBBB is a serial number assigned to the batch which is chosen by the producer or importer of the batch such that no two batches have the same value in a given calendar year.

(f) RR is a number representing the equivalence value of the renewable fuel as specified in § 80.1115 and multiplied by 10 to produce the value for RR.

(g) D is a number identifying the type of renewable fuel, as follows:

(1) D has the value of 1 if the renewable fuel can be categorized as cellulosic biomass ethanol as defined in § 80.1101(a).

(2) D has the value of 2 if the renewable fuel cannot be categorized as cellulosic biomass ethanol as defined in § 80.1101(a).

(h) SSSSSSS is a number representing the first gallon-RIN associated with a batch of renewable fuel.

(i) EEEEEEE is a number representing the last gallon-RIN associated with a batch of renewable fuel. EEEEEEE will be identical to SSSSSSS if the batch-RIN represents a single gallon-RIN. Assign the value of EEEEEEE as described in § 80.1126.

§ 80.1126 How are RINs generated and assigned to batches of renewable fuel by renewable fuel producers or importers?

(a) *Regional applicability.* (1) Except as provided in paragraph (b) of this section, a RIN must be assigned by a renewable fuel producer or importer to every batch of renewable fuel produced by a facility located in the contiguous 48 states of the United States, or imported into the contiguous 48 states.

(2) If the Administrator approves a petition of Alaska, Hawaii, or a United

States territory to opt-in to the renewable fuel program under the provisions in § 80.1143, then the requirements of paragraph (a)(1) of this section shall also apply to renewable fuel produced or imported into that state or territory beginning in the next calendar year.

(b) *Volume threshold.* Renewable fuel producers located within the United States that produce less than 10,000 gallons of renewable fuel each year, and importers that import less than 10,000 gallons of renewable fuel each year, are not required to generate and assign RINs to batches of renewable fuel. Such producers and importers are also exempt from the registration, reporting, and recordkeeping requirements of §§ 80.1150–80.1152. However, for such producers and importers that voluntarily generate and assign RINs, all the requirements of this subpart apply.

(c) *Definition of batch.* For the purposes of this section and § 80.1125, a “batch of renewable fuel” is a volume of renewable fuel that has been assigned a unique RIN code BBBB within a calendar year by the producer or importer of the renewable fuel in accordance with the provisions of this section and § 80.1125.

(1) The number of gallon-RINs generated for a batch of renewable fuel may not exceed 99,999,999.

(2) A batch of renewable fuel cannot represent renewable fuel produced or imported in excess of one calendar month.

(d) *Generation of RINs.* (1) Except as provided in paragraph (b) of this section, the producer or importer of a batch of renewable fuel must generate RINs for that batch, including any renewable fuel contained in imported gasoline.

(2) A producer or importer of renewable fuel may generate RINs for volumes of renewable fuel that it owns on September 1, 2007.

(3) A party generating a RIN shall specify the appropriate numerical values for each component of the RIN in accordance with the provisions of § 80.1125 and this paragraph (d).

(4) Except as provided in paragraph (d)(6) of this section, the number of gallon-RINs that shall be generated for a given batch of renewable fuel shall be equal to a volume calculated according to the following formula:

$$V_{RIN} = EV * V_s$$

Where:

V_{RIN} = RIN volume, in gallons, for use determining the number of gallon-RINs that shall be generated.

EV = Equivalence value for the renewable fuel per § 80.1115.

V_s = Standardized volume of the batch of renewable fuel at 60 °F, in gallons, calculated in accordance with paragraph (d)(7) of this section.

(5) Multiple gallon-RINs generated to represent a given volume of renewable fuel can be represented by a single batch-RIN through the appropriate designation of the RIN volume codes SSSSSSS and EEEEEEE.

(i) The value of SSSSSSS in the batch-RIN shall be 00000001 to represent the first gallon-RIN associated with the volume of renewable fuel.

(ii) The value of EEEEEEE in the batch-RIN shall represent the last gallon-RIN associated with the volume of renewable fuel, based on the RIN volume determined pursuant to paragraph (d)(4) of this section.

(6) (i) For renewable crude-based renewable fuels produced in a facility or unit that coprocesses renewable crudes and fossil fuels, the number of gallon-RINs that shall be generated for a given batch of renewable fuel shall be equal to the gallons of renewable crude used rather than the gallons of renewable fuel produced.

(ii) Parties that produce renewable crude-based renewable fuels in a facility or unit that coprocesses renewable crudes and fossil fuels may submit a petition to the Agency requesting the use of volumes of renewable fuel produced as the basis for the number of gallon-RINs, pursuant to paragraph (d)(4) of this section.

(7) *Standardization of volumes.* In determining the standardized volume of a batch of renewable fuel for purposes of generating RINs under this paragraph (d), the batch volumes shall be adjusted to a standard temperature of 60 °F.

(i) For ethanol, the following formula shall be used:

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

Where:

$V_{s,e}$ = Standardized volume of ethanol at 60 °F, in gallons.

$V_{a,e}$ = Actual volume of ethanol, in gallons.

T = Actual temperature of the batch, in °F.

(ii) For biodiesel (mono alkyl esters), the following formula shall be used:

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

Where:

$V_{s,b}$ = Standardized volume of biodiesel at 60 °F, in gallons.

$V_{a,b}$ = Actual volume of biodiesel, in gallons.

T = Actual temperature of the batch, in °F.

(iii) For other renewable fuels, an appropriate formula commonly accepted by the industry shall be used to standardize the actual volume to 60 °F. Formulas used must be reported to the Agency, and may be reviewed for appropriateness.

(8) (i) A party is prohibited from generating RINs for a volume of renewable fuel that it produces if:

(A) The renewable fuel has been produced from a chemical conversion process that uses another renewable fuel as a feedstock; and

(B) The renewable fuel used as a feedstock was produced by another party.

(ii) Any RINs that the party acquired with renewable fuel used as a feedstock shall be assigned to the new renewable fuel that was made with that feedstock.

(e) *Assignment of RINs to batches.* (1) Except as provided in paragraph (e)(4) of this section, the producer or importer of renewable fuel must assign all RINs generated to volumes of renewable fuel.

(2) A RIN is assigned to a volume of renewable fuel when ownership of the RIN is transferred along with the transfer of ownership of the volume of renewable fuel, pursuant to § 80.1128(a).

(3) All assigned RINs shall have a K code value of 1.

(4) *RINs not assigned to batches.* (i) If a party produces or imports a batch of cellulosic biomass ethanol or waste-derived ethanol having an equivalence value of 2.5, that party must assign at least one gallon-RIN to each gallon of cellulosic biomass ethanol or waste-derived ethanol, representing the first 1.0 portion of the Equivalence Value.

(ii) Any remaining gallon-RINs generated for the cellulosic biomass ethanol or waste-derived ethanol which represent the remaining 1.5 portion of the Equivalence Value may remain unassigned.

(iii) The producer or importer of cellulosic biomass ethanol or waste-derived ethanol shall designate the K code as 2 for all unassigned RINs.

§ 80.1127 How are RINs used to demonstrate compliance?

(a) *Renewable volume obligations.* (1) Except as specified in paragraph (b) of this section, each party that is obligated to meet the Renewable Volume Obligation under § 80.1107, or each party that is an exporter of renewable fuels that is obligated to meet a Renewable Volume Obligation under § 80.1130, must demonstrate pursuant to § 80.1152(a)(1) that it has taken ownership of sufficient RINs to satisfy the following equation:

$$(\sum RINNUM)_i + (\sum RINNUM)_{i-1} = RVO_i$$

Where:

$(\sum RINNUM)_i$ = Sum of all owned gallon-RINs that were generated in year i and are being applied towards the RVO_i , in gallons.

$(\sum RINNUM)_{i-1}$ = Sum of all owned gallon-RINs that were generated in year i – 1 and are being applied towards the RVO_i , in gallons.

RVO_i = The Renewable Volume Obligation for the obligated party or renewable fuel exporter for calendar year *i*, in gallons, pursuant to § 80.1107 or § 80.1130.

(2) For compliance for calendar years 2008 and later, the value of $(\Sigma \text{RINNUM})_{i-1}$ may not exceed a value determined by the following inequality: $(\Sigma \text{RINNUM})_{i-1} \leq 0.20 \times \text{RVO}_i$

(3) RINs may only be used to demonstrate compliance with the RVO for the calendar year in which they were generated or the following calendar year. RINs used to demonstrate compliance in one year cannot be used to demonstrate compliance in any other year.

(4) A party may only use a RIN for purposes of meeting the requirements of paragraphs (a)(1) and (a)(2) of this section if that RIN is an unassigned RIN with a K code of 2 obtained in accordance with §§ 80.1126(e)(4), 80.1128, and 80.1129.

(5) The number of gallon-RINs associated with a given batch-RIN that can be used for compliance with the RVO shall be calculated from the following formula:

$\text{RINNUM} = \text{EEEEEEEEE} - \text{SSSSSSSS} + 1$
Where:

RINNUM = Number of gallon-RINs associated with a batch-RIN, where each gallon-RIN represents one gallon of renewable fuel for compliance purposes.

EEEEEEEEE = Batch-RIN component identifying the last gallon-RIN associated with the batch-RIN.

SSSSSSSS = Batch-RIN component identifying the first gallon-RIN associated with the batch-RIN.

(b) *Deficit carryovers.* (1) An obligated party or an exporter of renewable fuel that fails to meet the requirements of paragraphs (a)(1) or (a)(2) of this section for calendar year *i* is permitted to carry a deficit into year *i+1* under the following conditions:

(i) The party did not carry a deficit into calendar year *i* from calendar year *i-1*.

(ii) The party subsequently meets the requirements of paragraph (a)(1) of this section for calendar year *i+1* and carries no deficit into year *i+2*.

(2) A deficit is calculated according to the following formula:

$D_i \text{ RVO}_{i-1} (\Sigma \text{RINNUM})_{i+1}$
 $(\Sigma \text{RINNUM})_{i-1}$

Where:

D_i = The deficit, in gallons, generated in calendar year *i* that must be carried over to year *i+1* if allowed to do so pursuant to paragraph (b)(1)(i) of this section.

RVO_i = The Renewable Volume Obligation for the obligated party or renewable fuel exporter for calendar year *i*, in gallons.

$(\Sigma \text{RINNUM})_{i-1}$ = Sum of all acquired gallon-RINs that were generated in year *i* and

are being applied towards the RVO_i, in gallons.
 $(\Sigma \text{RINNUM})_{i-1}$ = Sum of all acquired gallon-RINs that were generated in year *i-1* and are being applied towards the RVO_i, in gallons.

§ 80.1128 General requirements for RIN distribution.

(a) *RINs assigned to volumes of renewable fuel.* (1) *Assigned RIN*, for the purposes of this subpart, means a RIN assigned to a volume of renewable fuel pursuant to § 80.1126(e) with a K code of 1.

(2) Except as provided in § 80.1126(e)(4) and § 80.1129, no party can separate a RIN that has been assigned to a batch pursuant to § 80.1126(e).

(3) An assigned RIN cannot be transferred to another party without simultaneously transferring a volume of renewable fuel to that same party.

(4) No more than 2.5 assigned gallon-RINs with a K code of 1 can be transferred to another party with every gallon of renewable fuel transferred to that same party.

(5) (i) On each of the dates listed in paragraph (a)(5)(v) of this section in any calendar year, the following equation must be satisfied for assigned RINs and volumes of renewable fuel owned by a party:

$\Sigma(\text{RIN})_D \leq \Sigma(\text{V}_{si} \times \text{EV}_i)_D$

Where:

D = Applicable date.

$\Sigma(\text{RIN})_D$ = Sum of all assigned gallon-RINs with a K code of 1 that are owned on date D.

$(\text{V}_{si})_D$ = Volume *i* of renewable fuel owned on date D, standardized to 60 °F, in gallons.

EV_i = Equivalence value representing volume *i*.

$\Sigma(\text{V}_{si} \times \text{EV}_i)_D$ = Sum of all volumes of renewable fuel owned on date D, multiplied by their respective equivalence values.

(ii) The equivalence value EV_i for use in the equation in paragraph (a)(5)(i) of this section for any volume of ethanol shall be 2.5.

(iii) If the equivalence value for a volume of renewable fuel *i* can be determined pursuant to § 80.1115 based on its composition, then the appropriate equivalence value shall be used for EV_i.

(iv) If the equivalence value for a volume of renewable fuel cannot be determined based on its composition, the value of EV_i shall be 1.0.

(v) The applicable dates are March 31, June 30, September 30, and December 31. For 2007 only, the applicable dates are September 30, and December 31.

(6) *Producers and importers of renewable fuel.* (i) Except as provided in paragraph (a)(6)(ii) of this section, a producer or importer of renewable fuel

must transfer ownership of a number of gallon-RINs with a K code of 1 whenever it transfers ownership of a volume of renewable fuel such that the ratio of gallon-RINs to gallons is equal to the equivalence value for the renewable fuel.

$\Sigma(\text{RIN}) / \text{V}_s = \text{EV}$

Where:

$\Sigma(\text{RIN})$ = Sum of all gallon-RINs with a K code of 1 which are transferred along with volume V_s .

V_s = A volume of renewable fuel transferred, standardized to 60 °F, in gallons.

EV = Equivalence value assigned to the renewable fuel being transferred.

(ii) A producer or importer of renewable fuel can transfer ownership of a volume of renewable fuel without simultaneously transferring ownership of gallon-RINs having a K code of 1 if it can demonstrate one of the following:

(A) It is a small volume producer exempt from the requirement to generate RINs pursuant to § 80.1126(b); or

(B) The producer or importer received an equivalent volume of renewable fuel from another party without accompanying RINs.

(C) The producer or importer has generated RINs for cellulosic biomass ethanol or waste-derived ethanol having an equivalence value of 2.5, and has chosen to specify as unassigned a number of gallon-RINs pursuant to § 80.1126(e)(4).

(7) Any transfer of ownership of assigned RINs must be documented on product transfer documents generated pursuant to § 80.1153.

(i) The RIN must be recorded on the product transfer document used to transfer ownership of the RIN and the volume to another party; or

(ii) The RIN must be recorded on a separate product transfer document transferred to the same party on the same day as the product transfer document used to transfer ownership of the volume of renewable fuel.

(b) *RINs not assigned to volumes of renewable fuel.* (1) *Unassigned RIN*, for the purposes of this subpart, means a RIN with a K code of 2 that has been separated from a volume of renewable fuel pursuant to § 80.1126(e)(4) or § 80.1129.

(2) Any party that has registered pursuant to § 80.1150 can hold title to an unassigned RIN.

(3) Unassigned RINs can be transferred from one party to another any number of times.

(4) An unassigned batch-RIN can be divided by its holder into multiple batch-RINs, each representing a smaller number of gallon-RINs, if all of the following conditions are met:

(i) All RIN components other than SSSSSSSS and EEEEEEEE are identical for the original parent and newly formed daughter RINs.

(ii) The sum of the gallon-RINs associated with the multiple daughter batch-RINs is equal to the gallon-RINs associated with the parent batch-RIN.

§ 80.1129 Requirements for separating RINs from volumes of renewable fuel.

(a)(1) Separation of a RIN from a volume of renewable fuel means termination of the assignment of the RIN to a volume of renewable fuel.

(2) RINs that have been separated from volumes of renewable fuel become unassigned RINs subject to the provisions of § 80.1128(b).

(b) A RIN that is assigned to a volume of renewable fuel is separated from that volume only under one of the following conditions:

(1) Except as provided in paragraph (b)(6) of this section, a party that is an obligated party according to § 80.1106 must separate any RINs that have been assigned to a volume of renewable fuel if they own that volume.

(2) Except as provided in paragraph (b)(5) of this section, any party that owns a volume of renewable fuel must separate any RINs that have been assigned to that volume once the volume is blended with gasoline or diesel to produce a motor vehicle fuel.

(3) Any party that exports a volume of renewable fuel must separate any RINs that have been assigned to the exported volume.

(4) Any renewable fuel producer or importer that produces or imports a volume of renewable fuel shall have the right to separate any RINs that have been assigned to that volume if the producer or importer designates the renewable fuel as motor vehicle fuel and the renewable fuel is used as motor vehicle fuel.

(5) RINs assigned to a volume of biodiesel (mono-alkyl ester) can only be separated from that volume pursuant to paragraph (b)(2) of this section if such biodiesel is blended into diesel fuel at a concentration of 80 volume percent biodiesel (mono-alkyl ester) or less.

(i) This paragraph (b)(5) shall not apply to obligated parties or exporters of renewable fuel.

(ii) This paragraph (b)(5) shall not apply to renewable fuel producers meeting the requirements of paragraph (b)(4) of this section.

(6) For RINs that an obligated party generates, the obligated party can only separate such RINs from volumes of renewable fuel if the number of gallon-RINs separated is less than or equal to its annual RVO.

(7) A producer or importer of cellulosic biomass ethanol or waste-derived ethanol can separate a portion of the RINs that it generates pursuant to § 80.1126(e)(4).

(c) The party responsible for separating a RIN from a volume of renewable fuel shall change the K code in the RIN from a value of 1 to a value of 2 prior to transferring the RIN to any other party.

(d) (1) Upon and after separation from a renewable fuel volume, a RIN shall not appear on documentation that is either:

(i) Used to identify title to the volume of renewable fuel; or

(ii) Transferred with the volume of renewable fuel.

(2) Upon and after separation of a RIN from its associated volume, product transfer documents used to transfer ownership of the volume must continue to meet the requirements of § 80.1153(a)(5)(iii).

(e) Any obligated party that uses a renewable fuel in a boiler or heater must retire any RINs associated with that volume of renewable fuel and report the retired RINs in the applicable reports under § 80.1152.

§ 80.1130 Requirements for exporters of renewable fuels.

(a) Any party that owns any amount of renewable fuel (in its neat form or blended with gasoline or diesel) that is exported from the region described in § 80.1126(a) shall acquire sufficient RINs to offset a Renewable Volume Obligation representing the exported renewable fuel.

(b) *Renewable Volume Obligations.* An exporter of renewable fuel shall determine its Renewable Volume Obligation from the volumes of the renewable fuel exported.

(1) A renewable fuel exporter's total Renewable Volume Obligation shall be calculated according to the following formula:

$$RVO_i = \Sigma(VOL_k * EV_k)_i + D_{i-1}$$

Where:

RVO_i = The Renewable Volume Obligation for the exporter for calendar year i, in gallons of renewable fuel.

k = A discrete volume of renewable fuel.

VOL_k = The standardized volume of discrete volume k of exported renewable fuel, in gallons, calculated in accordance with § 80.1126(d)(7).

EV_k = The equivalence value associated with discrete volume k.

Σ = Sum involving all volumes of renewable fuel exported.

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

(2)(i) If the equivalence value for a volume of renewable fuel can be determined pursuant to § 80.1115 based

on its composition, then the appropriate equivalence value shall be used in the calculation of the exporter's Renewable Volume Obligation.

(ii) If the equivalence value for a volume of renewable fuel cannot be determined, the value of EV_k shall be 1.0.

(c) Each exporter of renewable fuel must demonstrate compliance with its RVO using RINs it has acquired pursuant to § 80.1127.

§ 80.1131 Treatment of invalid RINs.

(a) *Invalid RINs.* An invalid RIN is a RIN that is any of the following:

(1) Is a duplicate of a valid RIN.

(2) Was based on volumes that have not been standardized to 60 °F.

(3) Has expired.

(4) Was based on an incorrect equivalence value.

(5) Is deemed invalid under § 80.1167(g).

(6) Does not represent renewable fuel as it is defined in § 80.1101.

(7) Was otherwise improperly generated.

(b) In the case of RINs that are invalid, the following provisions apply:

(1) Invalid RINs cannot be used to achieve compliance with the Renewable Volume Obligation of an obligated party or exporter, regardless of the party's good faith belief that the RINs were valid at the time they were acquired.

(2) Upon determination by any party that RINs owned are invalid, the party must adjust their records, reports, and compliance calculations as necessary to reflect the deletion of the invalid RINs.

(3) Any valid RINs remaining after deleting invalid RINs must first be applied to correct the transfer of invalid RINs to another party before applying the valid RINs to meet the party's Renewable Volume Obligation at the end of the compliance year.

(4) In the event that the same RIN is transferred to two or more parties, all such RINs will be deemed to be invalid, unless EPA in its sole discretion determines that some portion of these RINs is valid.

§ 80.1132 Reported spillage of renewable fuel.

(a) A reported spillage under paragraph (d) of this section means a spillage of renewable fuel associated with a requirement by a federal, state or local authority to report the spillage.

(b) Except as provided in paragraph (c) of this section, in the event of a reported spillage of any volume of renewable fuel, the owner of the renewable fuel must retire a number of gallon-RINs corresponding to the volume of spilled renewable fuel multiplied by its equivalence value.