Draft Regulatory Impact Analysis: RFS Standards for 2023-2025 and Other Changes

United States Environmental Protection Agency

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

NOTICE

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EPA United States Environmental Protection Agency

EPA-420-D-22-003
November 2022

Table of Contents

Executive Summary

The Renewable Fuel Standard (RFS) program began in 2006 pursuant to the requirements in Clean Air Act (CAA) section 211(o) that were added through the Energy Policy Act of 2005 (EPAct). The statutory requirements for the RFS program were subsequently amended and extended through the Energy Independence and Security Act of 2007 (EISA). In addition to increasing the number of renewable fuel categories from one to four, increasing the volume targets, and extending those volume targets from 2012 to 2022, EISA also expanded the waiver provisions in CAA section 211(o)(7) that authorize EPA to waive the statutory volume targets under certain conditions.

The statute includes annual, nationally applicable volume targets through 2022 for cellulosic biofuel, advanced biofuel, and total renewable fuel, and through 2012 for biomass-based diesel (BBD). For years after those for which the statute specifies volume targets, the statute directs EPA to establish volume requirements based on a review of implementation of the program in prior years and an analysis of a set of specified factors. In order to effectuate those volume requirements, EPA must also translate them into percentage standards that obligated parties then use to determine the compliance obligations that they must meet every year.

In this action we are proposing to establish the applicable volume targets for all four categories of renewable fuel for the years 2023, 2024, and 2025, as well as proposing a supplemental standard for 2023 to address the remand of the 2016 annual rule by the D.C. Circuit Court of Appeals, in *Americans for Clean Energy v. EPA*, 864 F.3d 691 (2017) (hereinafter "*ACE*"). We are also proposing to establish the annual percentage standards for all four categories that will apply to gasoline and diesel fuel produced or imported by obligated parties in 2023–2025, as well as the percentage standard for the 2023 supplemental standard.

This Draft Regulatory Impact Analysis (DRIA) supports our proposed rulemaking in several ways. First, this DRIA addresses our statutory obligations under CAA section 211(o)(2)(B)(ii) for determining the applicable volume requirements for cellulosic biofuel, BBD, advanced biofuel, and total renewable fuel. Specifically, this section of the statute directs us to establish the applicable volumes based upon a review of the implementation of the program and an analysis of various environmental, economic, and other factors. We provide this analysis here, in conjunction with the analysis in the preamble and several technical memoranda to the docket. Second, this DRIA supports the proposed 2023 supplemental standard in response to the *ACE* remand. Among other things, Chapters 3 and 6 describe the availability of renewable fuel to meet the supplemental standard.

Table ES-1 summarizes certain potential impacts associated with the proposed volumes in this rule, including both quantified and unquantified impacts. The table is not a comprehensive listing of all the potential impacts that EPA considered in this rulemaking. The inclusion of an impact in this table also does not indicate that EPA gave it greater weight than impacts not listed in this table. A full discussion of each impact, including the uncertainties associated with estimating the impact, is contained in the DRIA Chapter identified under the "More Information" column. EPA compiled this table to provide additional information to the public regarding this rulemaking and to comply with Circular A-4.

Table ES-1: Potential Quantified and Unquantified Impacts Associated with the Proposed Volumes in this Rule[a]

Potential impacts associated with the volumes in this rule	Effect	Effect Quantified	Effect Monetized	More Information
Impacts on air quality from biofuel production and use	Increases in CO, NH_3, NO_x, PM_{10}, $PM_{2.5}$, SO_2 and VOC emissions associated with biorefinery production and product transport.	Emission inventory impacts	-	4.1
	Higher ambient concentrations of NO_x, HCHO and SO_2 downwind of production facilities	Emission inventory impacts	-	4.1
	Varying emission impacts from vehicles running on ethanol blends	Emission inventory impacts	-	4.1
	Decrease for THC, CO, and $PM_{2.5}$, but increase slightly for NO_x emissions from pre-2007 diesels running on biodiesel	Emission inventory impacts	-	4.1
Impacts on climate change from biofuel feedstocks production and displacement of petroleum fuels	Reduced GHG Emissions	Illustrative	Illustrative	4.2
Impacts on wetlands, ecosystems, and wildlife habitat from land use change	Increased conversion of pasture, grasslands and other habitats to cropland	Qualitative	-	4.3
	Decreased plant diversity and decreased natural forage for wildlife, particularly for birds and insects	Qualitative	-	4.3
	Increased use of pesticides and reduced access to natural forage leading to reduced insect biodiversity, especially in pollinators	Qualitative	-	4.3
Impacts on soil and water quality from biofuel feedstock production	Increased erosion, fertilizer and pesticide runoff and/or leachate	Qualitative	-	4.4
	Depletion of natural soil organic matter, thereby depleting the soils nutrients	Qualitative	-	4.4
	Chemical contamination from releases and spills	Qualitative		4.4
	Increased erosion from tilling and other land management practices	Qualitative	-	4.4
	Increased chance of a cyanobacterium bloom occuring	Qualitative		4.4
	Increased turbidity and sedimentation in aquatic ecosystems; Nutrient loading in waterways; Increased stress on aquatic organisms	Qualitative	-	4.4
Impacts on water quantity and availability from biofuel and feedstock production	Aquifer depletion	Qualitative	-	4.5
	Use of limited water resources for irrigation instead of meeting human needs	Qualitative	-	4.5
Energy security	Increased energy security	Energy security benefits	$634 million	5
Production and use of renewable fuels	Increased production and use of renewable fuels	Increased production and use of renewable fuels	-	6
Infrastructure	Increased development of infrastructure of deliver and use renewable fuels	Qualitative		7
	No adverse impact on deliverability of materials, goods, and products other than renewable fuel	Qualitative		7
Jobs	Increased employment	Qualitative	-	8.1
Rural economic development	Support for rural economic development associated with biofuel and feedstock production	Qualitative		8.2
Commodity supply and price impacts	Increased supply of certain agricultural commodities	Qualitative		8.3
	Higher corn, soybean, and soybean oil prices	Commodity price increases	-	8.4
	Higher food prices	Food price increases	-	8.5
Costs	Increased societal cost	Fuel cost increases	$29.5 billion	10.4
	Changes to costs to consumers of transportation fuel	Cost changes	-	10.5
	Increased costs to transport goods	Cost increases	-	10.5

[a] This table includes both societal costs and benefits (fuel costs, energy security, GHG emissions) as well as distributional effects or transfers (jobs, rural economic development, etc.).

Overview

Chapter 1: Review of the Implementation of the Program
This chapter reviews the implementation of the RFS program, focusing on renewable fuel production and use in the transportation sector since the RFS program began.

Chapter 2: Baselines
This chapter identifies the appropriate baselines for comparison.

Chapter 3: Volume Scenarios
This chapter identifies the specific biofuel types and associated feedstocks that are projected to be used to meet the proposed volume requirements.

Chapter 4: Environmental Impacts
This chapter discusses the environmental factors EPA analyzed in developing the proposed volume requirements.

Chapter 5. Energy Security Impacts
This chapter reviews the literature on energy security impacts associated with petroleum consumption and imports and summarizes EPA's estimates of the benefits that would result from the proposed volume requirements.

Chapter 6: Rate of Production of Renewable Fuel
This chapter discusses the expected annual rate of future commercial production of renewable fuels, including advanced biofuels in each category (cellulosic biofuel and BBD).

Chapter 7: Infrastructure
This chapter analyzes the impact of renewable fuels on the distribution infrastructure of the U.S.

Chapter 8: Other Factors
This chapter provides greater detail on our evaluation of impacts of renewable fuels on job creation, rural economic development, supply and price of agricultural commodities, and food prices.

Chapter 9: Environmental Justice
This chapter describes potential environmental justice impacts associated with the production and use of renewable fuels.

Chapter 10: Estimated Costs and Fuel Price Impacts
This chapter assess the impact of the use of renewable fuels on the social cost, the cost to consumers of transportation fuel, and on the cost to transport goods.

Chapter 11: Screening Analysis
This chapter discusses EPA's screening analysis evaluating the potential impacts of the proposed RFS standards on small entities.

Note: Unless otherwise stated, all documents cited in this document are available in the docket for this action (EPA-HQ-OAR-2021-0427). We have generally not included in the docket Federal Register notices, court cases, statutes, or regulations. These materials are easily accessible to the public via the Internet and other means.

List of Acronyms and Abbreviations

Numerous acronyms and abbreviations are included in this document. While this may not be an exhaustive list, to ease the reading of this document and for reference purposes, the following acronyms and abbreviations are defined here:

AAA	American Automobile Association
ACE	*Americans for Clean Energy v. EPA*, 864 F.3d 691 (2017)
AEO	Annual Energy Outlook
ASTM	American Society for Testing and Materials
BBD	Biomass-Based Diesel
bbl	Barrel
BOB	Gasoline Before Oxygenate Blending
bpd	Barrels Per Day
CAA	Clean Air Act
CAFE	Corporate Average Fuel Economy
CBI	Confidential Business Information
CBOB	Conventional Gasoline Before Oxygenate Blending
CG	Conventional Gasoline
CI	Carbon Intensity
CNG	Compressed Natural Gas
CO	Carbon Monoxide
CWC	Cellulosic Waiver Credit
DCO	Distillers Corn Oil
DDGS	Dried Distillers Grains with Solubles
DGS	Distillers Grains with Solubles
DOE	U.S. Department of Energy
DRIA	Draft Regulatory Impact Analysis
EIA	U.S. Energy Information Administration
EISA	Energy Independence and Security Act of 2007
EJ	Environmental Justice
EMTS	EPA-Moderated Transaction System
EO	Executive Order
EPA	U.S. Environmental Protection Agency
EPAct	Energy Policy Act of 2005
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
FFV	Flex-Fuel Vehicle
FOG	Fats, Oils, and Greases
gal	Gallon
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model
LCA	Lifecycle Analysis
IEA	International Energy Agency
IEO	International Energy Outlook

IPCC	Intergovernmental Panel on Climate Change
LCFS	Low Carbon Fuel Standard
LNG	Liquified Natural Gas
MMBD	Million Barrels per Day
MSW	Municipal Solid Waste
MTBE	Methyl Tertiary Butyl Ether
MY	Model Year
NAICS	North American Industry Classification System
NASS	National Agricultural Statistics Service
NEMS	National Energy Modeling System
NGLs	Natural Gas Liquids
NHTSA	National Highway Transportation Administration
NOx	Nitrogen Oxides
NREL	National Renewable Energy Laboratory
OPEC	Organization of Petroleum Exporting Countries
OPIS	Oil Price Information Service
ORNL	Oak Ridge National Laboratory
PADD	Petroleum Administration for Defense District
PHEV	Plug-in Hybrid Electric Vehicle
PM	Particulate Matter
PTD	Product Transfer Document
RBOB	Reformulated Gasoline Before Oxygenate Blending
RFA	Regulatory Flexibility Act
RFF	Resources for the Future
RFG	Reformulated Gasoline
RFRA	Renewable Fuels Reinvestment Act
RFS	Renewable Fuel Standard
RIA	Regulatory Impact Analysis
RIN	Renewable Identification Number
RNG	Renewable Natural Gas
RVO	Renewable Volume Obligation
RVP	Reid Vapor Pressure
SBA	Small Business Administration
SBREFA	Small Business Regulatory Enforcement Fairness Act of 1996
SES	Socioeconomic Status
SOx	Sulfur Oxides
SPR	Strategic Petroleum Reserve
SRE	Small Refinery Exemption
STEO	Short Term Energy Outlook
UCO	Used Cooking Oil
ULSD	Ultra-Low-Sulfur Diesel
USDA	U.S. Department of Agriculture
USGCRP	U.S. Global Change Research Program
VEETC	Volumetric Ethanol Excise Tax Credit
VOC	Volatile Organic Compounds
WTI	West Texas Intermediate

Chapter 1: Review of the Implementation of the Program

The statute directs EPA to establish volumes based on several factors, including "a review of the implementation of the program during calendar years specified in the tables …." This chapter reviews the implementation of the RFS program in previous years, focusing on renewable fuel production and use in the transportation sector since the beginning of the RFS program. Of particular interest is a comparison of what the expectations were when the RFS program was initially designed and implemented to what actually occurred, and an investigation into the reasons that the renewable fuels market developed as it did. To this end, the focus of this chapter is on factors related to the production and use of renewable fuels:

- Feedstock availability, production, and collection
- Renewable fuel production technology and capacity
- Distribution, storage, blending, and dispensing of renewable fuels
- The consumption of renewable fuels in vehicles and engines

1.1 Progression of the Fuels Market

At the time that the RFS program was initially created by EPAct, the transportation fuels market was already undergoing changes. Multiple state bans on the use of methyl tertiary butyl ether (MTBE) in gasoline—due to concerns about leaking underground storage tanks and groundwater contamination—had caused refiners to look for replacement sources of high octane gasoline blendstocks. Crude oil prices had also begun to rise over the lower levels seen in the previous decade, improving the relative economic value of alternative fuels. Both of these factors provided an incentive for the increased use of ethanol in gasoline even before the RFS program went into effect.

Congressional activity related to MTBE also had an impact on ethanol use in the years leading up to EPAct. For instance, Congress had considered providing liability protection to refiners using MTBE under the premise that they had no choice but to use an oxygenate in the reformulated gasoline (RFG) and oxyfuels programs.[1] Congressional consideration of some sort of liability protection for refiners, as well as the lack of sufficient infrastructure between 2000–2005 for distributing and blending ethanol, likely contributed to the continued use of MTBE despite state bans and concerns expressed by EPA and the public about MTBE in the years prior to and including 2005.[2]

Ultimately, however, Congress rejected any form of liability protection for MTBE in EPAct. While EPAct did not include a nationwide ban on the use of MTBE, it did remove the RFG oxygen mandate, eliminating any argument that MTBE use was necessary to comply with the statute. In combination with the removal of the RFG oxygen mandate, the creation of the RFS program, and the increased economic value of ethanol in light of increasing crude oil prices, refiners now had increased disincentives to continue using MTBE after 2005. In addition, although the oxygen requirement for RFG was removed in EPAct, the emission standards for

[1] "Timeline - A Very Short History of MTBE in the US."
[2] "Clinton-Gore Administration Acts To Eliminate MTBE, Boost Ethanol."

RFG were neither eliminated nor modified.[3] Without MTBE, something was quickly needed to replace the lost volume and octane that had been provided by MTBE while also ensuring that the RFG emission standards would continue to be met. The net result of these factors is that the market made a dramatic shift away from MTBE to ethanol in a very short period of time. By the end of 2006, MTBE use in gasoline had fallen by about 80% in comparison to 2005 levels and by 2007 was essentially zero, while ethanol replaced MTBE on an almost one-for-one energy-equivalent basis over those same two years, growing by 56%.[4] The sudden demand for ethanol use in RFG areas, representing about one-third of all gasoline, was so great that its use was temporarily reduced in much of the rest of the country (conventional gasoline (CG) areas) where ethanol was not needed to meet state fuel program requirements until additional ethanol supply could be brought online. This occurred despite the fact that E10 in CG areas benefitted from a 1 psi Reid Vapor Pressure (RVP) waiver, while RFG's emission standards precluded that waiver.

After the RFS program first went into effect in 2006, other factors continued to affect the biofuels market. Crude oil prices continued to rise, state mandates for ethanol and biodiesel use expanded, California's Low Carbon Fuel Standard (LCFS) program was implemented, and foreign demand for biofuels increased. At the same time, the federal ethanol tax subsidy expired at the end of 2011,[5] and the federal oxygenated fuels (oxyfuels) program was largely phased out as areas came into attainment with ambient wintertime carbon monoxide (CO) standards. Furthermore, the statutory requirements were amended by the Energy Independence and Security Act of 2007 (EISA), replacing the single total renewable fuel standard under the RFS1 program with four nested standards (cellulosic biofuel, BBD, advanced biofuel, and total renewable fuel). EPA implemented these changes through the RFS2 program, which began in the midst of these other changes, first with a single but considerably higher total renewable fuel standard in 2009 compared to previous years, and then with the addition of separate standards for cellulosic biofuel, BBD, and advanced biofuel beginning in 2010. In the following years, cellulosic ethanol production struggled to develop despite Congressional aspirations, and increases in ethanol use slowed as the nationwide average ethanol concentration approached 10%.[6] BBD volume, in contrast, expanded beyond the Congressional targets, outcompeting other advanced biofuels with the help of an ongoing tax incentive, and EPA reflected this by setting higher BBD volume requirements for years after 2012.

The history of the progression of the fuels market indicates that consumption of renewable fuels has been a function of many factors, of which the RFS program was only one. Many of these factors can be expected to contribute to renewable fuel production and consumption in the future. These factors include other federal and state fuels programs and incentives, the octane value of ethanol, and foreign demand for renewable fuel.

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[3] See 40 CFR 80.41(e) and (f).

[4] Based on EPA batch data, available at https://www.epa.gov/fuels-registration-reporting-and-compliance-help/gasoline-properties-over-time (excludes California).

[5] The Volumetric Ethanol Excise Tax Credit (VEETC) was instituted through the American Jobs Creation Act of 2004 and the deadline was extended to December 31, 2011, through the Renewable Fuels Reinvestment Act (RFRA).

[6] Here and elsewhere in this DRIA, "ethanol concentration" refers to the concentration of denatured ethanol in gasoline.

1.2 In-Use Consumption of Renewable Fuels

There are several reasons why actual renewable use may differ from the renewable fuel volume targets specified in the statute or even the volumes required through the RFS regulations. First, the statutory provisions of the RFS program provide EPA with several waiver authorities to reduce the statutory volumes under particular circumstances.[7] The statutory volumes minus waived volumes equal applicable volumes. In turn, the applicable percentage standards, which are the mechanism through which the obligations of an individual “obligated party” are determined under the RFS program, are based on the applicable volumes.[8]

The “general waiver” authority at CAA section 211(o)(7)(A) was enacted by EPAct and maintained in EISA. It permits EPA to reduce any of the four applicable volume targets in the statute if EPA makes one of the following findings:

> (i) based on a determination by the Administrator, after public notice and opportunity for comment, that implementation of the requirement would severely harm the economy or environment of a State, a region, or the United States; or
>
> (ii) based on a determination by the Administrator, after public notice and opportunity for comment, that there is an inadequate domestic supply.

The “cellulosic waiver” authority at CAA section 211(o)(7)(D) was introduced by EISA. It requires (not merely permits) EPA to reduce the statutory cellulosic volume target to the projected volume available in years that the projected volume of cellulosic biofuel production is less than the statutory target. When making such a reduction, EPA may also reduce the statutory volume targets for total renewable fuel and advanced biofuels by the same or a lesser volume.

The “biomass-based diesel waiver” authority at CAA section 211(o)(7)(E) was also introduced by EISA. It requires a reduction from the statutory BBD volume for up to 60 days if EPA determines that there is a significant renewable feedstock disruption or other market circumstances that would make the price of BBD increase significantly. When making such a reduction in BBD volume, EPA may also reduce the statutory volume targets for total renewable fuel and advanced biofuels by the same or a lesser volume, similar to the cellulosic waiver authority.

The statute only specifies volume targets for BBD for 2009 through 2012, and EPA did not reduce the statutory target for any of those years under either the general or BBD waiver authorities. Under the cellulosic waiver authority, however, EPA has reduced the statutory target for cellulosic biofuel in every year since 2010 and the statutory targets for advanced biofuel and total renewable fuel in every year since 2014.

EPA has used the general waiver authority on only one occasion, for the 2016 compliance year based on a finding of inadequate domestic supply.[9] However, the D.C. Circuit

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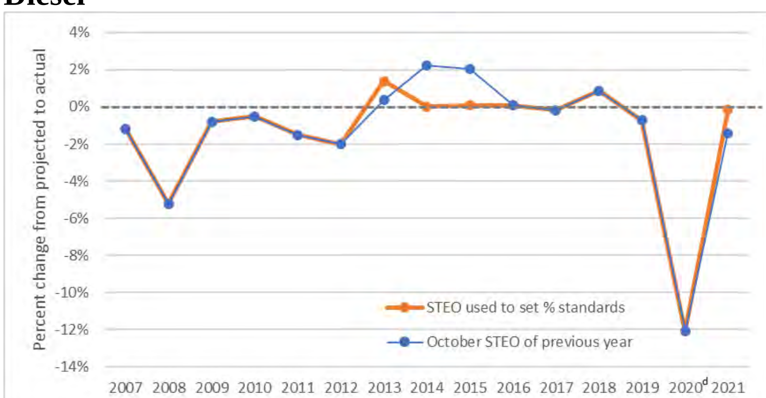
[7] CAA section 211(o)(7).
[8] Obligated parties are producers and importers of gasoline and diesel. See 40 CFR 80.1406.
[9] 80 FR 77420 (December 14, 2015).

vacated EPA's use of this waiver authority in *ACE*. Specifically, the court found that EPA had impermissibly considered demand-side factors in its assessment of inadequate domestic supply, rather than limiting that assessment to supply-side factors. The court remanded the rule back to EPA for further consideration in light of its ruling. EPA took the first step to respond to that remand when it established the applicable volume requirements for 2022,[10] and is proposing to complete its response to that remand in this rulemaking.

In addition to the waiver authorities mentioned above, there are at least five other reasons why actual renewable fuel use may differ from either the statutory or applicable volume requirements. The first is that the percentage standards are based on projected volumes of gasoline and diesel consumption, which typically deviate to some degree from what actually occurs. EPA relies on forecasts provided by the U.S. Energy Information Administration (EIA) in the Short Term Energy Outlook (STEO).[11] In the context of the RFS program, the sum of non-renewable gasoline and diesel demand is relevant. Since the first percentage standard was applied in 2007, this forecast has both over- and under-predicted actual consumption, as shown in Figure 1.2-1.

Figure 1.2-1: Percent Change from Projected to Actual Sum of Non-Renewable Gasoline + Diesel[a,b,c]



[a] From 2007 to 2009, the RFS1 regulatory structure was in effect, and the applicable percentage standards were based on non-renewable gasoline projections only. Therefore, the values for these three years represent non-renewable gasoline.
[b] For purposes of demonstrating the error in forecasts, the blue line uses projected volumes derived from the October edition of the STEO for the following year. The orange line, in contrast, uses forecasted volumes derived from the version of the STEO that was actually used to calculate the percentage standards, which in some years was not the October edition of the preceding year (e.g., the 2014 standards were established in December 2015, well after the 2014 compliance year was over).
[c] See data and calculations in "Calculation of Percent Change from Projected to Actual Gasoline and Diesel," available in the docket for this action.
[d] Represents the 2020 rulemaking that established the original 2020 standards on February 6, 2020 (85 FR 7016). The rulemaking that revised those standards on July 1, 2022 (87 FR 39600) based them on actual consumption of gasoline and diesel in that year. The orange data point for 2020 would thus be at exactly 0%.

In the event that the actual consumption of non-renewable gasoline and diesel is lower than the projection that EPA used to set the applicable percentage standards (i.e., negative values

[10] 87 FR 36900 (July 1, 2022).
[11] CAA section 211(o)(3)(A).

in Figure 1.2-1), the obligations applicable to individual obligated parties are likewise lower and, all other things being equal, the actual volumes of renewable fuel used as transportation fuel will fall short of the volumes EPA used in setting the percentage standards. Likewise, if the actual consumption of non-renewable gasoline and diesel is higher than the projection that EPA used to set the applicable percentage standards (i.e., positive values in Figure 1.2-1), the actual volumes of renewable fuel used as transportation fuel will exceed the volumes EPA used in setting the percentage standards. Despite the fact that the statute directs EPA to set standards that ensure that transportation fuel sold or introduced into commerce contains the applicable volumes of renewable fuel, the statute also directs EPA to use projections of gasoline and diesel for this purpose, and does not mandate that EPA correct the volume requirements based on deviations in those projections from the volumes actually consumed.

Another reason that the volume requirements may not be reached by the market in a particular year is related to the credit system that is used to demonstrate compliance with the RFS program.[12] These credits are called Renewable Identification Numbers, or "RINs." Obligated parties have the flexibility to use RINs representing renewable fuel produced in the previous year, often called "carryover RINs" or "banked RINs," to demonstrate compliance rather than by using RINs representing current year renewable fuel production.[13,14] The nationwide total of banked RINs grew dramatically in the early years of the RFS program, and obligated parties have at times drawn down this bank to help fulfill their obligations. For instance, consumption of renewable fuels fell more than 500 million ethanol-equivalent gallons short of the applicable volume requirement in 2013, and obligated parties used banked RINs to make up the shortfall. Similarly, we estimate that obligated parties used a significant number of banked RINs in 2019 to make up for a shortfall in actual consumption.[15]

The third reason that the applicable volume requirements may vary from actual renewable fuel use is the difficulty in projecting the future market's ability to make available and consume renewable fuels. For instance, in several cases producers of cellulosic biofuel made plans that did not come to fruition, such as Cello Energy, Range Fuels, and KiOR.[16] In the past, there was also considerable uncertainty associated with estimating the ability of the RFS standards to incentivize increases in the consumption of ethanol above the E10 blendwall.[17] Other unforeseen circumstances such as the drought in 2012 that adversely affected crops yields and the impacts of the COVID-19 pandemic in 2020 have also contributed to shortfalls in renewable fuel production in comparison to the intended volume requirements. By contrast, in some other years, the market used more renewable fuel than what EPA projected, typically when the economics of doing so were favorable or as a result of other incentives such as state LCFS programs.

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[12] CAA section 211(o)(5) establishes the provisions for credits under the RFS program. This system is discussed in more detail in Chapter 1.9.
[13] This flexibility is a function of the two-year life of RINs as discussed more fully in Chapter 1.9.
[14] The use of previous year RINs for compliance with the applicable standards is limited to 20% of an obligated party's Renewable Volume Obligation (RVO). See 40 CFR 80.1427(a)(5).
[15] "Carryover RIN Bank Calculations for 2023-2025 Proposed Rule," available in the docket for this action.
[16] 80 FR 77506 (December 14, 2015).
[17] 80 FR 77457 (December 14, 2015).

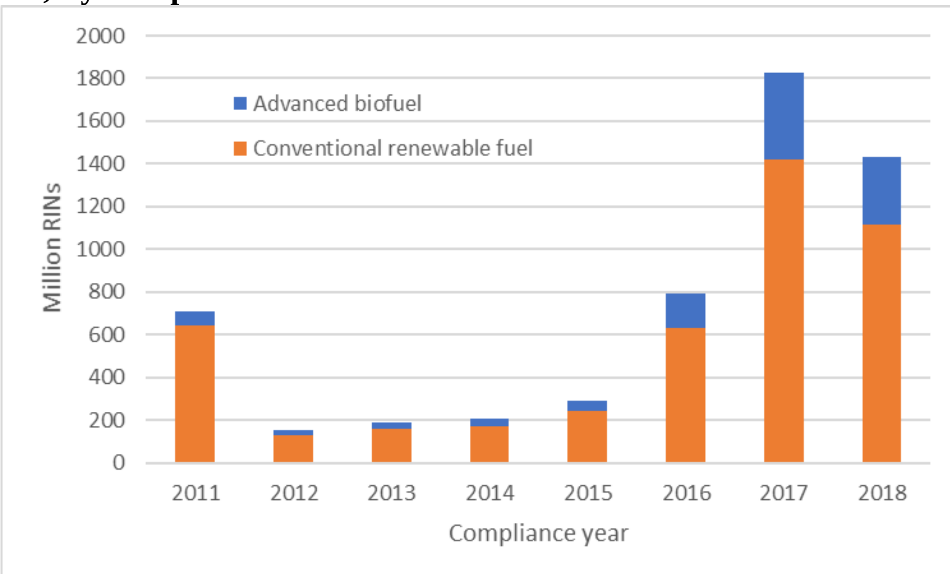
A fourth reason that the applicable volume requirements may vary from actual renewable fuel use is that there are other drivers for renewable fuel use besides the RFS program. For instance, as discussed in Chapter 1.1, in the early years of the RFS program, renewable fuel use significantly outpaced the RFS requirements spurred by the transition from MTBE to ethanol as an oxygenate. We discuss numerous other, non-RFS economic drivers for renewable fuel use throughout this chapter.

Finally, exemptions for small refineries due to disproportionate economic hardship have effectively reduced the required volume of renewable fuel for those years in comparison to the volumes on which the percentage standards were based. These exemptions are permitted under CAA section 211(o)(9)(B) and are evaluated on a refinery-by-refinery basis. In cases where a small refinery exemption (SRE) was granted after the applicable percentage standards were set, the percentage standards remained unchanged but were then applicable to a smaller number of parties, resulting in smaller effective aggregate renewable fuel requirements.

Historically, once the percentage standards were established for a given year, EPA has not adjusted them to account for SREs that were subsequently granted. Rather, from the start of the RFS program through the 2019 annual rule, EPA's standard-setting only accounted for SREs that had been granted at the time of the final annual rule. In essence, this meant that non-exempt obligated parties did not have to make up for volumes that would not be attained by the exempt small refineries.[18] This approach is consistent with that taken for the projected non-renewable gasoline and diesel volumes used to calculate the percentage standards, where errors in projected volumes could likewise result in actual consumption of renewable fuel falling short of the intended volume requirements.

[18] 75 FR 76805 (December 9, 2010).

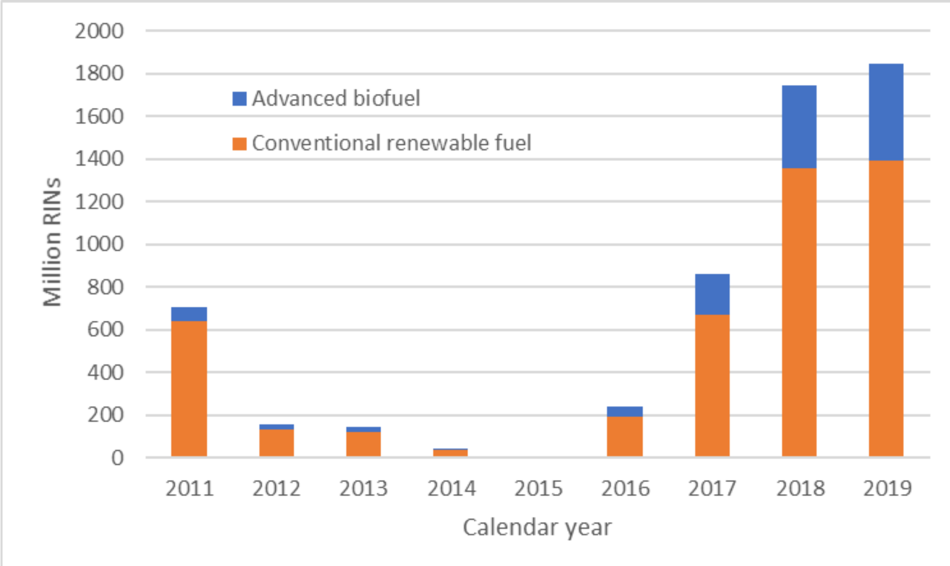
Figure 1.2-2: Volume of SREs Granted After the Applicable Percentage Standards Were Set, By Compliance Year[a]



[a] No SREs have been granted after compliance year 2018. This chart shows the impact of certain SREs previously granted for compliance years 2016, 2017, and 2018 that have since been remanded, reconsidered, and denied.

As shown in Figure 1.2-2, SREs granted after the standards were set varied significantly by compliance year. However, these SREs did not necessarily translate into an equivalent reduction in actual consumption. Other factors also played a role in determining whether and when actual consumption was affected by SREs. For instance, the combination of the economic attractiveness of marketing ethanol to consumers as E10 and the infrastructure to blend, distribute, and dispense E10, along with longer-term contracts for ethanol blending, meant that the nationwide average ethanol concentration remained very near 10.00% ethanol even when large numbers of SREs were granted. With regard to the timing of the impacts, SREs generally affected the demand for RINs in the calendar year in which they were granted and/or the following years, rather than in the compliance year to which they applied, as shown in Figure 1.2-3. This was often due to EPA granting the SREs after the compliance year had passed.

Figure 1.2-3: Volume of SREs Granted After the Applicable Percentage Standards Were Set, By Calendar Year When Exemptions Were Granted[a]



[a] No SREs have been granted after calendar year 2019. This chart shows the impact of certain SREs previously granted for compliance years 2016, 2017, and 2018 in calendar year 2019 that have since been remanded, reconsidered, and denied.

However, it was not always the case that SREs affected the demand for RINs only in the calendar year in which they were granted and/or the following years. For instance, some small refineries adjusted their RIN acquisition efforts to reflect anticipated grants of their SRE petitions, effectively resulting in SREs having a market impact before they were actually granted. In all or almost all cases, a small refinery that was granted an exemption continued to blend renewable fuel into its own gasoline and/or diesel due to the economic attractiveness of doing so. In such cases, the total number of RINs generated may not have been reduced by the SRE, but the carryover RIN bank may have increased. Finally, as discussed above, higher-than-projected gasoline and diesel demand could offset the effect of SREs to some degree.

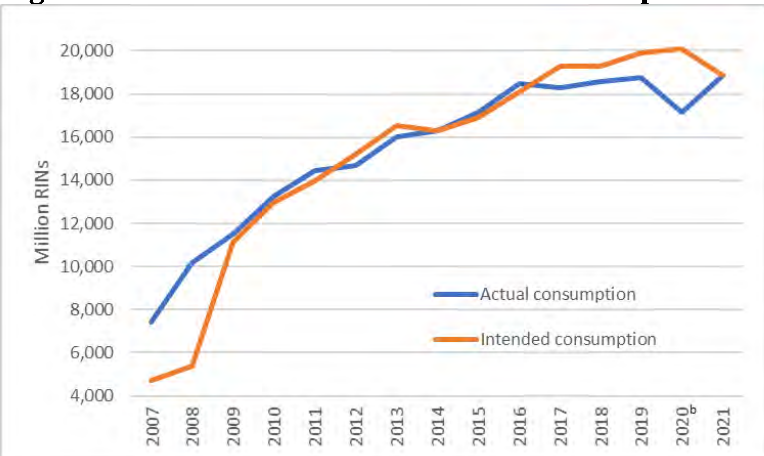
In the final rule that established the original 2020 standards, EPA revised the RFS regulations to account for a projection of exempt small refinery volumes, increasing the 2020 percentage standards applicable to non-exempt refineries.[19] Given that EPA subsequently made a decision not to exempt any volumes of gasoline or diesel for 2020 (i.e., no SREs were granted), the original 2020 percentage standards were applicable to a larger volume of gasoline and diesel, effectively increasing the total requirement for renewable fuel.[20]

In sum, due to the many factors that affect renewable fuel consumption, actual consumption has been both higher and lower than the volumes that EPA originally intended to be achieved in setting the percentage standards.

[19] 85 FR 7016 (February 6, 2020).

[20] We note, however, that on July 1, 2022, EPA revised the 2020 standards to account for the fact that no SREs were granted for 2020, as well as to address impacts of the COVID-19 pandemic. See 87 FR 39600.

Figure 1.2-4: Intended[a] Versus Actual Consumption of Total Renewable Fuel



Source for actual consumption: EPA-Moderated Transaction System (EMTS)

[a] Intended volumes represent the volumes used to calculate the applicable percentage standards. As such, the intended volumes do not account for the effects of SREs granted after the percentage standards were established, errors in projected demand for gasoline and diesel, or the use of carryover RINs for compliance.

[b] The "intended consumption" for 2020 represents the 2020 rulemaking that established the original 2020 standards on February 6, 2020 (85 FR 7016), not the rulemaking that revised those standards on July 1, 2022 (87 FR 39600).

The total volume of renewable fuel that was intended to be used between 2007 and 2021 (i.e., the volume that was used to calculate the applicable percentage standards) was about 229 billion ethanol-equivalent gallons. In comparison, actual consumption was about 231 billion ethanol-equivalent gallons over the same time period. Thus, actual consumption has exceeded what was intended over the life of the RFS program through 2020. In 2007 and 2008, the significant oversupply in comparison to the intended volumes was due primarily to the expansion of E10 when the market as a whole had not yet reached the E10 blendwall and blending ethanol as E10 was economically attractive relative to gasoline. In years after 2016, the significant undersupply in comparison to the intended volumes affected all types of renewable fuel more equitably rather than just ethanol, and was precipitated by a combination of the approval of SREs after the applicable percentage standards had been set, lower than projected gasoline and diesel consumption, and other economic factors.

Economic factors impact conventional renewable fuel and non-cellulosic advanced biofuel differently. These factors include crude oil prices, renewable fuel production costs (which are in turn a function of feedstock, process heat, and power costs), tax subsidies, and the market pressures created by the RFS standards to increase ethanol use above the E10 blendwall. Economic factors are coupled with the use of carryover RINs for compliance, the size of the carryover RIN bank, and deficit carry-forwards. In 2013, for instance, the implied conventional renewable fuel standard was 13.8 billion gallons, which was considerably higher than the E10 blendwall. The market responded by producing less conventional renewable fuel but more non-cellulosic advanced biofuel than required. The net effect of these two outcomes nevertheless still fell short of the applicable volume requirements, and the market thus relied on some carryover RINs for compliance. In 2019, the E10 blendwall was again lower than the implied conventional renewable fuel volume requirement, and the carryover RIN bank was drawn down by 1.6 billion RINs from 3.43 to 1.83 billion RINs.

1.3 2010 Biofuel Projections Versus Reality

In the 2010 rule that established the RFS2 program, EPA projected volumes of each type of renewable fuel that in the aggregate would meet the applicable volume targets in the statute for cellulosic biofuel, BBD, advanced biofuel, and total renewable fuel.[21] These projections did not include any consideration of potential future waivers or any other factor that might cause the statutory volumes not to be met. In reality, actual consumption of renewable fuel typically fell short of the statutory targets for all renewable fuel categories except for BBD. Moreover, the specific types of renewable fuel that were projected in 2010 to be used to fulfill the mandates differed from what was actually used, most notably in regard to the relative amounts of ethanol and non-ethanol renewable fuels.

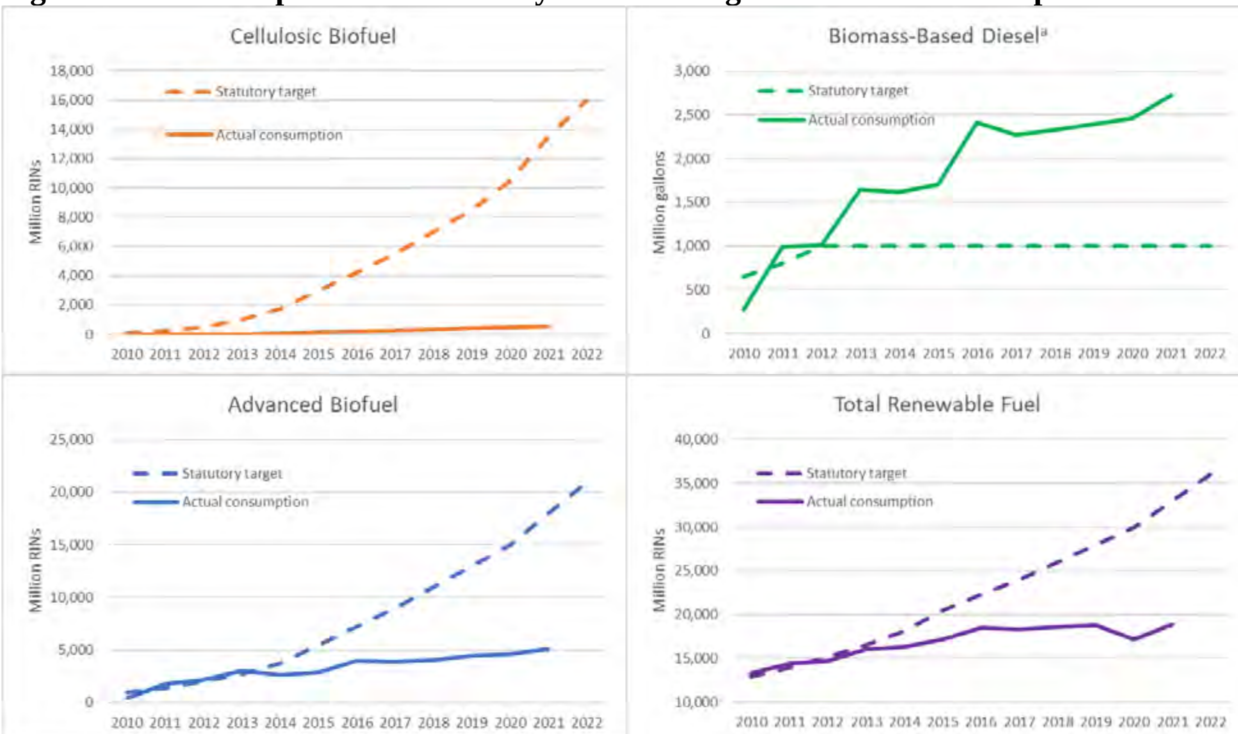
This chapter highlights the aspirational nature of the statutory volume targets, especially for cellulosic biofuel and its carry through impact on advanced biofuel and total renewable fuel. This chapter also highlights the difficulty in projecting the ability of the market to meet applicable standards as well as the specific mix of biofuels that will be produced, imported, and consumed.

1.3.1 Shortfalls in Comparison to Statutory Targets

As explained in Chapter 1.2, there are many reasons why actual use of renewable fuels fell short of the statutory targets. Figure 1.3.1-1 compares the statutory targets to actual consumption for the four categories of renewable fuel.

[21] 75 FR 14670 (March 26, 2010).

Figure 1.3.1-1: Comparison of Statutory Volume Targets to Actual Consumption

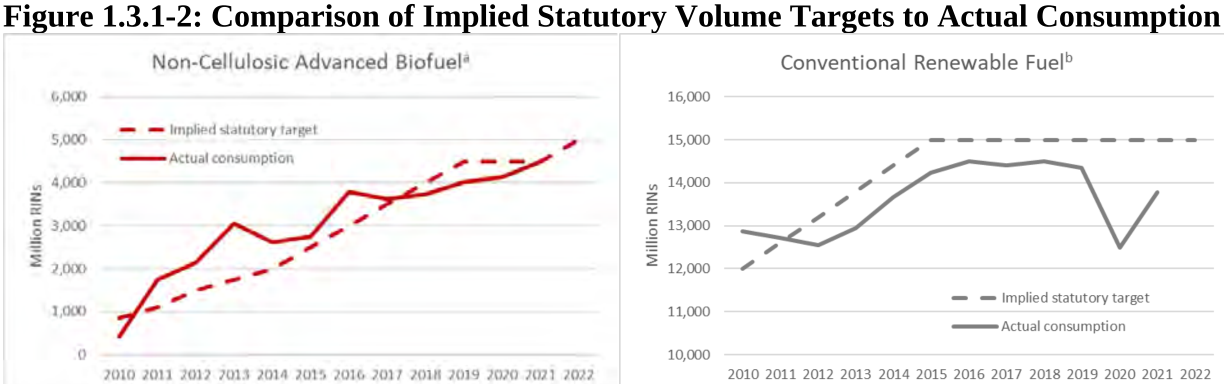


Source for actual consumption: EMTS

[a] The statute specifies BBD volume targets only through 2012. Thereafter, the required BBD volume can be no less than 1.0 billion gallons, but can be more based on an analysis of specified factors.

The significant shortfalls in advanced biofuel and total renewable fuel for more recent years are primarily the result of shortfalls in cellulosic biofuel. This fact is more evident in Figure 1.3.1-2, which shows that consumption is considerably closer to the implied statutory volume targets for non-cellulosic advanced biofuel and conventional renewable fuel.

Figure 1.3.1-2: Comparison of Implied Statutory Volume Targets to Actual Consumption



Source for actual consumption: EMTS

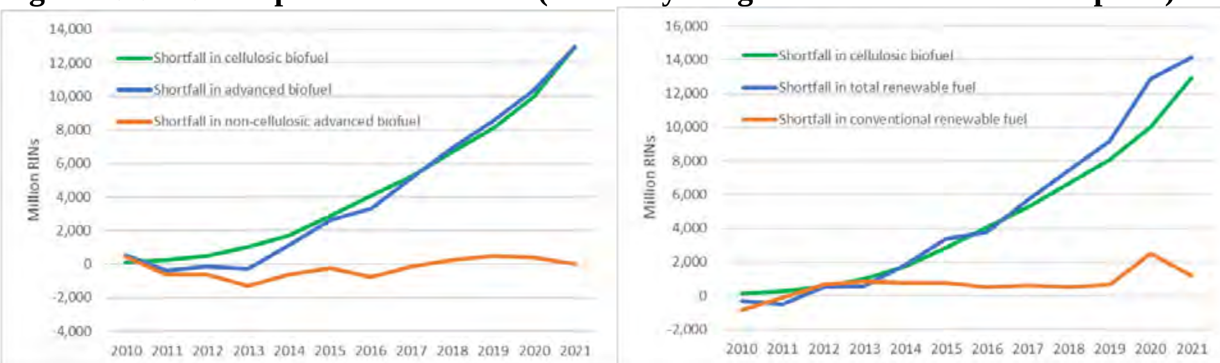
[a] Non-cellulosic advanced biofuel represents D4 and D5 RINs.

[b] Conventional renewable fuel represents D6 RINs.

The oversupply in non-cellulosic advanced biofuel between 2011 and 2017 partially offset some of the shortfall in conventional renewable fuel in the same years, and also contributed to increases in the carryover RIN bank in some years.

A direct comparison of shortfalls in consumption of cellulosic biofuel to shortfalls in the other categories of renewable fuel makes it clear that consumption of advanced biofuel and total renewable fuel was directly affected by the shortfall in cellulosic biofuel, while the consumption of non-cellulosic advanced biofuel and conventional renewable fuel was not. This is to be expected since the cellulosic biofuel category is nested within advanced biofuel and total renewable fuel categories, but cellulosic biofuel is independent of non-cellulosic advanced biofuel and conventional renewable fuel.

Figure 1.3.1-3: Comparative Shortfalls (Statutory Target Minus Actual Consumption)

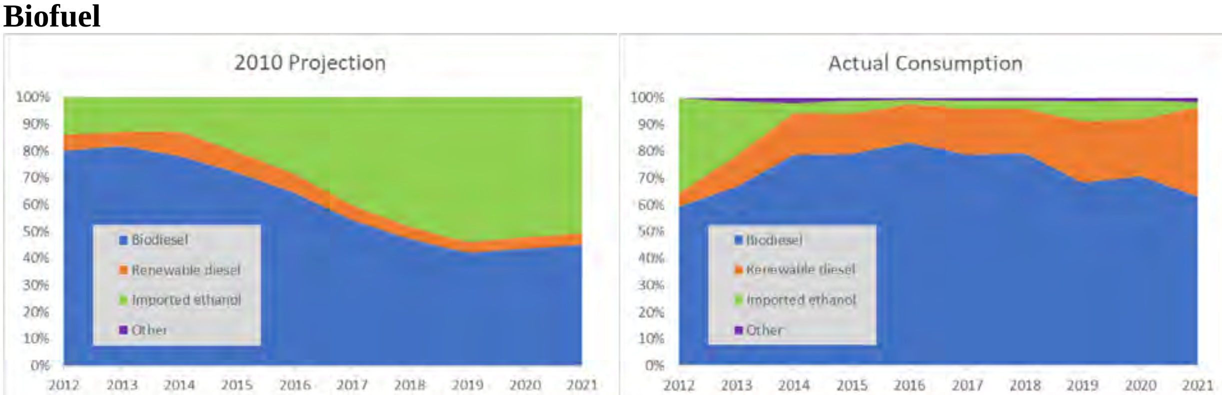


Source for actual consumption: EMTS

1.3.2 Relative Proportions of Ethanol and Non-Ethanol Renewable Fuel

In the RFS2 rule, non-cellulosic advanced biofuel through 2022 was projected to be composed of biodiesel, renewable diesel, and imported sugarcane ethanol. This has proved largely true as volumes of renewable jet fuel, biogas, heating oil, domestic advanced ethanol, and naphtha—the only other eligible advanced biofuels—have represented only a very small fraction of non-cellulosic advanced biofuel consumption. However, the relative proportions of biodiesel, renewable diesel, and imported sugarcane ethanol have been far different in actual consumption than in the projections from the RFS2 rule.

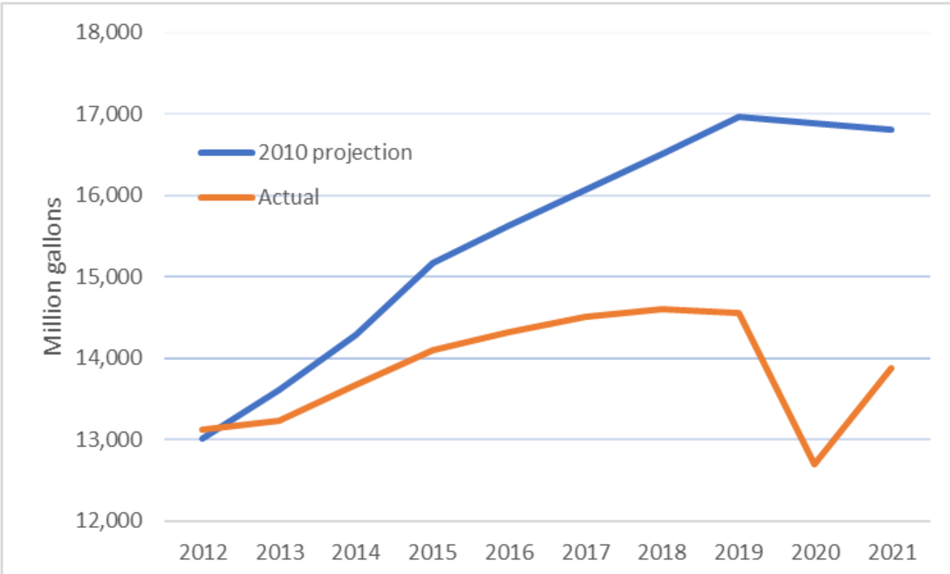
Figure 1.3.2-1: Volumetric Proportions of Each Fuel Type in Non-Cellulosic Advanced Biofuel



Source: “2010 projection” is from Table 1.2-3 of the RIA for the RFS2 rule. “Actual consumption” is from EMTS.

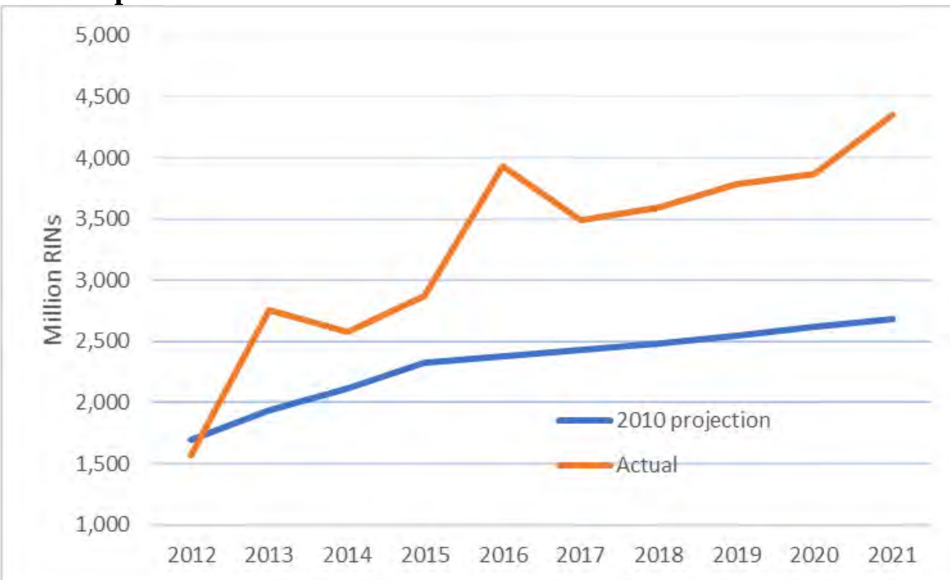
Actual consumption of imported sugarcane ethanol has been considerably lower than in the 2010 projection, and consumption of advanced biodiesel and renewable diesel has been higher. This outcome for imported sugarcane ethanol is mirrored in the outcome for total ethanol: actual consumption of ethanol has been lower than the 2010 projection and actual biodiesel and renewable diesel has been higher.

Figure 1.3.2-2: Actual Versus 2010 Projection of Ethanol Consumption in Non-Cellulosic Renewable Fuel[a]



Source: "2010 projection" is from Table 1.2-3 of the RIA for the RFS2 rule. "Actual consumption" is from EMTS.
[a] The 2010 projection of ethanol shown here represents the "primary control case" from the RFS2 rule. EPA also analyzed a "low ethanol control case" and a "high ethanol control case".

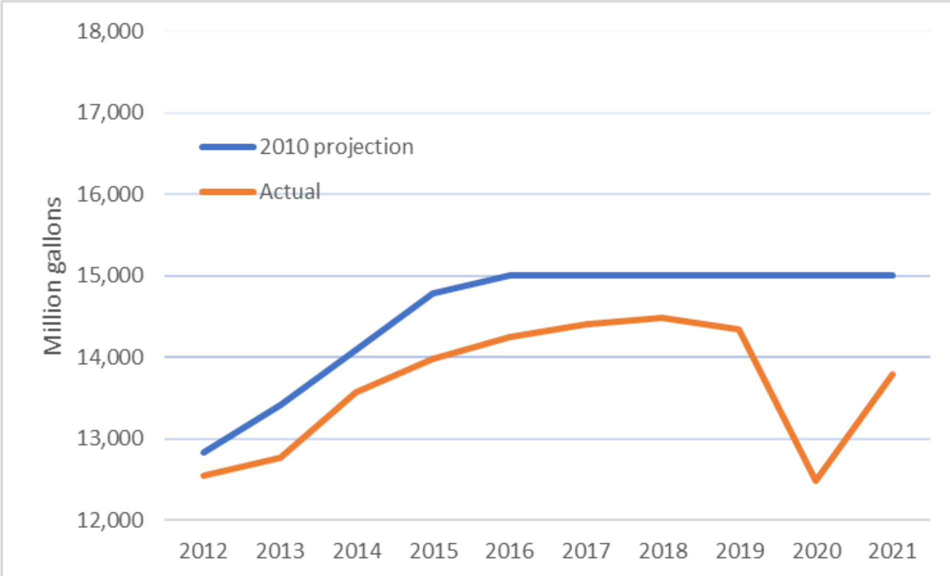
Figure 1.3.2-3: Actual Versus 2010 Projection of Biodiesel + Renewable Diesel Consumption in Non-Cellulosic Renewable Fuel



Source: "2010 projection" is from Table 1.2-3 of the RIA for the RFS2 rule. "Actual consumption" is from EMTS.

This pattern of lower ethanol and higher non-ethanol volumes in comparison to expectations appears to be linked to the E10 blendwall and the difficulty that the market has had in increasing sales of higher-level ethanol blends (e.g., E15 and E85). The 2010 projections included a significant volume of E85 that did not materialize. The result is that, rather than being met entirely with corn ethanol as projected in 2010, the implied conventional renewable fuel volume requirement has included volumes of ethanol up to and just slightly greater than the E10 blendwall, while biodiesel and renewable diesel have made up the difference.

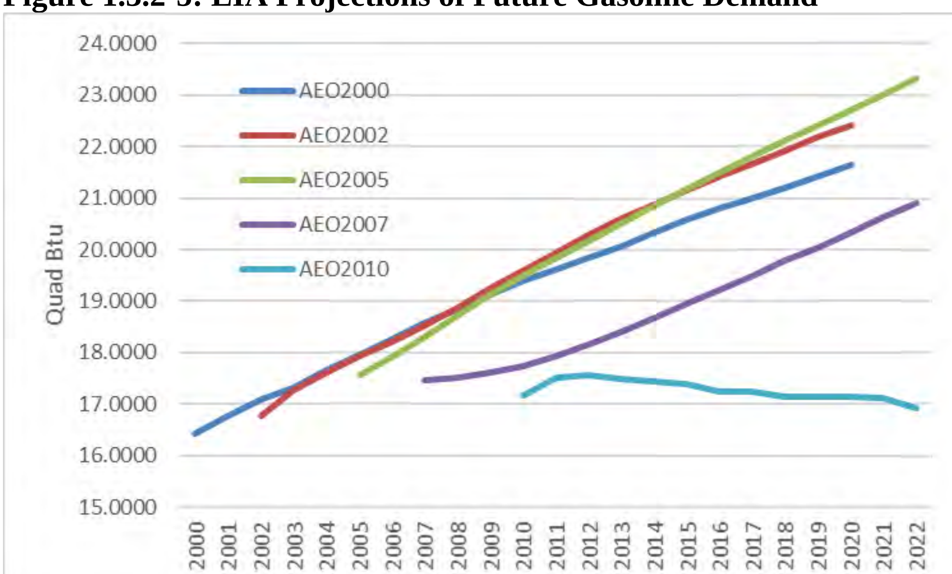
Figure 1.3.2-4: Actual Versus 2010 Projection of Ethanol Consumption in Conventional Renewable Fuel



Source: "2010 projection" is from Table 1.2-3 of the RIA for the RFS2 rule. "Actual consumption" is from EMTS.

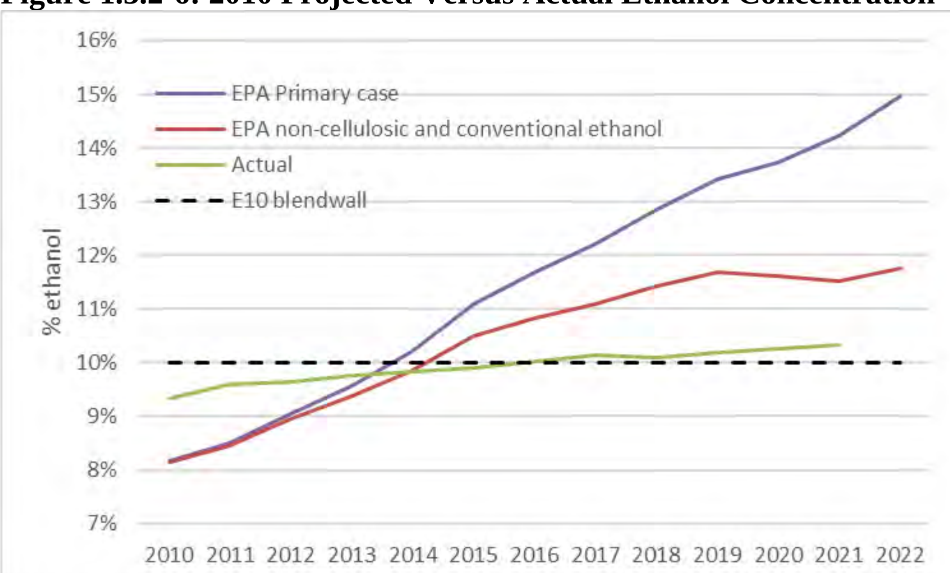
The expectation at the time that EISA was enacted in 2007 was that the implied conventional renewable fuel volume requirement could be met entirely with ethanol as E10 without the nation as a whole exceeding an average ethanol content of 10.00%, and without the need for E15 or E85. This expectation was based on the assumption that gasoline demand would continue to increase in the future, as had been projected by EIA since 2000. By the time RFS2 regulations were finalized in 2010, however, EIA's Annual Energy Outlook (AEO) projected that future gasoline demand was likely to decrease rather than increase.

Figure 1.3.2-5: EIA Projections of Future Gasoline Demand



While EPA's projections in the 2010 rule for how the statutory targets through 2022 might be met included significant volumes of drop-in renewable diesel, it also included total ethanol volumes in excess of the implied statutory conventional renewable fuel volume targets; EPA's projections assumed that substantial volumes of ethanol would also be used to meet the cellulosic biofuel and implied non-cellulosic advanced biofuel volume targets. These projections were based on what EPA believed at that time was reasonable to expect for production and consumption of all renewable fuel types under the influence of the RFS standards, as well as the growth in the flex-fuel vehicle (FFV) fleet and the availability of E85 at retail service stations that would be needed in order for the projected ethanol volumes to be consumed (E15 had not been approved at that time). Based on EPA's projections of total ethanol volume in the RFS2 rule and EIA's projection of gasoline demand in AEO 2010, the nationwide average ethanol content would have first exceeded 10.00% in 2014 in the primary case and would have continued upwards to 15.5% by 2022. In reality, the actual increase in the nationwide average ethanol concentration over time has been considerably slower; the same is true even when ignoring cellulosic ethanol (i.e., when comparing actual ethanol use to the projected volume of conventional ethanol and non-cellulosic advanced ethanol such as imported sugarcane ethanol).

Figure 1.3.2-6: 2010 Projected Versus Actual Ethanol Concentration



Source for actual ethanol concentration: Gasoline and ethanol consumption from EIA's Monthly Energy Review

The considerably slower-than-projected approach to and exceedance of the E10 blendwall suggests that increasing sales of E85 were more difficult to achieve than either EPA or ethanol proponents had projected it would be when the RFS program was established.

1.4 Gasoline, Diesel, and Crude Oil

This chapter compares crude oil prices with crude oil price projections, and discusses observed changes in petroleum imports, refinery margins, and transportation fuel demand prior to and during the years of the implementation of the RFS program.

1.4.1 Crude Oil Prices vs. Crude Oil Price Projections

Crude oil prices have a significant impact on the economics of increased use of renewable fuels. When crude oil prices increase, both renewable fuel feedstock prices and gasoline and diesel prices tend to increase as well, although gasoline and diesel prices generally increase more relative to renewable fuel feedstock prices. Thus, higher crude oil prices generally improve the economics of renewable fuels relative to gasoline and diesel. Conversely, lower crude oil prices tend to hurt the economics of renewable fuels.

When EPA was projecting the cost of future renewable fuels for the RFS2 rule, crude oil prices were very high compared to historical crude oil prices. For estimating the cost of rulemakings, EPA uses projections for the future prices of petroleum products. The cost analysis for the RFS2 rule was based on crude oil, gasoline, and diesel prices projected by EIA in AEO 2008, which projected crude oil prices for decades into the future. Figure 1.4.1-1 shows AEO 2008 projected crude oil prices, as well as actual crude oil prices, for both West Texas Intermediate (WTI, a light, sweet crude produced in the U.S.) and Brent (a light, sweet European crude oil).[22,23,24,25] When there was separation in Brent and WTI crude oil prices and Brent prices were higher than WTI, Brent crude oil prices likely represented the marginal price of crude oils purchased by U.S. refiners and set the marginal price of U.S. refined products, while WTI tended to reflect crude purchase price for many U.S. refiners.

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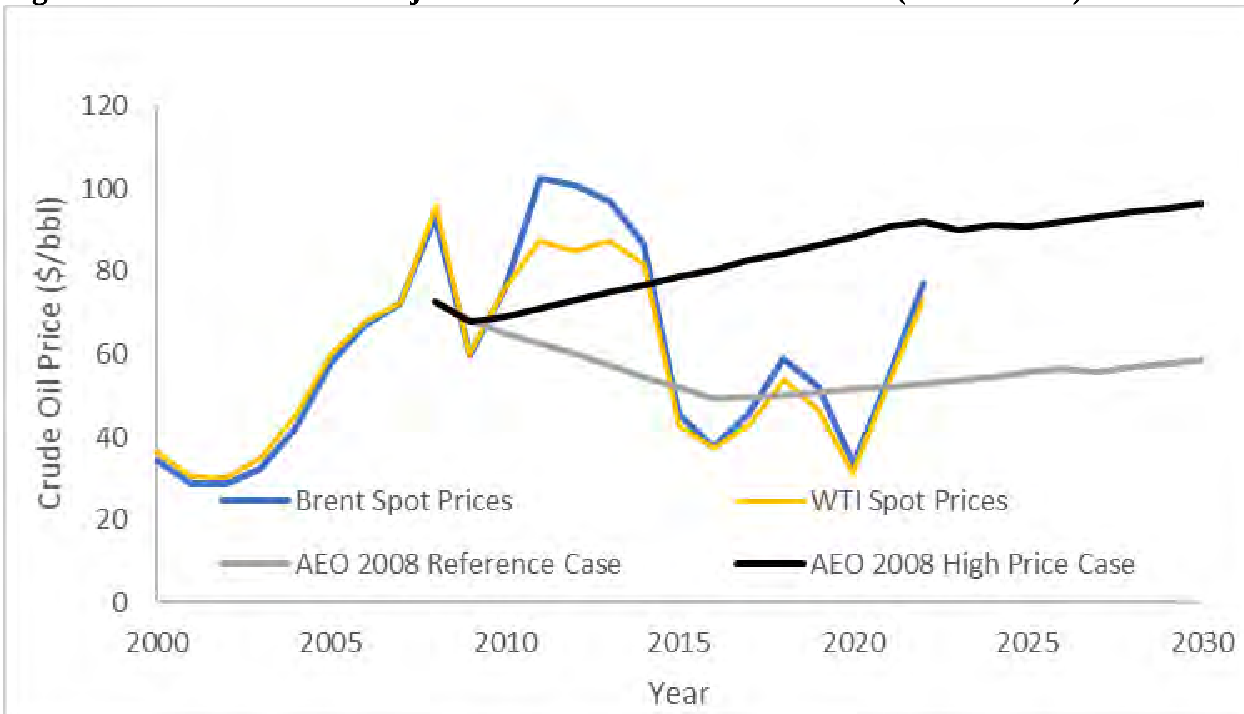
[22] Light crude oils are comprised of more lower temperature boiling, shorter chain hydrocarbons, while heavy crude oils are comprised of more higher temperature boiling, longer chain hydrocarbons. Sweet crude oils have less sulfur, while sour crude oils have more sulfur. Increased sulfur in crude oils make them more expensive to refine to meet gasoline and diesel sulfur specifications; thus, sour crude oils are typically priced lower than sweet crude oils.
[23] AEO 2008 – Petroleum Product Prices; Reference Case; EIA; June 2008.
[24] AEO 2008 – Petroleum Product Prices; High Price Case; EIA: June 2008.
[25] Petroleum and Other Liquids – Spot Prices WTI – Cushing and Brent - Europe; EIA; https://www.eia.gov/dnav/pet/pet_pri_spt_s1_a.htm.

Figure 1.4.1-1: AEO 2008 Projected and Actual Crude Oil Prices (2007 dollars)[a]



[a] Actual crude oil prices have been adjusted to 2007 dollars to be consistent with the value of money used in AEO 2008; 2022 data represents the first 6 months only.

Figure 1.4.1-1 shows actual crude oil prices beginning to increase in 2004 and reaching an average price of nearly $100 per barrel in 2008. Furthermore, some reports at that time projected even higher crude oil prices due to crude oil production not keeping up with demand.[26] Nevertheless, EIA crude oil price projections during this time were much lower, and it was during this time that the RFS2 rule was written. The AEO 2008 reference case projected crude oil prices decreasing to under $60 per barrel and remaining that low all the way out to 2030. Because the AEO 2008 reference case projected much lower crude oil prices than actual prices and many other independent predictions at that time, EPA also analyzed the cost of the RFS2 program based on AEO 2008 high crude oil prices. The AEO 2008 high price case estimated crude oil prices rising from $70 per barrel to mid-$90s per barrel out to 2030. Actual crude oil prices decreased in 2014 back down to the $40 to $60 per barrel price range (after adjusting the prices back to 2007 dollars—the dollar value used in AEO 2008), which were much lower than the peak prices, but higher than the typical historical crude oil prices prior to 2004. In retrospect, the reference case and high crude oil price projections of AEO 2008 essentially represented the range of crude oil prices since the RFS2 program was promulgated.

1.4.2 Petroleum Imports

As discussed further in Chapter 5, energy security is an important goal of the RFS program. Importing a significant amount of crude oil and finished petroleum products from abroad creates an energy security concern if the foreign petroleum supply is disrupted. A good

[26] Hirsch, Robert L.; Peaking of World Oil Production: Impacts, Mitigation & Risk Management; Report to the Department of Energy; February 2005.

example is the oil embargo by the Organization of Petroleum Exporting Countries (OPEC) against the U.S. in 1973 and 1974, which drove up prices, reduced supply, and is attributed to causing the U.S. economy to slide into a recession.[27] It also led to Congress banning the export of U.S. oil from 1975 to 2015.[28]

At the time that Congress passed EPAct and EISA and EPA promulgated the RFS1 and RFS2 rules, the U.S. was importing a large portion of its crude oil and refined petroleum products. That trend was expected to continue because the eventual increase in U.S. crude oil production due to fracking was not known at that time. Below we consider the petroleum trade imbalance during that time and what has transpired since.

EIA collects data on imports of crude oil and petroleum products, receives data on crude oil and petroleum product exports from the U.S. Bureau of the Census, and calculates net imports of petroleum into the U.S.[29] The EIA-reported net imports of petroleum values account for imports and exports of crude oil, petroleum products, and biofuels.[30] For the net imports figures shown in Figure 1.4.2-1, the renewable fuel volumes were removed to only show the U.S. net imports of petroleum for the years from 2000–2021. Because the production volume of U.S. tight oil (fracked oil) impacted the net petroleum imports in such a significant way, those volumes are also shown in the figure, along with the individual net imports of gasoline and diesel.

[27] Verrastro, Frank A., The Arab Oil Embargo-40 Years Later; Center for Strategic & International Studies; October 16, 2013.
[28] 1975 Energy Policy and Conservation Act; Consolidated Appropriations Act of 2016.
[29] U.S. Net Imports by Country; Petroleum and Other Liquids; EIA; https://www.eia.gov/dnav/pet/pet_move_neti_a_EP00_IMN_mbblpd_m.htm
[30] To calculate net petroleum imports, EPA subtracted net biofuel imports from the U.S. Net Imports reported by EIA.

Figure 1.4.2-1: U.S. Net Petroleum Imports and U.S. Tight Oil Production

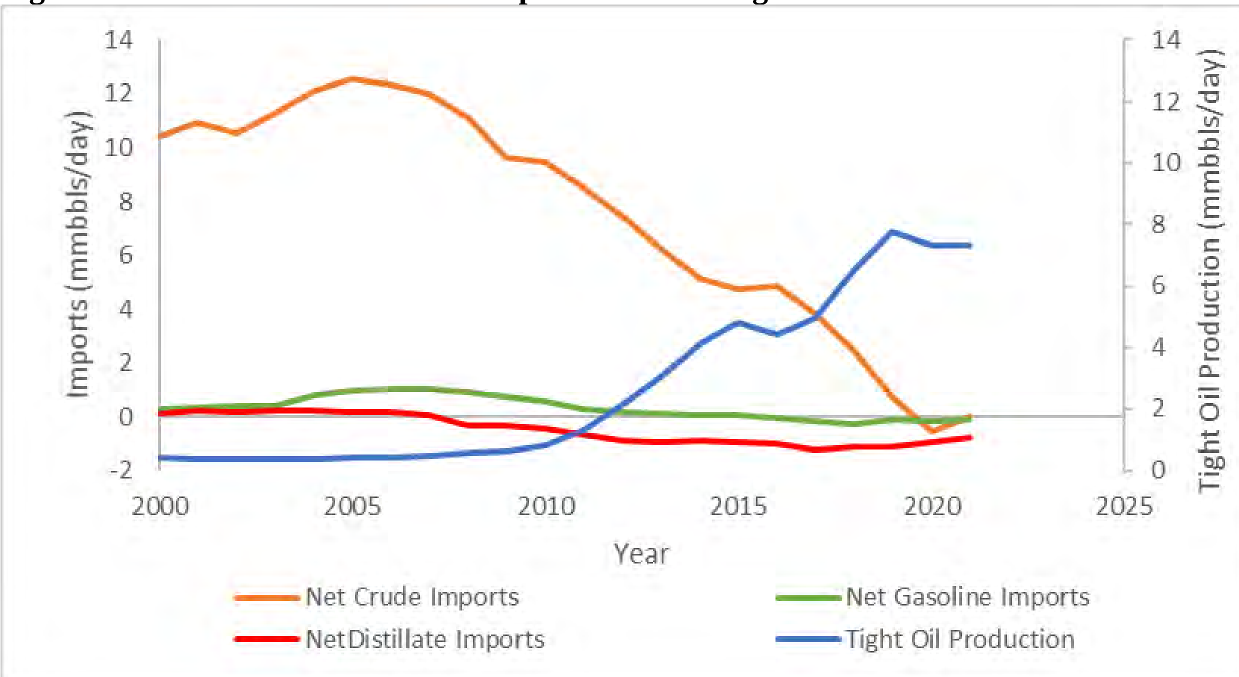


Figure 1.4.2-1 shows that net petroleum imports increased from just over 10 million barrels per day (bpd) in 2000 to a maximum of about 12.5 million bpd in 2005. After peaking in 2005 when EPAct was passed, net petroleum imports started to decrease, very slowly at first, in 2006 and 2007. Starting in 2008, net petroleum imports declined each year by roughly 1 million bpd.

Increased tight oil production and changes in gasoline and distillate (comprised largely of diesel) net imports were responsible for reducing net petroleum imports. Figure 1.4.2-1 clearly shows that tight oil production—which increased from about zero in 2009 to 8 million bpd in 2018—had a very large impact on net petroleum imports. Distillate exports began to increase starting in 2006 and they continued to increase through 2017. As a result, net distillate imports—which were somewhat positive at 0.2 million bpd initially—trended downward starting in 2006 to negative 1.1 million bpd in 2017. Gasoline net imports reached a maximum of over 1 million bpd in 2007. Like distillate, gasoline exports also began to increase, which likewise corresponded with a reduction in net gasoline imports. By 2017, gasoline net imports were 1.1 million bpd lower than in 2007.

Renewable fuels likely contributed to reducing net petroleum imports by a relatively modest amount. The volume of corn ethanol increased from about 2 billion gallons in 2000 to over 14 billion gallons in 2015.[31,32] Biodiesel consumption increased from 10 million gallons in 2001 to over 1 billion gallons in 2013, and biodiesel and renewable diesel consumption totaled

[31] EIA, Monthly Energy Review, Table 10.3, Fuel Ethanol Review; https://www.eia.gov/totalenergy/data/monthly/pdf/sec10_7.pdf

[32] Note that "corn ethanol" also includes small amounts of ethanol produced from other sources of starch such as wheat and grain sorghum.

over 2 billion gallons in 2019.[33,34] Assuming that this total renewable fuel volume displaced an energy-equivalent volume of petroleum imports, corn ethanol and biodiesel/renewable diesel combined would have displaced about 0.75 million bpd of petroleum equivalent volume in 2019—which is equivalent to 6% of the highest import volume.

Petroleum imports also contributed to a monetary trade imbalance that was of particular concern prior to the passage of EISA in 2007. What made the continued increase of net petroleum imports until 2005 of particular concern was that crude oil prices were increasing at the same time.[35] Crude oil spot prices (both WTI and Brent) had doubled in 2005 to over $50/bbl compared to average crude oil spot prices prior to 2004. Crude oil prices continued to increase, nearly doubling again in 2008 compared to 2005. Thus, the U.S. imported petroleum trade imbalance quadrupled in monetary terms. However, petroleum imports have decreased in recent years.

The total U.S. trade imbalance increased to just under $800 billion in 2005 and increased further to over $800 billion per year in 2006 through 2008.[36] The increasing crude oil prices on top of the increasing petroleum imports contributed to this increasing trade imbalance. The 12 million bpd net petroleum import volume combined with the approximately $70/bbl crude oil price in 2006 contributed to about $300 billion of the total U.S. trade imbalance. While petroleum imports directly comprised a large portion of the increasing trade imbalance, higher crude oil prices also increased the prices of many other goods that were imported into the U.S., which likely indirectly contributed to the trade imbalance.[37] In 2009, the U.S. trade imbalance dropped to $500 billion. Since then, the U.S. trade imbalance increased back into the $600–700 billion per year range until 2018 and 2019, when it increased again back above $800 billion per year. Then, in 2020, the U.S. trade imbalance further increased above $900 billion. As shown in Figure 1.4.2-1, the decreasing net imports of petroleum means that petroleum is not a factor for this increasing trade imbalance.

We recognize that because the U.S. is a participant in the world market for petroleum products, its economy cannot be shielded from world-wide price shocks.[38] However, the potential for petroleum supply disruptions due to supply shocks has been significantly diminished due to the increase in tight oil production and, to a lesser extent, renewable fuels, which has shifted the U.S. to being a modest net petroleum importer in the world petroleum market in 2023–2025. Nevertheless, the potential for supply disruptions (discussed further in Chapter 5) has not been eliminated.[39]

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[33] Biodiesel consumption data from EIA, Monthly Energy Review, Table 10.4, Biodiesel and Other Renewable Fuels Overview; https://www.eia.gov/totalenergy/data/monthly/pdf/sec10_8.pdf
[34] Renewable consumption data from Public Data for the Renewable Fuel Standard; EPA Moderated Transaction System; https://www.epa.gov/fuels-registration-reporting-and-compliance-help/public-data-renewable-fuel-standard
[35] Spot Prices - Petroleum and Other Liquids; EIA; https://www.eia.gov/dnav/pet/pet_pri_spt_s1_a.htm
[36] U.S. Trade in Goods with World, Seasonally Adjusted; United States Census Bureau; https://www.census.gov/foreign-trade/balance/c0004.html
[37] U.S. Trade Deficit and the Impact of Changing Oil Prices; Congressional Research Service; February 24, 2020; https://fas.org/sgp/crs/misc/RS22204.pdf
[38] Bordoff, Jason; The Myth of US Energy Independence has Gone Up in Smoke; Foreign Policy; September 18, 2019; https://foreignpolicy.com/2019/09/18/the-myth-of-u-s-energy-independence-has-gone-up-in-smoke
[39] Foreman, Dean; Why the US must Import and Export Oil; American Petroleum Institute; June 14, 2018; https://www.api.org/news-policy-and-issues/blog/2018/06/14/why-the-us-must-import-and-export-oil

1.4.3 Refinery Margins

Refinery margins reveal the economic health of refineries. The higher the margins for a refinery, the greater its profitability and economic viability. Over time, refinery margins vary considerably, but must average at least a certain level in order to remain viable long term.

Publicly available refinery margin data from BP is shown in Figure 1.4.3-1 for three different types of refineries: (1) A U.S. Gulf Coast coking refinery; (2) A Northwest European sweet crude oil cracking refinery; and (3) A medium crude oil hydrocracking refinery in Singapore.[40] The refinery margin data is for three refineries owned by BP; thus, it may not represent the margins of other refineries in the same regions. The margin data is on a semi-variable basis, accounting for all variable costs and fixed energy costs.

Figure 1.4.3-1: Refinery Margins in Three Different Regions ($/bbl)

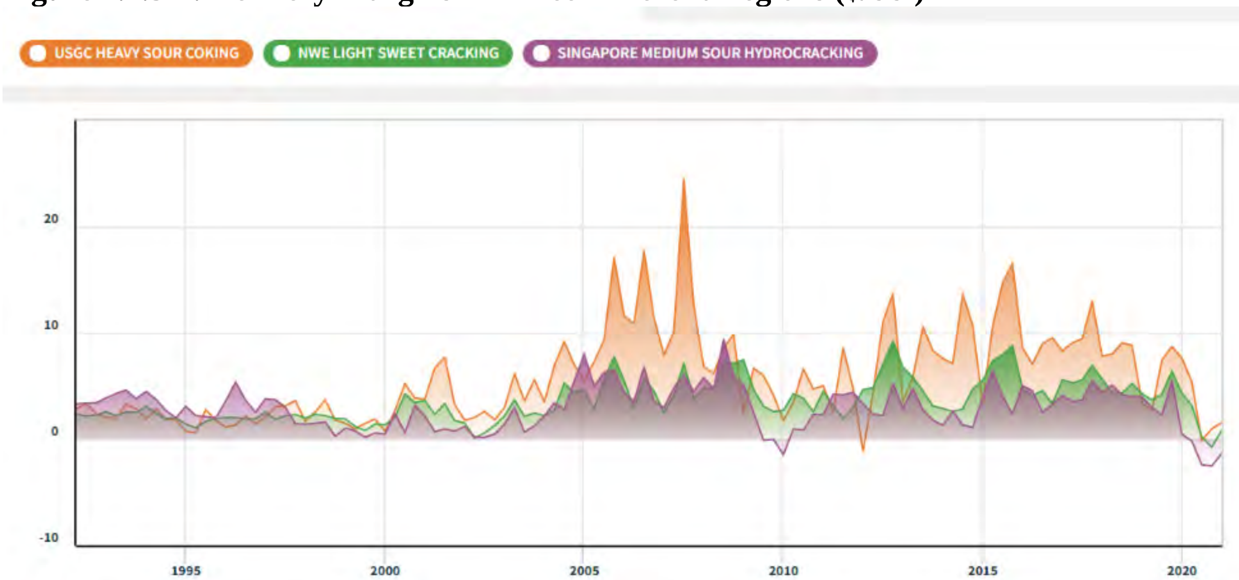


Figure 1.4.3-1 shows that from 1993–2004, refinery margins were modest, and the Singapore refinery in particular experienced zero or near-zero margins over much of 1998–2004. From 2004–2009, crude oil prices were rising and it was a much better period for these refineries' margins, particularly for the Gulf Coast refinery. The Gulf Coast refinery's margins were likely much higher due to the heavy sour crude oil processed there being much less expensive than the crude oils processed at the other two refineries. All three refineries' margins decreased dramatically after 2008, likely due to the large decrease in refined product demand associated with the Great Recession. As the world emerged from the Great Recession, the three refineries' margins started improving in 2010, and in particular, the refinery margins improved more dramatically for the heavy sour coking refinery in the Gulf Coast. However, refinery margins for U.S. refineries that refine light, sweet crude oil are not represented in Figure 1.4.3-1. As shown in Figure 1.4.1-1, but not reflected in Figure 1.4.3-1, light sweet crude oil prices were

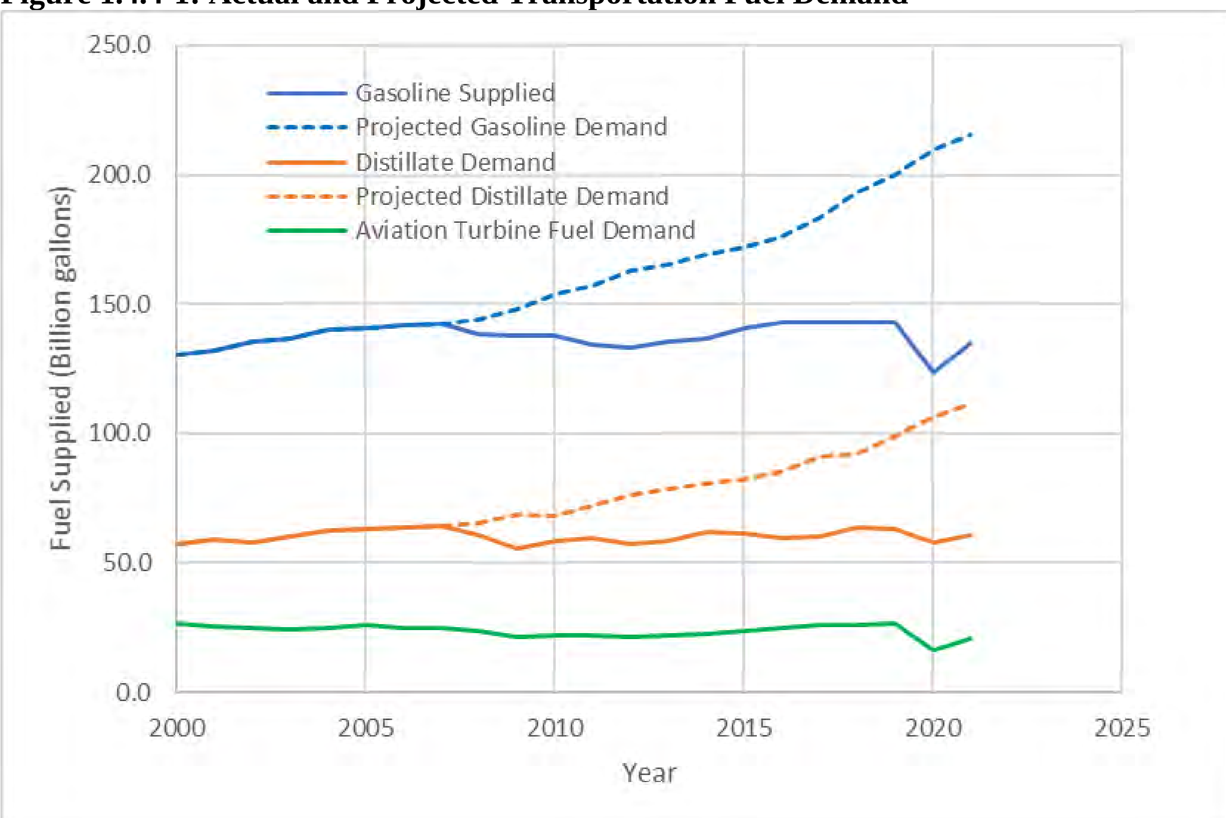
[40] Oil Refinery Margins - Regional; NASDAQ Data Link; https://data.nasdaq.com/data/BP/OIL_REF_MARG-oil-refining-margins-regional.

depressed in the U.S. during 2011–2014. Lower prices of sweet crude oil provided high margins for U.S. refineries that processed sweet crude oil during this time period. The Gulf Coast refinery margins stayed elevated all the way up to 2020, at which point refinery margins declined steeply for all three refinery types due to the COVID-19 pandemic. Refinery margins returned to their pre-pandemic levels in 2022, but then increased significantly starting in March 2022 due to geopolitical factors.[41]

1.4.4 Transportation Fuel Demand

At the time the RFS2 program was being enacted through EISA in 2007, there had been a consistent increase in U.S. petroleum demand. However, transportation fuel demand fell short of historical demand increases starting in 2008 and has remained relatively stable since that time. Figure 1.4.4-1 shows the actual volume of gasoline, distillate, and jet fuel consumed in the U.S. from 2000–2018, as well as the projected demand of gasoline and distillate if transportation fuel demand growth had continued at the historic rate based on AEO 2008.[42,43]

Figure 1.4.4-1: Actual and Projected Transportation Fuel Demand



Source: EIA's AEO 2008; includes renewable fuel volumes

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[41] McGurty, Janet; Refinery Margin Tracker: Russian crude cargoes taper off as margins rise; S&P Global; April 4, 2022.

[42] Product Supplied; Petroleum and Other Liquids, Energy Information Administration, https://www.eia.gov/dnav/pet/pet_cons_psup_dc_nus_mbbl_a.htm.

[43] Annual Energy Outlook 2008; Energy Information Administration; June 2008; https://www.eia.gov/outlooks/archive/aeo08/index.html.

Figure 1.4.4-1 shows that both gasoline and distillate demand increased up to 2007. During previous years, gasoline and distillate demand was increasing 1.3% and 1.7% per year on average, respectively. The dashed lines in Figure 1.4.4-1 show projected gasoline and distillate demand if they had continued to increase at the same rate as that prior to 2008. The figure clearly shows that actual gasoline and distillate demand fell far short of projected demand after 2007. Conversely, jet fuel demand was essentially flat during the entire period.

Several factors led to the decrease of transportation fuel demand after 2007 relative to projected values:

- *The Great Recession*. The Great Recession began in 2008 and officially lasted for 18 months, although employment did not return to pre-recession levels until over 6 years after the onset of the recession. The Great Recession caused a large impact on economic activity, which reduced transportation fuel demand during these years.

- *Increased crude oil prices*. Sustained, higher crude oil prices resulted in increased transportation fuel prices over this time period, which affected consumer behavior by impacting the number of miles traveled and vehicle purchase decisions. After 2014, crude oil prices decreased to the $40–50 price range, which brought gasoline prices back down and likely reversed some of the consumer behavior changes.

- *Increasing fuel economy of the motor vehicle fleet*. EPA and the National Highway Transportation Administration (NHTSA) finalized standards which reduced light-duty motor vehicle greenhouse gas (GHG) emissions and increased the Corporate Average Fuel Economy (CAFE) of motor vehicles. The GHG/CAFE standards applied to light-duty vehicles sold in 2012–2025 and thereafter.[44] EPA and NHTSA also established GHG/CAFE standards for new heavy-duty vehicles and their trailers.[45] The phase 1 and phase 2 heavy-duty GHG standards began to phase-in in 2014 and will continue to do so through 2027.[46] The GHG standards only affect new internal combustion vehicles; thus, as consumers purchase new motor vehicles, these new vehicles consume less gasoline and diesel compared to the vehicles sold in previous years, reducing overall petroleum demand.

- *Electric vehicle penetration and fuel displacement*. Electric vehicles (EVs) and plug-in hybrid electric vehicles (PHEVs) reduce consumption of petroleum fuel by either partially displacing petroleum fuels (in the case of PHEVs) or completely displacing petroleum demand (in the case of EVs). Data on annual electrified vehicle sales indicates that EVs and PHEVs displaced an estimated 5 million gallons of fuel in 2011 and that this increased to over 400 million gallons in 2019.[47]

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[44] 75 FR 25324 (May 7, 2010) and 86 FR 74434 (December 30, 2021).
[45] 76 FR 57106 (September 15, 2011).
[46] 81 FR 73478 (October 25, 2016).
[47] Transportation Research Center at Argonne National Laboratory, https://www.anl.gov/es/light-duty-electric-drive-vehicles-monthly-sales-updates

1.5 Cellulosic Biofuel

Actual production of cellulosic biofuel through 2021 has been significantly less than the statutory volumes, which reached 16 billion gallons in 2022. Minimal volumes of cellulosic biofuel were produced through 2013. Since 2013, volumes of the types of liquid cellulosic biofuels projected in the RFS2 rule have remained limited. There are numerous reasons that liquid cellulosic biofuel production has not developed as anticipated. In some years, the lower than anticipated crude oil prices discussed in Chapter 1.4.1 certainly impacted the market's ability to produce liquid cellulosic biofuels at competitive prices. The relatively low production costs estimated in the RFS2 rule (generally $1.00–2.50 per gallon of liquid cellulosic biofuel based on NREL modeling, depending on the production technology and technology year) have not been realized.[48] While the issues associated with each individual company and facility are unique, and the reasons facilities fail to consistently produce cellulosic biofuel at the expected volumes are not always publicly disclosed, there appear to be several common challenges across the liquid cellulosic biofuel industry. These challenges include: (1) Feedstock quality and handling issues; (2) Higher than anticipated feedstock and capital costs; and (3) Difficulty scaling up technology to commercial scale. The inability of several first-of-a-kind cellulosic biofuel production facilities to continue operating has also likely impacted investment in the commercialization of similar technologies. As we discuss further in Chapter 6.1, the availability of liquid cellulosic biofuel has historically been very low and has typically fallen short of EPA's projections.

Although production of liquid cellulosic biofuel from commercial scale production facilities has been far lower than projected in the RFS2 rule, smaller volumes of qualifying cellulosic biofuel have been produced using technologies not discussed in that rule. The production of compressed natural gas and liquified natural gas (CNG/LNG) derived from biogas, which was not one of the cellulosic biofuel production technologies discussed in the RFS2 rule, has accounted for the vast majority of the cellulosic biofuel produced since 2010. The RFS2 rule contained a pathway[49] for the production of biogas from landfills, sewage and waste treatment plants, and manure digesters to generate advanced biofuel (D5) RINs.[50] In response to questions from multiple companies, EPA subsequently evaluated whether biogas from several different sources could be considered not just an advanced biofuel, but also a cellulosic biofuel. In the Pathways II rule, EPA added a pathway for CNG/LNG derived from biogas from landfills, municipal wastewater treatment facility digesters, agricultural digesters, and separated MSW digesters, as well as biogas from the cellulosic components of biomass processed in other waste digesters, to generate cellulosic biofuel (D3) RINs when used as a transportation fuel.[51] Following this decision, production of CNG/LNG derived from biogas increased rapidly, from approximately 33 million RINs in 2014 to over 560 million RINs in 2021.[52] Through 2021, over

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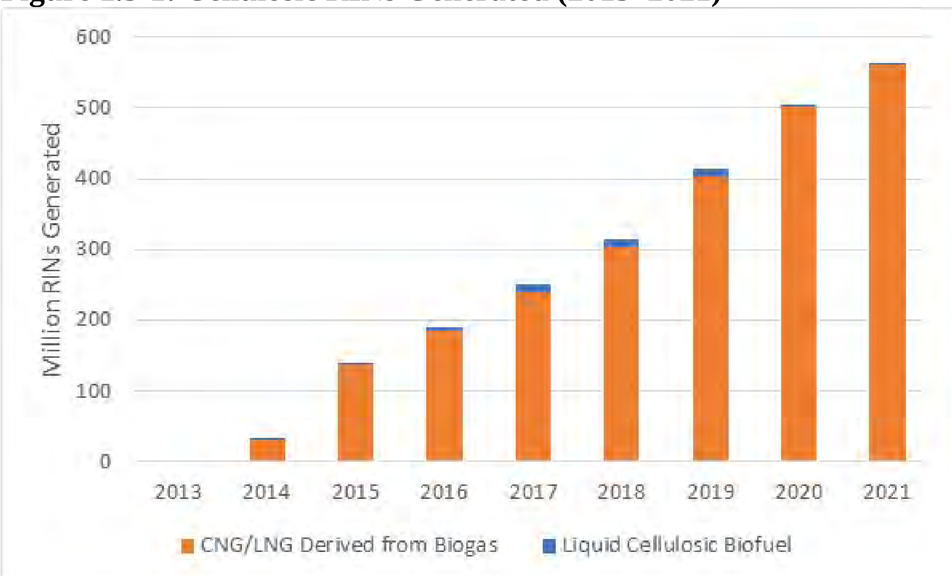
[48] Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis. EPA-420-R-10-006. February 2010.
[49] A pathway is a combination of feedstock, production process, and fuel type. EPA has evaluated a number of different pathways to determine the category of renewable fuel that fuel produced using the various pathway qualifies for. The list of generally applicable pathways can be found in 40 CFR 80.1426(f).
[50] 75 FR 14872 (March 26, 2010).
[51] 79 FR 42128 (July 18, 2014).
[52] One RIN can be generated for each ethanol-equivalent gallon of renewable fuel. One gallon of ethanol is eligible to generate one RIN; other types of fuel generate RINs based on their energy content per gallon relative to ethanol. For CNG/LNG derived from biogas, every 77,000 BTU of qualifying biogas generates one RIN.

98% of all of the cellulosic RINs generated in the RFS program have been for CNG/LNG derived from biogas. We anticipate that CNG/LNG derived from biogas will continue to be the source of the vast majority of cellulosic biofuel in the RFS program through 2023, with significant volumes of eRINs starting in 2024. Actual cellulosic biofuel production for each year from 2014–2021 is shown in Figure 1.5-1.

Figure 1.5-1: Cellulosic RINs Generated (2013–2021)

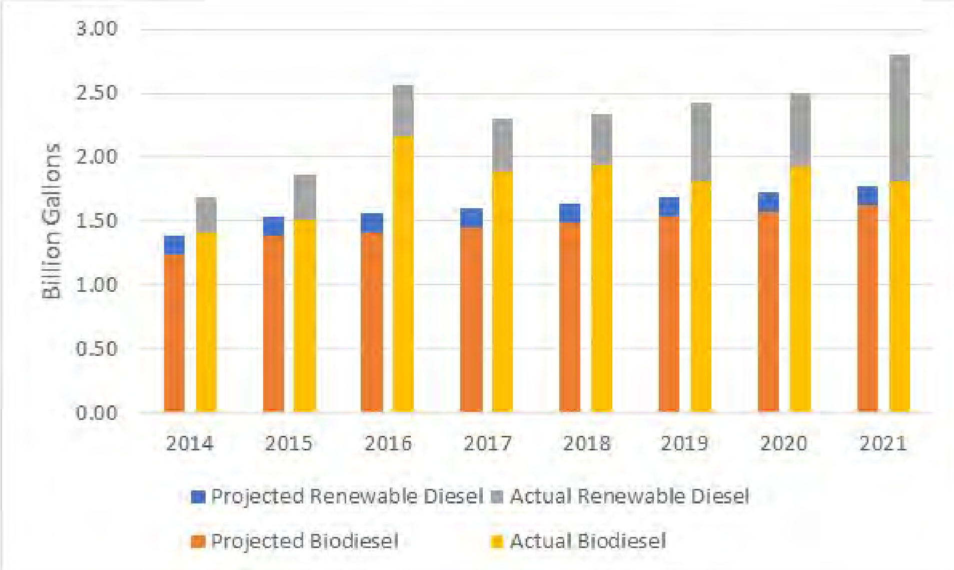


1.6 Biodiesel and Renewable Diesel

The actual supply of biodiesel and renewable diesel has significantly exceeded the supply projected by EPA in the RFS2 rule. In that rule, EPA projected that 1.62 billion gallons of biodiesel and 0.15 billion gallons of renewable diesel would be supplied in 2021, all of which was projected to be produced in the U.S.[53] The actual supply of biodiesel and renewable diesel in 2021 was 1.82 billion gallons and 0.99 billion gallons, respectively. While the majority of these volumes were produced domestically, significant volumes were imported. Further, while the vast majority of biodiesel and renewable diesel supplied since 2010 has met the requirements for BBD or advanced biofuel, smaller volumes were produced from grandfathered facilities using renewable biomass that does not qualify for BBD or advanced RINs and therefore only qualify to generate conventional renewable fuel (D6) RINs. The most likely feedstock used to produce grandfathered biodiesel and renewable diesel is palm oil; however, other types of renewable biomass that have not been approved to generate advanced or BBD RINs could also have been used.

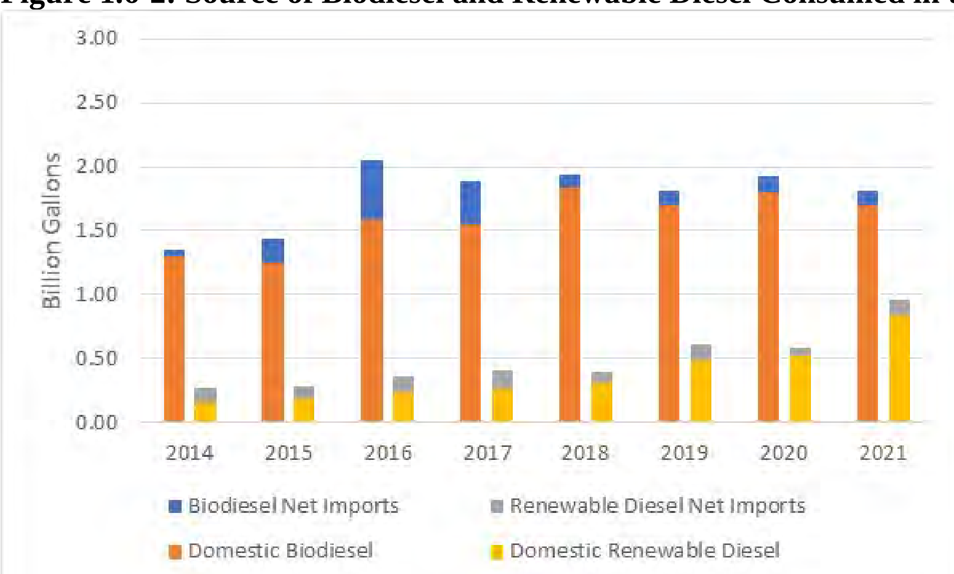
[53] 2021 is the most recent year for which data are available for comparison.

Figure 1.6-1: 2010 Projected vs. Actual Biodiesel and Renewable Diesel Supply (2014–2021)



Projected volumes are from the RFS2 rule. Actual volumes are from EMTS data.

Figure 1.6-2: Source of Biodiesel and Renewable Diesel Consumed in the U.S. (2014–2021)



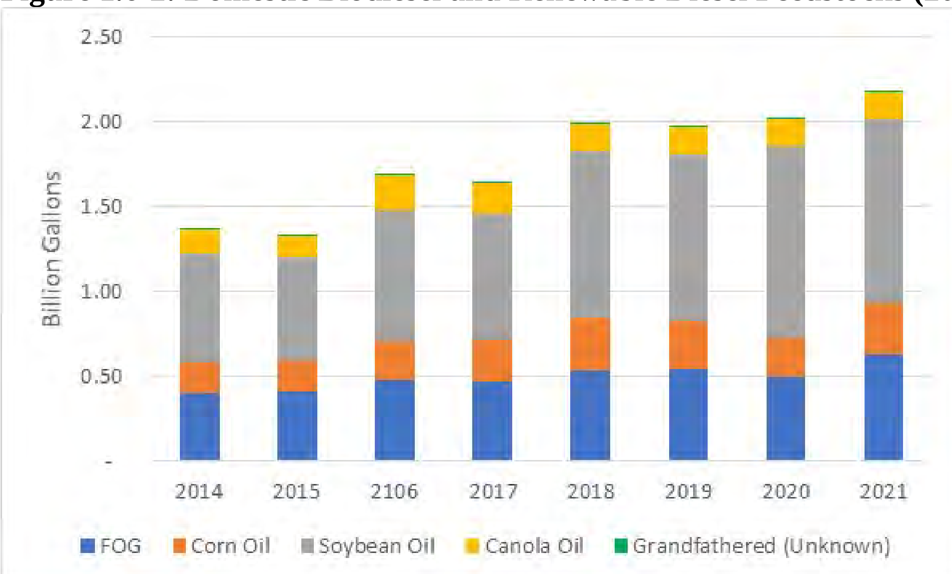
The reason that the supply of biodiesel and renewable diesel has been much higher than projected in the RFS2 rule is primarily related to challenges associated with consuming ethanol as higher-level blends with gasoline (i.e., greater that 10% ethanol), which we discuss further in Chapter 1.7. The limited use of higher-level ethanol blends, together with lower than projected gasoline demand, resulted in total ethanol consumption in 2020 and 2021 (12.70 and 13.88 billion gallons, respectively) that was lower than the projected ethanol consumption volume in 2022 even under the low ethanol case from the RFS2 rule (17.04 billion gallons).[54] Since the

[54] Ethanol consumption volume are from EIA's Monthly Energy Review, while the ethanol projections are from the RFS2 rule. Ethanol consumption in 2020 was significantly impacted by the COVID-19 pandemic. Ethanol

primary fuels available to meet the advanced biofuel requirements are biodiesel, renewable diesel, and sugarcane ethanol, the challenges associated with increasing ethanol consumption is a significant factor in a much smaller-than-projected supply of sugarcane ethanol. Instead, greater volumes of biodiesel and renewable diesel have been used to meet the advanced biofuel requirement and at times even the total renewable fuel requirement, as further discussed in Chapter 6.

The feedstocks used to produce biodiesel and renewable diesel each year from 2014–2021 for domestically produced and imported biodiesel and renewable diesel are shown in Figures 1.6-2 and 1.6-3.

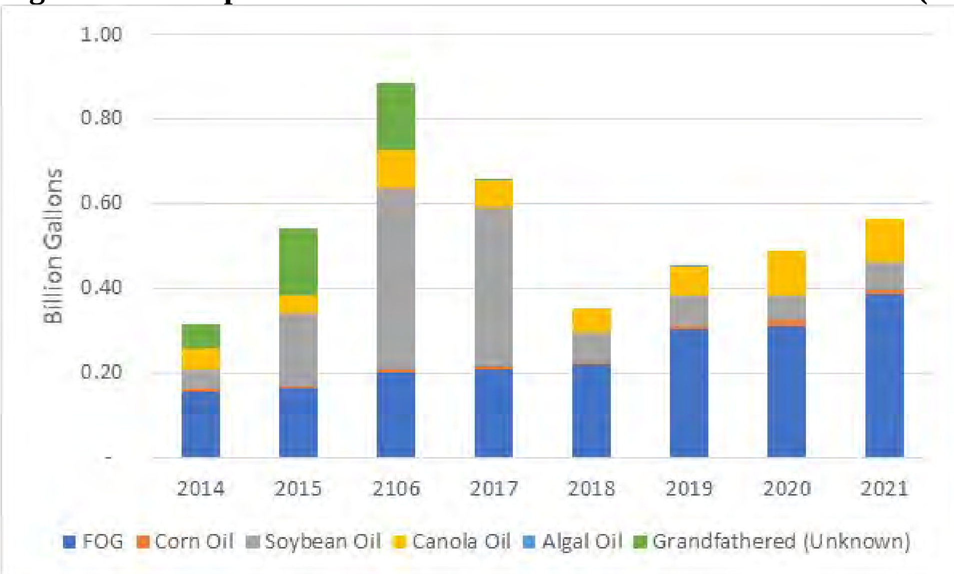
Figure 1.6-2: Domestic Biodiesel and Renewable Diesel Feedstocks (2014–2021)



Source: EMTS

consumption in the U.S. reached a peak of 14.49 billion gallons in 2017, still far short of the volumes projected in the RFS2 rule.

Figure 1.6-3: Imported Biodiesel and Renewable Diesel Feedstocks (2014–2021)



Source: EMTS

There are several notable differences between the quantities of feedstock projected to be used to produce biodiesel and renewable diesel in the RFS2 rule and the actual feedstocks used to produce these fuels in 2021. Domestic biodiesel production in 2021 was fairly similar to the volume of biodiesel projected in the RFS2 rule for that year (all of which was projected to be produced domestically), but there were significant differences in the feedstocks used to produce this biodiesel. Relative to the quantities projected in the RFS2 rule, the use of soybean oil, fats, oils, and greases (FOG), and other sources were all higher than projected, while the use of corn oil from ethanol plants was lower than projected. These differences largely reflect the greater than anticipated demand for biodiesel as a result of the limitations on ethanol consumption (see Chapter 1.7). The lower than expected use of corn oil is likely the result of production of non-food grade corn oil being a relatively new feedstock at the time of the RFS2 rule, EPA's projections being over-ambitious, and demand for this feedstock in animal feed and other sectors.

Domestic renewable diesel production in 2021 was significantly higher than projected in the RFS2 rule, in which EPA projected that all renewable diesel would be produced domestically from FOG. While the majority of domestic renewable diesel was produced from FOG in 2021, significant volumes were also produced from soybean oil and corn oil from ethanol plants. The U.S. also imported significant volumes of biodiesel and renewable diesel in 2021, as well as in previous years. By 2021, the majority of the imported biodiesel and renewable diesel was produced from FOG; however, in earlier years the U.S. also imported large volumes of biodiesel produced from soybean oil.[55]

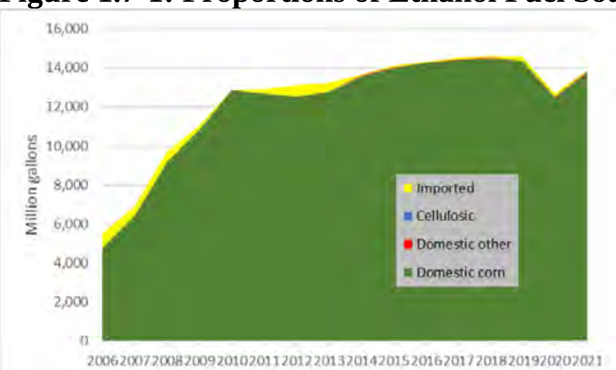
[55] Source: EMTS.

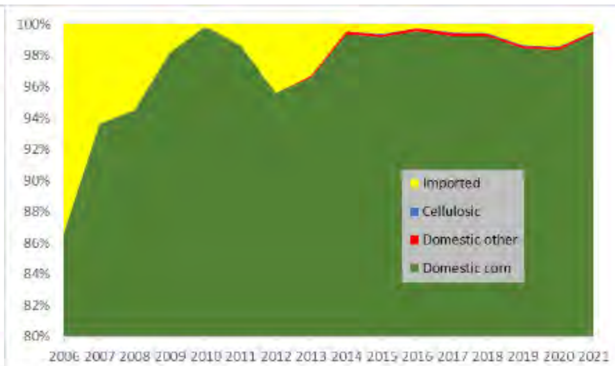
1.7 Ethanol

The predominant form of biofuel used to meet the standards under the RFS program—and in particular the total renewable fuel standard—has been ethanol. In 2005, just prior to implementation of the RFS1 program, ethanol accounted for 97% of all biofuel consumed in the U.S. transportation sector.[56] Since then, the total volume of ethanol used in the U.S. has more than tripled from 5.5 million gallons in 2006 to 14.5 million gallons in 2019.[57,58] By 2010, ethanol use in the U.S. was approaching the "E10 blendwall" (as represented by the nationwide average ethanol concentration) and actually exceeded 10.00% in 2016. By 2021, ethanol accounted for 80% of the 17.2 billion gallons of biofuel consumed in the U.S.[59]

In all years since ethanol was approved for use in gasoline in 1979, the vast majority of ethanol consumed in the U.S. has been produced domestically from corn starch with small amounts from other starches. Cellulosic ethanol has represented at most 0.07% (2019) of all ethanol consumed in the U.S., while the proportion of imported sugarcane ethanol has been small but highly variable.

Figure 1.7-1: Proportions of Ethanol Fuel Sources



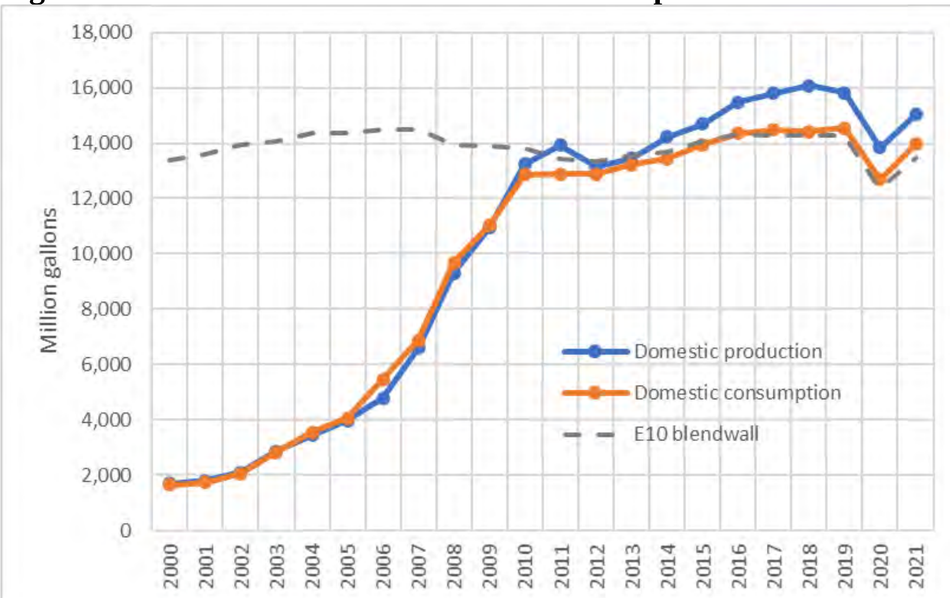


Source: EMTS

As shown in Figure 1.7-2, actual consumption of ethanol in the U.S. was very close to domestic production through 2009. Thereafter, domestic production began exceeding domestic consumption, indicative of an increase in exports.

[56] EIA's Monthly Energy Review, April 2021, Tables 10.3 and 10.4. Comparison is based on ethanol-equivalence.
[57] Id.
[58] In 2020 and 2021, total ethanol consumption dropped significantly as a result of the COVID-19 pandemic.
[59] "RIN supply as of 2-17-22," available in the docket for this action.

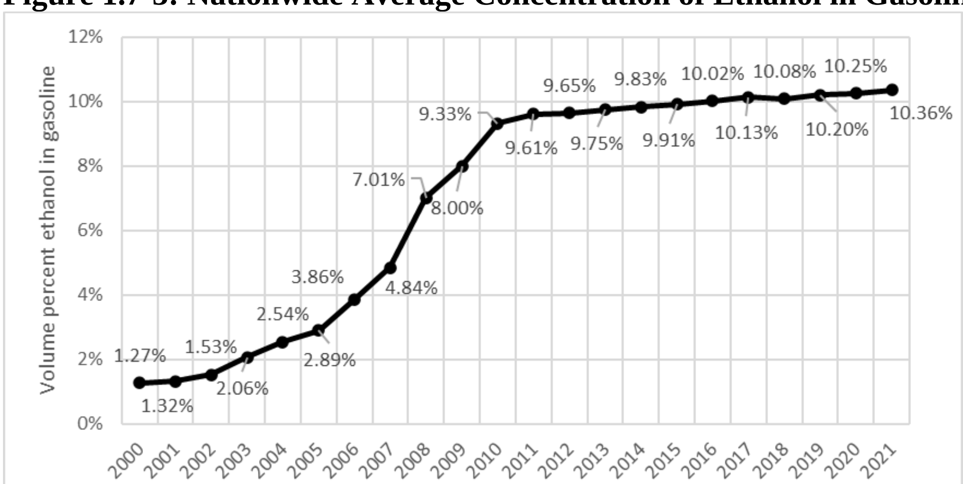
Figure 1.7-2: Domestic Production and Consumption of Ethanol



Source: Domestic consumption from EIA's Monthly Energy Review. The E10 blendwall was derived from total gasoline energy demand. Domestic production = domestic consumption – imports + exports.

The E10 blendwall appears to have been a deciding factor in limiting growth in domestic consumption of ethanol. As illustrated in Figure 1.7-3, the nationwide average ethanol concentration did not increase at the same pace after 2010 as it did in previous years, but instead slowed significantly, approaching and then slightly exceeding 10.00% at a comparative crawl after 2010. Ethanol production exceeded domestic consumption through exports.

Figure 1.7-3: Nationwide Average Concentration of Ethanol in Gasoline



Source: Derived from EIA's Monthly Energy Review - ethanol consumption divided by motor gasoline consumption

After E10 was approved for use in all vehicles in 1979, consumers had a choice between E0 (gasoline without ethanol) and E10. Consumers likely made their choice based on knowledge of what fuels were available based on pump labeling, relative price, perceptions (or lack thereof) of impacts on vehicle fuel economy, vehicle operability or longevity, comfort with an unfamiliar fuel, and perceived benefits to the environment or economy. Since approaching and exceeding the E10 blendwall between 2010 and 2016, virtually all gasoline nationwide contains 10% ethanol. As a result, most consumers today have little choice but to use E10. However, with the expansion of retail service stations offering E15 and E85, the choice for consumers has now shifted to between E10 and these higher-level ethanol blends. For higher-level ethanol blends, consumers likely consider all of the factors they considered when the choice was between E0 and E10, plus whether the fuel is legally permitted to be used in their vehicle and whether the manufacturer has warranted their vehicle for its use.

1.7.1 E85

The earliest form of a higher-level ethanol blend was E85. In 1996, the first FFV was produced that could operate on fuel containing up to 85% denatured ethanol (83% ethanol).[60] Starting in 2007, ASTM International limited the maximum ethanol content of E85 to 83% in specification D5798, with a minimum ethanol content of 51%. EIA assumes that the annual, nationwide average ethanol concentration of E85 is 74%.[61]

E85 is not considered gasoline under EPA's regulations, and as such is permitted to be used only in FFVs. However, FFVs can operate on either gasoline or E85. Under basic economic theory, and assuming all other factors are equal, FFV owners are more likely to purchase E85 if they believe that doing so reduces their fuel costs. E85 reduces fuel economy in comparison to E10, and E85 must sell at a discount to E10 if it is to represent an equivalent value in terms of energy content. For an average E85 containing 74% ethanol, its volumetric energy content is approximately 21% less than E10 (or 24% lower than that of E0, though E0 is rarely the point of comparison as sales volumes of E0 are considerably lower than sales volumes of E10).[62,63] In order for E85 to be priced equivalently to gasoline on an energy-equivalent basis, then, its price must be on average 21% lower than that of E10. As shown in Figure 1.7.1-1, the nationwide average price of E85 compared to E10 has only rarely achieved the requisite energy equivalent pricing needed for FFV owners who are aware of and concerned about the fuel economy impacts of E85. Furthermore, E85 purchasers generally have no way of knowing whether their fuel contains 83% ethanol, 51% ethanol, or something in-between.

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[60] "Alternative Fuel Ford Taurus," available in the docket for this action.

[61] "AEO2022 Table 2," available in the docket for this action. See footnote 11.

[62] Assumes ethanol energy content is 3.555 mill Btu per barrel and gasoline energy content is 5.222 mill Btu per barrel. EIA Monthly Energy Review for April 2021, Tables A1 and A3.

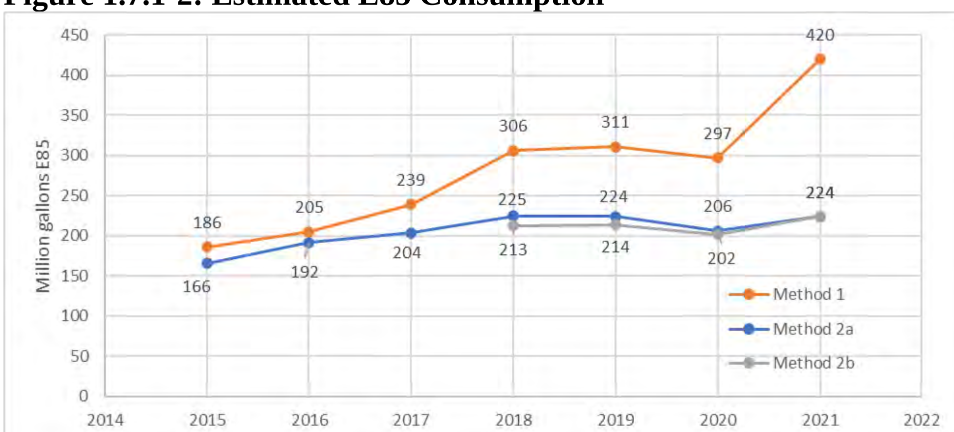
[63] A comparison to E0 would be more relevant prior to 2010 when there remained significant volumes of E0 for sale at retail stations.

Figure 1.7.1-1: Volumetric Price Reduction of E85 Compared to E10[a]

[a] The 21% energy equivalence level of E85 compared to E10 assumes that E85 contains 74% ethanol.
Note: While E85prices.com is a decentralized system consisting of voluntary submissions from motorists, the American Automobile Association (AAA) data is based on a daily collection of credit card swipe and direct feed price data from up to 130,000 retail stations. Moreover, the data collection by AAA is done in cooperation with the Oil Price Information Service (OPIS) and Wright Express to ensure reliability of the results.

EPA has estimated the nationwide volume of E85 consumed in recent years using two different methods.[64] The results of those analyses are shown in Figure 1.7.1-2.

Figure 1.7.1-2: Estimated E85 Consumption[a]



[a] The ethanol concentration of E85 is assumed to be 74% on average.

As discussed in Chapter 6.5, we do not need estimates of E85 (or E15) for the purposes of estimating total ethanol consumption for the years covered by this rule. However, for cost purposes only, we have estimated E15 and E85 volumes using a methodology and dataset different from that used to estimate the values in Figure 1.7.1-2. These estimates cover 2023, 2024, and 2025.

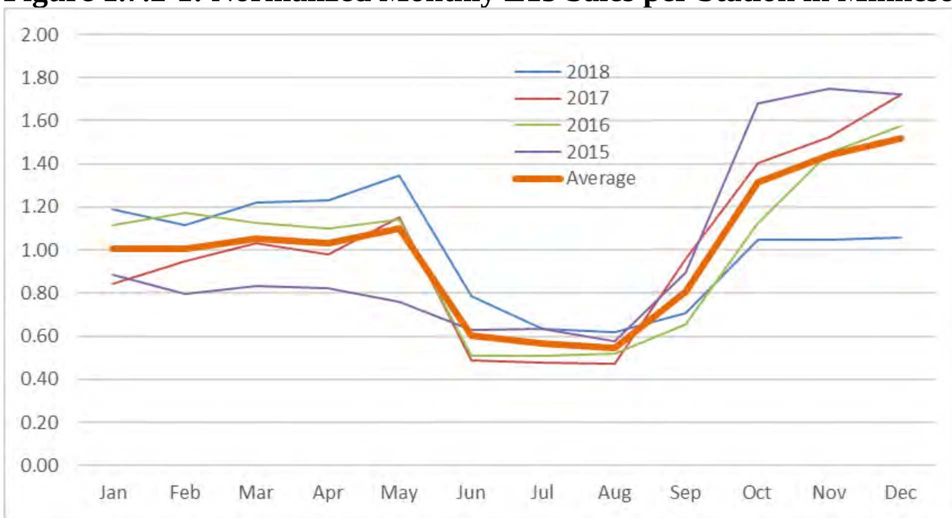
[64] "Estimate of E85 consumption in 2020," available in the docket for this action.

1.7.2 E15

In 2011, gasoline containing up to 15% ethanol was permitted to be used in model year (MY) 2001 and newer vehicles.[65] E15 has since been offered at an increasing number of retail service stations.[66] However, there is currently no publicly available data on actual nationwide E15 sales volumes.

Sales of E15 prior to 2019 were seasonal due to the fact that E15 did not qualify for the 1-psi RVP waiver for summer gasoline in CG areas that has been permitted for E10 since the summer volatility standards were implemented in 1989.[67] As shown in Figure 1.7.2-1, monthly E15 sales in Minnesota from 2015–2018 demonstrate that sales volumes of E15 in summer months were notably lower than in non-summer months in this time period.

Figure 1.7.2-1: Normalized Monthly E15 Sales per Station in Minnesota[a]



Source: Minnesota Commerce Department
[a] Normalized values derived by dividing the monthly E15 sales volume per station by the annual average E15 sales volume per station.

In 2019, EPA extended the 1-psi waiver to E15 by regulation.[68] EPA estimated that the annual average E15 sales per station in Minnesota would have been 16% higher had the 1-psi waiver been in place from 2015–2018.[69] On July 2, 2021, the U.S. Court of Appeals for the D.C. Circuit ruled that EPA's extension of the 1-psi waiver to E15 was based on an impermissible reading of the statute and vacated it. Insofar as the regulatory 1-psi waiver for E15 had an impact on summer sales of E15, therefore, it did so only for 2019–2021. While EPA issued emergency fuel waivers throughout the summer of 2022 that allowed E15 to take advantage of the 1-psi waiver to address issues related to fuel price and supply, we not expect to do so again in the future and thus do not expect that the 1-psi waiver for E15 will have an impact in 2023 or later years.

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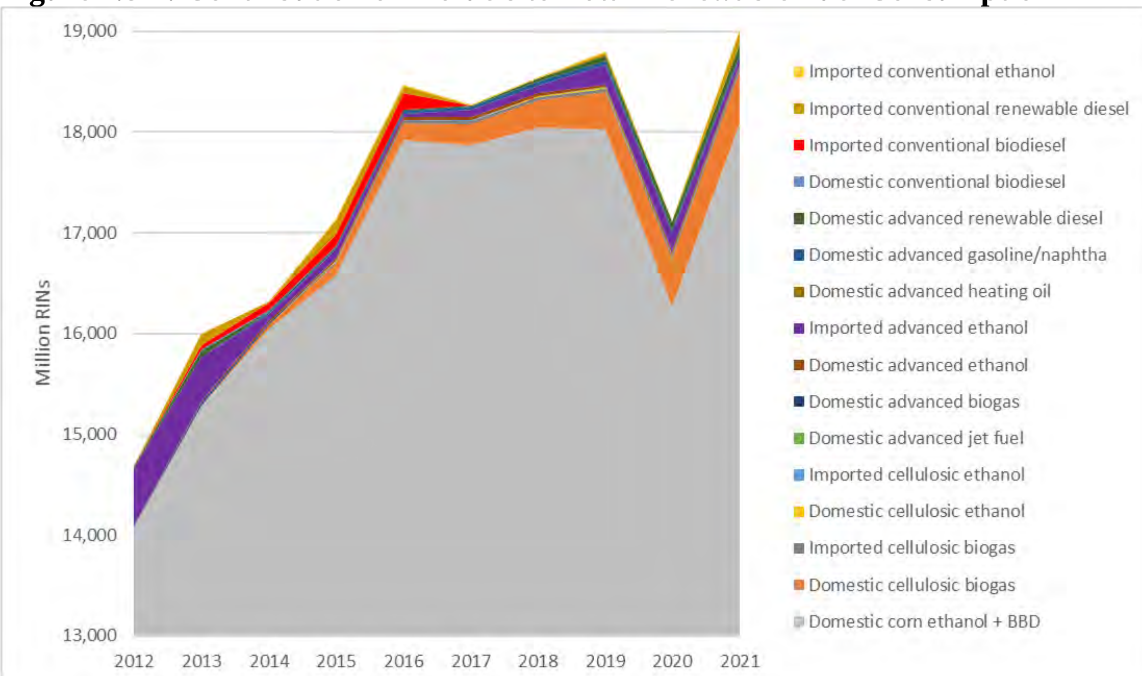
[65] 76 FR 4662 (January 26, 2011).
[66] See Chapter 6.4.3.
[67] 54 FR 11883(March 22, 1989).
[68] 84 FR 26980 (June 10, 2019).
[69] "Estimating the impacts of the 1psi waiver for E15," memorandum from David Korotney to EPA docket EPA-HQ-OAR-2019-0136.

1.8 Other Biofuels

Although domestic corn ethanol and BBD have dominated the biofuels landscape since implementation of the RFS program began in 2006, other biofuels have also contributed to the total renewable fuel pool, sometimes providing the marginal volumes needed to meet the other applicable standards. As shown in Figures 1.8-1 and 2, biofuels other than corn ethanol and BBD represented between 2–5% of total renewable fuel from 2012–2021.[70]

Figure 1.8-1: Contribution of Biofuels to Total Renewable Fuel Consumption[a,b]



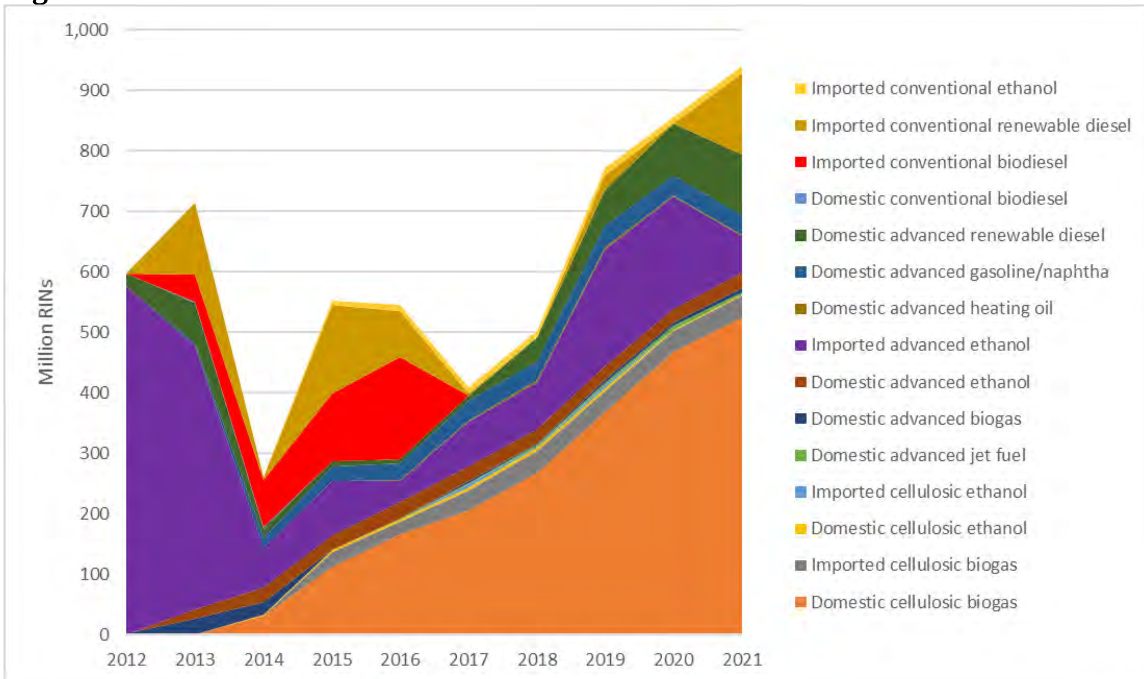
Source: EMTS

[a] Ignores any biofuels that contributed less than 1 million RINs in aggregate over all years shown. This affects domestic cellulosic gasoline/naphtha, domestic cellulosic diesel, and domestic conventional butanol.

[b] Fuel type and D code of exports is known, but whether the exported fuel was originally produced domestically or was imported is not known. For purposes of this chart, exports were assumed to be distributed to domestic production and imports in proportion to the relative production volumes of each.

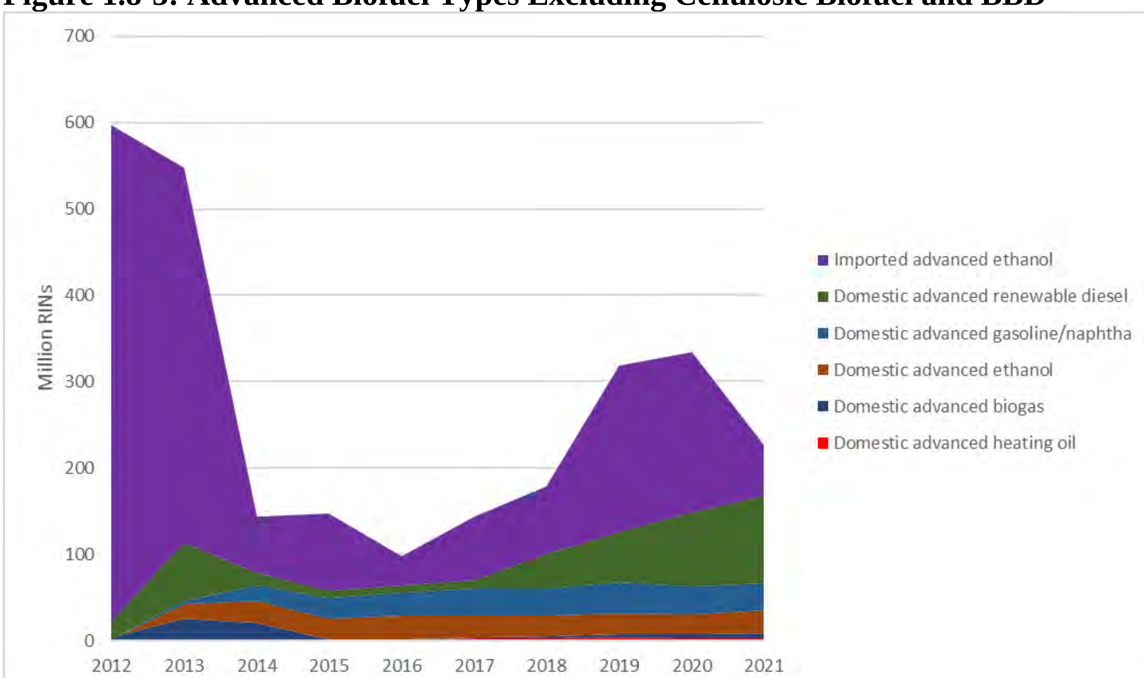
[70] Detailed data prior to 2012 on RIN generation, adjustments to account for invalid RINs, and exports is less robust and is therefore not presented here.

Figure 1.8-2: Biofuels Other than Corn Ethanol and BBD



As illustrated in Figure 1.8-3, advanced biofuel exclusive of cellulosic biofuel or BBD (i.e., renewable fuel having a D code of 5) has been met with the greatest variety of fuel types compared to the other statutory categories.

Figure 1.8-3: Advanced Biofuel Types Excluding Cellulosic Biofuel and BBD



Source: EMTS

These sources of advanced biofuel varied widely in both their overall contributions to the advanced biofuel pool from 2012–2021, as well as in each individual year. As the largest overall contributor, imported advanced ethanol produced from sugarcane in Brazil is discussed separately in Chapter 6.3. Production of domestic advanced renewable diesel,[71] gasoline/naphtha, and ethanol were of approximately similar magnitude and demonstrated no consistent increasing or decreasing trends between 2012–2021. Domestic advanced biogas fell to near zero in 2015 after biogas from landfills was recategorized as cellulosic biofuel in 2014.[72] Domestic advanced heating oil has grown steadily since 2012 but has never generated more than 3 million RINs in a single year.

As described in Chapter 1.5, cellulosic biofuel has been composed predominately of biogas-based CNG/LNG. Smaller volumes of cellulosic ethanol and heating oil and very small volumes of gasoline/naphtha and renewable diesel have also been used.

1.9 RIN System

RINs were created by EPA under CAA section 211(o)(5) as a flexible mechanism to enable obligated parties across the country to meet their renewable fuel blending obligations under the RFS program without having to blend the renewable fuel themselves.[73] RINs allow: (1) Obligated parties (i.e., the refining industry) to comply with the RFS program without producing, purchasing, or blending the renewable fuel themselves; (2) Non-obligated blenders of renewable fuel to maintain their preexisting blending operations; and (3) The ethanol and other biofuel industries to continue to produce biofuels, now with the support of the RIN value. Obligated parties, of course, can and do produce, purchase, and blend their own renewable fuel, but the RIN system allows them the option of not doing so and instead relying on the business practices of other market participants that are already set up to do so. RINs are generated by renewable fuel producers (or in some cases renewable fuel importers) and are assigned to the renewable fuel they produce. These RINs are generally sold together with the renewable fuel to refiners or blenders. RINs can be separated from renewable fuel by obligated parties or when renewable fuel is blended into transportation fuel. Once separated, RINs can be used by obligated parties to demonstrate compliance with their RFS obligations or can be traded to other parties.

Under the RFS program, EPA created five different types of RINs: cellulosic biofuel (D3) RINs, BBD (D4) RINs, advanced biofuel (D5) RINs, conventional renewable fuel (D6) RINs, and cellulosic diesel RINs (D7).[74] The type of RIN that can be generated for each renewable fuel depends on a variety of factors, including the feedstock used to produce the fuel, the type of fuel produced, and the lifecycle GHG reductions relative to petroleum fuel. As shown in Figure 1.9-1, the obligations under the RFS regulations are nested, such that some RIN types can be used to satisfy obligations in multiple categories.

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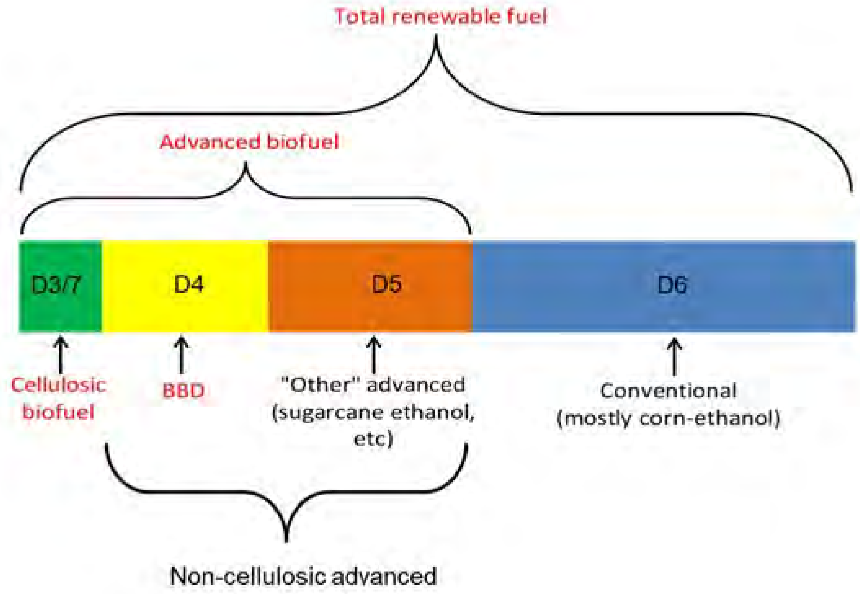
[71] Small quantities of renewable diesel are not BBD but are nonetheless advanced biofuel.
[72] 79 FR 42128 (July 18, 2014).
[73] The RIN system was created in the RFS1 rule (72 FR 23900, May 1, 2007) and modified in the RFS2 rule (75 FR 14670, March 26, 2010).
[74] 40 CFR 80.1425(g).

Figure 1.9-1: Nested Structure of the RFS Program



1.9.1 Carryover RIN Bank

CAA section 211(o)(5) requires that EPA establish a credit program as part of its RFS regulations, and that the credits be valid for obligated parties to show compliance for 12 months as of the date of generation. EPA implemented this requirement through the use of RINs, which can be used to demonstrate compliance for the year in which they are generated or the subsequent compliance year. Obligated parties can obtain more RINs than they need in a given compliance year, allowing them to "carry over" these surplus RINs for use in the subsequent compliance year. In order to ensure reasonably consistent demand for new renewable fuel use in the ensuing year, however, our regulations limit the use of these carryover RINs to 20% of an obligated party's renewable volume obligation (RVO). For the bank of carryover RINs to be preserved from one year to the next, individual carryover RINs are used for compliance before they expire and are essentially replaced with newer vintage RINs that are then held for use in the next year. For example, vintage 2022 carryover RINs must be used for compliance in 2023, or they will expire. However, vintage 2023 RINs can then be "banked" for use in 2024.

In the context of setting the annual volume standards, the relative number of carryover RINs projected to be available compared to the projected volume requirement for each category has helped inform EPA's decisions regarding the extent to which it should exercise its waiver authorities. During the first several years of the RFS2 program, the total number of RINs generated far exceeded the total number of RINs needed for obligated parties to demonstrate compliance. This resulted in a dramatic increase in the carryover RIN bank, up to an estimated 2.67 billion total carryover RINs in 2013, which represented over 16% of the total renewable fuel volume standard for that year.[75] As a result, EPA determined that sufficient carryover RINs existed such that it was not necessary for EPA to use its cellulosic or general waiver authority to

[75] EPA first began projecting the size of the carryover RIN bank in the 2013 RFS annual rule.

reduce the total or advanced biofuel volume requirements specified in the statute.[76] At the time, EPA recognized that this decision may result in a reduction in the carryover RIN bank, and this in fact occurred, as the total number of carryover RINs dropped by over 900 million RINs to an estimated 1.74 billion total carryover RINs in 2014.[77] As seen in Table 1.9.1-1, at the time the annual standards for 2013–2022 compliance years were established (i.e., the information available to EPA when the standards were finalized for the subsequent year), the relative size of the projected total carryover RIN bank compared to the projected total renewable fuel volume requirement ranged from a high of over 16% in 2013 to a low of 8% in 2017. However, the magnitude of the carryover RIN bank deviated from these projections sometimes significantly based on the decisions of the market players that only became known after the rule were finalized. With the benefit of hindsight, EPA can calculate the number of carryover RINs for each category that were actually available for compliance for a given year. As seen in Table 1.9.1-1, the actual size of the total carryover RIN bank compared to the actual volume obligation for 2013–2019 has ranged from a high of nearly 17% in 2018 to a low of 9% in 2016.[78] In absolute terms, the carryover RIN bank reached its highest historical levels going into the 2019 compliance year, at 3.43 billion RINs. However, as discussed in Preamble Section IV, the carryover RIN bank was significantly drawn down after 2019 compliance to 1.83 billion RINs.

[76] 78 FR 49820-22 (August 15, 2013).
[77] 80 FR 77482-87 (December 14, 2015).
[78] Similar comparisons can also be made for the advanced biofuel, BBD, and cellulosic biofuel categories, and are presented in Tables 1.9.1-2 through 4.

Table 1.9.1-1: Total Renewable Fuel Carryover RINs Compared to Total Renewable Fuel Volume Requirement[a]

Compliance Year	Total Renewable Fuel Carryover RINs Available (billion RINs)		Total Renewable Fuel Volume Requirement (billion gal)		Carryover RINs as % of Volume Requirement	
	Projected[b]	Actual[c]	Projected[b]	Actual[c]	Projected	Actual
2013	2.67	2.47	16.55	16.92	16.1%	14.6%
2014	1.74	1.58	16.28	16.31	10.7%	9.7%
2015	1.74	1.69	16.93	17.00	10.3%	10.0%
2016	1.74	1.65	18.11	17.93	9.6%	9.2%
2017	1.54	2.48	19.28	18.49	8.0%	13.4%
2018	2.22	3.13	19.29	18.51	11.5%	16.9%
2019	2.59	3.43	19.92	21.03	13.0%	16.3%
2020	1.83	n/a	17.13	n/a	10.7%	n/a
2021	1.83	n/a	18.84	n/a	9.7%	n/a
2022	1.83	n/a	20.63	n/a	8.9%	n/a
2023	1.83	n/a	20.82	n/a	8.8%	n/a
2024	1.83	n/a	21.87	n/a	8.3%	n/a
2025	1.83	n/a	22.68	n/a	8.1%	n/a

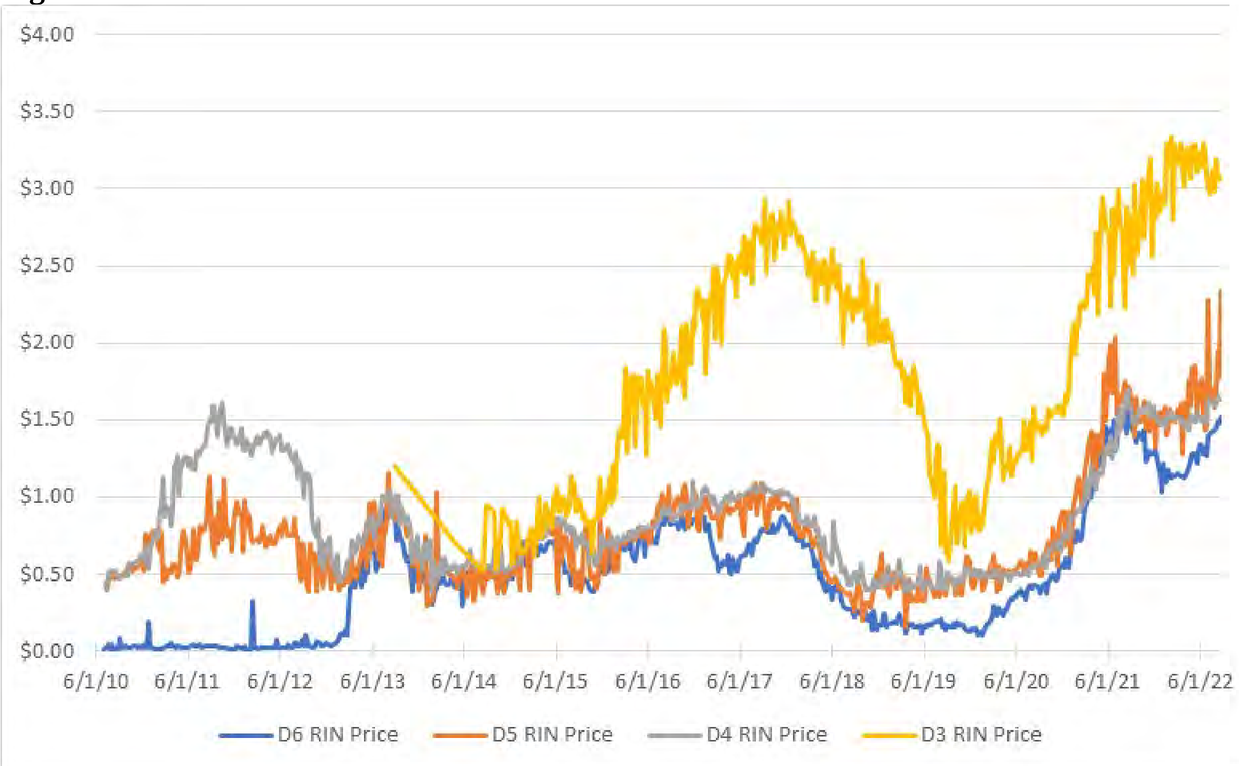
[a] For further discussion of these calculations, see "Carryover RIN Bank Calculations for 2023–2025 Proposed Rule," available in the docket for this action.
[b] Projected volume requirements and number of carryover RINs reflect the values projected in the rules establishing the standards for those years.
[c] Data current as of March 10, 2022, and compiled from Tables 2 and 3 at https://www.epa.gov/fuels-registration-reporting-and-compliance-help/annual-compliance-data-obligated-parties-and. Actual Volume Requirement = Reported Volume Obligation (Table 2) + Total End-of-Year Compliance Deficit (Table 5).

1.9.2 RIN Prices

RIN prices have varied significantly since 2010. There have also been significant and notable differences between the prices of each of the four major RIN types. A chart of RIN prices, as reported to EPA through EMTS, is shown in Figure 1.9.2-1.[79] While there are a wide variety of factors that impact RIN prices, including both market-based and regulatory factors, a review of RIN prices reveals several notable aspects of the RFS program.

[79] RIN prices are reported publicly on EPA's website (https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rin-trades-and-price-information). These prices are reported to EPA by the parties that trade RINs and are inclusive of all RIN trades (with the exception of RIN prices that appear to be outliers or data entry errors). Several other services also report daily RIN prices; however, these reports are generally not publicly available. Further, the prices reported by these services generally represent only spot trades and do not include RINs traded through long-term contracts.

Figure 1.9.2-1: RIN Prices



Data Source: EMTS Price Data

Prior to 2013, D6 RIN prices were low (less than $0.05 per RIN). These low prices were likely due to the fact that from 2010–2012 it was cost-effective to blend ethanol into gasoline as E10 even without the incentives provided by the RFS program. The low RIN prices during this period also indicate that the RFS requirements were not the driving force behind increased use of E10.

Beginning in 2013, D6 RIN prices rose sharply. 2013 marked the first time the implied conventional renewable fuel requirement exceeded the volume of ethanol that could be consumed as E10.[80] While it has generally been cost-effective to blend ethanol as E10, higher-level ethanol blends (e.g., E15 and E85) have generally not been cost effective, even with the incentives provided by the RFS program. This is largely because: (1) Fuel blends that contain greater than 10% ethanol are currently not able to be optimized to take advantage of the high octane value of ethanol; (2) The lower energy content of ethanol is more noticeable as the amount of ethanol increases; and (3) Infrastructure limitations have restricted the availability of higher-level ethanol blends (see Chapter 6.4).

In subsequent years, D6 RIN prices have varied significantly, but they have never returned to the low prices observed prior to 2013. It is also notable that, from 2013–2016, D6 RIN prices remained close to, but slightly less than, D4 and D5 RIN prices. During this time, obligated parties were purchasing D4 and D5 RINs in excess of their BBD and advanced biofuel

[80] The conventional renewable fuel requirement is the difference between the total renewable fuel requirement and the advanced biofuel requirement.

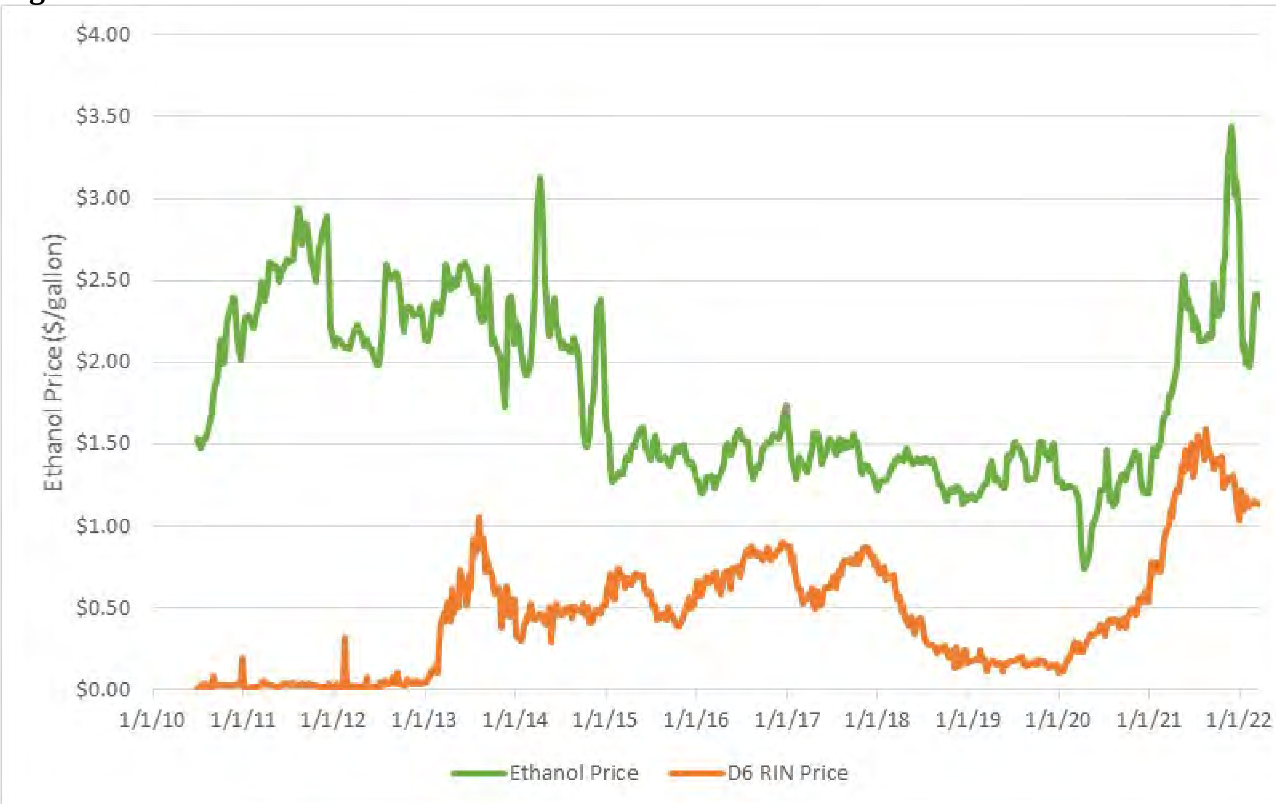
obligations to make up for the shortfall in conventional biofuel volume and used those RINs to meet their total renewable fuel obligations. Essentially, given the inability to successfully introduce higher-level ethanol blends into the market in sufficiently large quantities, the market relied upon biodiesel and renewable diesel (primarily advanced biofuel and BBD, but also some volume of conventional biodiesel and renewable diesel) as the marginal RFS compliance option when other sources of conventional biofuel were not available at competitive prices. After 2018, D6 RIN prices were, for some time, significantly lower than D4 and D5 RIN prices, but still higher than the D6 RIN prices observed prior to 2013. These lower D6 RIN prices are largely the result of: (1) SREs granted in 2018, which reduced the total number of D6 RINs needed for compliance with the RFS obligations to a number that was below the E10 blendwall; and (2) The large number of carryover RINs available, as discussed in Chapter 1.9.1. More recently, D4, D5, and D6 RIN prices have risen dramatically, reaching nearly $2 per RIN in the summer of 2021 before decreasing slightly to between $1.00–1.50 by the end of 2021. These prices reflect the cost of biodiesel and renewable diesel production (the marginal supply) at a time of unusually high commodity prices for soybean and other oil feedstocks, less the value of other subsidies and credits (e.g., the $1.00 per gallon federal tax subsidy and state LCFS credits).

While D6 RIN prices have remained relatively high in recent years, these price levels have not translated into higher ethanol prices for ethanol producers. After examining market data, EPA found no correlation between D6 RIN prices and ethanol prices from 2010–2022. Instead, higher D6 RIN prices have resulted in lower effective prices for ethanol after the RINs have been separated and sold.[81] Higher D6 RIN prices have thus served to subsidize fuel blends that contain higher proportions of conventional biofuel (e.g., E85 and B20 biodiesel/renewable diesel blends) and increased the cost of fuel blends that contain little or no conventional biofuel (e.g., E0 and B0).[82]

[81] The effective price is the price of the ethanol after subtracting the RIN value from the price of the ethanol with the attached RIN.

[82] Burkholder, Dallas. "A preliminary Assessment of RIN Market Dynamics, RIN Prices, and Their Effects." U.S. EPA Office of Transportation and Air Quality. May 2015.

Figure 1.9.2-2: Ethanol Prices and D6 RIN Prices



Data Sources: Ethanol Price from USDA Weekly Ag Roundup, D6 RIN Price from EMTS data

D5 RINs were priced at a level between D4 and D6 RINs from 2010–2013. However, since 2013, D5 RIN prices have been nearly identical to D4 RIN prices. This shift in the relative pricing of D5 and D4 RINs also corresponds with the market reaching the E10 blendwall. This is because there are two primary fuel types that have been used to satisfy the advanced biofuel requirements: sugarcane ethanol and BBD. From 2010–2012, obligated parties generally met their implied requirements for "other advanced biofuel" with sugarcane ethanol.[83] This is apparent in the volumes of sugarcane ethanol (which supplied the vast majority of volume requirement for "other advanced" biofuels) and BBD (which did not exceed the volume requirement for BBD by an appreciable volume) used in the U.S. in these years.[84] It is also indicated by the prices for D5 RINs, which were significantly lower than the price of D4 RINs during this time, suggesting that it was more cost effective for obligated parties to meet their compliance obligations with D5 RINs (generated for sugarcane ethanol) than D4 RINs (generated for biodiesel and renewable diesel). When the E10 blendwall was reached in 2013, however, it became much more expensive to increase the volume of ethanol blended into the gasoline pool. While obligated parties could still import sugarcane ethanol to satisfy their advanced biofuel obligations, doing so would reduce the volume of corn ethanol that could be used as E10. Available non-ethanol renewable fuels were almost entirely advanced biodiesel and

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[83] "Other advanced biofuel" is not an RFS standard category, but is the difference between the advanced biofuel requirement and the sum of the cellulosic biofuel and BBD requirements, both of which are nested within the advanced biofuel category.

[84] See Chapters 6.3 and 6.2 for volumes of sugarcane ethanol and BBD used in the U.S., respectively.

renewable diesel, so obligated parties generally used these fuels (rather than sugarcane ethanol) to meet the advanced biofuel requirements so that they could use corn ethanol to satisfy the remaining total renewable fuel requirements. RIN prices responded, and since 2013 the prices of D4 and D5 RINs have been nearly identical.

D4 RIN prices, much like all RIN prices, have varied significantly since 2010. The pricing of these RINs, however, has been fairly straightforward. D4 RINs are generally priced to account for the price difference between biodiesel and petroleum diesel, which in turn are largely a function of the pricing of their respective oil supplies. Other factors can also impact this relationship; most significantly are the presence or absence of the biodiesel tax credit and the impact of other subsidies and credits (e.g., the $1.00 per gallon federal tax subsidy and state LCFS credits).[85] Most recently, in 2021 and 2022, D4 RIN prices have increased quite significantly, tracking with an increase in feedstock commodity prices (e.g., soybean oil), which comprise greater than 80% of the cost of production of BBD. Generally, D4 RIN prices have increased to a level that allows BBD to be cost-effective with petroleum-based fuels, increasing BBD production and use. A 2018 paper exploring the relationship between the price of D4 RINs and economic fundamentals concluded that "movements in D4 biodiesel RIN price at frequencies of a month or longer are well explained by two economic fundamentals: (a) the spread between the biodiesel and ULSD prices and (b) whether the $1 per gallon biodiesel tax credit is in effect."[86] This same paper discusses in greater detail the strong correlation between weekly D4 RIN prices and predicted D4 RIN price values using a model based on economic fundamentals. As state LCFS programs have come online and increased in stringency, the value of these credits is now another increasingly important factor.

Data on cellulosic RIN (D3 and D7) prices were not generally available until 2015. This is likely due to the fact that prior to 2015, the market for cellulosic RINs was too small to support commercial reporting services; very few cellulosic RINs were generated and traded in years prior to 2016. From 2015—when D3 RIN prices were first regularly available—through 2018, the price of these RINs was very closely related to the sum of the D5 RIN price plus the price of the cellulosic waiver credit (CWC).[87] This is as expected, since obligated parties can satisfy their

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[85] A $1 per gallon biodiesel blenders tax credit has been available to biodiesel blended every year from 2010–2022. However, at various times this credit has expired and been reinstated retroactively. The biodiesel tax credit expired at the end of 2009 and was not reinstated until December 2010, applying to all biodiesel blended in 2010 and 2011. The biodiesel tax credit has since been again reauthorized semi-regularly, including in January 2013 (applying to biodiesel produced in 2012 and 2013), December 2014 (applying to biodiesel produced in 2014), December 2015 (applying to biodiesel produced in 2015 and 2016), and February 2018 (applying to biodiesel produced in 2017). In December 2019 the tax credit was retroactively reinstated for 2018 and 2019 and put in place prospectively through 2022. In August 2022, the tax credit was extended through 2024. Beginning in 2025 biodiesel and renewable diesel could qualify for the clean fuel production credit.

[86] Irwin, S.H, K. McCormack, and J. H. Stock (2018). "The price of biodiesel RINs and economic fundamentals." NBER working paper series, working paper 25341.

[87] Pursuant to CAA section 211(o)(7)(D)(ii), EPA makes CWCs available for sale to obligated parties at a price determined by a statutory formula in any year in which EPA reduces the required volume of cellulosic biofuel using the cellulosic waiver authority. A CWC satisfies an obligated party's cellulosic biofuel obligation. However, unlike a cellulosic RIN, which also helps satisfy an obligated party's advanced biofuel and total renewable fuel obligations, a CWC does not help satisfy an obligated party's advanced biofuel and total renewable fuel obligations. A cellulosic RIN (which can be used to meet all 3 obligations) has similar compliance value as a CWC (which can only be used to satisfy the cellulosic biofuel obligation) and an advanced RIN (which can be used to satisfy the advanced biofuel and total renewable fuel obligations).

cellulosic biofuel obligations through the use of either cellulosic RINs or CWCs plus D5 RINs. The slight discount for D3 RINs (as opposed to the combination of a CWC and a D5 RIN) is also as expected, as CWCs can be purchased directly from EPA when obligated parties demonstrate compliance and carry no risk of RIN invalidity.[88] This discount tends to be larger at the beginning of the year, before narrowing near the end of the year as the RFS compliance deadline nears for obligated parties. Starting in 2019, the D3 RIN price was significantly lower than the CWC plus D5 RIN price. This is likely due to an over-supply of D3 RINs caused by EPA granting a relatively large number of SREs for the 2017 and 2018 compliance years, lowering the effective RFS standards (see Chapter 1.2). The average D3 RIN price fell to near the D5 RIN price, before slowly increasing relative to the D5 RIN price starting in the second half of 2019.

Figure 1.9.2-3: D3 RIN Prices and D5 RIN Price Plus CWC Price[89]

Source: RIN price data from EMTS

The fact that the price of D3 RINs, with very few exceptions, has not exceeded the CWC plus D5 RIN price has potentially significant consequences for both the cellulosic biofuel and petroleum fuel markets. For obligated parties, the CWC price effectively sets a maximum price for cellulosic RINs and protects these parties from excessively high cellulosic RIN prices. The CWC price is also informational to potential cellulosic biofuel producers. Potential cellulosic

[88] During a few time periods (such as late 2016), the price for D3 RINs was higher than the price for a CWC + D5 RIN. This was likely due to the fact that up to 20% of a previous year's RINs can be used towards compliance in any given year, while CWCs can only be used towards compliance obligations in that year. Obligated parties likely purchased 2016 D3 RINs at a premium anticipating the sharp increase in the CWC price in 2017.

[89] EPA offers cellulosic waiver credits for years in which we reduce the cellulosic biofuel volume from the statutory target. Cellulosic waiver credit prices are available at: https://www.epa.gov/renewable-fuel-standard-program/cellulosic-waiver-credits-under-renewable-fuel-standard-program.

biofuel producers can use the CWC price, along with the price of the petroleum fuel displaced by the cellulosic biofuel they produce and any tax credits or other incentives available for the fuel, as an approximation of the maximum price they can reasonably expect to receive for the cellulosic biofuel they produce. Knowing this price can help potential cellulosic biofuel producers determine whether their cellulosic biofuel production processes are economically viable under both current and likely future market conditions.

At the same time, the relatively high value of the CWC plus D5 RIN price, in conjunction with EPA's statutory obligation since 2010 to set the required volume of cellulosic biofuel at the volume expected to be produced each year,[90] has resulted in generally high D3 RIN prices. These RIN prices are realized for all cellulosic RINs, even those generated for biofuels such as CNG/LNG derived from biogas that can often be produced at a cost that is competitive with the petroleum fuels they displace even without the RIN value. While some of this excess RIN value may be passed on to consumers who use CNG/LNG derived from biogas as transportation fuel in the form of lower cost fuel and/or longer term fixed-price fuel contracts, a significant portion of the RIN value may remain with the biofuel producer, the parties that dispense CNG/LNG derived from biogas, and any other parties involved in the production of this type of cellulosic biofuel.[91] Unlike other RIN costs that are generally transfered within the liquid fuel pool (e.g., from consumers of fuels with relatively low renewable fuel content such as E0 or B0 to consumers of fuels with relatively high renewable fuel content such as E85 or B20), much of the RIN value for CNG/LNG derived from biogas may be transferred from consumers who purchase gasoline and diesel to parties outside of the liquid fuel pool (e.g., landfill owners). For example, the average cellulosic RIN price was $2.75 in 2021.[92] Thus, the total cost associated with the 560 million cellulosic RINs required for compliance in 2021 was approximately $1.54 billion. Therefore, the cellulosic biofuel requirement likely increased the price of gasoline and diesel sold in the U.S. in 2021 by approximately $0.01 per gallon.[93] These transfers would be expected to increase significantly through 2025 if the cellulosic biofuel volumes we are proposing in this rule are finalized. For example, using the average cellulosic RIN price in 2021 of $2.75 and the proposed cellulosic biofuel volume for 2025 of 2.13 billion gallons, we estimate that the cost associated with cellulosic RIN purchases would be $5.86 billion, and would be expected to increase the price of gasoline and diesel in 2025 by approximately $0.03 per gallon.[94]

[90] CAA section 211(o)(7)(D).
[91] EPA currently does not have sufficient data to determine the proportion of the RIN value that is used to discount the retail price of CNG/LNG derived from biogas when used as transportation fuel.
[92] Average D3 RIN price in 2021 according to EMTS RIN price data.
[93] In the January 2022 STEO, EIA forecasted gasoline and diesel consumption in 2021 at 8.79 million bpd (134.5 billion gallons per year) and 3.25 million bpd (49.9 billion gallons per year) respectively. Dividing the total cost of cellulosic RINs in 2021 ($1.54 billion) by the total consumption of gasoline and diesel (184.4 billion gallons) results in an estimated cost of $0.008 per gallon of gasoline and diesel as a result of the cellulosic biofuel requirement.
[94] In the 2022 AEO, EIA forecasted gasoline and diesel consumption in 2021 at 139.1 billion gallons and 52.5 billion gallons respectively. Dividing the total cost of cellulosic RINs in 2025 ($5.86 billion) by the total consumption of gasoline and diesel (191.6 billion gallons) results in an estimated cost of $0.031 per gallon of gasoline and diesel as a result of the cellulosic biofuel requirement.

Chapter 2: Baselines

This DRIA contains a collection of analyses prescribed by the CAA, as well as other analyses EPA conducted to evaluate the impacts of this rule. The choice of baseline has a first-order impact on the outcome of those analyses. In Preamble Section III.D, we discuss the fact that a "No RFS" baseline is the most appropriate among available options for purposes of evaluating the impacts of the proposed volumes for 2023–2025. This chapter describes our derivation of the No RFS baseline, as well as an alternative baseline representing the 2022 volume requirements.

The No RFS baseline represents our projection of the world as it would exist if EPA did not establish volume requirements for 2023–2025.[95] Conceptually, the No RFS baseline allows EPA to directly project the impacts of the candidate volumes for 2023–2025 relative to a scenario without volume requirements. For the No RFS baseline, we assumed that the RFS program existed as administered by EPA from its inception through 2022, and that renewable fuel production developed with the support of the RFS program in these years. We also assumed that non-RFS federal and state programs that support renewable fuel production and use (e.g., the BBD tax credit and state LCFS programs), would continue to exist in 2023–2025.

While the No RFS baseline represents the renewable fuel volumes we expect would be used in the U.S. if EPA did not establish RFS volume requirements, we note that this baseline is a hypothetical scenario because we have a statutory requirement to establish volume requirements for each year.[96] Moreover, the statute places a few key conditions on the volume requirements for years after those established in the statute,[97] and these conditions would not permit the volumes to be set equivalent to the No RFS baseline. First, we note that the No RFS baseline volumes projected in this section would not meet the statutory requirement that the advanced biofuel volume requirement be at least the same percentage of the total renewable fuel volume requirement as in calendar year 2022.[98] Second, the No RFS baseline volumes projected in this chapter would not meet the statutory requirement that the BBD volume requirement be at least 1 billion gallons for every year after 2012.[99] Nevertheless, the No RFS baseline is an appropriate point of reference since it allows us to estimate the impacts of this proposed action alone.

To project the No RFS baseline, we began by projecting renewable fuel use in the U.S. in 2023–2025 in the absence of volume requirements for these years.[100] We assumed that all state mandates for renewable fuel use would continue, and that additional volumes of renewable fuel would be used if these fuels could be provided at a lower price than petroleum-based fuels, after taking into account available federal and state incentives. The differences between the candidate

[95] Or, alternatively, if EPA established volume requirements at levels lower than what the market would have supplied anyway.
[96] CAA section 211(o)(2)(B)(ii).
[97] See Preamble Section II.C.3.
[98] CAA section 211(o)(2)(B)(iii). The ratio of advanced to total for the 2022 volume requirements is 0.273, while the ratio of advanced to total for the No RFS baseline is 0.124 in 2023.
[99] CAA section 211(o)(2)(B)(v). The statutory volume for BBD in 2012 was 1 billion gallons. CAA section 211(o)(2)(B)(i)(IV).
[100] The analyses conducted to make this projection are described in Chapter 2.1.

volumes and the No RFS baseline represent the volume changes that we analyzed for this proposed rule. These volumes changes, as detailed in Chapter 3, are the starting point for the analyses presented in this DRIA, except where noted.

In some cases, the volume changes between the No RFS baseline and the candidate volumes is sufficient to assess the impacts of the various factors enumerated in the statute. For example, the GHG impacts and the costs are directly dependent on the volume of renewable fuel used in the U.S. In other cases, however, these volume changes alone are insufficient and potentially misleading. For example, the candidate volume for total domestic ethanol consumption is 706–840 million gallons per year higher than under the No RFS baseline. This projected volume increase could imply that additional ethanol production capacity and distribution infrastructure would be needed to supply the candidate volumes. But total domestic ethanol consumption in the candidate volumes for 2023–2025 is lower than total domestic ethanol consumption achieved in previous years. Thus, no additional ethanol production capacity or distribution infrastructure are projected to be needed to meet the candidate ethanol volumes for 2023–2025. Where appropriate, such as in our assessment of infrastructure, we have therefore considered not only the change in domestic renewable fuel consumption from the No RFS baseline to the candidate volumes, but also other relevant factors as they exist in 2022.

There are some cases where we have insufficient information to project a No RFS baseline for 2023–2025, such as U.S. crop production. U.S. crop production has an impact on a number of the statutory factors, such as the projected conversion of wetlands, ecosystems, and wildlife habitat, water quality, and water availability. At this time, we have insufficient information to determine what U.S. crop acreage and production would be under a No RFS baseline. One potential scenario is that total U.S. crop acreage and production would decrease in 2023–2025 if there was lower demand for crops for biofuel production. But other scenarios are also possible and may be more likely. If demand for biofuel in the U.S. were lower in 2023–2025 in the absence of the RFS program, it is possible that biofuel exports would increase, and the market would see little to no change in domestic biofuel production or biofuel feedstock crop production. For instance, there have been significant exports of ethanol in recent years,[101] and both imports and exports of biodiesel and renewable diesel.[102] Foreign markets may be able to absorb additional renewable fuel exports from the U.S. Alternatively, domestic biofuel production could decrease with little change in U.S. crop acreage and production if there is sufficient demand for these crops in other markets, or production of crops used for biofuel production could decrease and farmers could plant other crops on land previously used for production of biofuel feedstocks. In cases where we have insufficient information to determine what would happen under the No RFS baseline, we have used the most recent data available (generally from 2021 or 2022) as a proxy for the No RFS baseline.

Finally, for our assessment of costs and fuel price impacts we have considered the impacts of the candidate volumes relative to both the No RFS baseline and a 2022 baseline. We recognize that the 2022 baseline may be of interest to the public as it gives an indication of changes in volume requirements over time and how costs and fuel prices may change from current levels as a result of this proposal. Nevertheless, we believe that the No RFS baseline

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[101] See Chapter 6.6.
[102] See Chapter 6.2.4.

better represents the overall impacts of taking an action to establish volume requirements for 2023–2025 versus not taking that action.

2.1 No RFS Baseline

The No RFS baseline was derived from the relative economics of biofuels and the petroleum fuels that those biofuels are blended into. If the blending cost of a biofuel is less than the petroleum fuel that it is blended into, we assume that the biofuel would be used and displace the respective petroleum fuel. The blending cost of a biofuel includes the value that the biofuel has when blending it into the petroleum fuel. There are several components that must be considered for each fuel:

- Production cost
- Distribution cost
- Blending value to the fuel blender (i.e., octane value and RVP cost of ethanol)
- Federal and state subsidies
- Relative energy value of the fuel, which may or not be a factor
- Cost to upgrade retail stations to enable them to offer the renewable fuel

These various cost components of each renewable fuel are added together to determine the value of each fuel at the point that it is to be blended into petroleum fuel. For each renewable fuel, the combination of these various cost components is represented using an equation that will be described in each case.

There are many similarities between this No RFS baseline analysis and that of the cost analysis described in Chapter 10, but there are differences as well. Table 2.1-1 summarizes the various cost components considered for this analysis and provides comments how this analysis differs from the cost analysis.

Table 2.1-1: Comparison of No RFS Baseline Analysis to Cost Analysis

	Included in No RFS and Cost Analysis		
	No RFS	Cost	Notes
Production Cost	Yes	Yes	For the No RFS baseline, capital costs are amortized using higher return on investment with taxes, while cost analysis uses lower pre-tax return on investment used for social analyses
Distribution Cost	Yes	Yes	Same
Blending Cost	Yes	Yes	Same
Fuel Economy Cost	Yes	Yes	The cost analysis always accounts for fuel economy cost, while the No RFS baseline only does so if it impacts the value of the renewable fuel to fuel blenders
Federal and State Subsidies	Yes	No	The social cost analysis never takes subsidies into account
Conducted on a State-by-State, Fuel Type-by-Fuel Type Basis	Yes	No	While a national-average cost is sufficient for the cost analysis, it was necessary to estimate the economics of blending renewable fuel in individual states that offer subsidies, and by fuel type, to assess whether the renewable fuel would be blended into each fuel in that state

For the No RFS baseline analysis, we use the latest projected feedstock prices (e.g., corn, vegetable oil) for estimating the production costs for their associated fuels. For some renewable fuels, the estimated volume under a No RFS scenario is projected to be significantly smaller than under the RFS program. This result could in turn result in lower market prices for the agricultural feedstocks, making the renewable fuels made from them more attractive. We did not evaluate such a feedback mechanism. The various economic factors shown in Table 2.1-1 are further discussed below for each renewable fuel.[103]

2.1.1 Ethanol

By far the largest volume of ethanol blended into U.S. gasoline is produced from corn and is mostly blended into gasoline at 10% (i.e., E10). However, some volume of ethanol is also blended at higher blend percentages of 15% and 51-83% (i.e., E15 and E85, respectively).[104] This chapter discusses the blending economics of ethanol and estimates the No RFS baseline for all three of these ethanol fuel blends.

[103] The spreadsheets used to estimate the No RFS baseline for corn ethanol and biodiesel and renewable diesel are available in the docket for this action.

[104] E85 (Flex Fuel), Alternative Fuels Data Center, https://afdc.energy.gov/fuels/ethanol_e85.html.

2.1.1.1 E10

The cost of blending ethanol into gasoline at 10% was analyzed by EPA in a peer reviewed technical report.[105] That report and its appendix provides both an historical review and prospective analysis for the economics of blending ethanol into gasoline. The methodology used in that analysis and its conclusion are summarized here.

A number of key factors were considered when evaluating the relative economics of blending ethanol into gasoline. These factors depend on the type of gasoline the ethanol is blended into, the season or year, and tax policies. Since ethanol is blended into gasoline at the gasoline distribution terminal, it is most straightforward to consider those economic factors that impact the decision to blend ethanol at that point. From that vantage point, the relative economics of blending ethanol into gasoline—or the value of replacing ethanol in gasoline with other components—can be summarized by the following equation:

$$EBC_{E10} = (ESP + EDC - ERV - FETS - SETS) - GTP$$

Where:

- EBC_{E10} is ethanol blending cost for E10
- *ESP* is ethanol plant gate spot price
- *EDC* is ethanol distribution cost
- *ERV* is ethanol replacement value
- *FETS* is federal ethanol tax subsidy
- *SETS* is state ethanol tax subsidy
- *GTP* is gasoline terminal price; all are in dollars per gallon

This equation allows us to break down these factors by year, by state, and by gasoline type, enabling a detailed assessment of the relative blending economics of ethanol to gasoline over time and by location. If the resulting ethanol blending cost is negative, it is assumed to be cost-effective to blend ethanol. Since gasoline is marketed based on volume, not energy content, the lower energy density of ethanol is not part of the ethanol blending cost equation. E10 contains about 3% less energy content than E0, and the cost of the lower energy content of the gasoline is paid by consumers through lower fuel economy and more frequent refueling. Since this small change in energy content is largely imperceptible to consumers and because gasoline without ethanol is not widely available, refiners are able to price ethanol based on its volume (unlike E85, for example, which must be priced lower at retail due to its lower energy density). Thus, energy density is not a factor in this blending cost equation for E10. It is an important part of assessing the overall social costs of ethanol use, but does not factor into the decision to blend ethanol as E10.

[105] "Economics of Blending 10 Percent Corn Ethanol into Gasoline," EPA-420-R-22-034, November 2022.

Ethanol Plant Gate Spot Price (ESP)

We estimated future ethanol plant gate prices by gathering projected ethanol plant input information (e.g., future corn prices projected by USDA and utility prices projected by EIA) to estimate ethanol production costs that we presume represents plant gate prices. This is essentially the same information used for estimating ethanol production costs for the cost analysis, except that the capital costs are handled differently. Instead of amortizing the capital costs using a 7% before tax rate of return on investment, capital costs are amortized using a 10% after tax return on investment. As shown in Table 2.1.1.1-1, the capital amortization factor increases to 0.16 from 0.11 used for the cost analysis.

Table 2.1.1.1-1: Capital Amortization Factor Used for Estimating Plant Gate Spot Prices Based on Production Costs

Depreciation Life	Economic and Project Life	Federal and State Tax Rate	Return on Investment	Resulting Capital Amortization Factor
10 Years	15 Years	39%	10%	0.16

The year-by-year ethanol plant gate price projections are based on production costs and are summarized in Table 2.1.1.1-2. There are two sets of ethanol price projections, one made by the Energy Information Administration (EIA) and the second by the Food and Agricultural Policy Research Institute (FAPRI), which are also summarized in Table 2.1.1.1-2.

Table 2.1.1.1-2: Projected Ethanol Plant Gate Prices

Year	Price ($/gal)
2023	1.82
2024	1.72
2025	1.66

Ethanol Distribution Cost (EDC)

This factor represents the added cost of moving ethanol from production plants to gasoline distribution terminals, reflecting its different modes of transport (the gasoline terminal prices in the equation already includes distribution costs). Because ethanol is primarily produced in the Midwest and distributed longer distances to the rest of the country, the terminal price of ethanol is usually lower in the Midwest than in other parts of the U.S. Ethanol distribution costs were estimated for EPA on a regional basis, but to conduct the analysis on a state-by-state basis, these costs were interpolated or extrapolated to estimate state-specific costs based on ethanol spot prices.[106] The estimated distribution costs for ethanol ranged from 11¢/gal in the Midwest to 29¢/gal when moved to the furthest distances along the U.S. coasts, and over 50¢/gal when shipped to Alaska and Hawaii. The distribution cost to each state is summarized in Table 2.1.1.1-3.

[106] Modeling a "No-RFS" Case; refinery modeling conducted by Mathpro for EPA under ICF Contract EP-C-16-020, July 17, 2018.

Table 2.1.1.1-3: Ethanol Distribution Cost by State

Region	States	Average Ethanol Distribution Cost (¢/gal)
PADD 1	New York, Pennsylvania, West Virginia	28.7
	District of Columbia, Connecticut, Delaware, Maryland, Massachusetts, New Jersey, Rhode Island, Virginia	20.7
	Georgia, South Carolina Vermont, New Hampshire, North Carolina	22.7
	Florida, Maine	28.8
PADD 2	Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Nebraska, Ohio, South Dakota, Wisconsin	11.0
	Kentucky, North Dakota, Oklahoma, Tennessee	20.7
PADD 3	Arkansas, Louisiana, Mississippi, Texas	15.5
	Alabama, New Mexico	20.7
PADD 4	Colorado, Idaho, Montana, Utah, Wyoming	17.2
PADD 5	Oregon, Washington	21.4
	Arizona, California, Nevada	25.4
	Alaska, Hawaii	51.0

Ethanol Replacement Value (ERV)

Ethanol has properties that provide value (primarily octane) or cost (vapor pressure impacts) when it is blended into gasoline. We use the term “ethanol replacement value” to refer to the sum of the costs due to these properties, including properties that increase and decrease ethanol’s blending value. Depending on where and when the ethanol is used, the ethanol blending value is an important consideration when gasoline production is modified to take into account the subsequent addition, or potential removal, of ethanol.

Essentially all E10 blending in the U.S. now occurs by “match-blending,” where the base gasoline (“gasoline before oxygenate blending” or BOB) is modified to account for the subsequent addition of ethanol, in which the blending value of ethanol is important. In RFG areas, refiners produce a reformulated gasoline before oxygenate blending (RBOB) that has both a lower octane value and lower RVP tailored to still meet the RFG standards after the addition of ethanol. This has been typical for ethanol-blended RFG since the mid-1990s. As the use of ethanol expanded into CG areas, a similar match-blending process began to be used there as well, replacing splash-blending. In these areas, a conventional gasoline before oxygenate blending (CBOB) is produced by refiners for match-blending with ethanol. CG is also adjusted to account for the octane value of ethanol, but unlike RFG, most CG is not adjusted for RVP due to a 1-psi RVP waiver provided for E10 in most locations. When RBOB and CBOB are produced, the refiner makes the decision that ethanol will be blended into their gasoline since the BOBs cannot be sold as finished gasoline without adding 10% ethanol, but the ethanol is still blended into the gasoline at the terminal.[107] It is likely that refiners make their decision on producing BOBs based on the economics of producing finished gasoline at terminals. In the case

[107] The exception to this is a small amount of premium grade BOB that is sold as regular or midgrade E0.

of such match blends, the economic value of ethanol relative to gasoline includes a consideration of not only its value on a volumetric basis as a substitute for gasoline, but also the blending value of ethanol resulting from its higher octane, and in some cases, its impact on volatility.

The full value of ethanol is best reflected by the cost associated with meeting all of the gasoline standards and requirements through some means other than blending ethanol, including any capital costs to produce ethanol replacements. To assess this, ICF conducted refinery modeling for EPA for removing ethanol from the gasoline pool.[108] After aggregating the refinery cost modeling results—which account for the octane value and volatility of ethanol, as well as replacing its volume—the replacement costs of ethanol in regular grade CG and RFG are summarized in Table 2.1.1.1-4.

Table 2.1.1.1-4 Ethanol Replacement Value ($/gal)

Gasoline Type	Gasoline Grade	Year 2023	2024	2025
Conventional Gasoline	Summertime Regular	1.44	1.60	1.66
	Summertime Premium	1.08	1.20	1.26
Reformulated Gasoline	Summer Regular	1.24	1.38	1.43
	Summer Premium	0.89	0.99	1.03
Conventional and Reformulated	Winter Regular	0.58	0.65	0.67
	Winter Premium	0.44	0.49	0.51

The ethanol replacement costs were estimated based on a certain set of modeling conditions—projected prices for the year 2020 with crude oil priced $72/bbl. The economics for replacing ethanol, however, would be expected to vary over time based on changing market factors, such as the market value for RVP control costs, crude oil prices, and particularly the market value for octane. The ethanol replacement costs were adjusted for the years analyzed under the No RFS baseline based on crude oil prices, which likely provides a reasonable estimate of how refiners would value the octane, RVP, and other replacement costs of ethanol over time.

Federal and State Ethanol Tax Subsidies (FETS and SETS)

The federal ethanol blending tax subsidy expired in 2011, so it did not figure into the No RFS baseline analysis. Various state tax subsidies, however, have been provided for the use of ethanol. These tax subsidies incentivize the blending of ethanol into the gasoline pool and directly impact the decision of whether to use ethanol. Iowa and Illinois offer an ethanol blending subsidy of 25¢/gal and 29¢/gal, respectively.[109] The California LCFS program is estimated to provide ethanol a blending credit of 33¢/gal in 2019.[110,111] Several states also have

[108] The results of this refinery modeling are summarized in Chapter 10.1.3.1.1; Analysis of the Effects of Low-Biofuel Use on Gasoline Properties; An Addemdum to the "No-RFS" Study; refinery modeling study conducted by Mathpro for EPA under ICF Contract EP-C-16-020; June 7, 2019.
[109] States' Biofuels Statutory Citations; The National Agricultural Law Center; University of Arkansas, https://nationalaglawcenter.org/state-compilations/biofuels.
[110] California Air Resources Board (CARB), Fuel Pathway Table; LCFS Pathway Certified Carbon Intensities; https://ww2.arb.ca.gov/resources/documents/lcfs-pathway-certified-carbon-intensities.
[111] Weekly LCFS Credit Transfer Activity Reports; California Air Resources Board; https://ww3.arb.ca.gov/fuels/lcfs/credit/lrtweeklycreditreports.htm.

ethanol use mandates that require the use of ethanol regardless of the economics for doing so.[112] These mandates cannot be factored into the ethanol blending cost equation, but are accounted for in EPA's overall analysis by including the ethanol volume in gasoline in these states regardless of the blending economics. Other federal and state subsidies—such as ethanol production subsidies, loan guarantees, grants, and any other subsidies—were not considered by this analysis.

Gasoline Terminal Price (GTP)

Refinery rack price data from 2018—which already included the distribution costs for moving gasoline to downstream terminals—were used to represent the price of gasoline to blenders on a state-by-state basis.[113] However, these prices were not projected for future years. Instead, we used projected refinery wholesale price data from AEO 2022 to adjust the 2018 refinery rack price data to represent gasoline rack prices in future years. We used 2018 data instead of the most recent data to avoid abnormal pricing effects caused by the COVID-19 pandemic or the subsequent supply issues that emerged when the pandemic was subsiding. This gasoline price data, summarized in Table 2.1.1.1-5, was collected for each states and is assumed to represent the average gasoline price for all the terminals in each state.[114]

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[112] States' Biofuels Statutory Citations; The National Agricultural Law Center; https://nationalaglawcenter.org/state-compilations/biofuels.
[113] EIA; Spot Prices; https://www.eia.gov/dnav/pet/pet_pri_spt_s1_a.htm.
[114] EIA; Prime Supplier Sales Volume; https://www.eia.gov/dnav/pet/pet_cons_prim_dcu_nus_m.htm.

Table 2.1.1.1-5: Gasoline Terminal Prices in 2019 ($/gal)[a]

	Gasoline Grade				Gasoline Grade	
State	Regular	Premium		State	Regular	Premium
Alaska	2.37	2.44		Montana	1.84	2.30
Alabama	1.68	2.11		North Carolina	1.69	2.07
Arkansas	1.70	2.03		North Dakota	1.77	2.18
Arizona	2.00	2.29		Nebraska	1.74	2.55
California	2.37	2.61		New Hampshire	1.80	2.09
Colorado	1.85	2.26		New Jersey	1.72	2.91
Connecticut	1.77	2.09		New Mexico	1.82	2.18
D.C.	1.79	2.01		Nevada	2.11	2.36
Delaware	1.74	2.02		New York	1.78	2.14
Florida	1.72	2.07		Ohio	1.73	2.21
Georgia	1.69	2.10		Oklahoma	1.72	1.94
Hawaii	2.23	2.35		Oregon	1.95	2.26
Iowa	1.73	2.06		Pennsylvania	1.72	2.04
Idaho	1.92	2.21		Rhode Island	1.78	2.01
Illinois	1.75	2.17		South Carolina	1.69	2.09
Indiana	1.72	2.16		South Dakota	1.75	2.10
Kansas	1.71	1.97		Tennessee	1.68	2.03
Kentucky	1.75	2.16		Texas	1.72	1.98
Louisiana	1.66	1.92		Utah	1.86	2.13
Massachusetts	1.75	2.00		Virginia	1.73	2.06
Maryland	1.74	2.00		Vermont	1.76	2.13
Maine	1.83	2.17		Washington	1.97	2.30
Michigan	1.74	2.26		Wisconsin	1.75	2.24
Minnesota	1.73	2.01		West Virginia	1.75	2.13
Missouri	1.74	2.08		Wyoming	1.78	2.18
Mississippi	1.69	2.09				

[a] No data was provided by EIA for the values highlighted in grey; they were estimated by EPA.

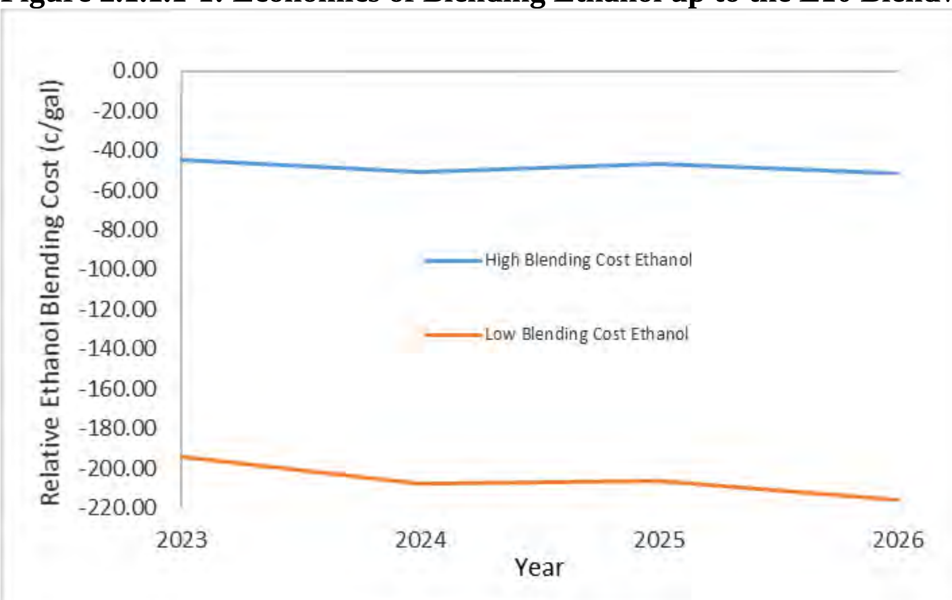
The AEO 2022 projected national average gasoline price information used to adjust gasoline prices in future years, and the national average gasoline price in 2018 that the projected gasoline prices are compared to, are summarized in Table 2.1.1.1-6. The differences in prices are additive to the state-by-state gasoline prices shown in Table 2.1.1.1-5. For example, the projected national average gasoline price in 2023 is $1.90 per gallon, which is 8¢ per gallon less than the national average gasoline price in 2018; therefore, gasoline prices in 2023 are 8¢ per gallon lower than the prices summarized in Table 2.1.1.1-5.

Table 2.1.1.1-6: National Average Gasoline Prices

	Year	Price
Actual National Average Gasoline Price	2018	$1.98
AEO 2022 Projected National Average Gasoline Prices	2023	$1.90
	2024	$1.93
	2025	$1.95

The No RFS Baseline analysis revealed that it is economic to blend ethanol into the entire gasoline pool up to 10%. As shown in Figure 2.1.1.1-1, ethanol is over 40¢/gal less expensive than gasoline in the most expensive market for blending ethanol, and about $2/gal less expensive than gasoline in the least expensive market for blending ethanol (in which a state subsidy applies).

Figure 2.1.1.1-1: Economics of Blending Ethanol up to the E10 Blendwall



2.1.1.2 E85

Some aspects of the ethanol blending cost equation developed for E10 in Chapter 2.1.1.1—such as the Ethanol Plant Gate Spot Price (ESP) and Ethanol Distribution Cost (EDC), remain largely the same for E85 and are not discussed further here. However, the analysis for E85 has some important differences. The Gasoline Terminal Price (GTP) was replaced by Ethanol Breakeven Blending Value. The Ethanol Replacement Value (ERV), which is an important cost factor for the value of E10, is not a factor for E85, although this is discussed below to characterize some E85 properties. Furthermore, an additional cost applies to E85 to account for the cost to modify retail stations to carry E85, which we have termed the Retail Cost (RC). While we normally would not include a fuel economy effect because consumers bear this cost, however, in E85's case consumers command a lower price for E85 before purchasing E85 which affects ethanol's value to fuel blenders. This E85 fuel pricing effect is captured in a breakeven price for ethanol.

The economics for using ethanol in E85 is estimated in two steps. First, we estimated the breakeven price for ethanol blended in E85 based on the price of gasoline price in each state. This calculation is made for regular and premium grades of both CG and RFG in each state. In the second step, the estimated ethanol plant gate price, ethanol distribution cost, retail cost, and E85 subsidies are combined together in the following equation to estimate whether ethanol blended into E85 is economical:

$$EBC_{E85} = (ESP + EDC - FETS - SETS + RC) - EBBV$$

Where:

- EBC_{E85} is ethanol breakeven price for ethanol blended as E85
- *ESP* is ethanol plant gate spot price
- *EDC* is ethanol distribution cost
- *FETS* is federal ethanol tax subsidy
- *SETS* is state ethanol tax subsidy
- *RC* is retail cost (service station revamp to sell E85)
- *EBBV* is ethanol breakeven blending value; all are in dollars per gallon

Ethanol Replacement Value (ERV)

Blending ethanol into gasoline for E85 is different than blending for E10 because refiners do not make a separate E85 BOB; thus, the E10 RBOBs and CBOBs are blended with ethanol to produce E85 and there is significant octane giveaway. Conversely, there is no risk that the E85 blend will exceed any RVP limits because E85 has a very low RVP. In fact, the resulting E85 blend is so low in vapor pressure that it causes most E85 blends to not meet the RVP minimum standards. In those cases, E85 is blended with less ethanol—usually 70% in the winter and up to 79% in the summer—and the year-round average is 74%, which allows ethanol to comply with the ASTM RVP minimum standards.[115]

Although refiners do not create a lower octane BOB for blending into E85, ethanol producers nonetheless saw the opportunity to blend natural gas liquids (NGLs) with ethanol to produce E85. NGLs are a low cost, low octane, higher RVP petroleum blending material that ethanol producers use to denature their ethanol. Since ethanol plants already have this blendstock material on hand, they blend E85 on-site using NGLs and then distribute the finished E85 from there. When blending up E85 with NGLs, the higher RVP of the NGLs allows blending a higher ethanol content of 83% in the summer. However, the RVP of NGLs is about the same or slightly higher than winter gasoline, so the winter blend percentage is the same. Because the more volatile NGLs are smaller hydrocarbons, they contain lower volumetric energy content, which is a factor in considering their value as well. Because NGLs are used as an E85 blendstock, we also evaluated the economics of blending E85 blended with NGLs.

[115] ASTM D5798-21, Standard Specification for Ethanol Fuel Blends for Flexible-Fuel Automotive Spark-Ignition Engines.

Federal and State Ethanol Tax Subsidies (FETS and SETS)

There is no federal ethanol blending tax subsidy for E85. Various state tax subsidies, however, have been provided for the use of ethanol. These tax subsidies incentivize the blending of ethanol into the gasoline pool and directly impact the decision of whether to use ethanol. Table 2.1.1.2-1 provides the E85 subsidies offered by different states.

Table 2.1.1.2-1: State E85 Subsidies

State	E85 Subsidy (¢/gal)
New York	53
Pennsylvania	25
Iowa	16
South Dakota	14
Kansas	12.5
Michigan	11

The California and Oregon LCFS blending credits for ethanol apply when ethanol is blended into E85 as well (Oregon's blending credit is assumed to be the same as California's). The blending credit applies to E85, so its credit is amortized over the ethanol portion of E85 to assess the blending value of ethanol. Aside from the retail cost credit offered by USDA described below, other federal and state subsidies—such as ethanol production subsidies, loan guarantees, grants, and any other subsidies—were not considered by this analysis.

Retail Cost (RC)

The retail costs for E85 are estimated based on the investments needed to offer E85 at retail stations and the estimated throughput at E85 stations.[116] We estimated the total cost for a typical retail station revamp to enable selling E85 to be $39,500, and that these stations sell on average 78,000 gallons of E85 per year. When amortizing this capital cost over the gallons of E85 sold, the total cost of the revamp adds 11.8¢/gal to the cost of blending ethanol into E85 (accounting only for the 64% of ethanol in E85 above the ethanol in E10).

Ethanol Breakeven Blending Value (EBBV)

There are downstream pricing effects for E85 that require the economics of E85 be assessed differently when blending ethanol into E85 compared to blending ethanol into E10. These downstream pricing effects exist because E85 contains less energy content compared to E10—22% and 30% less when blended with gasoline and NGLs, respectively. This lower energy density of E85 is noticeable to consumers in their fuel economy, so they demand a lower price at retail stations, which therefore requires that the economics of E85 be assessed at retail. Price information collected for E85 shows that it is typically priced 16% lower than E10 at retail.[117,118] For the No RFS analysis, we assumed that gasoline-blended E85 is priced 16% lower than E10

[116] The methodology used and the estimated costs for these revamps are discussed in Chapter 10.1.4.1.2.
[117] Retailing E85: An Analysis of Market Performance, July 2014 – August 2015; Fuels Institute; https://www.fuelsinstitute.org/Research/Reports; March 23, 2017.
[118] AAA Gas Prices; https://gasprices.aaa.com; downloaded June 15, 2022.

and that NGL-blended E85—which has much lower volumetric energy content—is priced 21% lower than E10.

Figures 2.1.1.2-1 and 2 show how the breakeven price for ethanol is estimated for E85 when blended with gasoline and NGLs, respectively, using the example of regular grade CG sold in Pennsylvania and Missouri. At the top of each figure, the pricing of gasoline is shown from terminal to retail, depicting the price impacts when distribution costs and taxes are added on. At the bottom of each figure, the pricing of E85 is shown when blended with gasoline and NGLs, respectively. The E85 prices are then estimated at the terminal after the retail, tax, and distribution costs are subtracted from the retail prices. Finally, the ethanol breakeven price is estimated for the ethanol blended into E85 based on the price of gasoline at the terminal and the fraction of gasoline and ethanol in E85.

Figure 2.1.1.2-1: Example Calculations for Ethanol Breakeven Price for Gasoline-Blended E85

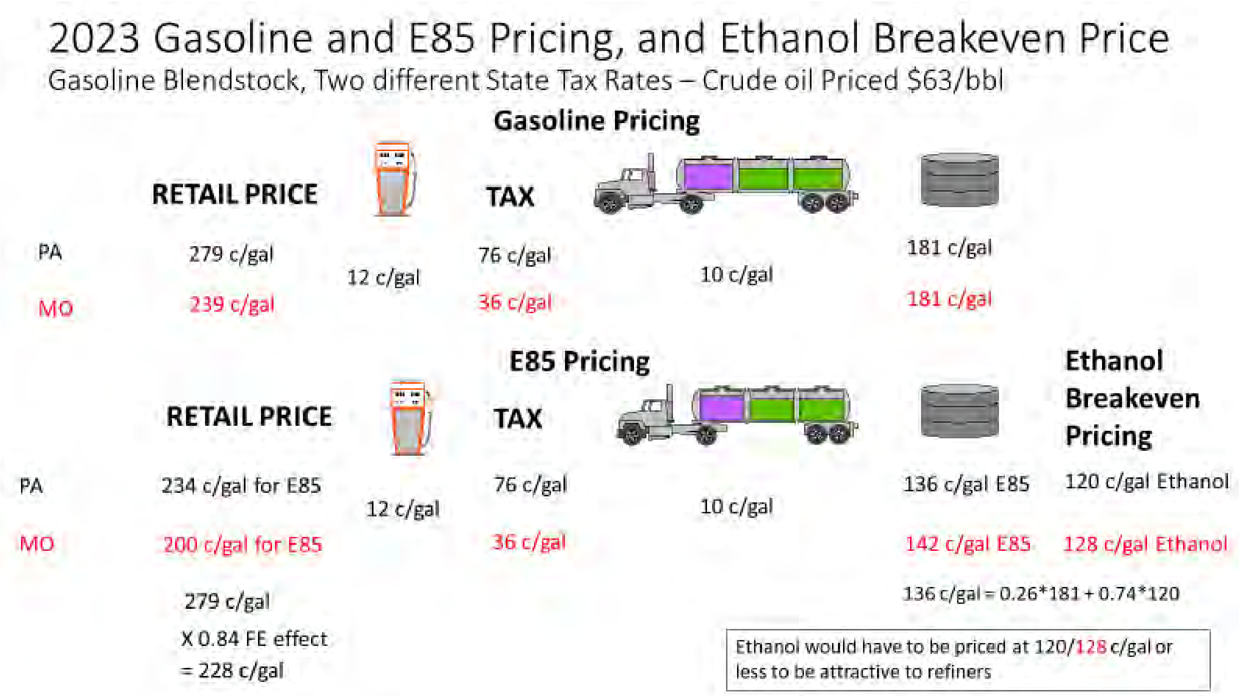


Figure 2.1.1.2-2: Example Calculations for Ethanol Breakeven Price for NGL-Blended E85

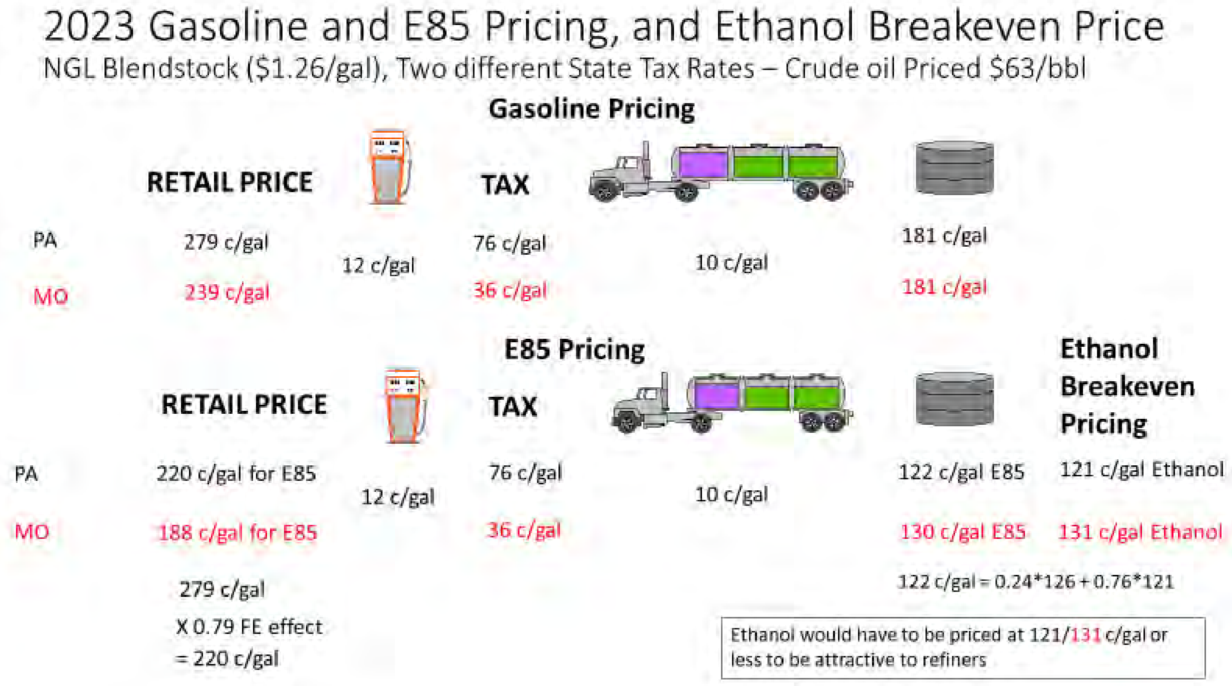


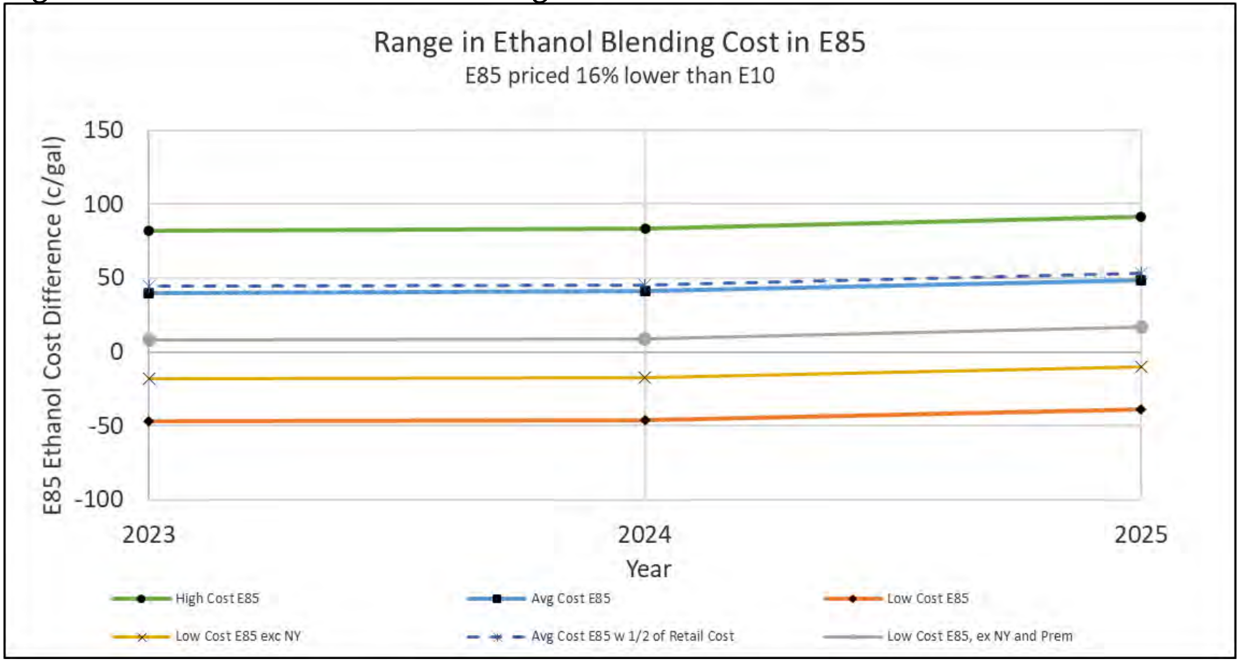
Figure 2.1.1.2-1 shows that when the E85 is blended with gasoline, the breakeven price of ethanol in E85 is 120¢/gal and 129¢/gal, which is 51¢/gal and 60¢/gal lower than the gasoline price, depending on whether the state gasoline tax is high (Pennsylvania) or low (Missouri), respectively. Similarly, Figure 2.1.1.2-2 shows that when the E85 is blended with NGLs, the breakeven price of ethanol in E85 is 121¢/gal and 131¢/gal, which is 50¢/gal and 60¢/gal lower than the gasoline price, depending on whether the state gasoline tax is high (Pennsylvania) or low (Missouri), respectively. A list of gasoline tax rates by state (including all federal and state taxes) is provided in Table 2.1.1.2-2.

Table 2.1.1.2-2: Gasoline Tax Rates by State (Includes Federal and State Taxes; ¢/gal)

State	Tax Rate		State	Tax Rate
Alaska	27		Montana	51
Alabama	45		North Carolina	55
Arkansas	43		North Dakota	41
Arizona	37		Nebraska	49
California	79		New Hampshire	42
Colorado	40		New Jersey	60
Connecticut	61		New Mexico	37
DC	42		Nevada	52
Delaware	41		New York	63
Florida	61		Ohio	57
Georgia	49		Oklahoma	38
Hawaii	67		Oregon	54
Iowa	49		Pennsylvania	76
Idaho	51		Rhode Island	54
Illinois	58		South Carolina	47
Indiana	65		South Dakota	48
Kansas	49		Tennessee	67
Kentucky	44		Texas	38
Louisiana	38		Utah	50
Massachusetts	45		Virginia	39
Maryland	55		Vermont	49
Maine	48		Washington	68
Michigan	46		Wisconsin	51
Minnesota	47		West Virginia	54
Missouri	36		Wyoming	42
Mississippi	37			

As for E10, if the ethanol blending cost is negative, ethanol is considered economical to blend into gasoline to produce E85; if it is positive, it is not economical. Figure 2.1.1.2-3 provides some key results of the No RFS baseline analysis for E85, showing a range in blending values for ethanol in E85, which vary from economic to blend to not economic to blend. For the highest cost market for E85, ethanol is priced 80–90¢/gal higher than its breakeven price. But for lowest cost market for E85, ethanol is around 50¢/gal lower than its breakeven price. It is important to understand which gasoline in which states are economically attractive to E85 since this determines the potential market size.

Figure 2.1.1.2-3: Economics of Blending Ethanol in E85



The lowest cost market for E85 is New York, due to its 53¢/gal blending subsidy for E85. After New York, the next lowest cost market for blending E85 is about 20¢/gal lower than the breakeven price. Reviewing the E85 markets that are favorable for blending E85, we find that it is comprised solely of premium gasoline in multiple states. This raises the question of whether retailers would pursue offering E85 if it was solely economic to blend compared to premium gasoline. Considering that premium gasoline only comprises about 10% of gasoline sales, coupled with the limited number of FFVs on the roadway, retailers would unlikely offer E85 at their retail stations if this is the case. For regular gasoline outside of New York, ethanol has unfavorable blending economics in E85 by about 10¢/gal, as seen in the third line from the bottom in Figure 2.1.1.2-3.

The solid blue line in Figure 2.1.1.2-3 represents the average ethanol blending value in E85, which is more than 40¢/gal unfavorable for blending ethanol into E85. Associated with this solid line is a dashed blue line just above it, which represents the marginal cost increase for amortizing half the retail investment cost for retrofitting retail stations to offer E85.[119] This retrofit cost does not have a large cost impact because E85 contains mostly ethanol, which defrays this cost.

Since New York is the only state in which retail stations would find it economic to offer E85, we can estimate a volume of E85 that would be sold there. New York has 80 retail stations that sell E85. If we assume that the average volume of E85 sold by these retail stations is the same as that sold by E85 stations nationwide, then New York retail stations would sell 6.2 million gallons of E85 per year under the No RFS baseline.

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[119] One-half of the investment cost for retrofitting the retail station to offer E85 is assumed to be paid by the retail station owner, while the other half is assumed to be paid by a USDA subsidy under the HBIIP program.

2.1.1.3 E15

The analysis for estimating the E15 baseline has similarities with how both E10 and E85 were estimated. Of the variables in the ethanol blending cost equation in Chapter 2.1.1.1, Ethanol Plant Gate Spot Price (ESP), Ethanol Distribution Cost (EDC), and Gasoline Terminal Price (GTP) are again the same. Like for E85, an additional cost applies to E15 to account for the cost to modify retail stations to carry E15 and we believe that Ethanol Replacement Value (ERV) does not apply as well, although we keep as a term and explain the possibility below for how it could apply.

The economics to determine whether ethanol blended into E15 is economical is estimated by combining the ethanol plant gate price, ethanol distribution cost, ethanol replacement cost, and retail cost in the following equation:

$$EBC_{E15} = (ESP + EDC - ERV - FETS - SETS + RC) - GTP$$

Where:

- EBC_{E15} is ethanol blending cost for E15
- *ESP* is ethanol plant gate spot price
- *EDC* is ethanol distribution cost
- *ERV* is ethanol replacement value
- *FETS* is federal ethanol tax subsidy
- *SETS* is state ethanol tax subsidy
- *RC* is retail cost (service station revamp to sell E15)
- *GTP* is gasoline terminal price; all are in dollars per gallon

Ethanol Replacement Value (ERV)

Blending ethanol into gasoline for E15 is different than blending for E10 because we believe that refiners do not make a separate E15 BOB; thus, E10 BOBs are blended with ethanol to produce E15, in which case there is octane giveaway and no blending value to refiners for ethanol. It is possible, though, that some refineries with extra gasoline storage tanks could blend an E15 BOB to sell off their refinery racks; however, we have no knowledge of this currently happening, Similarly, there should be no RVP cost for blending ethanol above that of E10 because ethanol-gasoline blends reach a maximum RVP at 10%.

A larger issue for E15 is that it does not receive a 1-psi waiver like E10 does in the summer, which means that ethanol cannot be blended into E10 to produce E15 without either exceeding summer RVP limits or incurring an additional cost. However, as discussed in Chapter 1.7.2, E15 did receive a regulatory 1-psi waiver for 2019–2021 and EPA-issued emergency fuel waivers throughout the summer of 2022 further allowed E15 to take advantage of the 1-psi waiver. Recently, a number of Midwestern states petitioned EPA to remove the 1-psi waiver for E10. If the 1-psi waiver were to be removed in those states, a new lower RVP, higher-cost BOB would be required for both E10 and E15.

Federal and State Ethanol Tax Subsidies (FETS and SETS)

There is no federal nor state ethanol blending tax subsidy for E15. It is important to know that California does not allow the sale of E15. Other federal and state subsidies—such as ethanol production subsidies, loan guarantees, grants, and any other subsidies—were not considered by this analysis.

Retail Cost (RC)

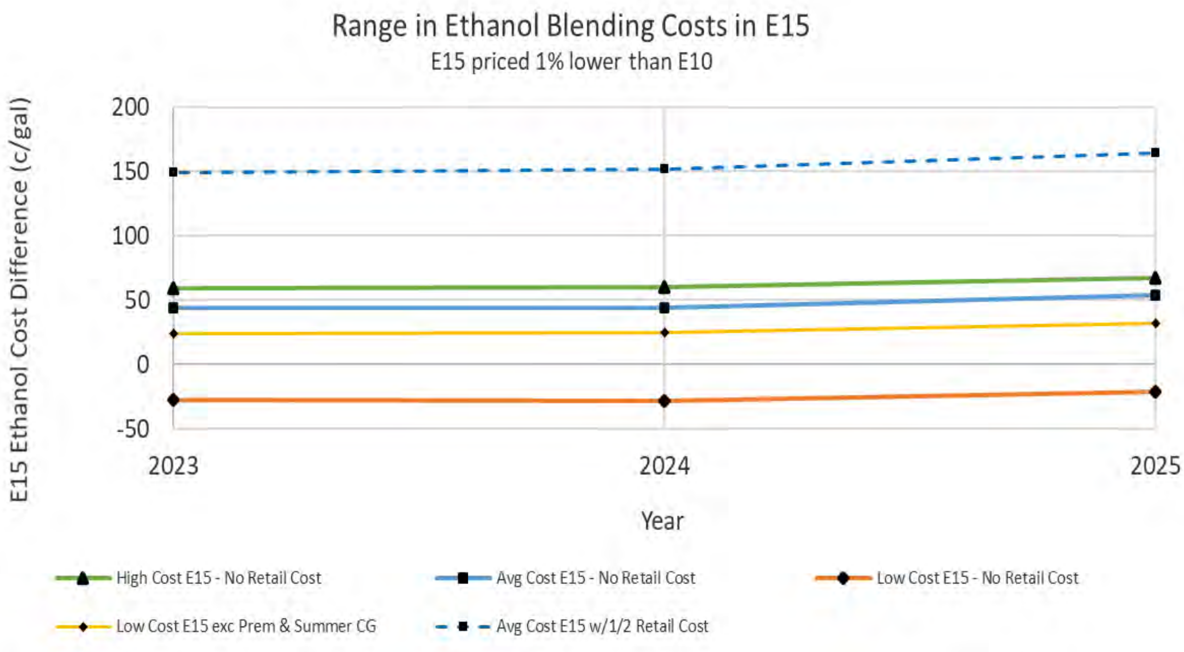
The retail costs for E15 are estimated based on the investments needed to offer E15 at retail stations and the estimated throughput at E15 stations.[120] We estimated the total cost for a typical retail station revamp to enable selling E15 to be $108,000, and that these stations sell on average 147,000 gallons of E15 per year. When amortizing this capital cost over the gallons of E15 sold, the total cost of the revamp adds 249¢/gal to the cost of blending ethanol into E15 (accounting only for the 5% of ethanol in E15 above the ethanol in E10).

E15 has different properties than E10 that allow it to be priced differently than E10. E15 has higher octane than E10, so the fuels industry could set E15 prices higher on that basis. Conversely, E15 has lower energy density than E10, which means that consumers are not able to drive the same distance on a tankful of E15. The website e85prices.com, which collects information on gasoline and ethanol-gasoline blend prices, reported that E15 is priced 8.5¢/gal cheaper than E10. A conversation with a gasoline retail marketer explained that when beginning to offer E15 for sale, marketers will typically price it lower than E10 as a means to promote E15 to consumers and increase its sales. If E15 is priced 8¢/gal lower than E10, it adds 160¢/gal (8/0.05) to the blending cost for blending ethanol into E15. However, if this is a marketing strategy, this practice would likely diminish over time. We do not know what the ultimate price of E15 will be relative to E10 since many retail station owners only began to offer E15 in recent years. To maximize their profit, retail station owners will seek the optimal E15 price that balances sales volume and pricing. For this analysis, we assumed that E15 is priced lower than E10 consistent with how E85 is priced.[121] Since E15 contains 1.8% less energy than E10, we assumed that E15 is priced 1.2%, or about 3¢/gal, less than E10.

Similar to E10, if the ethanol blending cost is negative, then ethanol is considered economic to blend into gasoline to produce E15, while it would not be economic if the value is positive. Figure 2.1.1.3-1 provides some key results of the No RFS baseline analysis for E15, showing a range in blending values for ethanol in E15, which vary from economic to blend to not economic to blend.

[120] The methodology used and the estimated costs for these revamps are discussed in Chapter 10.1.4.1.2.
[121] E85, which contains 74% ethanol and 21% less energy than E10, is typically priced 16% lower than E10.

Figure 2.1.1.3-1: Economics of Blending Ethanol in E15



It is important to recognize the cost impact due to revamping the retail station to enable it to sell E15. Assuming a typical retail station revamp cost of $108,000, and that the HBIIP program subsidized half the cost, the retail station is estimated to need to cover a cost of $1.25/gal for that 5% increment of ethanol in E15. This is shown in Figure 2.1.1.3-1 as the difference between the dashed blue line and the solid blue line, which represents the average E15 cost without any retail cost included. None of the solid lines in the figure include this retail revamp cost; adding in this retail cost component immediately makes every gasoline market uneconomic for blending additional ethanol into E10 to produce E15.

Assuming a best-case scenario in which a retail station was able to secure an additional local subsidy that covered the balance of the E15 revamp cost, then the lowest cost market for the additional 5% of ethanol in E15 would have a -30¢/gal blending cost for ethanol. However, similar to E85, this gasoline market is comprised solely of premium gasoline. Since the premium gasoline market is very small, it would likely not be sufficiently large to cause retail stations owners to revamp their stations to sell E15. The next most economic gasoline market includes regular grade gasoline, but its ethanol blending cost is about 30¢/gal. Thus, the ethanol blending cost analysis finds this gasoline market uneconomic for E15.

After reviewing the E15 blending economics, we project that without the RFS program in place, the fuels market would not offer E15 for sale.

2.1.2 Cellulosic Biofuel

There are two primary types of cellulosic biofuel that we project will generate appreciable quantities of cellulosic RINs in 2023–2025: CNG/LNG derived from biogas and biogas-based electricity (eRINs). We also project that small volumes of liquid cellulosic biofuel will be produced in these years. Cellulosic biofuels generally cost more to produce than the fossil fuels they displace, and therefore generally would not be used absent the incentives provided by the RFS program. There are, however, state incentive programs (e.g., the California and Oregon LCFS programs) that we project would be sufficient to incentivize the use of some types of cellulosic biofuels without the additional incentives provided by the RFS program. This chapter describes our projections of cellulosic biofuel use for the No RFS baseline.

2.1.2.1 CNG/LNG Derived from Biogas

As described in greater detail in Chapter 10, CNG/LNG derived from biogas is generally more expensive to produce than natural gas. Because of this higher cost, and because of the demand for renewable natural gas (RNG) in sectors other than the transportation sector, we project that without incentives for the use of renewable CNG/LNG in the transportation sector, very little or none of this fuel would be used in the transportation sector.

There are, however, two state LCFS programs (California and Oregon) that currently offer incentives for the use of CNG/LNG in the transportation sector. We have assumed that the incentives provided by these states would be sufficient for some quantity of CNG/LNG to be used in the transportation sector in the absence of the RFS program. To project the quantity of CNG/LNG used as transportation fuel in these states (including both fossil natural gas and RNG), we have used data provided by California and Oregon and extrapolated the use of these fuels through 2025. Specifically, we calculated a year-over-year growth rate for each year for California and Oregon separately. We then averaged the observed annual growth rates from 2015–2019 for California and 2017–2019 for Oregon[122] to determine an average annual rate of growth and used this growth rate to project CNG/LNG volumes in California and Oregon through 2025. This growth rate was applied to the reported use of renewable CNG/LNG in the transportation sector in 2020, the latest year for which data were available at the time this analysis for the No RFS baseline was completed. We assumed that all CNG/LNG used as transportation fuel in these states in 2023–2025 was from renewable sources and did not include the growth rate in 2020 due to the impacts of the COIVD-19 pandemic. The projected volume of renewable CNG/LNG used as transportation fuel in California and Oregon under the No RFS baseline is summarized in Table 2.1.2.1-1.

Table 2.1.2.1-1: CNG/LNG Derived from Biogas in the No RFS Baseline (million ethanol-equivalent gallons)

State	Annual Growth Rate	2020	2021	2022	2023	2024	2025
California	7.48%	280	301	324	348	374	402
Oregon	38.7%	3	4	6	8	11	15
Total	N/A	283	305	329	356	385	417

2.1.2.2 Electricity

This rule proposes to enable the generation of RINs for renewable electricity derived from biogas for the first time. As such, absent this rulemaking there would be zero renewable

[122] The Oregon LCFS program began in 2016, and therefore we cannot calculate an annual rate of growth prior to 2017.

electricity under the RFS program. However, as discussed in Chapter 6.1.4, we project that the existing capacity to generate renewable electricity derived from biogas exceeds the quantity of electricity that will be used as transportation fuel through 2025. Therefore, this rule is not anticipated to actually result in any increase in renewable electricity generation through 2025. Consequently, we are not changing the quantity of renewable electricity in 2024–2025 relative to the No RFS baseline and have therefore assumed that the No RFS baseline equals the volumes required in 2024–2025.

2.1.2.3 Liquid Cellulosic Biofuels

In recent years there have been very small quantities of liquid cellulosic biofuels produced. This is despite the fact that the combination of the RFS program, federal tax credit, and state incentives (e.g., the California LCFS program) have provided very large financial incentives for liquid cellulosic biofuels. While the incentives provided by state programs and the federal tax credit are expected to continue in future years, we do not expect that these incentives alone will be sufficient to support liquid cellulosic biofuel production in 2023–2025. We are therefore not projecting any liquid cellulosic biofuel production in 2023–2025 under the No RFS baseline.

2.1.3 Biomass-Based Diesel

2.1.3.1 Biodiesel

Estimating the economics of blending biodiesel is different than ethanol because, unlike corn ethanol plants that are almost exclusively located in the Midwest, biodiesel plants are more scattered around the country. The more diffuse location of biodiesel plants affects how we estimate distribution costs for using biodiesel. Also, refiners do not change the properties of the diesel they produce to accommodate the downstream blending of biodiesel, and as such there is no additional blending value associated with its use like there is for E10. However, blending biodiesel does often require the addition of additives to accommodate some of its properties. The blending cost of biodiesel is estimated using the following equation:

$$BBC = (BSP + BDC - FBTS - SBTS) - DTP$$

Where:

- *BBC* is biodiesel blending cost
- *BSP* is biodiesel plant gate spot price
- *BDC* is biodiesel distribution cost
- *FBTS* is federal biodiesel tax subsidy
- *SBTS* is state biodiesel tax subsidy
- *DTP* is diesel terminal price; all are in dollars per gallon

Biodiesel Plant Gate Spot Price (BSP)

USDA collects biodiesel plant gate pricing data, which is the price paid to biodiesel producers when they sell their biodiesel; however, USDA does not project future biodiesel prices.[123] Instead, we assumed that biodiesel production costs reflected plant gate prices and then estimated biodiesel production costs based on future vegetable oil and utility prices. This is essentially the same information used for estimating biodiesel production costs for the cost analysis in Chapter 10, except that the capital costs are amortized using the capital amortization factor in Table 2.1.1.1-1. Imports are assumed to be half produced from soybean oil and half from palm oil, and have the same production costs as that produced domestically. The resulting projected biodiesel plant gate prices are summarized in Table 2.1.3.1-1.

Table 2.1.3.1-1: Projected Biodiesel Plant Gate Prices ($/gal)

Projected Production Cost	2023	2024	2025
Soybean Oil	4.83	4.58	4.45
Corn Oil	4.34	4.12	4.00
Waste Oil	3.92	3.72	3.62
Palm Oil	4.83	4.58	4.44
FAPRI	4.77	4.55	4.51

Biodiesel Distribution Cost (BDC)

This factor represents the added cost of moving biodiesel from production plants to terminals where it is blended into diesel. Unlike ethanol, which is almost exclusively produced in the Midwest and distributed elsewhere from there, biodiesel is predominantly produced in the Midwest, but there are also biodiesel plants dispersed around the country. For this reason, we took a very different approach for this analysis. Using 2019 EIA data, we estimated the quantity of biodiesel produced within each PADD, the movement of biodiesel between PADDs, and the imports and exports of biodiesel into and out of each PADD, as summarized in Table 2.1.3.1-2.[124]

[123] USDA Economic Research Service; US Bioenergy Statistics. 2019. Table 14 Fuel ethanol, corn, and gasoline prices by month.
[124] Petroleum Administration for Defense District (PADD): The 50 U.S. states and the District of Columbia are divided into five districts. Each PADD comprise a subset of U.S. states; PADD 1: Eastern states; PADD 2: Midwest states; PADD 3: Gulf Coast; PADD 4: Rocky Mountain States; PADD 5: Pacific Coast states.

Table 2.1.3.1-2: Biodiesel Production, Imports, Export, and Movement Between PADDs and Consumption in 2019 (million gallons)

PADD	Production	Imports	Exports	From PADD 2	From PADD 3	Other Movement	Consumption
PADD 1	88	82	7	103	4	0	271
PADD 2	1,166	42	60	-	0	-363	785
PADD 3	337	12	14	140	-	115	450
PADD 4	0	9	0	21	0	5	35
PADD 5	134	22	32	99	22	-6	239
Total	1,725	168	114	363	26	-249	1,779

ICF estimated the distribution costs for distributing biodiesel both within and between PADDs, as summarized in Table 2.1.3.1-3.[125]

Table 2.1.3.1-3: Biodiesel Distribution Costs (¢/gal)

PADD	Within PADD	From Outside the PADD
PADD 1	15	35
PADD 2	15	15
PADD 3	15	18
PADD 4	15	25
PADD 5	15	32

As expected, distribution costs for distributing biodiesel within a PADD are less than when the biodiesel is distributed further away from outside the PADD. Since imports come from outside the PADD, we used outside the PADD values for imports. Comparing these biodiesel distribution costs to ethanol, distributing biodiesel is expected to be more expensive, which recognizes that the larger volume of ethanol provides the opportunity to optimize the distribution system more so than biodiesel. For example, the greater volume of ethanol allows for greater use of unit trains and more streamlined logistics overall. Like for ethanol, distribution costs of biodiesel to the East and West Coasts are higher compared to distribution in the Midwest where most of the biofuels are produced. Although the Rocky Mountain states are located much closer to the Midwest, it is expensive to distribute biodiesel to the rural areas there.

Federal and State Biodiesel Tax Subsidies (FBTS and SBTS)

In 2004, the federal government established a $1.00 tax subsidy for blending biodiesel into diesel as part of the American Jobs Creation Act of 2004, which has been extended multiple times over the past 18 years. Most recently, the biodiesel tax credit, which had expired in 2018, was extended in a government funding bill at the end of 2019 which retroactively subsidized the volume of biodiesel being blended into diesel for 2018 and 2019, and it also funded the tax credit through 2022. Since 2005, the federal biodiesel tax subsidy has expired multiple times, but it was always reestablished. Therefore, for 2023–2025, we assume that this $1.00 per gallon biodiesel blending subsidy will continue to be in place.

[125] Modeling a "No-RFS" Case; refinery modeling conducted by Mathpro for EPA under ICF Contract EP-C-16-020, July 17, 2018.

States also provide subsidies to blend biodiesel into diesel. These state subsidies were enacted in previous years and are presumed to continue through 2025. Table 2.1.3.1-4 summarizes the states that offer such subsidies and their amounts.

Table 2.1.3.1-4: State Biodiesel Subsidies (¢/gal)

State	Biodiesel Subsidy
Hawaii	36.5
Iowa	3.5
Illinois	14
North Dakota	100
Rhode Island	30
Texas	20

The California and Oregon LCFS programs do not offer specific subsides per se, but through the cap-and-trade nature of their programs, they can be equated to subsidies. Oregon also has a biodiesel blending mandate, which requires that their diesel contain 5% biodiesel. We assumed that, on average, each state would only blend up to 5% biodiesel, which means that Oregon's mandate would satisfy its biodiesel volume regardless of its LCFS program. In the case for California, which does not have a biodiesel mandate, we estimated the equivalent per-gallon subsidy amount from the incentives offered by its LCFS program. From 2023–2025, biodiesel produced from soybean oil is estimated to receive an LCFS blending incentive of $1.01/gal in 2023 decreasing to $0.96/gal in 2025. Biodiesel produced from non-soybean oil vegetable oils is expected to receive a blending incentive of $1.84 each year from 2023–2025.

Although different than subsidies, several state have mandates that require that the diesel within their state contain a minimum quantity of biodiesel. Table 2.1.3.1-5 lists the states that have such a mandate and the percentage of biodiesel required to be blended into diesel.

Table 2.1.3.1-5: State Biodiesel Mandates

State	Minimum % of Biodiesel
Minnesota	12.5
New Mexico	5
Oregon	5
Pennsylvania	2
Washington	2

Diesel Terminal Price (DTP)

Refinery rack price data from 2019—which already included the distribution costs for moving diesel to downstream terminals—were used to represent the price of diesel to blenders on a state-by-state basis. However, these prices were not projected for future years.[126] Instead, we used projected refinery wholesale price data from AEO 2022 to adjust the 2019 refinery rack price data to represent diesel rack prices in future years. We used 2019 data instead of more

[126] EIA; Spot Prices; https://www.eia.gov/dnav/pet/pet_pri_spt_s1_a.htm.

recent data to avoid abnormal pricing effects caused by the COVID-19 pandemic or the subsequent supply issues that emerged when the pandemic was subsiding. This diesel price data, summarized in Table 2.1.3.1-6, was collected by states and is assumed to represent the average diesel price for all the terminals in each state.[127]

[127] EIA; Prime Supplier Sales Volume; https://www.eia.gov/dnav/pet/pet_cons_prim_dcu_nus_m.htm.

Table 2.1.3.1-6: Diesel Terminal Prices ($/gal)

	Year				
State	2019	2023	2024	2025	2026
Alaska	2.43	2.20	2.32	2.41	2.48
Alabama	1.93	1.74	1.84	1.91	1.97
Arkansas	1.94	1.75	1.85	1.92	1.98
Arizona	2.07	1.87	1.98	2.05	2.12
California	2.20	1.99	2.10	2.18	2.25
Colorado	2.02	1.82	1.92	2.00	2.06
Connecticut	1.96	1.77	1.87	1.94	2.01
DC	1.95	1.76	1.86	1.93	1.99
Delaware	1.95	1.76	1.86	1.93	1.99
Florida	1.98	1.79	1.89	1.96	2.02
Georgia	1.94	1.75	1.85	1.92	1.98
Hawaii	2.17	1.96	2.07	2.15	2.21
Iowa	1.98	1.79	1.89	1.96	2.02
Idaho	2.01	1.81	1.92	1.99	2.05
Illinois	1.88	1.69	1.79	1.86	1.92
Indiana	1.90	1.71	1.81	1.88	1.94
Kansas	1.94	1.75	1.85	1.92	1.98
Kentucky	1.97	1.78	1.88	1.95	2.01
Louisiana	1.88	1.70	1.80	1.86	1.92
Massachusetts	1.98	1.79	1.89	1.96	2.02
Maryland	1.95	1.76	1.86	1.93	1.99
Maine	1.99	1.79	1.90	1.97	2.03
Michigan	1.91	1.73	1.83	1.90	1.96
Minnesota	1.99	1.80	1.90	1.97	2.04
Missouri	1.95	1.77	1.87	1.94	2.00
Mississippi	1.91	1.73	1.82	1.89	1.95
Montana	2.00	1.81	1.91	1.98	2.04
North Carolina	1.95	1.76	1.86	1.93	1.99
North Dakota	1.98	1.79	1.89	1.96	2.02
Nebraska	1.98	1.79	1.89	1.96	2.03
New Hampshire	1.98	1.79	1.89	1.96	2.02
New Jersey	1.93	1.74	1.84	1.91	1.97
New Mexico	2.05	1.85	1.95	2.03	2.09
Nevada	2.08	1.88	1.99	2.06	2.13
New York	2.00	1.81	1.91	1.98	2.04
Ohio	1.91	1.73	1.83	1.89	1.95
Oklahoma	1.91	1.73	1.82	1.89	1.95
Oregon	2.04	1.85	1.95	2.02	2.09
Pennsylvania	1.94	1.75	1.85	1.92	1.98
Rhode Island	1.95	1.76	1.86	1.93	1.99
South Carolina	1.94	1.76	1.86	1.93	1.98
South Dakota	2.00	1.81	1.91	1.98	2.04
Tennessee	1.94	1.76	1.85	1.92	1.98
Texas	1.91	1.73	1.82	1.89	1.95
Utah	2.05	1.86	1.96	2.04	2.10
Virginia	1.95	1.76	1.86	1.93	1.99
Vermont	1.99	1.80	1.90	1.97	2.03
Washington	1.98	1.79	1.89	1.96	2.02
Wisconsin	1.93	1.75	1.85	1.92	1.97
West Virginia	1.97	1.78	1.88	1.95	2.01
Wyoming	2.12	1.92	2.03	2.10	2.17

Because there are state mandates and blending subsidies for biodiesel, each state is represented in EPA's analysis. Since biodiesel distribution volumes and costs are estimated on a PADD basis, the states are grouped together within their respective PADDs. We then established a hierarchy for how biodiesel is consumed. First, state mandates are satisfied by biodiesel volume that is available to each state within its PADD. Next, biodiesel is allocated to states based on its blending cost—the state with the lowest biodiesel blending cost in each PADD (e.g., states with biodiesel blending subsidies) would receive biodiesel, with any one state assumed to blend biodiesel only up to 5%.[128] Therefore, once a state reaches 5% biodiesel content in its diesel and more biodiesel is available in the PADD, biodiesel is blended to the next lowest blending cost state, and so on until the biodiesel available in the PADD is exhausted.

Similar to the other biofuels analyzed for the No RFS baseline, mandates are satisfied regardless of the blending economics. If the biodiesel blending cost is negative, biodiesel is considered economical to blend into diesel and additional nonmandated volumes are assumed to be blended. Conversely, biodiesel is assumed to not be blended into diesel if the biodiesel blending value is positive. Because of its relative cost, biodiesel consumption without the RFS program would be driven mostly by the state mandates, but would also occur absent the RFS program due to state subsidies, mainly the California LCFS program. The volume of biodiesel estimated to be blended into diesel in each state is determined by the volume of diesel sold in that state multiplied by the biodiesel blend percentage.[129] Table 2.1.3.1-7 lists the states expected to consume biodiesel under the No RFS baseline and summarizes their volume of biodiesel by the biogenic oil feedstock types estimated to be used to produce the biodiesel. For the states that mandate the percentage of biodiesel to be blended into diesel, we apportioned the biogenic oil feedstock types based on the current mix of these vegetable oils currently being used to produce biodiesel. For the states that would use biodiesel based on economics, the use is a function of the biodiesel economics when using the various feedstocks.

[128] Minnesota is an exception because it mandates a higher volume. Limiting biodiesel blends to 5% in the remaining states is appropriate because at least one engine manufacturer does not warranty their truck engines if operated on diesel containing more than 5% biodiesel. Furthermore, California does not allow biodiesel blends above 5% in order to avoid increases in NOx emissions.

[129] Historical diesel sales volumes from EIA and projected diesel volumes in AEO 2022 were used to project the volume of diesel sold in each state. EIA; Prime Supplier Sales Volume; https://www.eia.gov/dnav/pet/pet_cons_prim_dcu_nus_m.htm.

Table 2.1.3.1-7: Biodiesel in No RFS Baseline (million gal/yr)

<table>
<tr><th rowspan="2"></th><th rowspan="2">State</th><th colspan="3">2023</th><th colspan="3">2024</th><th colspan="3">2025</th></tr>
<tr><th>Soybean Oil</th><th>Corn Oil</th><th>Waste</th><th>Soybean Oil</th><th>Corn Oil</th><th>Waste</th><th>Soybean Oil</th><th>Corn Oil</th><th>Waste</th></tr>
<tr><td rowspan="5">Mandated Volumes</td><td>Minnesota</td><td>97.51</td><td>19.59</td><td>5.07</td><td>98.02</td><td>19.69</td><td>5.10</td><td>98.77</td><td>19.84</td><td>5.14</td></tr>
<tr><td>New Mexico</td><td>29.25</td><td>3.80</td><td>1.55</td><td>29.63</td><td>3.82</td><td>1.55</td><td>29.86</td><td>3.85</td><td>1.57</td></tr>
<tr><td>Oregon</td><td>30.33</td><td>5.90</td><td>1.53</td><td>30.49</td><td>5.93</td><td>1.54</td><td>30.72</td><td>5.98</td><td>1.55</td></tr>
<tr><td>Pennsylvania</td><td>24.70</td><td>3.88</td><td>1.00</td><td>24.83</td><td>3.90</td><td>1.01</td><td>25.02</td><td>3.93</td><td>1.02</td></tr>
<tr><td>Washington</td><td>18.31</td><td>3.56</td><td>0.92</td><td>18.40</td><td>3.58</td><td>0.93</td><td>18.54</td><td>3.61</td><td>0.93</td></tr>
<tr><td rowspan="2">Economic Volumes</td><td>California</td><td>0</td><td>0</td><td>175</td><td>0</td><td>66</td><td>110</td><td>0</td><td>67</td><td>111</td></tr>
<tr><td>North Dakota</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>0</td><td>30</td></tr>
<tr><td colspan="2" rowspan="2">Total</td><td>200.1</td><td>36.7</td><td>185.1</td><td>201.4</td><td>102.9</td><td>120.1</td><td>202.9</td><td>104.2</td><td>151.2</td></tr>
<tr><td colspan="3">422</td><td colspan="3">424</td><td colspan="3">458</td></tr>
</table>

The analysis estimates the No RFS biodiesel baseline volumes to be somewhat more than 400 million gallons per year. Given the level of uncertainty in the projections and to simplify the use of the No RFS baseline for our analyses, we combined these volumes and used 432 million gallons of biodiesel per year.

2.1.3.2 Renewable Diesel

While renewable diesel is produced in a much different process than biodiesel, it uses the same feedstocks and so much of the blending cost analysis is similar. The blending cost of renewable diesel is estimated using the following equation:

$$RDBC = (RDSP + RDDC - FRDTS - SRDTS) - DTP$$

Where:

- *RDBC* is renewable diesel blending cost
- *RDSP* is renewable diesel plant gate spot price
- *RDDC* is renewable diesel distribution cost
- *FRDTS* is federal renewable diesel tax subsidy
- *SRDTS* is state renewable diesel tax subsidy
- *DTP* is diesel terminal price; all are in dollars per gallon

Some of the equation inputs, including the distribution costs (RDDC), federal tax subsidy (FRDTS), state tax subsidies (SRDTS), and diesel terminal price (DTP) are the same as that described in Chapter 2.1.3.1 for biodiesel, so they are not discussed further here. However, the state mandates described in Chapter 2.1.3.1 are assumed to not apply to renewable diesel.

Renewable Diesel Plant Gate Spot Price (RDSP)

Similar to biodiesel, we estimated future renewable diesel plant gate prices by gathering projected renewable diesel plant input information (e.g., future biogenic oil and utility prices) to estimate renewable diesel production costs, which we assumed represent plant gate prices. This is essentially the same information used for estimating renewable diesel production costs for the cost analysis in Chapter 10, except that the capital costs are amortized using the capital amortization factor in Table 2.1.1.1-1. Imports are assumed to be half produced from soybean oil and half from palm oil, and have the same production costs as that produced domestically. The resulting projected renewable diesel plant gate prices are summarized in Table 2.1.3.2-1.

Table 2.1.3.2-1: Projected Renewable Diesel Plant Gate Prices ($/gal)

Feedstock	2023	2024	2025
Soybean Oil	5.61	5.33	5.20
Corn Oil	5.08	4.84	4.72
Waste Oil	4.63	4.42	4.32
Palm Oil	5.61	5.33	5.19

The methodology for analyzing renewable diesel volumes is structured the same as that for biodiesel described in Chapter 2.1.3.1. States are grouped together within their respective PADDs and a hierarchy is established for how renewable diesel is consumed, except that we did not include any state mandates. The state with the lowest renewable diesel blending cost (e.g., states with blending subsidies) would receive renewable diesel first. An important difference from the analysis for biodiesel, however, is that states are able to displace up to 95% of their diesel volume with renewable diesel.[130]

Similar to the other biofuels analyzed for the No RFS baseline, if the renewable diesel blending cost is negative, renewable diesel is considered economical to blend into diesel. Conversely, renewable diesel is assumed to not be blended into diesel if the blending value is positive. Because of its relative cost, renewable diesel consumption without the RFS program would only be blended into diesel if a state offers a significant subsidy, mainly the California and Oregon LCFS programs. The volume of renewable diesel estimated to be blended into diesel in each state is determined by the volume of diesel sold in that state.[131]

Allowing up to 95% of the diesel in a state to be supplanted with renewable diesel would allow the results of the analysis to swing wildly from year to year based on even small changes in the economics of renewable diesel in any given year. In reality, the marketplace is unlikely to make such swings. To avoid this problem, the following steps were taken to rationalize the growth and use of renewable diesel:

[130] Renewable diesel has properties similar to petroleum diesel, so it can displace petroleum diesel without causing vehicle compatibility or drivability issues.
[131] Historical diesel sales volumes from EIA and projected diesel volumes in AEO 2022 were used to project the volume of diesel sold in each state. EIA; Prime Supplier Sales Volume; https://www.eia.gov/dnav/pet/pet_cons_prim_dcu_nus_m.htm.

- Renewable diesel economics were assessed from 2018–2025 to determine the states where renewable diesel would be economic to blend, and what the maximum volume could be.
- Renewable diesel demand in any one historical year was not allowed to exceed the demand that occurred in that year under the RFS program. This data was extrapolated to determine the maximum renewable diesel demand for future years (see Table 2.1.3.2-2).
- When combined with biodiesel, the demand for the lowest cost biogenic oils (i.e., waste oils (FOG) and corn oil) was not allowed to exceed the total demand for those oils that occurred in that year under the RFS program.
- The maximum demand for renewable diesel in any one year for a given state was then calculated to be the average of renewable diesel demand for that year and the previous three years. This step attempted to reflect how potential renewable diesel investors or banks would seek to assess the economics for investing in expanding renewable diesel plant capacity.

Table 2.1.3.2-2: Historical and Projected Maximum Renewable Diesel Demand (million gallons)

	Year	**Renewable Diesel Demand**
Historical	2018	402
	2019	627
	2020	580
Projected	2021	*716*
	2022	*813*
	2023	*910*
	2024	*1,007*
	2025	*1,104*

Table 2.1.3.2-3 list the states that are economically favorable for blending in renewable diesel, summarize the potential maximum volume of renewable diesel, and summarize the allowed volume of renewable diesel based on either the maximum renewable diesel demand (per Table 2.1.3.2-2) or the maximum volume of biogenic oil.

Table 2.1.3.2-3: Potential and Allowed Volume of Renewable Diesel

	State	Feedstock			Total
		Soybean Oil	Corn Oil	Waste Oil	
2018					
Potential Demand	California	0	1,426	2,375	3,801
	North Dakota	0	253	422	675
	Oregon	0	278	463	741
Amount Allowed	California	0	151	251	402
2019					
Potential Demand	California	0	1,322	2,202	3,524
	North Dakota	0	0	652	652
	Oregon	0	0	741	741
Amount Allowed	California	0	264	357	621
2020					
Potential Demand	California	0	1,208	2,012	3,220
	North Dakota	0	0	549	549
	Oregon	0	0	22	22
Amount Allowed	California	0	185	395	580
2021					
Potential Demand	California	0	0	3,326	3,326
	North Dakota	0	0	0	0
	Oregon	0	0	0	0
Amount Allowed	California	0	0	716	716
2022					
Potential Demand	California	0	0	22	22
	North Dakota	0	0	0	0
	Oregon	0	0	0	0
Amount Allowed	California	0	0	22	22
2023					
Potential Demand	California	0	0	22	22
	North Dakota	0	0	0	0
	Oregon	0	0	0	0
Amount Allowed	California	0	0	22	22
2024					
Potential Demand	California	0	0	3,343	3,343
	North Dakota	0	0	0	0
	Oregon	0	0	0	0
Amount Allowed	California	0	0	880	880
2025					
Potential Demand	California	0	0	3,369	3,369
	North Dakota	0	0	0	0
	Oregon	0	0	0	0
Amount Allowed	California	0	0	849	849

As revealed in Table 2.1.3.2-3, California, North Dakota, and Oregon are all economically attractive for blending renewable diesel into petroleum diesel during at least some of these years. For all of these years, however, California was the most economically attractive state to blend renewable diesel, and it alone was able to consume all of the renewable diesel allowed by the calculations. As a result, all renewable diesel was assigned to California.

Table 2.1.3.2-4 summarizes the total allowed volumes of renewable diesel in Table 2.1.3.2-3, as well as a running four-year average of these volumes. As described above, this step attempts to reflect how potential renewable diesel investors or banks might determine the economic market size for investing in expanding renewable diesel plant capacity. There was significant variability in the year-by-year estimates of four-year averages and the value seemed to stabilize after 2020. In light of the uncertainty in the analysis, we used a best fit line of the four-year average values to estimate a renewable diesel volume of 424 million gallons per year in 2021 and used this as the volume of renewable diesel used under the No RFS baseline, as we believe that this value best represents the range of four-year average values from 2021–2025.

Table 2.1.3.2-4: Summary of Renewable Diesel Volumes (million gallons)

	2018	2019	2020	2021	2022	2023	2024	2025
Allowed Volume	402	621	580	716	22	22	880	849
Four-Year Average	-	-	-	580	485	335	410	443
No RFS Baseline	-	-	-	424	424	424	424	424

2.1.4 Other Advanced Biofuel

In addition to ethanol, cellulosic biofuel, and BBD, we also estimated volumes of other advanced biofuel for the No RFS baseline. These biofuels include imported sugarcane ethanol, domestically produced advanced ethanol, non-cellulosic RNG used in CNG/LNG vehicles, heating oil, naphtha, and advanced renewable diesel that does not qualify as BBD (coded as D5 rather than as D4). In Chapters 6.3 and 6.4, we present a derivation of the projected volumes of these other advanced biofuels for 2023–2025 in the context of the candidate volumes that we analyzed. Here we discuss the deviations from those projections that we believe would apply under a No RFS baseline.

According to data from EIA, all ethanol imports entered the U.S. through the West Coast in 2019–2021. We believe that these imports were likely used to help refiners meet the requirements of the California LCFS program, which provides significant additional incentives for the use of advanced ethanol beyond that of the RFS program. In the absence of the RFS program, we believe that these incentives would remain. Thus, we have assumed that the volume of imported sugarcane ethanol would be the same regardless of whether the RFS program were in place in 2023–2025. For similar reasons, we believe that domestically produced advanced ethanol would also continue to find a market in California in the absence of the RFS program.

As discussed in Chapter 6.2.4, a similar situation exists for advanced renewable diesel. The vast majority of the renewable diesel consumed in the U.S. has been consumed in California to fulfill the mandates of its LCFS program. Some renewable diesel would continue to be consumed in California in the absence of the RFS program, particularly that produced from FOG due to the lower Carbon Intensity (CI) value assigned to it under the LCFS program. We believe that this would also be the case for advanced renewable diesel that does not qualify as BBD since the statutory threshold of 50% GHG reduction is the same for advanced biofuel and for BBD, and because such renewable diesel is generally produced from FOG. Thus, we have assumed that the volume of advanced renewable diesel that does not qualify as BBD would be the same regardless of whether the RFS program were in place in 2023–2025.

Remaining forms of other advanced biofuel (i.e., non-cellulosic RNG used in CNG/LNG vehicles, heating oil, and naphtha) are much less likely to find their way to markets such as the California LCFS program, where the incentive would be insufficient to continue supporting their use in the absence of the RFS program. Therefore, we have assumed that consumption of these biofuels would be zero under the No RFS baseline.

2.1.5 Summary of No RFS Baseline

Following our analysis of individual biofuel types as described above, we estimated the constituent mix of both renewable fuel types and feedstocks that could be used under a No RFS baseline, as shown in Table 2.1.5-1.

Table 2.1.5-1: No RFS Baseline for 2023–2025 (million RINs)

	2023	2024	2025
Cellulosic Biofuel	356	385	417
CNG/LNG from biogas	356	385	417
Diesel/jet fuel from wood waste/MSW	0	0	0
Electricity from biogas	0	0	0
Total Biomass-Based Diesel	1,374	1,374	1,374
Biodiesel	648	648	648
Soybean oil	298	298	298
FOG	220	220	220
Corn oil	130	130	130
Canola oil	0	0	0
Renewable Diesel	721	721	721
Soybean oil	0	0	0
FOG	663	663	663
Corn oil	58	58	58
Canola oil	0	0	0
Jet fuel from FOG	5	5	5
Other Advanced Biofuels	216	216	216
Renewable diesel from FOG	81	81	81
Imported sugarcane ethanol	110	110	110
Domestic ethanol from waste ethanol	25	25	25
Other[a]	0	0	0
Conventional Renewable Fuel	13,750	13,730	13,693
Ethanol from corn	13,750	13,730	13,693
Renewable diesel from palm oil	0	0	0

[a] Composed of non-cellulosic biogas, heating oil, and naphtha.

2.2 2022 Baseline

As discussed in Preamble Section III.D.3, while we believe that the No RFS baseline is preferable as a point of reference for analyzing the impacts of the candidate volumes, we have also estimated the costs of this rule relative to the 2022 volume requirements as an additional informational case. These alternative estimated costs allow a comparison to those presented in recent RFS annual rules and provide an appreciation for what the impacts of the rule may be relative to the current situation.

As with the No RFS baseline, we needed to estimate the mix of biofuels that could be used to meet the 2022 volume requirements in order to be able to use those volume requirements as a point of reference. In the 2020–2022 annual rule, we made just such an estimate of the mix of biofuels.[132] However, that mix included some simplifying assumptions for advanced biodiesel and renewable diesel. For the purposes of this rule, the more robust cost estimation methodology that we are using would be better served with a more precise estimate of the individual

[132] See Table 2.1-1, Renewable Fuel Standard (RFS) Program: RFS Annual Rules – Regulatory Impact Analysis, EPA-420-R-22-008, June 2022.

feedstocks likely to be used to produce advanced biodiesel and renewable diesel in 2022. To that end, we estimated the mix of feedstocks likely to be used in 2022 to produce these two fuels using the volume requirements for 2022 and the historical trends in the use of feedstocks to produce these fuel.[133] The results are shown in Table 2.2-1, along with the other biofuel mix estimates presented in the 2020–2022 annual rule.

Table 2.2-1: Estimated Mix of Biofuels for 2022 (million RINs)

Cellulosic Biofuel	630
CNG/LNG from biogas	630
Diesel/jet fuel from wood waste/MSW	0
Electricity from biogas	0
Total Biomass-Based Diesel	5,555
Biodiesel	2,650
Soybean oil	1,438
FOG	537
Corn oil	308
Canola oil	367
Renewable Diesel	2,900
Soybean oil	1,714
FOG	1,014
Corn oil	172
Canola oil	0
Jet fuel from FOG	5
Other Advanced Biofuels	256
Renewable diesel from FOG	81
Imported sugarcane ethanol	110
Domestic ethanol from waste ethanol	25
Other[a]	40
Conventional Renewable Fuel	14,439
Ethanol from corn	14,175
Renewable diesel from palm oil	264

[a] Composed of non-cellulosic biogas, heating oil, and naphtha.

[133] See Chapter 6.2 for a description of the methodology used to project biodiesel and renewable diesel feedstocks in 2022.

Chapter 3: Candidate Volumes and Volume Changes

For analyses in which we have quantified the impacts of the candidate volumes for 2023–2025 and the 2023 supplemental standard, we have identified the specific biofuel types and associated feedstocks that are projected to be used to meet those volumes. While we acknowledge that there is significant uncertainty about the types of renewable fuels that would be used to meet the candidate volumes, we believe that the mix of biofuel types described in this chapter are reasonable projections of what could be supplied for the purpose of assessing the potential impacts. As described in Chapter 2, we also acknowledge that the choice of baseline affects the estimated impacts of the candidate volumes and the 2023 supplemental standard. This chapter describes both the methodology for identifying the mix of biofuels that could result from the candidate volumes and the 2023 supplemental standard and the change in volumes in comparison to the No RFS and 2022 baselines.

3.1 Mix of Renewable Fuel Types for Candidate Volumes

The candidate volumes that we developed for 2023–2025 (excluding the 2023 supplemental standard) are presented in Preamble Section III.C.5 and are repeated in Tables 3.1-1 and 2.

Table 3.1-1: Candidate Volume Components (million RINs)[a]

	D Code[b]	2023	2024	2025
Cellulosic biofuel	D3 + D7	719	1,419	2,131
Biomass-based diesel	D4	5,389	5,689	5,760
Other advanced biofuel	D5	256	256	256
Conventional renewable fuel	D6	14,455	14,505	14,534

[a] Does not include RINs used to meet the 2023 supplemental standard.
[b] The D codes given for each component category are defined in 40 CFR 80.1425(g). D codes are used to identify the statutory categories that can be fulfilled with each component category according to 40 CFR 80.1427(a)(2).

Table 3.1-2: Candidate Volumes in Statutory Categories (million RINs)[a]

	D Code	2023	2024	2025
Cellulosic biofuel	D3 + D7	719	1,419	2,131
Non-cellulosic advanced biofuel[b]	D5	5,100	5,200	5,300
Advanced biofuel	D3 + D4 + D5 + D7	5,819	6,619	7,431
Conventional renewable fuel[b]	D6	15,000	15,250	15,250
Total renewable fuel	All	20,819	21,869	22,681

[a] Does not include RINs used to meet the 2023 supplemental standard.
[b] These are implied volume requirements, not regulatory volume requirements.

We estimated the constituent mix of renewable fuel types and feedstocks that could be used to meet the candidate volumes (absent the 2023 supplemental standard) as shown in Table 3.1-3.[134]

Table 3.1-3: Candidate Volumes Assessed for 2023–2025 (million RINs)

	2023	2024	2025
Cellulosic Biofuel	719	1,419	2,131
CNG/LNG from biogas	719	814	921
Diesel/jet fuel from wood waste/MSW	0	5	10
Electricity from biogas	0	600	1,200
Total Biomass-Based Diesel[a]	5,389	5,689	5,760
Biodiesel	2,580	2,530	2,480
Soybean oil	1,390	1,340	1,290
FOG	520	520	520
Corn oil	310	310	310
Canola oil	360	360	360
Renewable Diesel	2,804	3,154	3,275
Soybean oil	1,494	1,744	1,755
FOG	1,120	1,210	1,310
Corn oil	190	200	210
Canola oil	0	0	0
Jet fuel from FOG	5	5	5
Other Advanced Biofuels	256	256	256
Renewable diesel from FOG	81	81	81
Imported sugarcane ethanol	110	110	110
Domestic ethanol from waste ethanol	25	25	25
Other[b]	40	40	40
Conventional Renewable Fuel	14,455	14,505	14,534
Ethanol from corn	14,455	14,505	14,534
Renewable diesel from palm oil	0	0	0

[a] Includes BBD in excess of the candidate volume for advanced biofuel. The excess would be used to help meet the candidate volume for conventional renewable fuel.
[b] Composed of non-cellulosic biogas, heating oil, and naphtha.

Unlike for 2022, wherein we projected that some palm-based, imported conventional renewable diesel would be needed in order to meet the applicable standards and the 2022 supplemental standard,[135] we do not believe that any palm-based, imported conventional renewable diesel would be needed in 2023–2025. Our assessment of BBD, described more fully in Chapter 6.2, leads us to a provisional conclusion that there would be sufficient volumes available to meet the candidate volumes for non-cellulosic advanced biofuel and conventional renewable fuel and, in the case of 2023, the proposed supplemental standard.

[134] The analyses leading to the mix of renewable fuel types and feedstocks are presented in Chapter 6. We have also analyzed the impacts of the 2023 supplemental standard under the assumption that it would be met with soybean oil-based renewable diesel in Chapter 3.4.
[135] 87 FR 39600 (July 1, 2022).

3.2 Volume Changes Analyzed With Respect to the No RFS Baseline

For those factors that we quantified the impacts of the candidate volumes for 2023–2025, the impacts were based on the difference in the volumes of specific renewable fuel types between the candidate volumes and the No RFS baseline. These differences are shown in Tables 3.2-1 and 2 in terms of RINs and physical volumes, respectively. The values in these tables reflect the difference between values in Tables 3.1-3 and 2.1.5-1.

Table 3.2-1: Volume Changes for Candidate Volumes Relative to the No RFS Baseline (million RINs)

	2023	**2024**	**2025**
Cellulosic Biofuel	363	1,034	1,714
CNG/LNG from biogas	363	429	504
Diesel/jet fuel from wood waste/MSW	0	5	10
Electricity from biogas	0	600	1,200
Total Biomass-Based Diesel	4,015	4,315	4,386
Biodiesel	1,932	1,882	1,832
Soybean oil	1,092	1,042	992
FOG	300	300	300
Corn oil	180	180	180
Canola oil	360	360	360
Renewable Diesel	2,083	2,433	2,554
Soybean oil	1,494	1,744	1,755
FOG	457	547	647
Corn oil	132	142	152
Canola oil	0	0	0
Jet fuel from FOG	0	0	0
Other Advanced Biofuels	40	40	40
Renewable diesel from FOG	0	0	0
Imported sugarcane ethanol	0	0	0
Domestic ethanol from waste ethanol	0	0	0
Other[a]	40	40	40
Conventional Renewable Fuel	706	776	840
Ethanol from corn	706	776	840
Renewable diesel from palm oil	0	0	0

[a] Composed of non-cellulosic biogas, heating oil, and naphtha.

Table 3.2-2: Volume Changes for Candidate Volumes Relative to the No RFS Baseline (million gallons)[a]

	2023	2024	2025
Cellulosic Biofuel	363	1,032	1,710
CNG/LNG from biogas[a]	363	429	504
Diesel/jet fuel from wood waste/MSW	0	3	6
Electricity from biogas[a]	0	600	1,200
Total Biomass-Based Diesel	2,513	2,686	2,724
Biodiesel	1,288	1,255	1,221
Soybean oil	728	695	661
FOG	200	200	200
Corn oil	120	120	120
Canola oil	240	240	240
Renewable Diesel	1,225	1,431	1,503
Soybean oil	879	1,026	1,032
FOG	269	322	381
Corn oil	78	84	90
Canola oil	0	0	0
Jet fuel from FOG	0	0	0
Other Advanced Biofuels	31	31	31
Renewable diesel from FOG	0	0	0
Imported sugarcane ethanol	0	0	0
Domestic ethanol from waste ethanol	0	0	0
Other[b]	31	31	31
Conventional Renewable Fuel	706	776	840
Ethanol from corn	706	776	840
Renewable diesel from palm oil	0	0	0

[a] Electricity and CNG/LNG remain in ethanol-equivalent gallons in this table.
[b] Composed of non-cellulosic biogas, heating oil, and naphtha.

Note that the changes in ethanol from corn shown in Tables 3.2-1 and 2 can be entirely attributed to ethanol used as E15 and E85, since under the No RFS baseline we project that there would not be any E15 or E85.[136]

Tables 3.2-1 and 2 represent the change in biofuel use in the transportation sector that could occur if the candidate volumes were to become the basis for the applicable percentage standards. For most biofuels, the volume changes in the transportation sector correspond directly to changes in the production and/or importation of those volumes. However, the same is not true for cellulosic biofuels produced from biogas. In particular, renewable electricity is currently being generated from biogas, but that renewable electricity is not currently being used as transportation fuel. For 2023–2025, we project that there would not be any additional renewable electricity generated from biogas than would occur in the absence of the RFS program. Instead, renewable electricity that is already being generated would simply be redirected from non-transportation uses (e.g., residential and commercial power) to use as a transportation fuel. Thus,

[136] See Chapter 2.1.1 for more discussion on E15 and E85.

while there would be in increase in renewable electricity used as transportation fuel as shown in Tables 3.2-1 and 2, there would not in fact be a corresponding change in the generation of that electricity. For the purposes of analysis of the candidate volumes, therefore, we treated the volume change in renewable electricity as zero.

In a similar fashion, biogas used to produce RNG for use in CNG/LNG vehicles is also not expected to change to the same degree that Tables 3.2-1 and 2 would suggest. In the absence of the RFS program, we project that companies that had already made investments to produce and distribute RNG through commercial pipelines would redirect this RNG from transportation uses to non-transportation uses (e.g., commercial or industrial uses) rather than reducing RNG production. Thus, we project that the actual increase in the production of RNG under the No RFS baseline would be smaller than the projected increase in RNG used in transportation as shown in Tables 3.2-1 and 2. For the purposes of analysis of the candidate volumes, therefore, we estimated the volume change for RNG as the increase from projected use of RNG as transportation fuel in 2022 in Table 2.2-1 to the candidate volumes shown in Table 3.1-3, yielding the volume changes shown in Table 3.2-3.

In the 2020–2022 annual rule, we made some simplifications to the projected volume changes for the purposes of our analyses. Namely, we grouped fuels with very small changes in volumes with similar fuels having much larger volume changes. We did this because: (1) we had more limited data on the impacts of those renewable fuel types with smaller volume changes; (2) the impacts on many of the factors evaluated in Chapter 4 are expected to be similar; and (3) we expect small volume changes to have little material impact on the overall conclusions of the analyses. For this rule, we have taken a similar approach. This simplification fell into three areas:

1. We have treated all liquid cellulosic biofuels as hydrocarbons produced from wood waste.
2. We have treated all volume changes in canola oil as if they were changes in soybean oil.
3. We have treated all volume changes in “Other” advanced biofuel, which is dominated by naphtha, as if they were changes in renewable diesel.[137]

As a result of these adjustments and simplifications, the volume changes that we used in our analyses were as follows:

[137] We assumed that the feedstocks used to produce these “other” advanced biofuels were proportional to the feedstocks used to produce renewable diesel.

Table 3.2-3: Volume Changes Analyzed for the Candidate Volumes With Respect to the No RFS Baseline (million gallons)[a]

	2023	2024	2025
CNG/LNG from biogas[a]	87	182	289
Electricity from biogas[a]	0	0	0
Diesel/jet fuel from wood waste/MSW	0	3	6
Biodiesel from soybean oil	968	935	901
Biodiesel from FOG	200	200	200
Biodiesel from corn oil	120	120	120
Renewable diesel from soybean oil	901	1,048	1,054
Renewable diesel from FOG	275	329	388
Renewable diesel from corn oil	80	86	91
Ethanol from corn	706	776	840
Renewable diesel from palm oil	0	0	0

[a] Electricity and CNG/LNG remain in ethanol-equivalent gallons in this table.

For the climate change analyses, we determined that a more robust analysis could be performed if BBD produced from FOG could be disaggregated into specific types. Therefore, using data from EIA's Monthly Biofuels Capacity and Feedstocks Update for the 12-month period of April 2021 through March 2022, we determined that FOG on average consists of about 60% used cooking oil (UCO) and about 40% tallow.[138] These fractions were applied to the volume changes shown in Table 3.2-3 for both biodiesel and renewable diesel produced from FOG in the context of the climate change analyses.

Table 3.2-4: Disaggregated Biofuels Made From FOG (million gallons)

	2023	2024	2025
Biodiesel from FOG	200	200	200
UCO	120	120	120
Tallow	80	80	80
Renewable diesel from FOG	275	329	388
UCO	165	197	233
Tallow	110	131	155

3.3 Volume Changes Analyzed with Respect to the 2022 Baseline

As described in Chapter 2.2, for cost purposes only, we also analyzed the impacts of volume changes with respect to the 2022 baseline. These differences are shown in Tables 3.3-1 and 2 in terms of RINs and physical volumes, respectively. The values in these tables reflect the difference between values in Tables 3.1-3 and 2.2-1.

[138] EIA Monthly Biofuels Capacity and Feedstocks Update - Table 2a, https://www.eia.gov/biofuels/update

Table 3.3-1: Volume Changes for Candidate Volumes Relative to 2022 Baseline (million RINs)

	2023	2024	2025
Cellulosic Biofuel	89	789	1,501
CNG/LNG from biogas	89	184	291
Diesel/jet fuel from wood waste/MSW	0	5	10
Electricity from biogas	0	600	1,200
Total Biomass-Based Diesel	-166	134	205
Biodiesel	-70	-120	-170
Soybean oil	-48	-98	-148
FOG	-17	-17	-17
Corn oil	2	2	2
Canola oil	-7	-7	-7
Renewable Diesel	-96	254	375
Soybean oil	-220	30	41
FOG	106	196	296
Corn oil	18	28	38
Canola oil	0	0	0
Jet fuel from FOG	0	0	0
Other Advanced Biofuels	0	0	0
Renewable diesel from FOG	0	0	0
Imported sugarcane ethanol	0	0	0
Domestic ethanol from waste ethanol	0	0	0
Other	0	0	0
Conventional Renewable Fuel	266	316	345
Ethanol from corn	280	330	359
Renewable diesel from palm oil	-14	-14	-14

Table 3.3-2: Volume Changes for Candidate Volumes Relative to 2022 Baseline (million gallons)[a]

	2023	2024	2025
Cellulosic Biofuel	89	787	1,497
CNG/LNG from biogas[a]	89	184	291
Diesel/jet fuel from wood waste/MSW	0	3	6
Electricity from biogas[a]	0	600	1,200
Total Biomass-Based Diesel	-103	69	107
Biodiesel	-47	-80	-113
Soybean oil	-32	-65	-99
FOG	-11	-11	-11
Corn oil	1	1	1
Canola oil	-5	-5	-5
Renewable Diesel	-57	149	221
Soybean oil	-130	17	24
FOG	62	115	174
Corn oil	11	16	22
Canola oil	0	0	0
Jet fuel from FOG	0	0	0
Other Advanced Biofuels	0	0	0
Renewable diesel from FOG	0	0	0
Imported sugarcane ethanol	0	0	0
Domestic ethanol from waste ethanol	0	0	0
Other	0	0	0
Conventional Renewable Fuel	272	322	351
Ethanol from corn	280	330	359
Renewable diesel from palm oil	-8	-8	-8

[a] Electricity and CNG/LNG remain in ethanol-equivalent gallons in this table

Unlike for the comparison to the No RFS baseline, the changes in ethanol from corn shown in Tables 3.3-1 and 2 are a function of both changes in total gasoline demand as well as changes in the consumption of E15 and E85. Table 3.3-3 shows the amount of ethanol that can be attributed to each.

Table 3.3-3: Source of Ethanol Changes in Comparison to the 2022 Baseline (million gallons)

	2023	2024	2025
Changes in ethanol consumption attributable to changes in gasoline demand	188	259	324
Changes in ethanol consumption attributable to changes in E15 and E85 consumption	92	71	35
Total	280	330	359

We made the same adjustments and simplifications to the volume changes in comparison to the 2022 baseline as we made to the volume changes in comparison to the No RFS baseline. The results are shown in Table 3.3-4.

Table 3.3-4: Volume Changes Analyzed for Candidate Volumes With Respect to the 2022 Baseline (million gallons)[a]

	2023	2024	2025
CNG/LNG from biogas[a]	87	182	289
Electricity from biogas[a]	0	0	0
Diesel/jet fuel from wood waste/MSW	0	3	6
Biodiesel from soybean oil	-37	-70	-103
Biodiesel from FOG	-11	-11	-11
Biodiesel from corn oil	1	1	1
Renewable diesel from soybean oil	-130	17	24
Renewable diesel from FOG	62	115	174
Renewable diesel from corn oil	11	16	22
Ethanol from corn	280	330	359
Renewable diesel from palm oil	-8	-8	-8

[a] Electricity and CNG/LNG remain in ethanol-equivalent gallons in this table

3.4 2023 Supplemental Volume Requirement

As discussed in Preamble Section V, we are proposing a supplemental volume requirement of 250 million gallons of renewable fuel that would apply in 2023, which would complete our response to the *ACE* remand. Although we are proposing to require this supplemental volume requirement in concert with the candidate volumes for 2023–2025 proposed under CAA section 211(o)(2)(B)(ii), the 2023 supplemental volume requirement is not proposed under our "set" authority, but rather our outstanding obligation from 2016 to promulgate standards under CAA section 211(o)(3)(B(i). It would in fact be an independent requirement that is separately justified. For this reason, our analysis of the statutory factors listed in CAA section 211(o)(2)(B)(ii)(I) through (VI) has been focused on the candidate volumes exclusive of the supplemental volume requirement.

The requirements of CAA section 211(o)(2)(B)(ii) do not apply to the 250-million-gallon supplemental volume requirement for 2023; we have not conducted an analysis of all of the factors listed in CAA section 211(o)(2)(B)(ii)(I) through (VI) as part of our assessment of the appropriateness of imposing the supplemental volume requirement on obligated parties. Nevertheless, it is both prudent and consistent with the requirements of Executive Order 12866 and Circular A-4 that we assess the costs, GHG, and energy security impacts of the 250-million-gallon supplemental volume requirement for 2023.

In our assessment for 2023, we have projected that biodiesel and renewable diesel would be the fuels most likely to be supplied to satisfy the 250-million-gallon supplemental volume requirement. We also determined that there would be sufficient quantities of biodiesel and renewable diesel available to satisfy the supplemental volume requirement beyond the quantity of these fuels needed to satisfy the BBD, advanced biofuel, and total renewable fuel requirements for 2023. However, it is difficult to identify the precise mix of biofuel types and feedstocks that would make up this 250 million gallons since it would not be a segregated and uniquely categorized pool of renewable fuel. For the purposes of analyzing its impacts, we have made the simplifying assumption that it would be composed entirely of soybean oil renewable diesel, as we project that this is the highest cost type of biodiesel or renewable diesel available, and therefore the fuel type that is likely to make up the marginal gallons used to satisfy the supplemental volume requirement.

Under the No RFS baseline, there would be no supplemental volume requirement because there would be no RFS obligations of any kind. However, under the 2022 baseline there is in fact a supplemental volume requirement.[139] As described in the 2020–2022 annual rule, we projected that the 250-million-gallon supplemental volume requirement for 2022 would be met with imported palm-based renewable diesel. The net result is that the 250-million-gallon supplemental volume requirement for 2023 would result in the following changes in fuel types in comparison to the No RFS and 2022 baselines:

Table 3.3-1: Volume Changes for 2023 Supplemental Volume Requirement (million gallons)[a]

In comparison to No RFS baseline	
Soybean oil renewable diesel	+147
Palm oil renewable diesel	0
In comparison to 2022 baseline	
Soybean oil renewable diesel	+147
Palm oil renewable diesel	-147

[a] The 250-million-allon supplemental volume requirement represents ethanol-equivalent gallons. Values are presented in physical gallons of renewable diesel, where 1 gallon of renewable diesel has the same amount of energy as 1.7 gallons of ethanol.

[139] 87 FR 36900 (July 1, 2022).

Chapter 4: Environmental Impacts

The statute requires EPA to analyze a number of environmental factors in its determination of the appropriate volumes to establish under the set authority. This chapter discusses those environmental factors required by the statute. Due to its close association with water quality, which is a factor listed in the statute, we also investigated soil quality even though it is not listed in the statute. In addition to the analysis presented here, we also considered the Second Triennial Report to Congress on Biofuels, which provides additional information on environmental impacts.[140]

4.1 Air Quality

Air quality, as measured by the concentration of air pollutants in the ambient atmosphere, can be affected by increased production and use of biofuels. Some air pollutants are emitted directly (e.g., nitrogen oxides (NOx)), other air pollutants are formed secondarily in the atmosphere (e.g., ozone), and some air pollutants have directly emitted and secondarily formed components (e.g., particulate matter (PM) and aldehydes). Health and environmental effects of criteria pollutants and air toxics which can be impacted by biofuel use are discussed in a memorandum to the docket.[141] Air quality can be affected by emissions from combustion of biofuels in vehicles, as well as emissions from production and transport of feedstocks, conversion of feedstocks to biofuels, and transport of the finished biofuels. Recent dispersion modeling has shown elevated pollutant concentrations near corn, soybean, and wood biorefineries, which were associated with adverse respiratory outcomes.[142]

In addition to the type of biofuel, other factors affect air quality, including but not limited to the blend level, the vehicle technology, emissions control technology, and operating conditions. Overall, the impacts on air quality resulting from the biofuel volume changes due to this rule are expected to be relatively minor and thus, provide little basis in favor of higher or lower volumes. First, the largest volume changes are for renewable diesel, primarily produced from soybean oil, with smaller volumes of biodiesel and renewable diesel from fats, oils, and greases (FOG), ethanol, and biogas. Much of the increase in renewable diesel is produced at traditional petroleum refineries that have been converted to renewable fuel production; at such facilities the emission impact is not likely to be significant because the processes used to produce renewable diesel are similar to processes used in the production of petroleum-based diesel. In addition, while data on end use impacts of renewable diesel are limited, the impacts are expected to be minor. We do not anticipate that this proposal will result in increases in emissions associated with biogas to electricity given the already available generation capacity. It should also be noted that, EPA's "anti-backsliding study" (ABS), required under CAA Section

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[140] EPA. Biofuels and the Environment: Second Triennial Report to Congress (Final Report, 2018). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-18/195, 2018. https://cfpub.epa.gov/si/si_public_record_report.cfm?Lab=IO&dirEntryId=341491

[141] EPA (2022). "Health and environmental effects of pollutants discussed in Chapter 4 of Regulatory Impact Analysis (RIA) supporting proposed RFS standards for 2023-2025." Memorandum from Rich Cook to Docket No. EPA-HQ-OAR-2021-0427, July 21, 2022.

[142] Lee, E. K., Romeiko, X. X., Zhang, W. Feingold, B., Khwaja, H., Zhang, X., and Lin, S. (2021). Residential proximity to biorefinery sources of air pollution and respiratory diseases in New York State. Environ. Sci., Technol. 55, 10035-10045.

211(v)(1), examined the impacts on air quality as a result of changes in vehicle and engine emissions resulting from required renewable fuel volumes of ethanol under the RFS, relative to approximately 2005 levels.[143] Hoekman et al. (2018) also reviewed available literature on potential air quality impacts for E10 versus E0 across the entire lifecycle.[144] Both studies found potential increases and decreases in ambient pollutant levels of pollutants, but none of them were large, even when they considered much greater changes in ethanol volumes than are being proposed in this rule. Finally, we cannot quantify air quality impacts of potential land use changes associated with biogas production at this time. As discussed in Section 4.2 in this RIA, there is considerable uncertainty concerning land use impacts of the volumes changes proposed in this rule.

Table 3.2-3 summarizes the changes in renewable production volume assessed for this rule. The discussion below focuses on potential impacts for these fuel/feedstock combinations.

4.1.1 Production Transport Emissions of Liquid Biofuels

Corn Ethanol

Air quality impacts of corn ethanol are associated with each step in the supply chain: (1) agricultural feedstock production and storage, (2) feedstock transport to the biorefinery, (3) ethanol production at the biorefinery, (4) ethanol distribution, blending and storage, and (5) end use.

There is little recent literature that addresses cumulative impacts of processes upstream of emissions from corn ethanol. A 2009 analysis using the GREET model concluded that criteria pollutant emissions for corn ethanol production are substantially higher than for gasoline on a mass per gasoline equivalent gallon basis.[145] A significant source of upstream emissions from corn ethanol is production facilities.[146,147] Table 4.1.1-1 summarizes corn ethanol plant emissions, using data from the 2017 National Emissions Inventory (NEI) where available.[148] For facilities not found in the 2017 NEI, we used data from the 2016 emissions modeling platform

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[143] EPA (2020). Clean Air Act Section 211(V)(1) Anti-Backsliding Study. https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100ZBY1.pdf

[144] Hoekman, S. K., Broch, A., & Liu, X. (2018). Environmental implications of higher ethanol production and use in the U.S. Renewable and Sustainable Energy Reviews, 81, 3140-3158.

[145] Hess P, Johnston M, Brown-Steiner B, Holloway T, de Andrade JB, Artaxo P. Chapter 10: air quality issues associated with biofuel production and use. In: Howarth RW, Bringezu S. editors. Biofuels: environmental consequences and interactions with changing land use. Gummersbach, Germany; 2009. p. 169–94. https://ecommons.cornell.edu/bitstream/handle/1813/46218/scope.1245782010.pdf?sequence=2

[146] 146 EPA. Biofuels and the Environment: Second Triennial Report to Congress (Final Report, 2018). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-18/195, 2018. https://cfpub.epa.gov/si/si_public_record_report.cfm?Lab=IO&dirEntryId=341491

[147] de Gouw, J. A., McKeen, S. A., Aikin, K. C., Brock, C. A., ABrown, S. S., Gilman, J. B., Graus, M., AHanisco, T., Holloway, J. S., Kaiser, J., Keutsch, F. N., Lerner, B. M., Liao, J., Markovic, M. Z., Middlebrook, A. M., Min, K.-E., Neuman, J. A., Nowak, J. B., Peischl, J., Pollack, I. B., Roberts, J. M., et al. (2015). Airborne measurements of the atmospheric emissions from a fuel ethanol refinery. Journal of Geophysical Research: Atmospheres, 120(9), 4385-4397. https://doi.org/10.1002/2015JD023138

[148] https://www.epa.gov/air-emissions-inventories/2017-national-emissions-inventory-nei-data

version 1[149] or inventory estimates using facility-level volume data from the EPA moderated transaction system.[150] Only a few plants used coal or coal in combination with other energy sources, although the small number of wet mill plants contributed disproportionately to emissions, especially sulfur dioxide.

Table 4.1.1-1: Pollutant Emissions (short tons) From Biodiesel and Corn Ethanol Biorefineries in U.S. in 2017

Finished Fuel	Number of Facilities	CO	NH_3	NOx	PM_{10}	$PM_{2.5}$	SO_2	VOCs
Corn Ethanol (total)	176	7362.8	278.7	9045.5	5218.7	4088.5	1854.4	8908.7
Coal; Dry Mill	2	75.3	0	55.8	20.7	20.0	n.a.	39.7
Coal; Wet Mill	2	455.9	23.2	603.2	376.5	260.0	547.1	827.9
Natural Gas; Dry Mill	160	6389.6	246.4	7880.6	4533.5	3647.2	904.4	7560.3
Natural Gas; Wet Mill	3	251.8	9.0	142.2	184.5	102.7	74.7	270.5
Unknown; Unknown	9	190.1	0.0	363.7	103.4	58.5	327.6	210.3
Biodiesel[6]	175	960.5	39.7	1277.0	815.7	556.2	3384.1	3987.2
Total	351	8323.2	318.4	10,322.5	6034.4	4644.6	5238.5	12,895.9

Sources: EPA 2017 NEI (https://www.epa.gov/air-emissions-inventories/2017-national-emissions-inventory-nei-data) and EPA 2016 version 1 modeling platform (https://www.epa.gov/air-emissions-modeling/2016v1-platform)

Once the ethanol is produced at biorefineries, it is transported to terminals for blending and storage. At the blending terminal, ethanol is blended with gasoline for various fuel combinations such as E10, E15 or E85. The blended fuel is then sent to retail gasoline outlets where it is sold to the customer. Primary modes of distributing ethanol to the blending terminal and the blended fuel to the retail outlets are rail, road, or barges. Emissions come from combustion and evaporation during transport by mobile sources, as well as evaporative losses during storage and transport. The largest emission contribution is for VOC due to evaporation. Table 4.1.1-2 presents emissions associated with transport. Air quality impacts associated with changes in ethanol production and transport are expected to be primarily in the local area where the emissions occur.[151] Ambient measurements also indicate concentrations of several pollutants,

[149] https://www.epa.gov/air-emissions-modeling/2016v1-platform

[150] https://www.epa.gov/fuels-registration-reporting-and-compliance-help/reporting-rfs-rin-transactions-epa-moderated

[151] Cook, R., Phillips, S., Houyoux, M., Dolwick, P., Mason, R., Yanca, C., Zawacki, M., Davidson, K., Michaels, H., Harvey, C., Somers, J., Luecken, D.. 2011. Air quality impacts of increased use of ethanol under the United States' Energy Independence and Security Act. *Atmospheric Environment*, 45: 7714-7724. https://www.sciencedirect.com/science/article/pii/S1352231010007375

such as NOx, formaldehyde, and SO_2,, are greater directly downwind of production facilities, up to a distance of 30 kilometers.[152]

Table 4.1.1-2. Emissions From Transportation of Ethanol (short tons) in 2016

CO	**NH_3**	**NO_X**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**VOC**
4,225	26	19,270	630	533	340	660,674

Source: EPA 2016 version 1 modeling platform (https://www.epa.gov/air-emissions-modeling/2016v1-platform)

Using the production and transport emissions data, along with total production in 2017, we calculated emission rates in grams per gallon for production of and transport of corn ethanol. We then multiplied the grams per gallon emission rates by the volume impacts for this rule, relative to the No RFS baseline (from Table 3.2-3), to estimate the impacts associated with ethanol production and transport (see Table 4.1.1-3). In doing so, we assumed that additional ethanol use in the U.S. is associated with ethanol production in the U.S. We describe this assumption further in Chapter 3. However, we note that volumes used domestically could be sourced from imports. Thus, it is unclear what overall impacts would be on domestic production and therefore emissions. We note, moreover, that significant quantities of domestically produced ethanol are exported and thus not used for RFS compliance; the below table does not capture emissions related to such exports.

[152] See, e.g., de Gouw, J. A., McKeen, S. A., Aikin, K. C., Brock, C. A., ABrown, S. S., Gilman, J. B., Graus, M., AHanisco, T., Holloway, J. S., Kaiser, J., Keutsch, F. N., Lerner, B. M., Liao, J., Markovic, M. Z., Middlebrook, A. M., Min, K.-E., Neuman, J. A., Nowak, J. B., Peischl, J., Pollack, I. B., Roberts, J. M., et al. (2015). Airborne measurements of the atmospheric emissions from a fuel ethanol refinery. *Journal of Geophysical Research: Atmospheres, 120*(9), 4385-4397. https://doi.org/10.1002/2015JD023138

Table 4.1.1-3: Pollutant Emission Impact Estimates for Production and Transport of Corn Ethanol of the 2023–2025 Proposed Volumes Relative to No RFS Baseline (short tons)

	CO	NH_3	NO_X	PM_{10}	$PM_{2.5}$	SO_2	VOC
Biorefinery Emissions	7,142	270	8,775	5,062	3,996	1,798	8,643
Transport Emissions	4,225	26	19,270	630	533	340	660,674
Total Emissions	11,558	305	28,316	5,849	4,622	2,194	669,583
Impacts per Million Gallons Ethanol[a]	0.75	0.02	1.83	0.38	0.30	0.14	43.45
2023 Volume Changes	530	14	1,291	268	211	99	30,676
2024 Volume Changes	582	16	1,420	295	233	109	33,717
2025 Volume Changes	630	17	1537	319	252	118	36,498

[a] Emissions per million gallons ethanol is calculated using total domestic ethanol production in 2017 as reported in the EIA Monthly Energy Review (15.41 billion gallons)

We also compared emission rates per energy unit produced for production of ethanol versus gasoline, using emissions data from the 2017 NEI and production for 2017 from the EIA. The portion of refinery emissions attributable to gasoline production was estimated using data from GREET.[153] As seen in Table 4.1.1-4, emissions per BTU produced are much higher for ethanol than gasoline.

Table 4.1.1-4: Emissions Per Energy Unit Produced for Ethanol Versus Gasoline (g/mmBTU) in 2017

Pollutant	g/mmBTU EtOH	g/mmBTU Gasoline
VOC	6.67	0.64
CO	5.51	0.37
NOx	6.77	0.81
PM_{10}	3.90	0.22
$PM_{2.5}$	3.08	0.20
SO_2	1.39	0.09
NH_3	0.21	0.04

[153] Sun, P., Zhu, L. Emissions Updates for Petroleum Products in GREET 2019, https://greet.es.anl.gov/files/petro_2019

Biodiesel/Renewable Diesel

Although biodiesel is sourced from a variety of feedstocks, domestic soybean and domestic FOGs made up nearly 70% of the biodiesel in 2019, with most of that being domestic soybean. Data are lacking on emission and air quality impacts of either soybean biodiesel or FOGs that address the feedstock production (soybean) or collection (FOGs), storage, and transport stages. In the soybean diesel production phase, emission impacts depend on the oil extraction method used. Mechanical expelling is the least efficient with the highest emissions of NOx, VOCs, CO, and PM2.5, followed by hexane extraction and then enzyme assisted aqueous extraction process (EAEP).[154] Hum et al (2016) compared life cycle emissions for low sulfur diesel (LSD), soybean-based biodiesel, and grease trap waste (GTW) based biodiesel.[155] This study relied on GREET-2014 for soybean-based biodiesel impacts.[156] The study found decreases in PM and CO (5% and 66%), but increases in NO_x and SO_x (10% and 39%, respectively). However, the comparison's end use emission estimates included only pre-2007 engines.

A smaller amount of biodiesel is derived from FOG. FOGs are waste products of processes like animal rendering. Overall, since FOG is a generally a byproduct, farming emissions are not attributed to it, and the effects from FOGs may be expected to be much lower than for soybean biodiesel.

Table 4.1.1-1 provides estimated emissions from biodiesel refineries in the U.S. Given the limited impact of this rule on biodiesel production, national-scale impacts are small. However, there could be localized impacts.

We also compared emission rates per energy unit produced for production of biodiesel versus distillate, using emissions data from the 2017 NEI and production for 2017 from the EIA. As seen in Table 4.1.1-5, emissions per BTU produced are much higher for ethanol than gasoline.

[154] Cheng, M., Sekhon, J. J. K., Rosentrater, K. A., Wang, T., Jung, S., Johnson, L. A. "Environmental Impact Assessment of Soybean Oil Production: Extruding-Expelling Process, Hexane Extraction and Aqueous Extraction." Food and Bioproducts Processing 108 (2018): 58-68. https://www.sciencedirect.com/science/article/abs/pii/S0960308518300014

[155] Hums, M., Cairncross, R., & Spatan, S. (2016). Life-cycle assessment of biodiesel produced from grease trap waste. Environmental Science & Technology, 50(5), 2718–2726. https://doi.org/10.1021/acs.est.5b02667

[156] Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model; Argonne National Laboratory: Argonne, IL, 2014. https://greet.es.anl.gov/

Table 4.1.1-5: Emissions Per Energy Unit Produced for Biodiesel Versus Distillate (g/mmBTU) in 2017

Pollutant	g/mmBTU Biodiesel	g/mmBTU Distillate
VOC	19.21	1.37
CO	4.63	0.84
NOx	6.15	1.49
PM_{10}	3.93	0.44
$PM_{2.5}$	2.68	0.38
SO_2	16.30	0.25
NH_3	0.19	0.07

While biodiesel is the predominant advanced biofuel used in diesel engines, renewable diesel is projected to account for roughly similar increases in biomass-based diesel during the 2023 through 2025 timeframe. Much renewable diesel is produced at traditional petroleum refineries; at such facilities the emission impact is not likely to be significant because the processes used to produce renewable diesel are similar to processes used in the production of petroleum-based diesel. However, there will be emission impacts from new facilities constructed to produce renewable diesel. Reported emissions data for such facilities are extremely limited and inadequate to draw any conclusions about potential level of impacts. Furthermore, these emission increases may be offset by emission decreases resulting from decreased petroleum distillate refining at other locations. Thus, given the limited research available on renewable diesel production and end use emissions, we have not been able to quantify the air quality impacts of the additional renewable diesel use associated with this rule.

4.1.2 End Use Emissions of Liquid Biofuels

Ethanol

After distribution to the retail outlet stations, end use at the vehicle occurs. This step includes both evaporative losses during dispensing the fuel, and exhaust emissions from combustion during vehicular use. Impacts of ethanol blends on vehicle exhaust emissions are the result of complex interactions between fuel properties, vehicle technologies, and emission control systems. Depending on the pollutant and blend concentration the impacts vary both in direction and magnitude.

Several test programs in recent years have evaluated the impacts of fuel properties, including those of certain ethanol blends on emissions from Tier 2 and Tier 3 compliant vehicles).[157,158,159,160] However, because the projected changes in volume of ethanol resulting from the proposal are much smaller than the total amount of fuel consumed across the country, and given the magnitude of the changes in emission rates when burning E10 vs E0, the overall end use impacts are expected to be small. The volume changes we are projecting are largely due to increased use of E10. We expect only very small increases in E15 and E85 use, as we discuss in Chapter 6.5, and thus emission changes due to increased use of these fuels are also anticipated to be very minor.

Biodiesel

Biodiesel consists of straight-chain molecules that boil in the diesel range and typically contain at least one double bond as well as an oxygen atom incorporated into a methyl ester group. These chemical features can cause differences in emissions relative to petroleum diesel, primarily when used in older engines. EPA's MOVES3 model assumes no emission impacts of biodiesel fuel for engines meeting 2007 and later standards due to their highly efficient emission controls. However, the model does estimate criteria pollutant emission impacts for pre-2007 engines based on data generated for B20 (20 vol%) blends of soybean-based biodiesel in petroleum diesel (Table 4.1.2-1; EPA, 2020, Table 8-1).[161] The biodiesel effects implemented in MOVES are obtained from an analysis conducted as part of the 2010 Renewable Fuel Standard Program.[162]

Table 4.1.2-1: Emission Impacts on Pre-2007 Heavy-Duty Diesel Engines for All Cycles Tested on 20 vol% Soybean-Based Biodiesel Fuel Relative to an Average Base Petroleum Diesel Fuel

Pollutant	Percent Change in Emissions
THC (Total Hydrocarbons)	-14.1
CO	-13.8
NO_x	+2.2
$PM_{2.5}$	-15.6

Renewable Diesel

[157] EPA (2013a). Assessing the Effect of Five Gasoline Properties on Exhaust Emissions from Light-Duty Vehicles Certified to Tier 2 Standards: Analysis of Data from Epact Phase 3 (Epact/V2/E-89).

[158] EPA (2013b). Epact/V2/E-89: Assessing the Effect of Five Gasoline Properties on Exhaust Emissions from Light-Duty Vehicles Certified to Tier 2 Standards - Final Report on Program Design and Data Collection.

[159] Morgan, P., Lobato, P., Premnath, V., Kroll, S., Brunner, K.. Impacts of Splash-Blending on Particulate Emissions for Sidi Engines. Coordinating Research Council (2018). http://crcsite.wpengine.com/wp-content/uploads/2019/05/CRC-E-94-3_Final-Report_2018-06-26.pdf

[160] Morgan, P., Smith, I., Premnath, V., Kroll, S., Crawford, R.. Evaluation and Investigation of Fuel Effects on Gaseous and Particulate Emissions on Sidi in-Use Vehicles. Coordinating Research Council (2017). http://crcsite.wpengine.com/wp-content/uploads/2019/05/CRC_2017-3-21_03-20955_E94-2FinalReport-Rev1b.pdf

[161] EPA. Fuel Effects on Exhaust Emissions from Onroad Vehicles in MOVES3. U. S. Environmental Protection Agency, Ann Arbor, MI, EPA-420-R-20-016. https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1010M6C.pdf

[162] USEPA Office of Transportation and Air Quality. Regulatory Impact Analysis: Renewable Fuel Standard Program (RFS2). EPA-420-R-10-006. Assessment and Standards Division, Ann Arbor, MI. February, 2010. (Appendix A).

Renewable diesel (RD) is made by hydrotreating vegetable oils or other fats or greases, a process that removes oxygen and double bonds and produces paraffins in the diesel boiling range. As a result, it has very high cetane and essentially zero aromatics or sulfur content.[163] Given the paucity of data at the time MOVES3 was released, and the fact that RD is chemically identical to material that already makes up a significant portion of petroleum diesel, we did not include any emission impacts for RD blends in the model. Since we are now forecasting a significant increase in the use of RD, it seems appropriate to include here a brief review of recent studies looking at its emission impacts.

In 2020, McCaffery *et al.* compared ULSD (ultra-low sulfur petroleum diesel) to a 98.5% RD-ULSD blend in a 2012 Chevrolet Silverado with Duramax engine.[164] The study sampled engine-out emissions to focus on the effects of the fuel itself, and ran the LA92 test cycle to represent real-world driving as well as eight steady-state speed-load combinations for additional data. Results for the LA92 cycle showed reductions in particulate mass and number, hydrocarbons, and NOx for RD compared to ULSD, while the steady-state tests showed lower hydrocarbons at all points, lower PM for six of the eight points (higher PM at two), and no change in NOx at seven of the eight points (higher NOx at one).

In a 2015 study, Na, *et al.*, compared RD to California ULSD and two intermediate blends at 20% and 50% RD using a model year 2000 Freightliner truck with Caterpillar C15 engine.[165] Test conditions included the EPA Urban Dynamometer Driving Schedule (UDDS) and the California Heavy Heavy-Duty Diesel Truck (HHDDT) cruise procedure. Results showed reductions or no statistically significant differences in PM, hydrocarbon, and NOx across both test conditions for RD and its blends.

Singh, *et al.*, in a 2018 literature review, concluded that RD blends consistently reduced particulate mass and number emissions relative to petroleum diesel.[166] They observed that NOx emission impacts were less consistent across test cycles and engine and injection technologies, but that the majority of studies that measured NOx found a trend of reductions with RD.

A 2015 multimedia evaluation of renewable diesel prepared by staff of the California Air Resources Board concluded that RD reduced emissions of PM, NOx, hydrocarbons, and CO in

[163] Coordinating Research Council, "Combustion and Engine-Out Emissions Characteristics of a Light Duty Vehicle Operating on a Hydrogenated Vegetable Oil Renewable Diesel", Project CRC E-117, July 2022.
[164] McCaffery, C., Karavalakis, G., Durbin, T. Johnson, K. (2020) Engine-Out Emission Charactristics of a Light Duty Vehicle Operating on a Hydrogenated Vegetable Oil Renewable Diesel. SAE Paper 2020-01-0337.
[165] Na, K., Biswas, S., Robertson, W., Sahay, K., Okamoto, R., Mitchell, A., & S., L. (2015). Impact of biodiesel and renewable diesel on emissions of regulated pollutants and greenhouse gases on a 2000 heavy duty diesel truck. *Atmospheric Environment*, *107*, 307-314.
[166] Singh, D., Subramanian, K.A., Garg, M.O. (2018). Comprehensive review of combustion, performance and emissions characteristics of a compression ignition engine fueled with hydroprocessed renewable diesel. *Renewable and Sustainable Energy Reviews*, *81*, 2947-2954.

diesel engine exhaust compared to petroleum diesel.[167] They also observed that RD is likely to reduce exhaust PAHs, a conclusion supported by Singer, et al., in a 2015 study.[168]

Overall, these studies suggest that emission increases of NOx are not expected with additional RD use, while emission reductions of PM and hydrocarbons are likely. We will continue to evaluate the need to include emissions impacts of RD in future MOVES updates as more data becomes available on RD volumes and blend-levels in the fuel supply.

4.1.3 Biogas Electricity Emissions

As discussed in Chapter 6.1.4.1, we are projecting large increases in the use of biogas under the RFS program in 2024 and 2025 in order to meet the proposed cellulosic biofuel standard. However, as also discussed in Chapter 6.1.4.2, we do not anticipate that this will require new growth in biogas to electricity until sometime after 2025. Therefore, we do not anticipate that this proposal will result in increases in emissions associated with biogas to electricity. Nevertheless, since we anticipate biogas to electricity will be an important aspect of the program going forward, we believe it is important to discuss its emission impacts.

Biogas fueled electricity generation facilities (EGUs) in general are susceptible to significant fugitive emissions, often from methane,[169] though some facilities emit high levels of other pollutants as well, as shown in Figures 4.1.3-1 through 4. Shown on a log-log plot, most biogas EGUs may compare to coal or natural gas in terms of annual electricity production, however they do so by producing a far greater rate of nitrogen oxide per megawatt-hour, while generally falling below their coal and natural gas counterparts in other categories. However, their emissions vary wildly. Their typically low electrical generation capacity typically falls below state and federal air permitting requirements, allowing for higher emission rates, and lack of reporting requirements. Currently, 97% of RINs generated from biogas as a feedstock come from mostly small facilities such as landfills, agricultural digesters, or wastewater treatment plants. We expect a similar pattern in biogas to electricity projects.

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[167] California EPA (2015). *Staff report: Multimedia evaluation of renewable diesel.* https://ww2.arb.ca.gov/sites/default/files/2018-08/Renewable_Diesel_Multimedia_Evaluation_5-21-15.pdf

[168] Singer, A., Schröder, O., Pabst, C., Munack, A., Bünger, J., Ruck, W., Krahl, J. (2015). Aging studies of biodiesel and HVO and their testing as neat fuel and blends for exhaust emissions in heavy-duty engines and passenger cars. *Fuel, 153*, 595–603.

[169] Inventory of U.S. Greenhouse Gas Emissions and Sinks, 2020.

Figure 4.1.3-1: eGRID NOx Emissions By Source Type, 2020

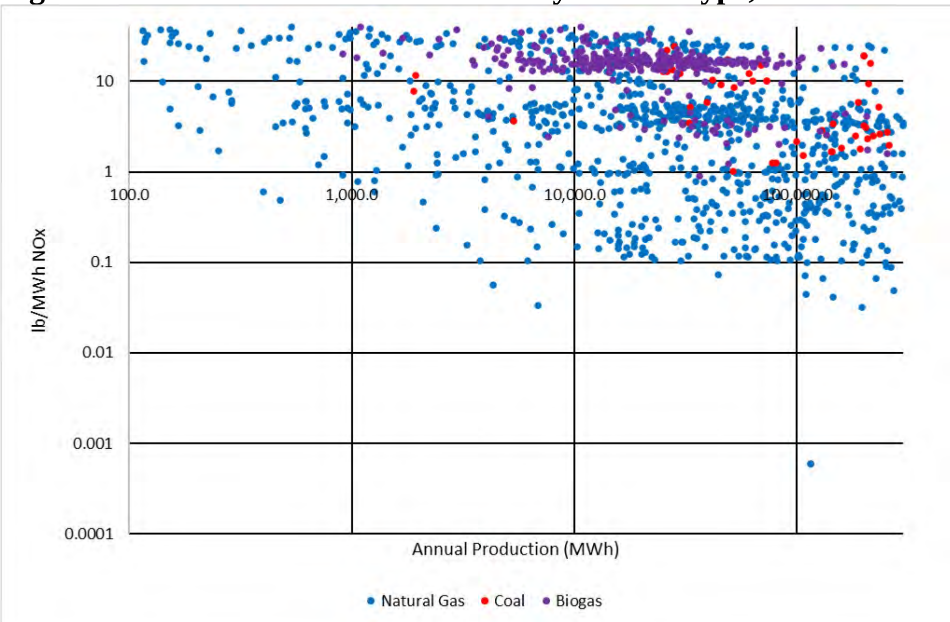


Figure 4.1.3-2: eGRID SO_2 Emissions By Source Type, 2020

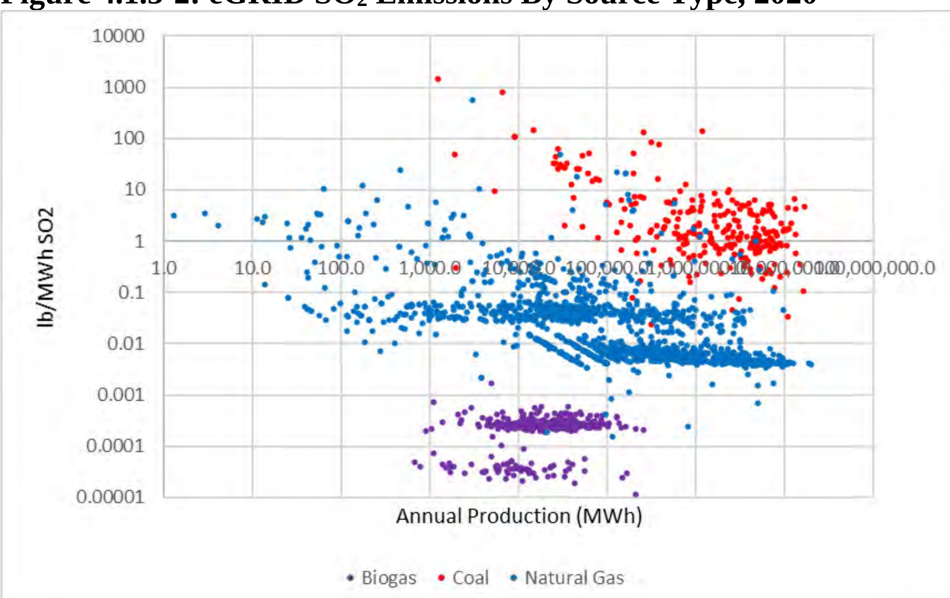


Figure 4.1.3-3: eGRID Methane Emissions By Source Type, 2020

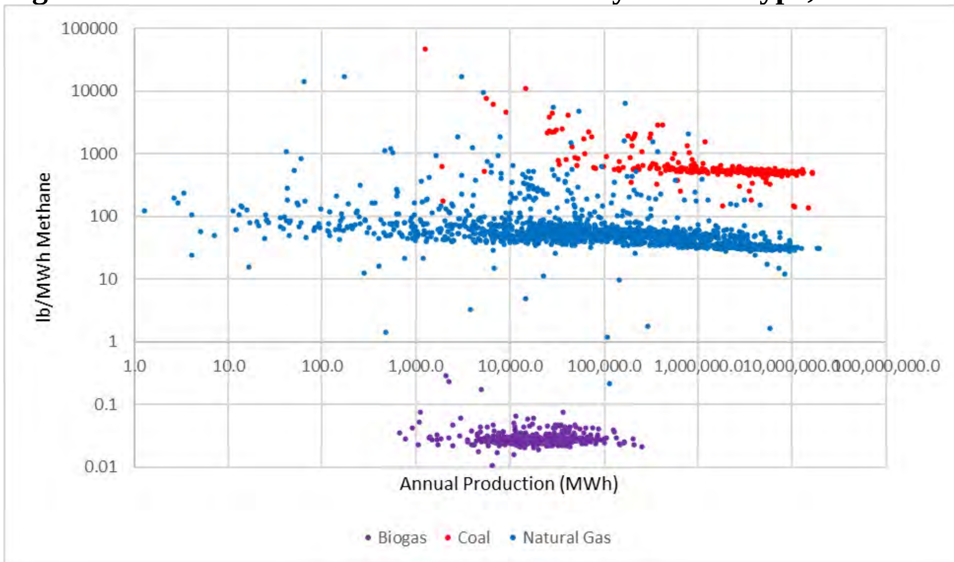
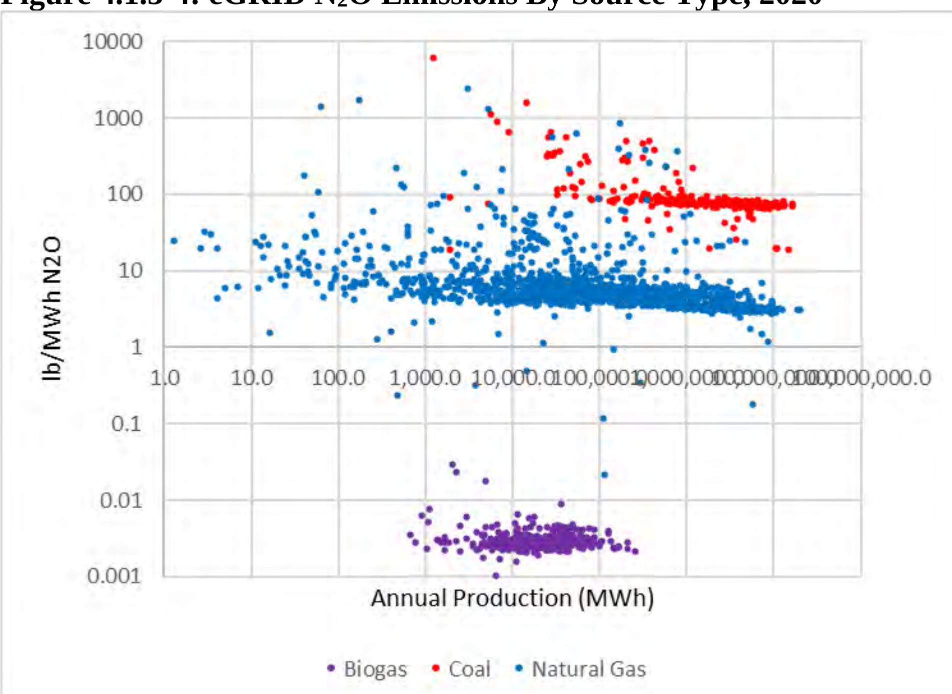


Figure 4.1.3-4: eGRID N_2O Emissions By Source Type, 2020



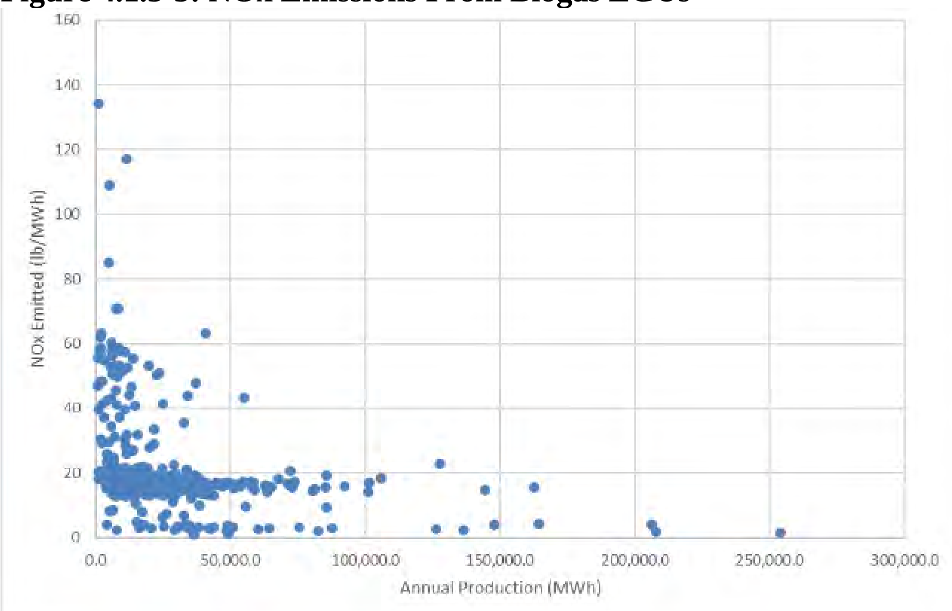
The lack of data on these many small facilities makes it difficult to quantify the emission impacts of biogas EGUs. However, they can be characterized by category using a mixture of modelled and estimated data. We used data from the 2020 Emissions and Generation Resource Integrated Database (eGRID), prepared by the Clean Air Markets Division of the Office of Atmospheric Programs in the EPA. We also obtained some data from stakeholders that represent monitored projects within the US. In California, where biogas electricity generators have been earning credit under the LCFS since 2018, engines using biogas emit a variety of criteria pollutants, and offer some of the best available data on emissions from EGUs powered by biogas.[170] It is important to note that EGUs often contain multiple engines and/or turbines, and that the numbers displayed in Table 4.1.3-1 represent a single turbine. Facilities can have between 1-48 turbines or engines on site[5].

Table 4.1.3-1: California Biogas EGU Individual Turbine Modelled Emissions[a]

Pollutant	Average (lb/MWh)
VOC	2.23
CO	6.96
NOx	1.67
SO_2	0.07
PM_{10}	0.14
CO_2	1,441

[a] Results from CA GREET Model

Figure 4.1.3-5: NOx Emissions From Biogas EGUs



[170] LCFS Guidance 19-06: Determining Carbon Intensity of Dairy and Swine Manure Biogas to Electricity Pathways, https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/guidance/lcfsguidance_19-06.pdf

Figure 4.1.3-6: SOx Emissions From Biogas EGUs

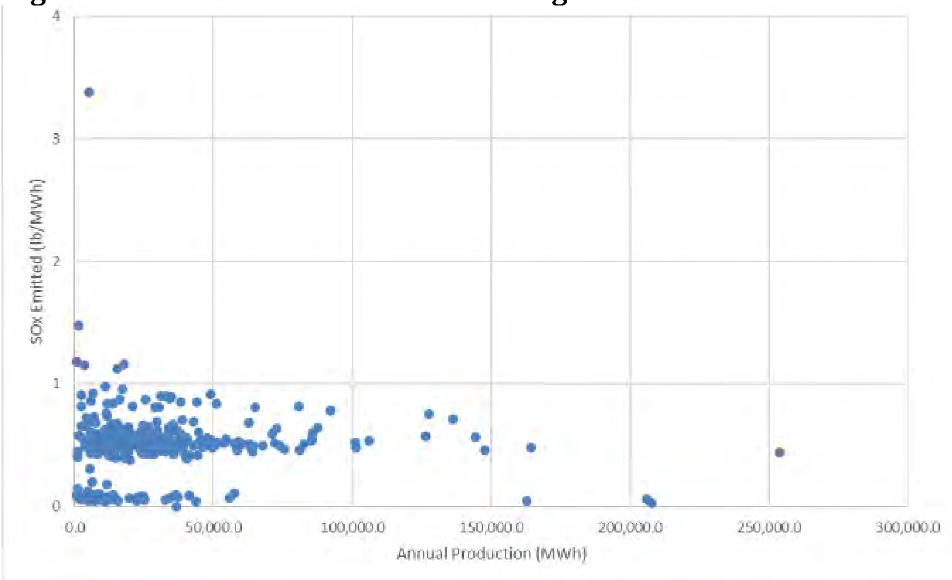


Figure 4.1.3-7: Methane Emissions From Biogas EGUs

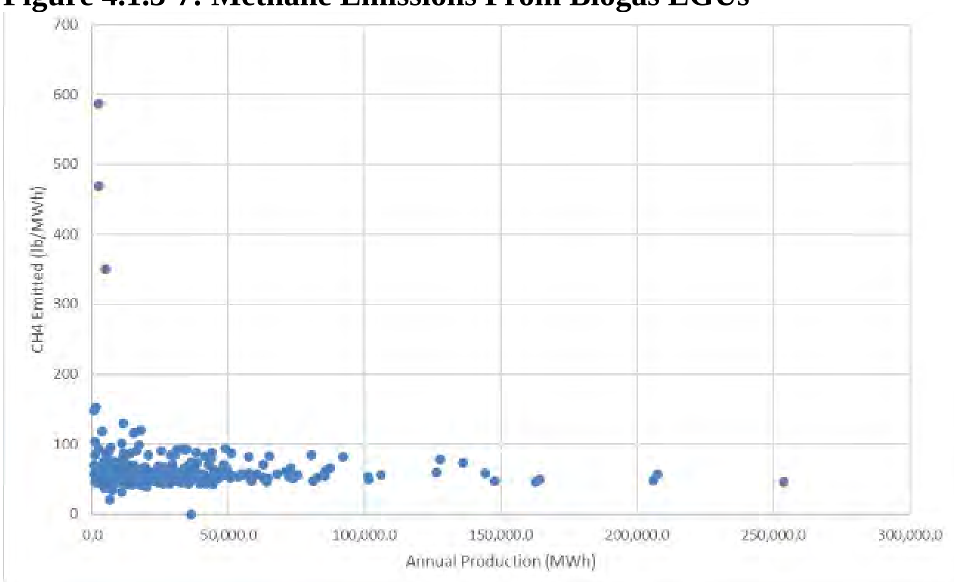
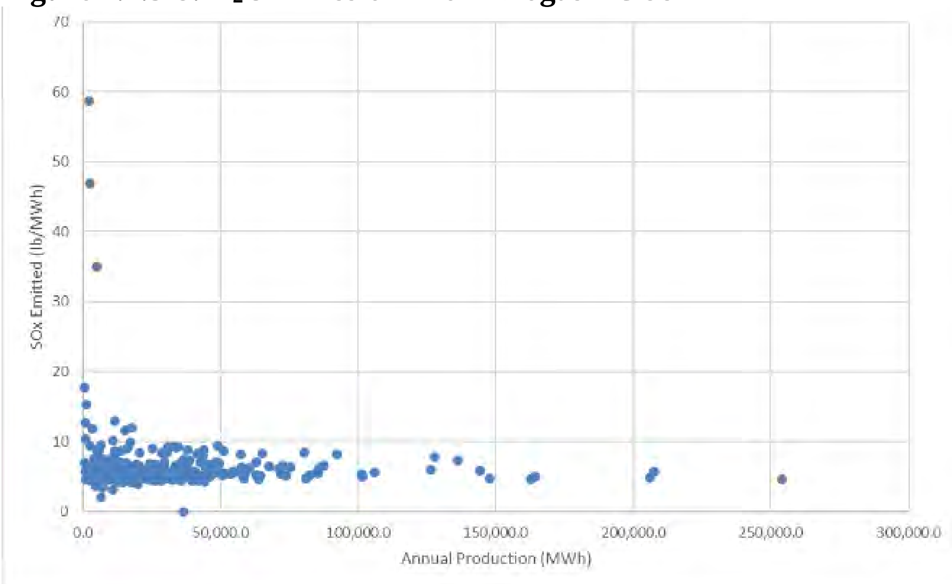


Figure 4.1.3-8: N$_2$O Emission From Biogas EGUs



As shown in Figures 4.1.3-1 through 4, we estimate emission rates per kWh of electricity produced for key pollutants for various biogas to electricity facilities in comparison to the rates for natural gas and coal fired EGUs. While for the largest biogas EGUs the rates are similar, for the vast majority of biogas EGUs, the rates are considerably higher. When it comes to overall facility emissions, however, these higher emission rates tend to be offset by the smaller size of biogas EGUs. Data shown in Table Figures 4.1.3-5 through 8 displays weighted averages of natural gas, coal, and biogas EGUs against their nameplate capacity. Some of these EGUs compare favorably against coal and natural gas plants,[171] while others exceed emissions from those plants, which can be seen in Figures 4.1.3-1 through 4.

4.1.3.1 Landfills

Landfill gas (LFG) is estimated to be 50% methane and 50% carbon dioxide and water vapor. However, it also contains less than 1% of non-methane organic components, including hazardous air pollutants, volatile organic compounds, and nearly 30 other hazardous air pollutants.[172] Using this gas to power gensets in turn causes the release of a variety of pollutants, including some criteria pollutants. Some pollutants, such as sulfur dioxide, are solely based on the sulfur content of the raw LFG, while others are based on gas usage and genset configuration. Table 4.1.3.1-1 shows data of emissions from three different landfill biogas EGUs.[173] While this is a small sample, it nevertheless provides both an indication of the magnitude of the emissions and the variability depending on the landfill and EGU configuration.

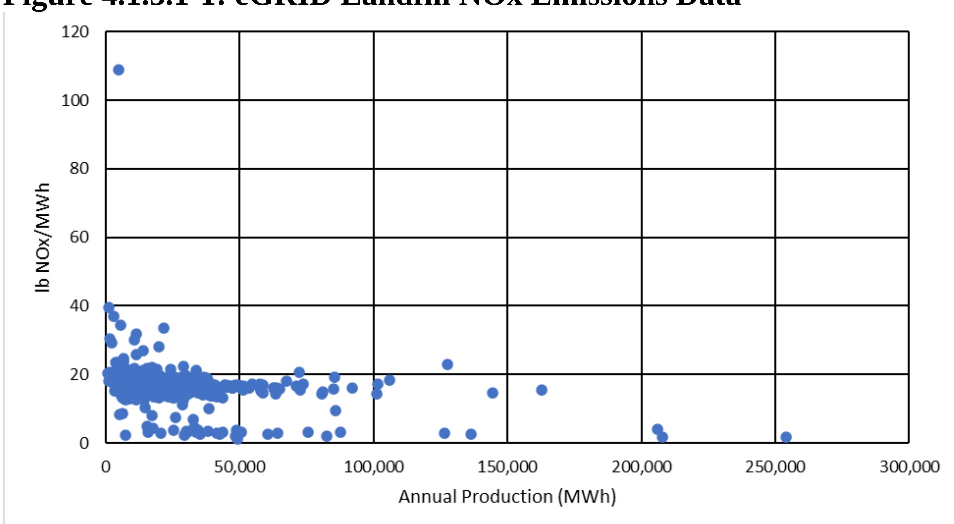
[171] eGRID Database, Clean Air Markets Division EPA.
[172] https://www.epa.gov/lmop/basic-information-about-landfill-gas#methane
[173] Data derived from a CBI source provided to us by a biogas developer/electric utility company.

Table 4.1.3.1-1: Landfill Biogas Dataset

Facility Type	Size (MW)	Annual Landfill Gas Usage (MMscf/yr)	Annual Power Production to Grid (MW/yr)	NOx (tons)	CO (tons)	VOC (tons)	SO2 (tons)	PM (tons)
Turbine	24.5	4,038.4	132,228	27.2	10.9	5.1	35.6	3.4
Engine	8	1,271.2	57,627.9	39.8	265.5	6.4	2.9	14.6
Engine	1.6	261.4	11,870.1	8.2	54.6	1.3	0.6	3.3

A broader set of emissions data modelled by the EPA Clean Air Market Division (Figures 4.1.3.1-1 through 4) is illustrative of the broad range of potential nitrogen dioxide, sulfur dioxide, methane, and nitrous oxide emitted from landfills. The emissions modelling in eGRID for landfills is adjusted based on the assumption that landfills would flare the gas if they did not combust it for electricity generation. It is therefore assumed that the gas would have been combusted in a flare and produced some amount of the pollutants tracked in eGRID.[174]

Figure 4.1.3.1-1: eGRID Landfill NOx Emissions Data



[174] The Emissions & Generation Resource Integrated Database Technical Guide with Year 2020 Data, https://www.epa.gov/system/files/documents/2022-01/egrid2020_technical_guide.pdf

Figure 4.1.3.1-2: eGRID Landfill SO_2 Emissions Data

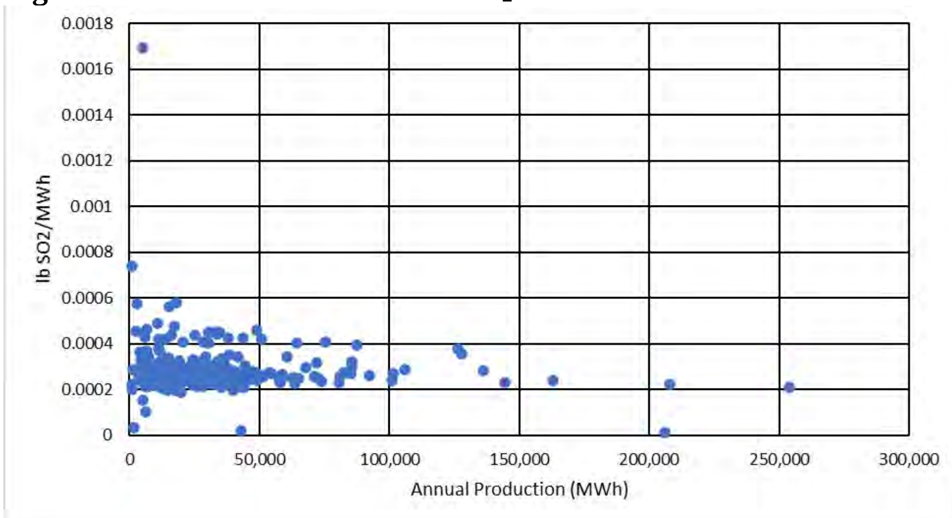


Figure 4.1.3.1-3: eGRID Landfill Methane Emissions Data

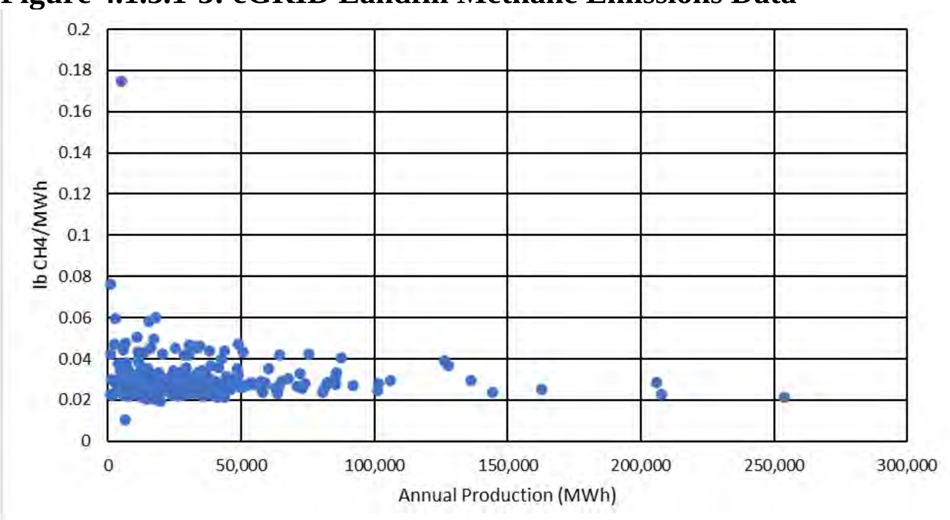
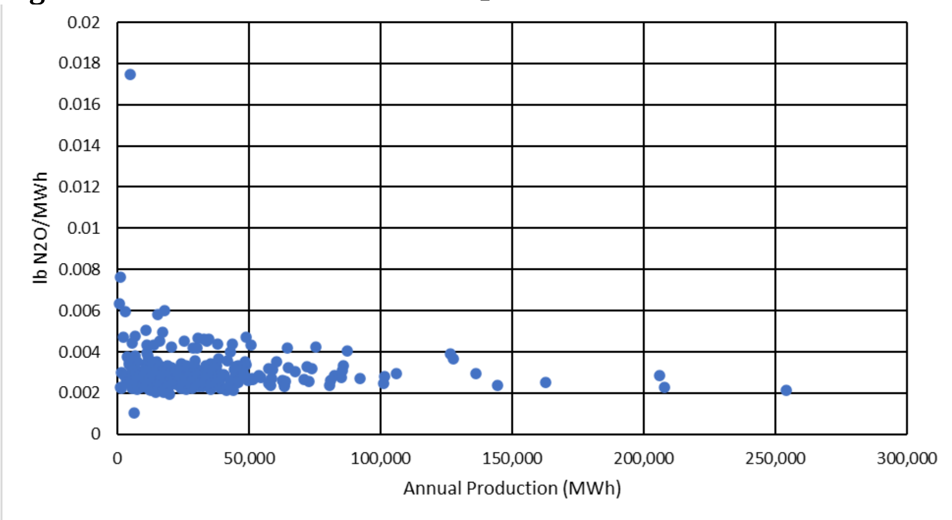


Figure 4.1.3.1-4: eGRID Landfill N_2O Emissions Data



4.1.3.2 Agricultural Digesters

Agricultural digesters are often under 10 MW and thus are lightly regulated by air permits. Literature and modeling results from eGRID offer varying estimates of the amount of criteria pollutant emissions, as seen in Figures 4.1.3.2-1 through 4.

Figure 4.1.3.2-1: eGRID Agricultural Digester NOx Emissions Data

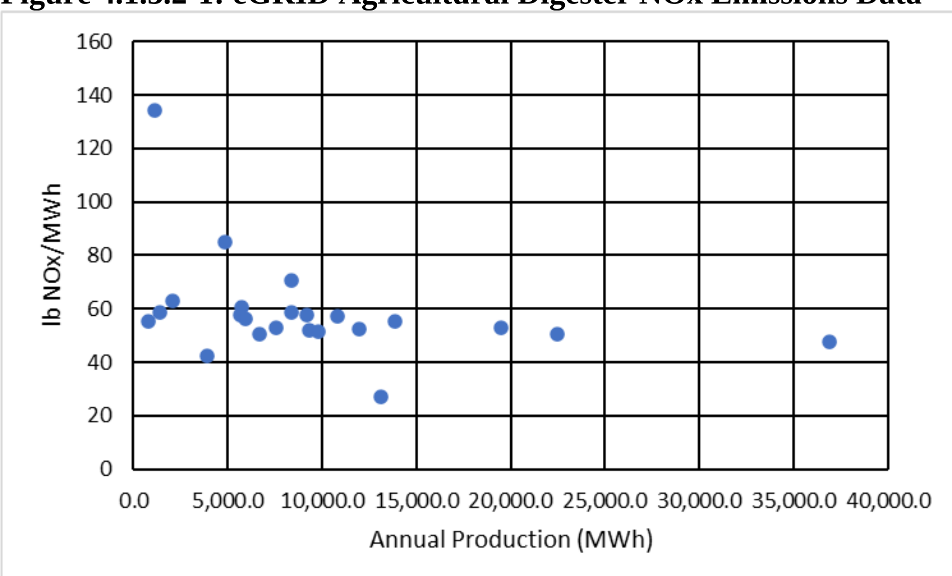


Figure 4.1.3.2-2: eGRID Agricultural Digester SO_2 Emissions Data

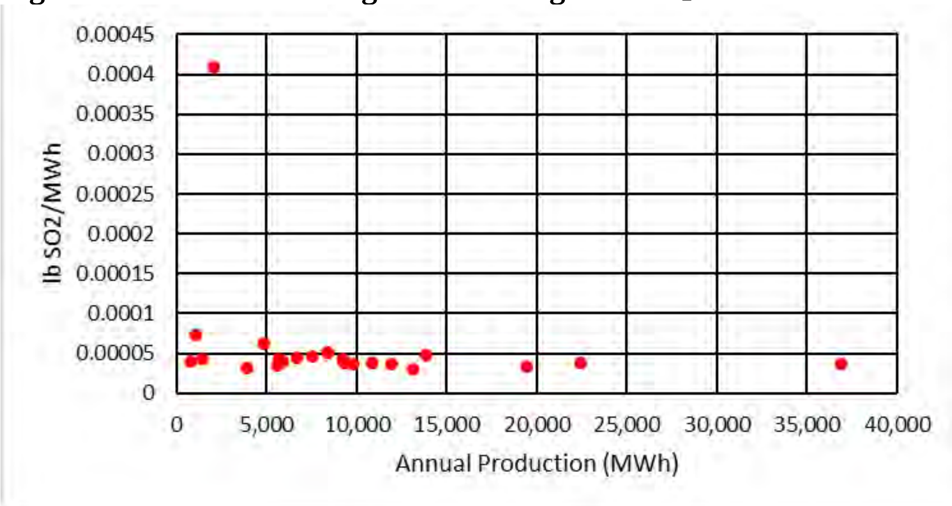


Figure 4.1.3.2-3: eGRID Agricultural Digester Methane Emissions Data

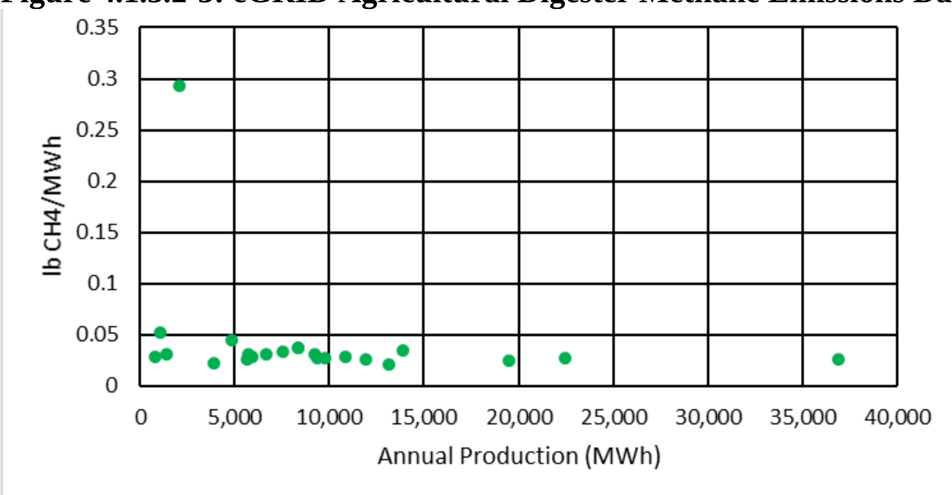
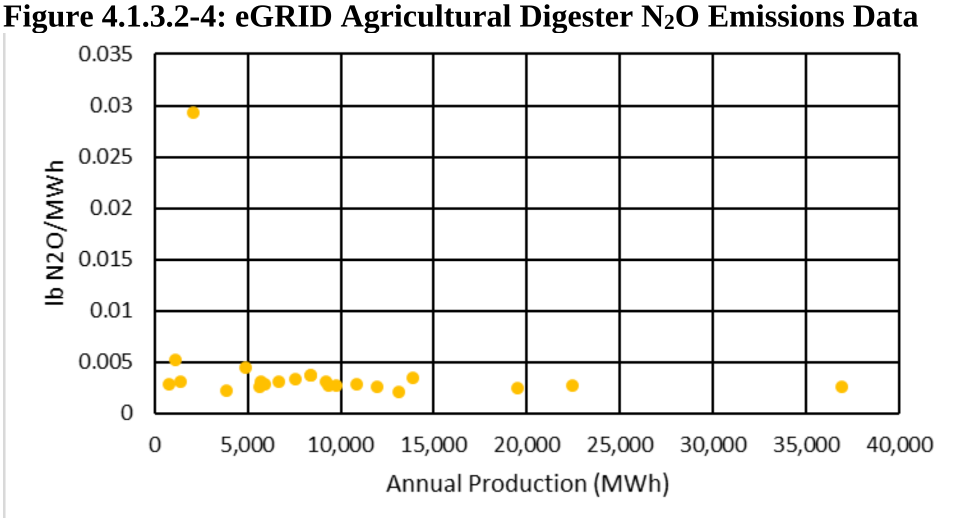


Figure 4.1.3.2-4: eGRID Agricultural Digester N_2O Emissions Data



4.1.3.3 Wastewater Treatment Plants

Figure 4.1.3.3-1 through 4 contains the EPA Clean Air Market Division's modelled data on wastewater treatment plants. These facilities have higher nameplate capacities than agricultural digesters and tend to be located nearer to urban areas, and are therefore more often to have their emission regulated. These facilities are most likely to also be using CHP/on-site electricity generation as a cost savings measure as they currently supply their own operational electricity needs.

Figure 4.1.3.3-1: eGRID Wastewater Treatment Plant NOx Emissions Data

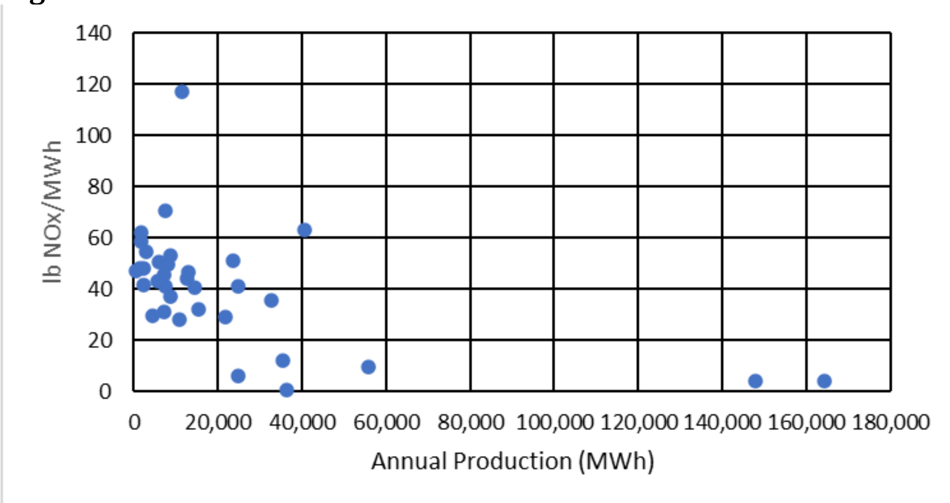


Figure 4.1.3.3-2: eGRID Wastewater Treatment Plant SO_2 Emissions Data

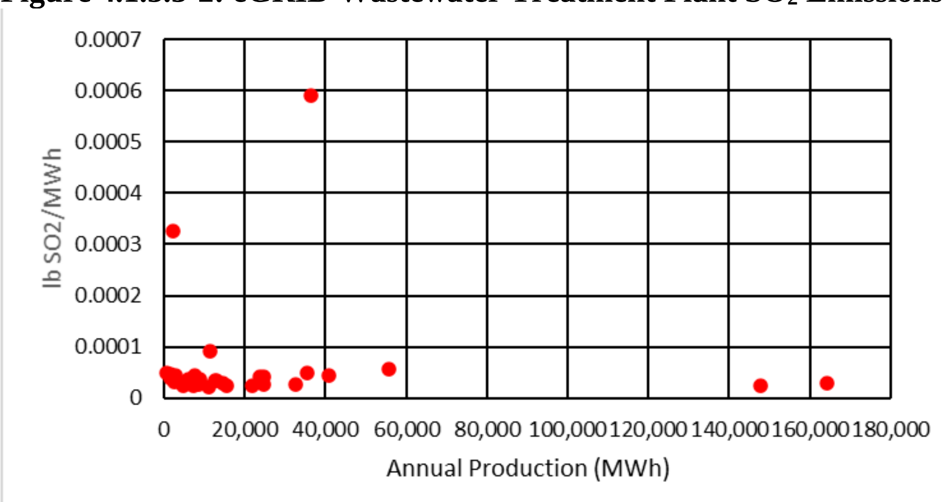


Figure 4.1.3.3-3: eGRID Wastewater Treatment Plant Methane Emissions Data

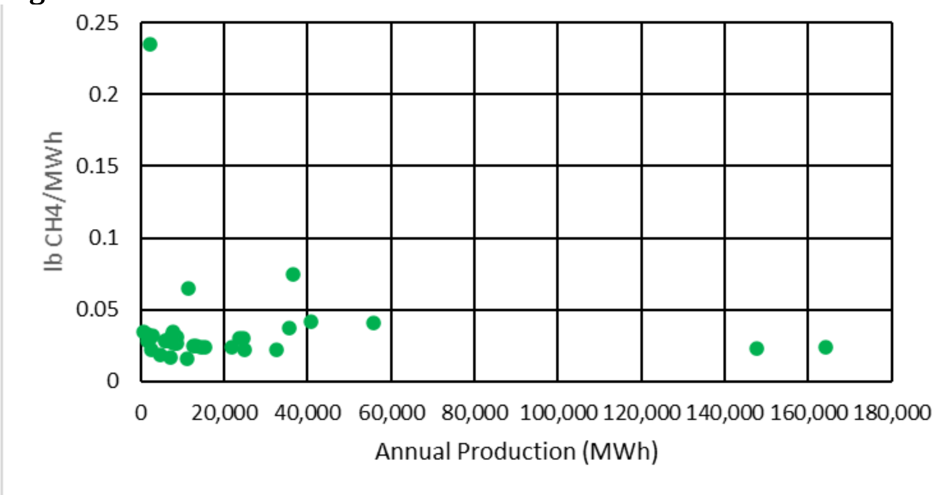
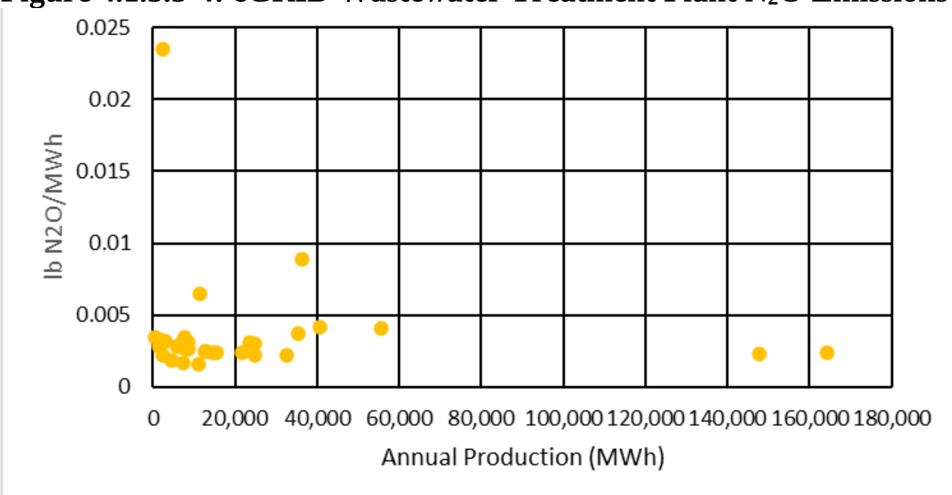


Figure 4.1.3.3-4: eGRID Wastewater Treatment Plant N_2O Emissions Data



4.1.4 Air Quality Modeling

As mentioned at the beginning of Chapter 4.1, air quality impacts resulting from this proposal are expected to be relatively minor. Any significant impacts are likely to be highly localized, and thus, would likely not be captured at the geographic scale used in photochemical air quality modeling. Thus, no air quality modeling was done. The largest impacts from this proposal are expected to be increased use of renewable diesel and biogas for electricity. Available data limit our ability to quantify renewable diesel impacts, and increases in biogas to electricity emissions are not expected from this proposal. Geographic distribution of emissions also varies, and a comprehensive evaluation of offsetting impacts is very complex. Furthermore, to the extent that this rule is associated with reductions in imported refined petroleum products, those upstream emissions and the adverse impacts they cause would occur in foreign countries. Such upstream international impacts are typically considered outside the scope of an RIA or other analysis used to support a rulemaking.

4.2 Climate Change

CAA section 211(o)(2)(B)(ii) states that the basis for setting applicable renewable fuel volumes after 2022 must include, among other things, "an analysis of…the impact of the production and use of renewable fuels on the environment, including on…climate change." While the statute requires that EPA base its determinations, in part, on an analysis of the climate change impact of renewable fuels, it does not require a specific type of analysis. While the impacts of climate change include rising temperatures and sea levels, ocean acidification, increased occurrence and intensity of wildfires and extreme weather events, and other impacts,[175] these impacts are driven by changes in greenhouse gas emissions. Since the CAA requires evaluation of lifecycle greenhouse gas (GHG) emissions as part of the RFS program, we believe the CAA gives us the discretion to use lifecycle GHG emissions estimates as a reasonable proxy for climate change impacts.

Our assessment of the climate change impacts of the candidate volumes relies on an extrapolation of lifecycle analyses (LCA) of GHG emissions.[176] As we did in the 2020-2022 RVO rulemaking, this approach involves multiplying LCA emissions of individual fuels by the change in the consumption of each fuel in the candidate volumes scenario relative to the No RFS baseline to quantify the GHG impacts. We repeat this process for each fuel (e.g., corn ethanol, soybean biodiesel, landfill biogas CNG) to estimate the overall GHG impacts of the candidate volumes. In the 2020-2022 RVO rulemaking, we applied the LCA estimates that we developed in the March 2010 RFS2 rule (75 FR 14670) and in subsequent agency actions. In this rulemaking, we are updating our approach to use a range of LCA emissions estimates that are in the literature. Instead of providing one estimate of the GHG impacts of each candidate volume, we provide a high and low estimate of the potential GHG impacts, which is inclusive of the values we estimated in the 2010 RFS final rule and subsequent agency actions. We then use this range of values for considering the GHG impacts of the candidate renewable fuel volumes that change relative to the No RFS baseline.

This section of the DRIA discusses our evaluation of the potential effects of the candidate volumes on GHG emissions. We start with background on our LCA of the GHG emissions associated with biofuels since the beginning of the RFS2 program in 2010. We then discuss advances in the modeling science since 2010, including a brief summary of currently available models that can be used to estimate biofuel GHG emissions. We then discuss how these models compare across a number of important characteristics. We review available biofuel LCA estimates and make observations about why some estimates are higher or lower than others. For example, we discuss the potential influence of model choice relative to input assumptions. Based

[175] Wuebbles, D.J., D.W. Fahey, K.A. Hibbard, B. DeAngelo, S. Doherty, K. Hayhoe, R. Horton, J.P. Kossin, P.C. Taylor, A.M. Waple, and C.P. Weaver, 2017: Executive summary. In: Climate Science Special Report: Fourth National Climate Assessment, Volume I [Wuebbles, D.J., D.W. Fahey, K.A. Hibbard, D.J. Dokken, B.C. Stewart, and T.K. Maycock (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, pp. 12-34, doi: 10.7930/J0DJ5CTG.

[176] In this chapter, we use a range of terminology, consistent with the scientific literature, to describe the concept of lifecycle GHG emissions. We sometimes call lifecycle GHG emissions "LCA emissions," "LCA ranges," LCA values," "LCA estimates," "carbon intensity (CI)," or some combination of these terms. For purposes of this discussion, the meaning of these terms is the same, namely the GHG emissions associated with all stages of fuel production and use, including significant indirect GHG emissions.

on our literature review, we produce a range of LCA carbon intensity estimates for each biofuel pathway affected by the candidate volumes. We use these ranges along with the volume scenarios discussed in Chapter 3 to produce a range of potential GHG emissions impacts. Finally, we monetize this range of GHG emissions to produce an estimate of the monetized GHG benefits associated with the candidate volumes.

For the final rule, we intend to conduct a model comparison exercise that will produce new estimates of crop-based biofuel GHG emissions from multiple models to expand upon what is already in the literature for the types of volume changes required. By running common scenarios and aligning results, the model comparison exercise should allow us to compare model estimates more directly, giving us further understanding of the best available science on the GHG impacts associated with biofuels. As we consider updates to our LCA methodology, we will consider the broad range of new science related to biofuel LCA, including the insights from the model comparison exercise.

As discussed elsewhere in this document, the science associated with the lifecycle assessment of biofuels is a much discussed topic. Significant analytical work has been undertaken since EPA laid out its lifecycle methodology in the 2010 RFS rulemaking, with work in this area continuing. For example, in October 2022, the National Academies of Science, Engineering and Medicine published a report titled “Current Methods for Life Cycle Analyses of Low-Carbon Transportation Fuels in the United States (2022).” This report assesses the current methods of estimating lifecycle GHG emissions associated with transportation fuels used in a potential national low-carbon fuels program. While this report does not endorse any particular numerical result or model, it provides useful insights into estimations of GHG emissions over each part of the lifecycle of a given fuel, indirect GHG emissions, and data quality and quantity. EPA is carefully reviewing this report as it adds to the feedback EPA received on lifecycle assessment through its LCA workshop held earlier this year. We also note the Administration, as part of its SAF Grand Challenge, has created a workgroup between DOE, EPA, FAA, and USDA to look at LCA methodologies and data needs specifically related to renewable aviation fuel, which will also be a useful platform in assessing LCA capabilities and uncertainties. As EPA uses LCA models not just for RFS analysis of program performance and feedstock assessment but also broader policy analysis, the Agency would benefit from updating its existing set of analytical methodologies. Data and findings from recent science and the modeling comparison exercise will help inform EPA’s specific next steps on updating its methodology as part of a separate action.

4.2.1 Background on Renewable Fuel GHG Analysis for the RFS Program

A primary policy goal of the RFS program is to reduce GHG emissions by increasing the use of renewable fuels such as ethanol and biodiesel. Renewable fuels composed of biogenic carbon recently sequestered from the atmosphere reduce GHGs and mitigate climate change if their use displaces petroleum derived fuels, provided that the full lifecycle GHG emissions associated with biofuels do not exceed those of the displaced petroleum fuels. Depending on the LCA of the fuel, renewable fuels can provide a substantial GHG emission reduction.

4.2.1.1 Clean Air Act Requirements

To support the GHG emission reduction goals of EISA, Congress required that biofuels used to meet the RFS obligations achieve certain lifecycle GHG reductions. To qualify as a renewable fuel under the RFS program, a fuel must be produced from approved feedstocks and have lifecycle GHG emission that are at least 20% less than the baseline petroleum-based gasoline and diesel fuels.[177] The CAA specifically defines the term "lifecycle greenhouse gas emissions" to mean "the aggregate quantity of greenhouse gas emissions (including direct emissions and significant indirect emissions such as significant emissions from land use changes), as determined by the Administrator, related to the full fuel lifecycle, including all stages of fuel and feedstock production and distribution, from feedstock generation or extraction through the distribution and delivery and use of the finished fuel to the ultimate consumer, where the mass values for all greenhouse gases are adjusted to account for their relative global warming potential."[178] In the March 2010 RFS2 rule (75 FR 14670), EPA interpreted the provision "including direct emissions and significant indirect emissions" as requiring our LCA to consider the consequential, or market-mediated, impacts of increased demand for renewable fuels. Indirect emissions, by definition, cannot be directly measured in the way that direct emissions can be calculated. Indirect emissions result from changes in prices (e.g., agricultural commodities or petroleum prices) that ripple through the economy. For example, if increased consumption of renewable fuel in the U.S. diverts U.S. exports of corn from the global markets, the market-mediated impact could be for other countries, such as Argentina, to produce more corn to supply the global demand for cereal grains. While all of the corn used to produce ethanol in the scenario may have been grown in the U.S., the land use changes emissions in Argentina would be considered "indirect" land use change emissions. Other examples of market-mediated impacts include changes in livestock production that result from increased production of renewable fuel co-products such as soybean meal. If the increased production of soybean meal leads to a decrease in feed prices for cattle, an indirect impact could include the increased production of beef.

While the term "significant indirect emissions" requires some analytical judgement, prior modeling work has indicated that the indirect impacts from land use change, livestock, and crop production can result in emissions that can have a large impact on the lifecycle analysis. Therefore, to be consistent with the CAA requirements, our lifecycle analysis must take into account global agricultural and livestock markets, since many biofuel feedstocks use globally traded commodities. In addition, the increasing interdependence of the energy and agricultural markets suggests that capturing indirect energy sector impacts could have important implications for lifecycle analysis. We consider these statutory requirements when describing the differences in modeling frameworks in Chapter 4.2.2.7.

4.2.1.2 Lifecycle Analysis Under the RFS Program

As part of the March 2010 RFS2 rule, EPA estimated lifecycle GHG emissions of different biofuel production pathways; that is, the emissions associated with the production and use of a biofuel, including indirect emissions, on a per-unit energy basis. At the time of the

[177] See 42 USC 7545(o)(1), (2)(A)(i).
[178] See 42 USC 7545(o)(1)(H).

analysis for the 2010 RFS2 rule, there were no models available off the shelf that could perform the type of lifecycle analysis required by EISA. Thus, EPA developed a new modeling framework to perform the required analysis. The framework we developed used multiple models and data sources.[179] We used the Forest and Agricultural Sector Optimization Model with Greenhouse Gases model (hereinafter referred to as "FASOM") and the FAPRI-CARD model (Food and Agricultural Policy Research Institute international model; hereinafter referred to as "FAPRI") developed at the Center for Agriculture and Rural Development at Iowa State University. We ran aligned scenarios in both models and used FASOM to estimate domestic agricultural and forestry sector impacts, and the FAPRI model to estimate international agricultural sector impacts. Our framework included data from many other sources, including emissions factors and other data from the GREET model (see below for a description of GREET). We proposed this new framework for public comment, organized four peer reviews of different aspects of it and held a public workshop. Based on all of this input we refined the modeling for the final March 2010 RFS2 rule. We also estimated the uncertainty associated with the land use change satellite data and emissions factors used in our analysis. The framework we developed in 2010 used the best science, data and models available at the time.

Since the 2010 RFS2 rule, we have used the RFS2 modeling framework to conduct numerous (over 140) analyses of new pathways and their lifecycle GHG emissions. Based on these analyses, we have approved additional pathways for participation in the RFS program. These pathways rely on novel feedstocks (e.g., canola oil, grain sorghum, camelina oil,[180] distillers sorghum oil[181]) and novel production processes involving existing feedstocks (e.g., catalytic pyrolysis and upgrading of cellulosic biomass,[182] gasification and upgrading of crop residues[183]). EPA maintains a summary of lifecycle greenhouse gas intensities estimated for the Renewable Fuel Standard program, which are available in spreadsheet form in a document titled "Summary Lifecycle Analysis Greenhouse Gas Results for the U.S. Renewable Fuels Standard Program."[184] Our lifecycle analyses of various pathways are also published online.[185] A list of pathways that have been approved by regulation can also be found at 40 CFR 80.1426(f)(1).

Depending on the renewable fuel, the feedstocks used to produce it, the amount of fossil energy used in growing the feedstocks and producing the fuel, land use change and associated agricultural emissions, and other factors, the GHG emission reductions will vary considerably. In general, we have found that renewable fuels that are not expected to have significant impacts on

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[179] EPA (2010). Renewable fuel standard program (RFS2) regulatory impact analysis. Washington, DC, US Environmental Protection Agency Office of Transportation Air Quality. EPA-420-R-10-006. Chapter 2.4.

[180] March 2013 Pathways I rule. 78 FR 14190. https://www.epa.gov/renewable-fuel-standard-program/final-rule-additional-qualifying-renewable-fuel-pathways-under

[181] August 2018 sorghum oil rule. 83 FR 37735. https://www.gpo.gov/fdsys/pkg/FR-2018-08-02/pdf/2018-16246.pdf

[182] March 2013 Pathways I rule. 78 FR 14190. https://www.epa.gov/renewable-fuel-standard-program/final-rule-additional-qualifying-renewable-fuel-pathways-under

[183] "San Joaquin Renewables Fuel Pathway Determination under the RFS Program." May 11, 2020. https://www.epa.gov/renewable-fuel-standard-program/san-joaquin-renewables-approval

[184] This document is available on EPA's website at: https://www.epa.gov/fuels-registration-reporting-and-compliance-help/lifecycle-greenhouse-gas-results. This summary is also available in docket EPA-HQ-OAR-2021-0324.

[185] See https://www.epa.gov/renewable-fuel-standard-program/approved-pathways-renewable-fuel and https://www.epa.gov/renewable-fuel-standard-program/other-actions-renewable-fuel-standard-program

land use, such as fuels produced from wastes, residues, or by-products, have greater GHG emission reductions than renewable fuels produced from crops intended to be used as feedstock for renewable fuel production. For instance, with respect to biodiesel and renewable diesel production, the use of waste fats, oils, and greases (FOG) as feedstocks typically results in lower lifecycle GHG emissions compared to use of vegetable oils, such as soybean or canola oil.[186] In addition, most cellulosic biofuels—which are required to meet the highest statutory lifecycle GHG reduction threshold of 60%—are currently produced from wastes, residues, or by-products, including landfill biogas.[187]

Since the existing LCA methodology was developed for the March 2010 RFS2 rule, there has been more research on the lifecycle GHG emissions associated with transportation fuels in general and crop-based biofuels in particular. New models have been developed to evaluate biofuels and more models have been developed for other purposes have been modified to evaluate the GHG emissions associated with biofuel production and use. There has also been rapid growth in available data on land use, farming practices, crude oil extraction and many other relevant factors. While our existing LCA estimates for the RFS program remain within the range of more recent estimates, we acknowledge that our previously relied on biofuel GHG modeling framework is comparatively old and an updated framework is needed. Accordingly, EPA has initiated work to develop a revised modeling framework of the GHG impacts associated with biofuels. In consultation with our interagency partners at USDA and DOE, we hosted a virtual public workshop on biofuel GHG modeling on February 28 and March 1, 2022.[188] At this workshop, speakers within and outside of the federal government presented on available data, models, methods, and uncertainties of assessing the GHG impacts of land-based biofuels.

In response to the public docket we opened for the workshop, we received approximately 30 comments, with the majority coming from industry representatives.[189] A large majority of the comments expressed support for the workshop. Many comments asked EPA to change the way it models biofuel GHG emissions, with updated data and/or a different model or combination of models. Most of these latter commenters asked EPA to consider using The Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies Model (GREET), though at least one commentor asked EPA to maintain its current model structures. Several other commenters asked EPA to consider applying a risk-based approach when considering biofuel targets and pathway approvals. Other commenters pointed to the importance of using real-world data. All of the commenters supported ongoing engagement with EPA on the topics discussed during the workshop.

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[186] According to EPA's assessment biodiesel produced from yellow grease has lifecycle GHG emissions of 13.8 kg CO_2e/mmBTU while biodiesel produced from soybean oil and canola oil have lifecycle GHG emissions of 42.2 kg CO_2e/mmBTU and 48.1 kg CO_2e/mmBTU respectively. See https://www.epa.gov/fuels-registration-reporting-and-compliance-help/lifecycle-greenhouse-gas-results.

[187] According to data from EMTS in 2020 over 92% of all cellulosic biofuel RINs were produced from biogas from landfills or biogas from municipal wastewater treatment facilities. An additional 7% of cellulosic biofuel was produced from agricultural residues or biogas from agricultural digesters.

[188] For more information see the Federal Register Notice, "Announcing Upcoming Virtual Meeting on Biofuel Greenhouse Gas Modeling." 86 FR 73756. December 28, 2021. More information is also available on the workshop webpage: https://www.epa.gov/renewable-fuel-standard-program/workshop-biofuel-greenhouse-gas-modeling.

[189] Docket number: EPA-HQ-OAR-2021-0921

Based on the workshop presentations and public input, it is clear that there continues to be significant uncertainty and a wide range of estimates on the climate effects of biofuels, especially when it comes to biofuel-induced land use change emissions. Uncertainties in land use change emissions estimates stem from both economic modeling of market-mediated effects as well as biophysical modeling of soil carbon and other biological systems. The workshop proceedings, including the workshop presentations and the comments submitted to the workshop docket, touch on a broad and complex set of topics. A general theme that emerged from this process is that, in support of a better understanding of the lifecycle GHG impacts of biofuels, it would be helpful to compare available models, identify how and why the model estimates differ, and evaluate which models and estimates align best with available science and data. The rest of this section makes progress in this direction by reviewing available models and published LCA estimates. To further explore the differences between the available models, for the final rule we intend to conduct new modeling and compare the results.

4.2.2 Review of Available Models for Renewable Fuel GHG Analysis

There are many factors that influence biofuel GHG estimates, including model framework choice, data inputs and assumptions and other methodological decisions. In this section we discuss available models. To the extent possible based on available information, we also discuss how the data and assumptions used in these models influence the biofuel GHG estimates they produce. The February 2022 biofuel GHG modeling workshop included presentations on five models (The Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies Model (GREET), Global Biosphere Management Model (GLOBIOM), Global Change Analysis Model (GCAM), Global Trade Project (GTAP), and Applied Dynamic Analysis of the Global Economy (ADAGE) used for biofuel GHG analysis. In this section we provide a summary of each of these models including their history, sectoral representation, spatial coverage and resolution, temporal representation, and GHG emissions representation. This selection of models provides a broad cross-section of the most common types of modeling frameworks used to assess biofuels, as discussed in the following paragraph. We chose to highlight these models based on discussions with our partners at USDA and DOE and our experience reviewing scientific literature on the lifecycle GHG emissions of biofuels. In addition, our choice to highlight these particular models is also informed by the statutory requirement to evaluate significant indirect emissions, including indirect land use change emissions. Furthermore, we are guided by our decision in the 2010 RFS2 rule to include significant indirect emissions occuring anywhere in the world (i.e., international impacts) given that GHG emission impacts are global. We also include a brief summary of other models that have been used for biofuel analysis. Models that exclude indirect emissions or are limited in geographic scope receive less attention in our review, except insofar as they can inform a broader analysis that meets the statutory requirements. We then compare the characteristics of all of these models and make some observations about what may be contributing to the different biofuel GHG estimates they have produced. Our goal is not to provide a comprehensive accounting of any one of these models or the differences between them. Rather, our objective is to summarize each model at a high level and highlight some of the differences between them that we intend to explore further as part of the model comparison exercise for the final rule.

There are four general types of models commonly used for biofuel GHG analysis: lifecycle inventory (LCI) models, partial equilibrium (PE) models, computable general equilibrium (CGE) models and integrated assessment models (IAM). LCI models, such as GREET, are designed to estimate in detail the inputs and outputs of a product supply chain, using rule-based methods (i.e., allocation or displacement) to account for co-products. PE models, such as GLOBIOM,[190] equate supply and demand in one or more markets such that prices stabilize at their equilibrium level. PE models offer highly detailed representations of one or a few sectors of the economy, such as the agricultural sector, but lack linkages to other sectors of the economy. In contrast, CGE models, such as GTAP and ADAGE, are comprehensive in their representation of the economy, reflecting feedback effects among all economic sectors and factors of production, such as capital and labor. IAMs, such as GCAM, integrate knowledge from several disciplines, for example, biogeochemistry, economics, engineering, and atmospheric science, to evaluate how changes in any of these areas affect the others. While it is hard to state the specific criteria for identifying an IAM, we might distinguish them from PE and CGE models by their deeper integration of human economic systems with Earth (biosphere and atmosphere) systems and GHG emissions into one modelling framework. LCI models, such as GREET, are designed to estimate in detail the inputs and outputs of a product supply chain, using rule-based methods (i.e., allocation or displacement) to account for co-products. PE, CGE and IAM models can all be called economic models. LCI models are categorically different from the other three model types as they do not simulate economic behavior or prices. Across the four model types there tends to be a tradeoff between scope and detail, which are discussed in more detail in section 4.2.2.7.

4.2.2.1 The GREET Model

The Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET) Model is a lifecycle analysis model. It provides well-to-wheels lifecycle energy, water, GHG, and other air emissions results intended to evaluate the impacts of various vehicle and fuel combinations. The developer is Argonne National Laboratory (ANL), and the project is sponsored by the U.S. Department of Energy (DOE). Initially made available in 1995, it was developed with the purpose of evaluating the energy and emission impacts of new fuels and vehicles for use in the transportation sector.[191]

GREET includes a suite of models and tools. It includes a fuel cycle model of vehicle technologies and transportation fuels (GREET1) and a vehicle manufacturing model of vehicle technologies (GREET2). Given that our focus is on renewable fuels, we are primarily concerned with GREET1. GREET is available in two platforms, a large Excel workbook and a ".net" version. The Excel version of GREET provides transparency while the .net version offers a modular user interface with a structured database. There are several derivates of the core GREET model, such as CA-GREET developed with the California Air Resources Board (CARB) and used in support of the California Low Carbon Fuels Standard (CA-LCFS), and ICAO-GREET developed with the International Civil Aviation Organization in support of the Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA). New versions of GREET are

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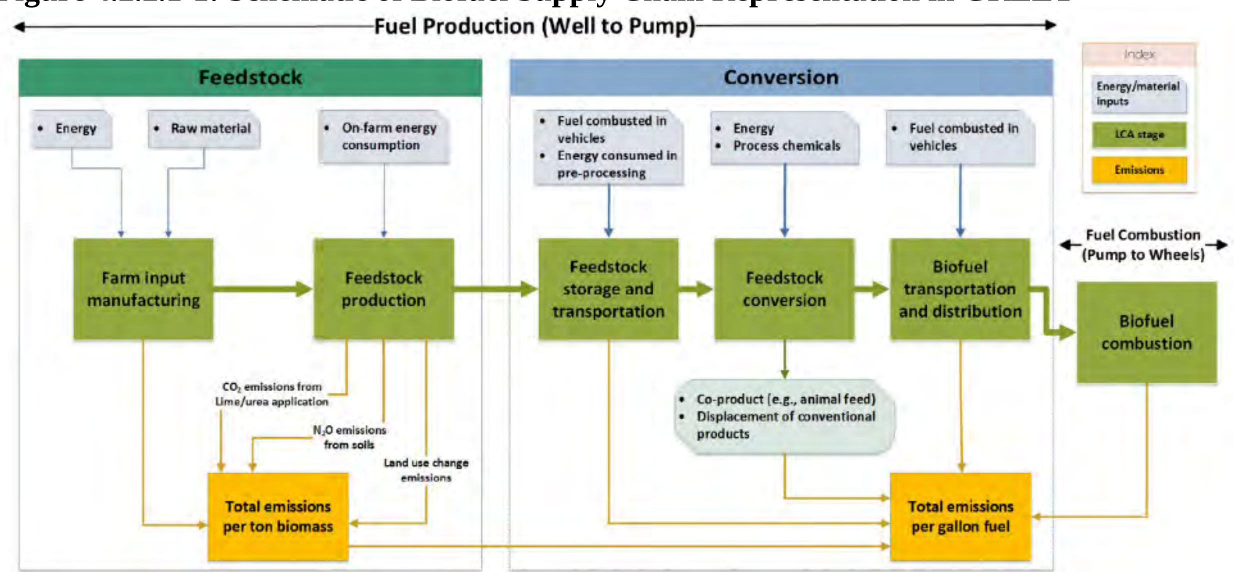
[190] The FASOM and FAPRI models EPA used for the March 2010 RFS2 rule biofuel GHG analysis are also categorized as PE models.
[191] Elgowainy, A. and Wang, M. (2019) 'Overview of Life Cycle Analysis (LCA) with the GREET Model', p. 21. Available at: https://greet.es.anl.gov/files/workshop_2019_overview.

released in October of each year, with the latest version as of the time of this writing being GREET-2021. GREET includes more than 100 fuel production pathways including fuels used in road, air, rail, and marine transportation. It also examines more than 80 on-road vehicle/fuel systems for both light and heavy-duty vehicles. The model reports lifecycle energy use, air pollutants, GHGs and water consumption. It includes detailed representations of the petroleum, electric, natural gas, hydrogen, and renewable energy sectors.

The GREET modeling framework is a process-based LCA approach (sometimes referred to as attributional LCA).[192] GREET can be used to estimate the carbon intensity of individual supply chains and the benefits of specific supply chain adjustments, such as reducing fertilizer application rates or switching to more efficient fuel distribution modes. Fundamentally, GREET is most closely related to other lifecycle inventory (LCI) models such as SimaPro, GaBi, and OpenLCA. In general, GREET assumes that additional production of a fuel commodity entails a linear increase in the activities from the associated supply chain with no market-mediated effects on other supply chains or economic sectors (e.g., diverting certain crops to biofuels may lead to new or more land area devoted to agriculture, increased use of fertilizers in addition to other energy inputs, and higher food or feed prices that in turn change what agricultural products are consumed by both people and livestock). Figure 4.2.2.1-1 provides a schematic overview of how the biofuel lifecycle is represented in GREET. GREET can be used to estimate the carbon intensity of individual supply chains and the benefits of specific supply chain adjustments, such as reducing fertilizer application rates or switching to more efficient fuel distribution modes.

Figure 4.2.2.1-1: Schematic of Biofuel Supply Chain Representation in GREET[193]



GREET primarily estimates fuel carbon intensities using data for average resource and energy production in the United States. For example, GREET by default models electricity based

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[192] Wang, M. (2022). "Biofuel Life-cycle Analysis with the GREET Model." Presentation at the EPA Biofuel Modeling Workshop. Argonne National Laboratory. March 1, 2022. https://www.epa.gov/system/files/documents/2022-03/biofuel-ghg-model-workshop-biofuel-lifecycle-analysis-greet-model-2022-03-01.pdf. Slide 5.
[193] Copied from Wang (2022), slide 9.

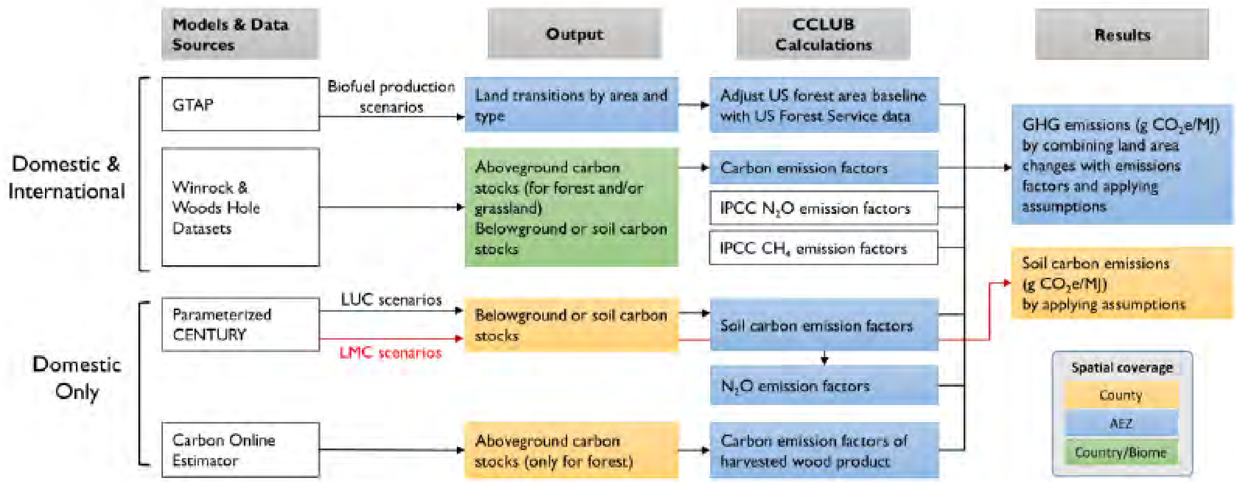
on data for average U.S. electricity generation. However, GREET includes some pathways representing foreign fuel production (e.g., Brazilian sugarcane ethanol) and in some cases users can choose to model some supply chains located in particular regions of the U.S. (e.g., states or electricity grid regions). A user with enough data on their supply chain could in certain cases customize GREET to estimate the carbon intensity of their fuel considering regional details and particular suppliers of energy and material inputs.

In general, GREET is not a dynamic or temporal model. Specifically, GREET does not take into account significant indirect emissions associated with increased biofuel demand, such as through market-mediated impacts on the agriculture, livestock, or energy sectors. GREET accounts for important biofuel co-products such as distillers grains and soybean meal through allocation or displacement rules. Furthermore, GREET is designed to estimate the carbon intensity of a fuel in a particular year, not modeling cascading changes across the economy and annualizing that stream of associated emission changes over time. However, the input data can be customized to estimate carbon intensities in any given year. Thus, it can be used to show how the estimated carbon intensity of a fuel changes over time based on changes in technological efficiency and other factors. For example, Lee et al. (2021) used data on U.S. ethanol production efficiencies and corn yields to estimate the carbon intensity of U.S. corn ethanol each year from 2005 to 2019.[194]

Although GREET does not endogenously estimate indirect emissions such as those resulting from indirect land use change, GREET incorporates a static module called the Carbon Calculator for Land Use Change from Biofuels Production (CCLUB) to account for indirect land use change emissions.[195] The opposing terms “static” and “dynamic” are used in different ways in modeling literature. In this instance, we describe CCLUB as a static module because it estimates land use area changes for one time period based on simulations with the GTAP-BIO model (discussed more below). In contrast, dynamic models, such as GCAM and GLOBIOM (discussed below), simulate land use changes and resulting GHG emissions over multiple decades. CCLUB relies on a selection of land use change estimates from GTAP-BIO studies conducted between 2011–2018 (see Table 4.2.2.1-1), combined with emissions factors from other sources to estimate land use change GHG emissions per unit of biofuel production.[196] Thus, the well-to-wheel emissions for crop-based pathways are estimated as the process-based emissions plus the induced land use change estimates from CCLUB. The data sources and calculations in CCLUB are summarized in Figure 4.2.2.1-2, reproduced from the CCLUB user manual.

[194] Lee, U., et al. (2021). "Retrospective analysis of the US corn ethanol industry for 2005–2019: implications for greenhouse gas emission reductions." Biofuels, Bioproducts and Biorefining.
[195] Dunn, J. B., et al. (2017). Carbon calculator for land use change from biofuels production (CCLUB) users' manual and technical documentation, Argonne National Lab, Argonne, IL.
[196] Hoyoung Kwon and Uisung Lee (2019) ‘Life Cycle Analysis (LCA) of Biofuels and Land Use Change with the GREET Model’. Available at: https://greet.es.anl.gov/files/workshop_2019_biofuel_luc.

Figure 4.2.2.1-2: Schematic of Data Sources and Calculations in CCLUB[197]



CCLUB includes land use change area estimates from nine different GTAP-BIO scenarios: four soy biodiesel shocks, two corn ethanol shocks, and one shock each for ethanol from corn stover, miscanthus and switchgrass. The corn ethanol and soy biodiesel scenarios included in CCLUB are described in Table 4.2.2.1-1. The two corn ethanol scenarios are similar except that the "Corn Ethanol 2013" estimate was produced with a version of GTAP-BIO with regionally differentiated land transformation elasticities and a modified land nesting structure to that makes it more costly within the model to convert forest to cropland relative to converting pasture to cropland.

[197] Kwon, Hoyoung, Liu, Xinyu, Dunn, Jennifer B., Mueller, Steffen, Wander, Michelle M., and Wang, Michael. (2020). Carbon Calculator for Land Use and Land Management Change from Biofuels Production (CCLUB). United States: N. p., 2020. Web. doi:10.2172/1670706. Copy of Figure 1.

Table 4.2.2.1-1: Corn Starch and Soybean Oil Based Biofuel Scenarios Modeled in CCLUB[198]

Case Description	Shock Size (Billion Gallons)	Source
"Corn Ethanol 2011." An increase in corn ethanol production from its 2004 level (3.41 billion gallons [BG]) to 15 BG	11.59	Taheripour et al. (2011)[199]
"Corn Ethanol 2013." An increase in corn ethanol production from its 2004 level (3.41 billion gallons [BG]) to 15 BG	11.59	Taheripour and Tyner (2013)[200]
Increase in soy biodiesel production by 0.812 BG (CARB case 8)	0.812	Chen et al. (2018)[201]
Increase in soy biodiesel production by 0.812 BG (CARB average proxy)	0.812	Chen et al. (2018)
Increase in soy biodiesel production by 0.8 BG (GTAP 2004)	0.8	Taheripour et al. (2017)[202]
Increase in soy biodiesel production by 0.5 BG (GTAP 2011)	0.5	Taheripour et al. (2017)

For each case, the estimates CCLUB uses from GTAP-BIO are the area of changes in cropland, forest, pasture in each agro-ecological zone (AEZ) and region, and cropland pasture in the U.S. and Canada. Land use change GHG emissions are estimated based on these land conversion areas using data from a few different sources. Based upon user selections, CCLUB ultimately combines a given GTAP scenario's expected land use change impacts with the user-selected emission factor data to provide domestic and international GHG emissions per functional unit of analyzed biofuel to GREET as the land use change emissions component for a given biofuel of interest.

A module called the Feedstock Carbon Intensity Calculator (FD-CIC) was recently added to GREET.[203] FD-CIC is designed to examine carbon intensity variations of different corn, soybean, sorghum, and rice farming practices at the farm level. The FD-CIC uses county level data and allows users to input their own farm level data on energy and chemical farming inputs, tillage, cover cropping and other crop management practices. Based on these input data, the FD-

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[198] Adapted from Table 1 in Dunn, J. B., et al. (2017). Carbon calculator for land use change from biofuels production (CCLUB) users' manual and technical documentation, Argonne National Lab.(ANL), Argonne, IL (United States).
[199] Taheripour, F., et al. (2011). Global land use change due to the U.S. cellulosic biofuels program simulated with the GTAP model, Argonne National Laboratory: 47.
[200] Taheripour, F. and W. E. Tyner (2013). "Biofuels and land use change: Applying recent evidence to model estimates." Applied Sciences 3(1): 14-38.
[201] Chen, R., et al. (2018). "Life cycle energy and greenhouse gas emission effects of biodiesel in the United States with induced land use change impacts." Bioresource Technology 251: 249-258.
[202] Taheripour, F., et al. (2017). "The impact of considering land intensification and updated data on biofuels land use change and emissions estimates." Biotechnology for Biofuels 10(1): 191.
[203] Liu, X., et al. (2020). "Shifting agricultural practices to produce sustainable, low carbon intensity feedstocks for biofuel production." Environmental Research Letters 15(8): 084014.

CIC estimates the farm level emissions from energy, fertilizers, herbicide, and insecticide, as well as effects on soil organic carbon relative to the baseline assumptions in GREET. The FD-CIC may be useful to estimate the soil carbon benefits of reduced tillage and cover cropping, and to examine regional differences in feedstock carbon intensity.

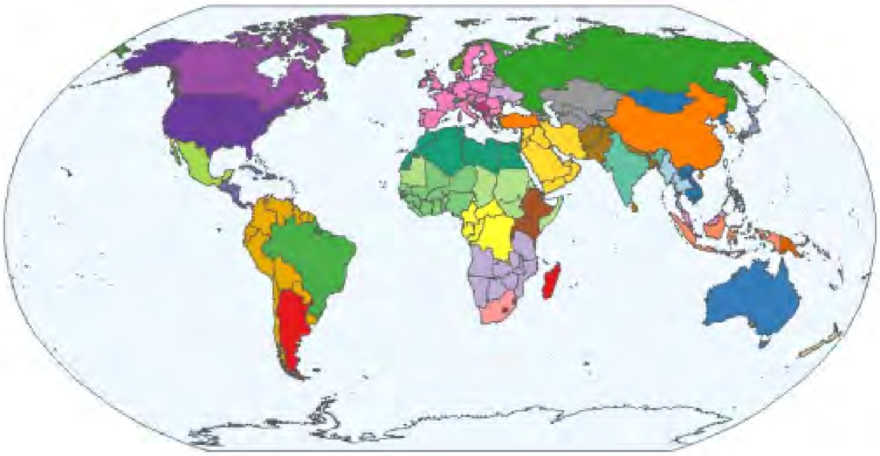
GREET is used by a variety of academic, commercial, and government users. California's Low Carbon Fuel Standards (LCFS) program relies in part on a customized version of GREET called CA-GREET to provide state-specific fuel pathways and carbon intensity values.[204] Oregon uses a similar approach for their LCFS program.[205] The International Civil Aviation Organization (ICAO) used GREET among several models to provide carbon intensities for specific aviation fuel pathways.[206] Most of these programs use the non-land use change GHG estimates from GREET and add their own land use change estimates instead of those derived from CCLUB to calculate biofuel carbon intensities. Among other applications, EPA has used GREET since the inception of the RFS program to provide data for rulemakings and pathway support as part of our suite of tools in addition to FASOM and FAPRI.

4.2.2.2 The GLOBIOM Model

The Global Biosphere Management Model (GLOBIOM) was developed and continues to be managed by the International Institute for Applied Systems Analysis (IIASA). The model was developed in the late 2000s originally to conduct impact assessments of climate change mitigation policies of biofuels and other land-based efforts.[207] It was developed on the basis of the U.S. Forest and Agricultural Sector Optimization Model (FASOM model).[208] There are several model versions of GLOBIOM available for different contexts. A sample of GLOBIOM code is available to the public, and an open source version is in the works.[209]

[204] California Air Resources Board. LCFS Life Cycle Analysis Models and Documentation. Available at: https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation (Accessed: 29 April 2022).
[205] Oregon Department of Environmental Quality. Carbon Intensity Values: Oregon Clean Fuels Program. Available at: https://www.oregon.gov/deq/ghgp/cfp/Pages/Clean-Fuel-Pathways.aspx (Accessed: 29 April 2022).
[206] ICAO. Models and Databases. Available at: https://www.icao.int/environmental-protection/pages/modelling-and-databases.aspx (Accessed: 29 April 2022).
207 International Institute for Applied Systems Analsyis, "GLOBIOM," https://previous.iiasa.ac.at/web/home/research/GLOBIOM/GLOBIOM.html.
208 Frank, Stefan, et al. "The Global Biosphere Management Model," https://www.epa.gov/system/files/documents/2022-03/biofuel-ghg-model-workshop-global-biosphere-mgmt-model-2022-03-01.pdf. And, Valin, Hugo et al. *The Land Use Change Impact of Biofuels Consumed in the EU: Quantification of Area Greenhouse Gas Impacts.* August 27, 2015, pg. 128. https://ec.europa.eu/energy/sites/ener/files/documents/Final%20Report_GLOBIOM_publication.pdf
209 See, GLOBIOM, "Model Code," https://iiasa.github.io/GLOBIOM/model_code.html.

Figure 4.2.2.3-1: GLOBIOM Regional Mapping[210]

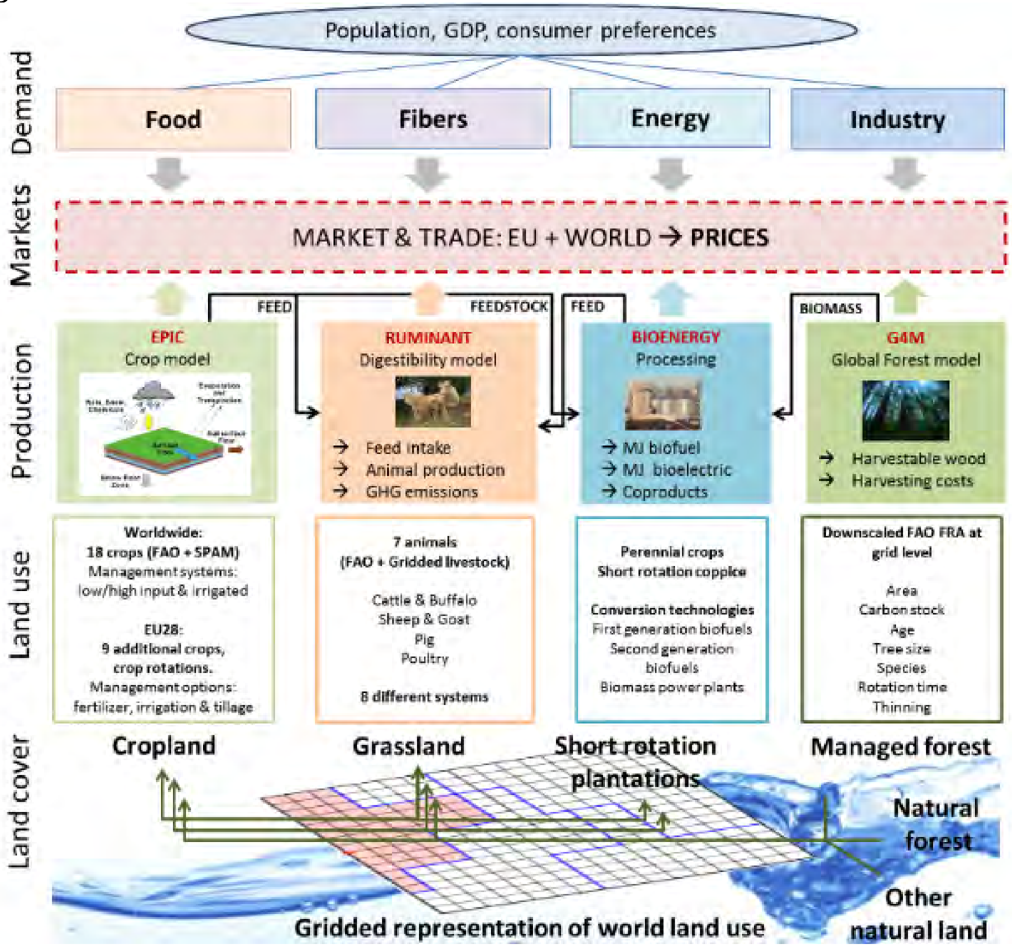


GLOBIOM is a PE model that captures the agricultural, forest, and bioenergy sectors. The model solves recursively dynamic using a spatial equilibrium modeling approach with detailed grid cell coverage. The model finds market equilibriums that maximize the sum of producer and consumer surplus subject to resource, technological, demand and policy constraints. Producer surplus is defined as the difference between market prices at a regional level and the product's supply curve. The supply curve takes into account labor, land, capital and other purchased input. Consumer surplus is based on the level of consumption of each market and is arrived at by integrating the difference between the demand function of a good and its market price. The model uses linear programming to solve, although it also contains some non-linear functions that have been linearized using stepwise approximation.[211] The global trunk version of the model features global coverage with 37 regions (see Figure 4.2.2.3-1) and simulates for the years 2000-2100 using ten-year time-steps. As a PE model, GLOBIOM does not have feedback from labor, capital, or other parts of the economy, however, the model can be linked to other models, such as IIASA's energy sector model MESSAGE.

[210] IIASA. (2020). "GLOBIOM regional and country level modeling." SUPREMA GLOBIOM-MAGNET Training. December 4, 2020. https://iiasa.github.io/GLOBIOM/training_material/GLOBIOM/GLOBIOM-Topic_RegionalApplications_APalazzo_Nov2020.pdf

211 IIASA, "GLOBIOM Documentation_20180604.pdf," https://iiasa.github.io/GLOBIOM/GLOBIOM_Documentation_20180604.pdf.

Figure 4.2.2.3-2: Schematic Overview of the GLOBIOM Model[212]



The detailed grid-cell level coverage for GLOBIOM includes more than 10,000 spatial units worldwide. The model represents 18 crops globally using FAOSTAT as the primary database for crop statistics. Crop modeling includes differentiation in management systems and multi-cropping.

GLOBIOM also features highly detailed livestock representation, based on FAOSTAT data. The model includes 7 animals, which can be raised on differentiated production systems. For ruminants there are 8 production system possibilities, including grazing systems in different climatic locations such as arid and humid, mixed crop-livestock systems, and others. Pigs and poultry are classified under either small holder or industrial systems. Based on the production system, animal species, and region, GLOBIOM differentiates diets, yields, and GHG emissions. For instance, dairy and meat herds are modeled separately and their diets are differentiated. Poultry in industrial systems is split into laying hens and broilers, again with different dietary needs.

Apart from monogastrics, livestock production is modeled spatially in GLOBIOM's gridded cell structure. At the cell level, animal yields for bovine and small ruminants are

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[212] IIASA. GLOBIOM Online Documentation. https://iiasa.github.io/GLOBIOM/introduction.html

estimated using the GLOBIOM module, RUMINANT. RUMINANT calculates a production yield that matches plausible feed rations and checks this against regional-level data of livestock production. Feed for animals is also differentiated in the RUMINANT model and can be composed of feed crops, grass, stover, and other feed. Monogastric productivities are calculated based on FAOSTAT and assumptions of potential productivities of smallholder and industrial systems. Livestock production is allowed to intensify or extensify thereby altering the amount of feed or grass consumed.[213] Since for ruminants this is modeled spatially, any changes in grassland consumed due to changes in production systems, animal type, yield, and GHGs is captured in the spatially-relevant areas. Each final livestock product is considered a differentiated good with its own specific market (apart from bovine and small ruminant milk).

Forestry in GLOBIOM is captured through the G4M module[214] and includes detailed representation of the sector and its supply chain and a differentiation between managed and unmanaged forest areas. GLOBIOM includes bilateral trade for agricultural and wood products. These products are assumed to be homogenous and traded based on least expensive production costs though transportation costs and tariffs are also included.

The model also includes a bioenergy sector with first and second generation biofuels and biomass power plants. Perennial crops and short-rotation coppice are included as inputs to the bioenergy sector. In 2014, GLOBIOM added biofuel co-products including distillers grains, oilseed meals, and sugar beet fibers. These co-products can be traded either in their processed or whole form. Co-products that can be used for livestock feed are incorporated into the livestock RUMINANT module and can substitute other forms of feed depending on protein and metabolizable energy content.[215]

There are nine land cover types in GLOBIOM, and 6 of these are modeled dynamically: cropland, grassland, short rotation plantations, managed forests, unmanaged forests, and other natural vegetation land. The final three land cover categories are represented in the model but kept constant, they include other agricultural land, wetlands, and not relevant (ice, water bodies etc). Greenhouse gas emission coverage includes 12 sources of emissions that cover crop cultivation, livestock, above and below-ground biomass, soil-organic carbon, and peatland. Although GLOBIOM does not track terrestrial carbon stocks dynamically, carbon fluxes from land use change are calculated with equations, following IPCC guidelines, that estimate changes over time and allocate the average annual emissions to the time period in which the land use change occurs.

Land use in GLOBIOM allows for both intensification and extensification. When land is converted, this is endogenously determined in the model based on conversion costs, and the profitability of primary, co-products, and final products. Costs increase as the area converted

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[213] Intensifying involves increasing livestock output without expanding the area of pasture land by grazing more livestock per area of land, increasing feed relative to grazing, or using feedlots. Extensifying is the opposite – it involves expanding pasture area in order to increase livestock production.

214 International Institute for Applied Systems Analysis, "Global Forest Model (G4M)", https://iiasa.ac.at/models-and-data/global-forest-model (accessed May 12, 2022).

215 Valin, Hugo, et al., September 17, 2014, "Improvements to GLOBIOM for Modelling of Biofuels Indirect Land Use Change," http://www.globiom-iluc.eu/wp-content/uploads/2014/12/GLOBIOM_All_improvements_Sept14.pdf pg. 38.

expands. Additionally, there are biophysical land suitability and production potential restrictions. Land use change is determined at the grid cell level, aka a one-by-one hectare. There is a land transition matrix that sets the options for land conversion for each cell and is based on land conversion patterns specific to that region and conversion costs depending on the type of land converted.[216]

In policy settings, GLOBIOM is used for both modeling the European Union's biofuel mandates and for estimating induced land use change impacts of biofuels for the International Civil Aviation Organization's Carbon Offsetting and Reduction Scheme for Civil Aviation (CORSIA). In research contexts, the model has regularly participated in AgMIP, an agricultural model intercomparison and improvement project.[217] One result of this project was an article published in the journal, Nature, on the key determinants of global land use projections.[218] GCAM, discussed in Section 4.2.2.3, was also part of the AgMIP study. GLOBIOM has been used to assess other topics in the academic literature, publishing work on topics such as reducing greenhouse gas emissions from the agricultural sector, food security, and climate mitigation of livestock system transitions.

4.2.2.3 The Global Change Analysis Model (GCAM)

The Global Change Analysis Model (GCAM) is a partial equilibrium, integrated assessment modeling framework which explores human and earth dynamics. The model includes representation of energy, economy, land, water, and physical earth systems and interactions between these systems within a fully integrated computational system. The model includes all human systems and economic sectors which produce or consume energy, or which emit GHGs. GCAM operates as a recursive dynamic framework, generally in 5-year time steps. In practice, the model is often run from a base year in the recent past through the years 2050 or 2100. However, time step and scenario length are flexible input assumptions to GCAM, and the framework can support scenario analysis across a wide range of time scales. By default, the model base year is currently 2015, but other historical base periods may be specified. For each modeled time period, GCAM iterates until it finds a vector of prices that clears all markets and satisfies all consistency conditions. The model is designed to explore different "what-if" scenarios, assessing the implications of different futures on a wide range of outcomes, such as energy supplies and demands, land allocation, or commodity prices.

216 IIASA, "Spatial Resolution and Land Use Representation," https://iiasa.github.io/GLOBIOM/documentation.html#spatial-resolution-and-land-use-representation. Accessed May 19, 2022.

[217] Several studies have estimated water use and availability impacts associated with future scenarios of increased cellulosic biofuel production. These studies often project future land use/management for different scenarios of increased production of cellulosic crops, and then estimate impacts on water use and changes in streamflow for specific watersheds. See for example: Cibin, R., Trybula, E., Chaubey, I., Brouder, S. M., & Volenec, J. J. (2016). Watershed-scale impacts of bioenergy crops on hydrology and water quality using improved SWAT model. Gcb Bioenergy, 8(4), 837-848 or Le, P. V., Kumar, P., & Drewry, D. T. (2011). Implications for the hydrologic cycle under climate change due to the expansion of bioenergy crops in the Midwestern United States. Proceedings of the National Academy of Sciences, 108(37), 15085-15090.

[218] Liu, X., Hoekman, S.K., and Broch, A. 2017. Potential water requirements of increased ethanol fuel in the USA. *Energy, Sustainability and Society*, 7: 18.

The core GCAM is developed and maintained at the Joint Global Change Research Institute, a partnership between Pacific Northwest National Lab (PNNL) and the University of Maryland (UMD) in College Park, Maryland. PNNL is the primary steward of the model, though members of a larger GCAM Community also contribute to development of the framework.[219] GCAM was originally developed in the early 1980s to assess the magnitude of GHG emissions from fossil fuel CO2 through the mid-21st Century. Over time, the model has expanded in scope to serve a wide set of scientific modeling applications. The model has now been in continuous development for over 40 years and has been applied in several studies and model inter-comparison activities, including the IPCC's Representative Concentration Pathways[220] and Shared Socioeconomic Pathways.[221] GCAM is an open-source community model that can be downloaded from a public repository.[222] The model documentation is also publicly available[223] and includes a partial list of GCAM publications.[224]

Economic systems in GCAM are divided into sectors and, within each sector, specific technologies. Figure 4.2.2.4-1 provides an overview of the sectors represented in GCAM, along with the inputs and outputs of the model. Each sector of GCAM is structured with a multi-level nesting approach that allows competition between different nodes at each level, and any number of levels. This nested competition follows a discrete logit[225] or modified logit model[226], depending on the object. The market share of each discrete technology is determined by a) a share-weight parameter that reflects the specific preferences for a particular choice, b) the cost, which includes fuel and non-fuel costs, and c) an exogenous logit exponent that determines the price responsiveness of the competition. In most cases the share-weights are derived from base-year calibration when market shares are known. Technologies that are introduced in future time periods are assigned exogenous share-weights in each model time period. The market shares are therefore influenced by a number of endogenous and exogenous parameters, including fuel and non-fuel costs, efficiency or input-output coefficients, share-weights, and logit exponents. These parameters are documented and can be consulted in online repository.[227]

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219 For more information, see https://gcims.pnnl.gov/community.

220 Thomson AM, Calvin KV, Smith SJ, Kyle GP, Volke A, Patel P, et al. RCP4. 5: a pathway for stabilization of radiative forcing by 2100. Clim Change 2011;109:77.

221 Calvin K, Bond-Lamberty B, Clarke L, Edmonds J, Eom J, Hartin C, et al. The SSP4: A world of deepening inequality. Glob Environ Change 2017;42:284–96.

222 See https://github.com/JGCRI/gcam-core.

223 See http://jgcri.github.io/gcam-doc/index.html

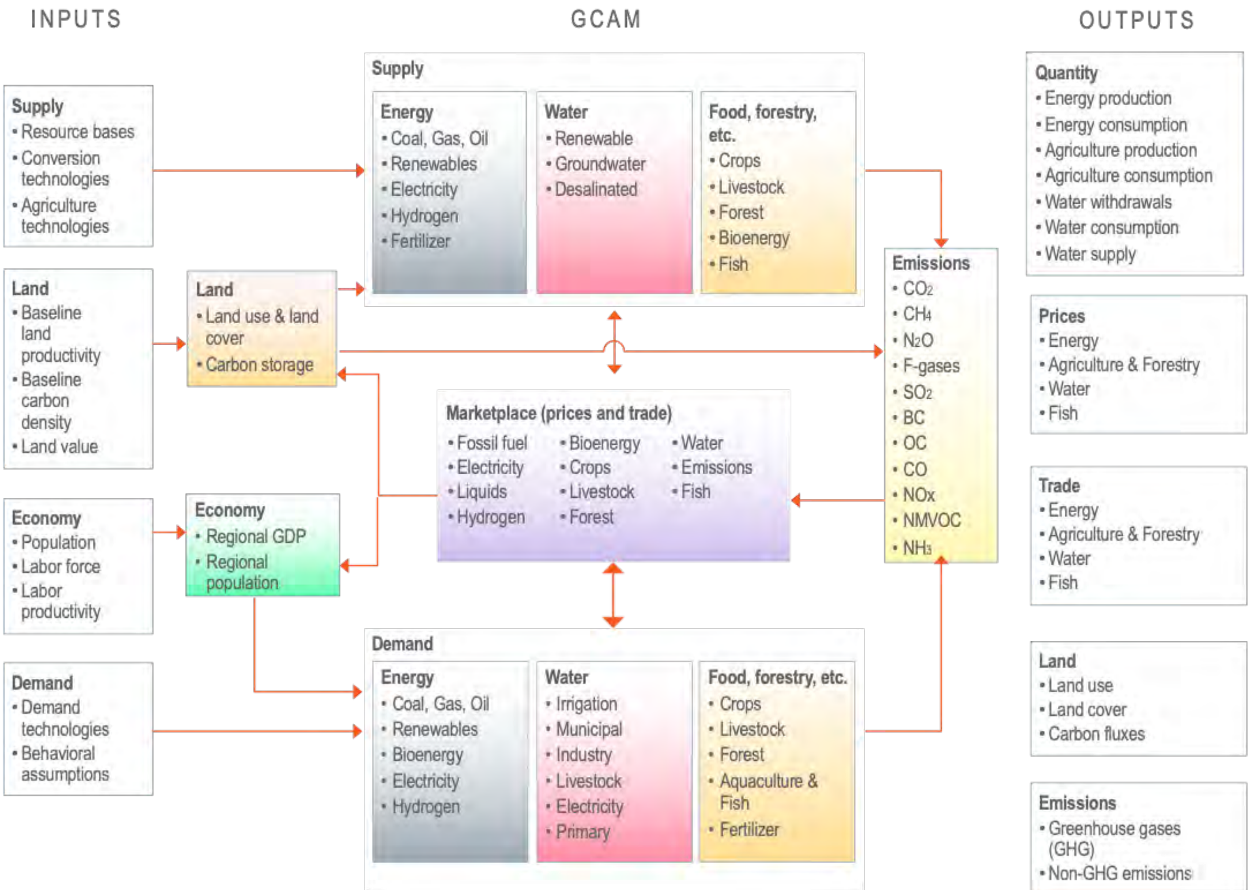
224 See more specifically http://jgcri.github.io/gcam-doc/references.html

225 McFadden D. Conditional logit analysis of qualitative choice behavior 1973.

226 Clarke JF, Edmonds JA. Modelling energy technologies in a competitive market. Energy Econ 1993;15:123–9.

227 See Calvin et al. 2019. GCAM v5.1: Representing the linkages between energy, water, land, climate, and economic systems. Geoscientific Model Development 12, 1–22. See also the online documentation (https://github.com/JGCRI/gcam-doc/blob/gh-pages/ssp.md) for the specific quantification of the inputs and parameters to the model.

Figure 4.2.2.4-1: GCAM diagram of model inputs, sectors, and outputs[228]



GCAM includes detailed representations of the energy sector, inclusive of liquid biofuels, and the agriculture and land sectors. The energy sector module in GCAM consists of depletable and renewable resources[229], energy transformation and distribution sectors (electricity, refining, gas processing, hydrogen production, and district services), and final energy demand sectors (buildings, industry, and transportation).[230] For transportation biofuels specifically (referred to in the GCAM documentation as "biomass liquids"), by default the model includes a total of 11 biofuel production technologies. These include four "first generation" technologies, representing ethanols and biodiesels produced from agricultural commodity crops, and seven "second generation" technologies representing fuels produced from a variety of feedstocks, including energy crops and residues. By default, the technology assumptions for second generation represent the inputs and outputs of cellulosic ethanol and Fischer-Tropsch fuels. However, the input assumptions for these technologies can be modified to represent other fuel production

[228] See http://jgcri.github.io/gcam-doc/index.html.

[229] Depletable resources are based on graded supply curves for coal, oil, gas and uranium. Renewable resources include annual flows of wind, solar, geothermal, hydropower, and biomass.

[230] More detailed information on the GCAM energy system can be found in online documentation, see http://jgcri.github.io/gcam-doc/index.html, and also in previous studies (see Clarke L, Eom J, Marten EH, Horowitz R, Kyle P, Link R, et al. Effects of long-term climate change on global building energy expenditures. Energy Econ 2018;72:667–77; Muratori M, Ledna C, McJeon H, Kyle P, Patel P, Kim SH, et al. Cost of power or power of cost: A US modeling perspective. Renew Sustain Energy Rev 2017;77:861–74.)

pathways. Secondary outputs such as dried distillers grains with solubles (DDGS) and electricity produced from lignin can be considered, as can the potential for carbon capture and storage. Further description of these technological representations is available in the online GCAM documentation.[231]

The agriculture and land use module differentiates 384 land use regions globally, generated as the intersection of 32 socioeconomic regions with 235 water basins (see Figure 4.2.2.2-2). Within each land use region, up to 25 land use types compete for land share based on the relative profitability of each use, using a nested land allocator tree structure.[232] This competition follows a similar profit-based logit structure, so economic land use decisions are based on the relative profitability of using land for competing purposes. Profitability of lands that are not in commercial production in the historical calibration period are inferred from the profitability of proximate lands used for agriculture and forestry. Land use types include exogenous land types (tundra, desert, urban), commercial and non-commercial pasture and forest lands, grasslands and shrublands, and a detailed set of agricultural crop commodities, including bioenergy crops, classified by irrigation type and fertilizer use.[233] Terrestrial carbon stocks and flows are modeled for each land type in each water basin.[234] The agricultural sector of the model primarily relies on input data from the UN Food and Agriculture Organization (FAO) historical data sets, and includes all crops for which FAO reports area and production data for the model base year of 2015.[235] Major global commodity crops, such as corn, rice, soybeans and wheat are modeled individually, while all other crops are modeled as a series of thematic aggregations.

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[231] See http://jgcri.github.io/gcam-doc/supply_energy.html.

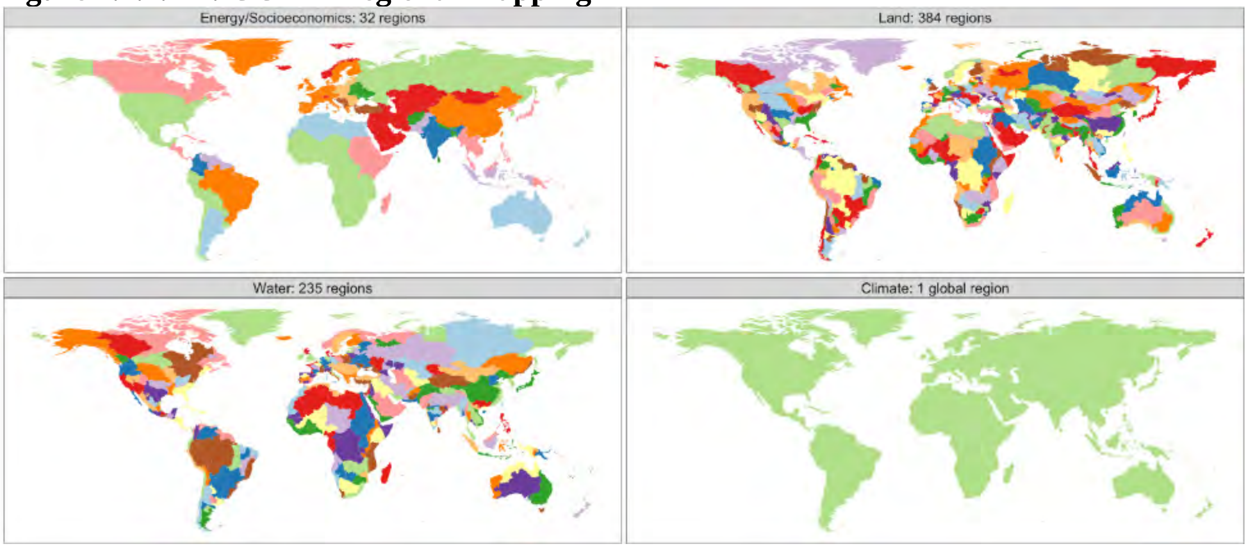
[232] See Wise M, Calvin K, Kyle P, Luckow P, Edmonds J. Economic and physical modeling of land use in GCAM 3.0 and an application to agricultural productivity, land, and terrestrial carbon. Clim Change Econ 2014;5:1450003, and Zhao X, Calvin KV, Wise MA. The critical role of conversion cost and comparative advantage in modeling agricultural land use change. Clim Change Econ 2020;11.

[233] A complete description of the land use module can be found in the online documentation (see http://jgcri.github.io/gcam-doc/toc.html) and in Kyle GP, Luckow P, Calvin KV, Emanuel WR, Nathan M, Zhou Y. GCAM 3.0 agriculture and land use: data sources and methods. Pacific Northwest National Lab.(PNNL), Richland, WA (United States); 2011.

[234] Input assumptions related to terrestrial carbon and land transitions are documented at http://jgcri.github.io/gcam-doc/inputs_land.html.

[235] See http://jgcri.github.io/gcam-doc/inputs_land.html for further data on land inputs to the model.

Figure 4.2.2.4-2: GCAM Regional Mapping[236]



In addition to the core GCAM described in this section, there exist several other subversions and downscaling tools which can be used to examine regions and systems at a finer grain of resolution. These include, among others, GCAM-USA[237], which models each US state as an individual region, Tethys[238], which allows for the downscaling of modeled GCAM water impacts, and Demeter[239], which allows for the downscaling of modeled land allocation impacts. Numerous additional tools are in various stages of development at JGCRI and other research groups which participate in the GCAM Community.[240] One of these, GCAM-T, was used in a recent study of corn ethanol impacts by Plevin et al. The results of that study are discussed in greater detail later in this chapter.[241]

4.2.2.4 The Global Trade Project (GTAP) Model

The GTAP model is a multisector, multiregion, general equilibrium model developed at the Center for Global Trade Analysis, Purdue University (Hertel, 1997 Ed.). It is widely used for analyzing international trade, agriculture, and environmental policy issues. It offers a framework to address the complex interactions of biofuels and other sectors of an economy.

Different applications of the GTAP model have resulted in establishing substitution among energy types,[242] and explicit global competition among different land categories classified at the agro-ecological zone (AEZ) level.[243] Based on these applications, a version of

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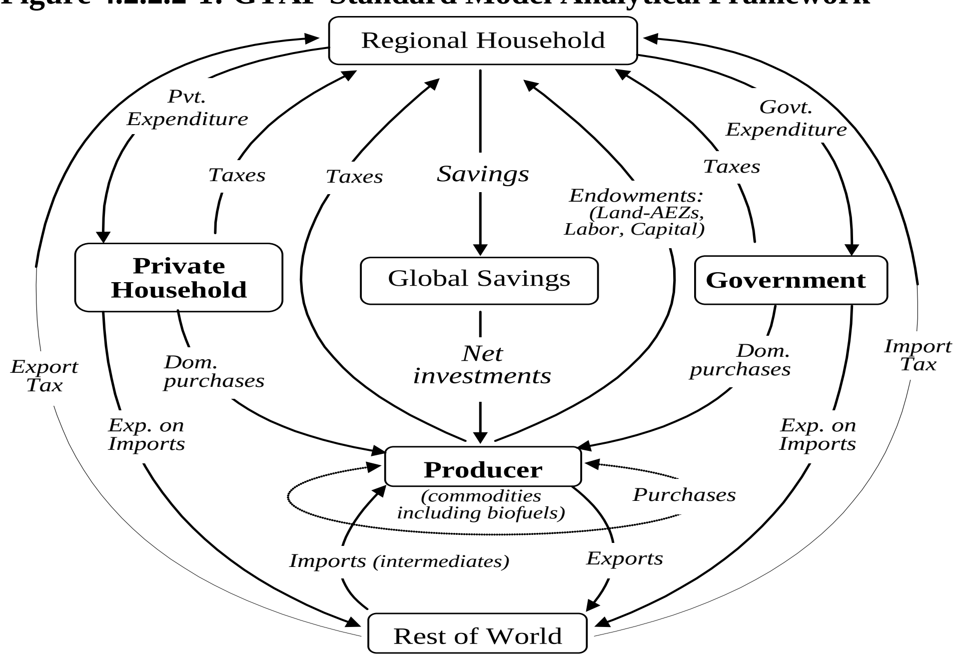
[236] See http://jgcri.github.io/gcam-doc/overview.html
[237] See http://jgcri.github.io/gcam-doc/gcam-usa.html
[238] https://github.com/JGCRI/tethys,
[239] https://github.com/JGCRI/demeter
[240] For more information, see https://gcims.pnnl.gov/community.
[241] Plevin, R. J., et al. (2022). "Choices in land representation materially affect modeled biofuel carbon intensity estimates." Journal of Cleaner Production: 131477.
[242] Burniaux, Jean-Marc, and Truong P. Truong. "GTAP-E: an energy-environmental version of the GTAP model." GTAP Technical Papers (2002): 18
[243] Lee, Huey-Lin. "The GTAP Land Use Data Base and the GTAPE-AEZ Model: incorporating agro-ecologically zoned land use data and land-based greenhouse gases emissions into the GTAP Framework." (2005).

the model called GTAP-BIO was developed to assess the economy-wide impact of first-generation biofuels production,[244] and later developments add the capability to model dedicated energy crops.[245]

Conceptually, the standard GTAP model assumes perfect competition in all markets with price adjustments to ensure that all markets clear simultaneously. The regional household collects all the income in its region and spends it over three expenditure types: private household (consumer), government, and savings, over a Cobb-Douglas utility function. A representative firm maximizes profits in nested CES functions in a perfectly competitive market for each industry/sector in each region and pays income to the regional household for using the endowment commodities (i.e., land, labor, capital, and natural resources). Consequently, firms sell the final goods produced by combining the endowments with the intermediates to the private households and the government, and the investment goods to the regional household. In an open economy, firms also export the tradable commodities and import the intermediate inputs from the rest of the world. The model follows Armington assumptions to account for product heterogeneity for outputs produced in different regions.

Figure 4.2.2.2-1: GTAP Standard Model Analytical Framework[246]



The land endowment in the GTAP model is imperfectly mobile, whereas labor and capital are perfectly mobile within a region but imperfectly mobile across regions. Government spending is modeled using a Cobb-Douglas subutility function, which maintains constant

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244 Birur D, Hertel T, Tyner WE. Impact of biofuel production on world agricultural markets: a computable general equilibrium analysis. GTAP Working Paper No. 53. Purdue University; 2008; Hertel TW, Tyner WE, Birur DK. The global impacts of biofuel mandates. Energy J. 2010;30:75–100.

245 Taheripour F, Tyner WE. Introducing first and second generation biofuels into GTAP data base version 7. In: GTAP, editor. GTAP Research Memorandum No. 21. Purdue University; 2011.

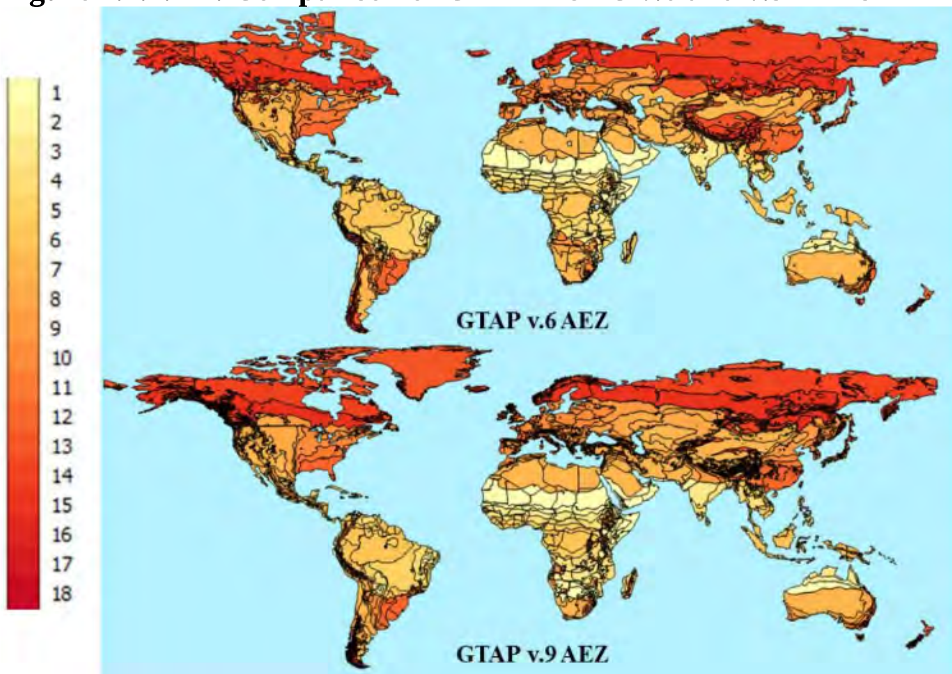
246 Taheripour, F. (2022). "GTAP-BIO Model and Data Base: Main Components and Improvements." Presentation for EPA Biofuels Modeling Workshop. March 1, 2022. Slide 7.

expenditure shares across all the sectors. The private household consumption is modeled by adopting a nonhomothetic Constant Difference of Elasticity implicit expenditure function, which allows for differences in income elasticities across commodities. Taxes (and subsidies) go as net tax revenues (subsidy expenditures) to the regional household from the private households, the government, and the firms.

The rest of the world gets revenues by exporting to private households, firms, and the government. These revenues are spent on export taxes and import tariffs, which eventually go to the regional household. A closure, defining the set of endogenous and exogenous variables in the model, is a typical GE closure in the GTAP model, which allows for equilibrium in all the markets, all firms earn zero profits, the regional household is on its budget constraint, global investment equals global savings, and sum of global exports and imports is zero. The global trade balance condition determines the world price of a given commodity. The Cobb-Douglas utility function of the regional household allows for maintaining constant budget shares.

The standard GTAP database does not disaggregate biofuels from other energy products. The biofuel linkages in the GTAP-BIO model are introduced into the version of the GTAP-E model to capture the implications of biofuels mandates on global energy and agricultural markets. The substitution of biofuels is represented by intermediate demand substitution as well as household substitution, by modifying the production and consumption structures, respectively. For analyzing the LUCs, GTAP-BIO features the GTAP 9 land use and land cover database developed by Baldos (2017), which aggregates 108 region-Agro-Ecological Zones (AEZs) into 18 global AEZs. The AEZs characterize the biophysical growing conditions and land use for crops and forestry.

Figure 4.2.2.2-2: Comparison of GTAP LULC v.6 and v.9 AEZs[247]



One of the key components of the GTAP model is the GTAP database, which is constructed based on national input-output tables, bilateral trade, protection, and macroeconomic data to give the consistent representation of the global economy in a given base year. The GTAP-BIO model was constructed based on the GTAP database version 6 database pertaining to the base year 2001 and has since been updated with GTAP database version 9, which represents the world economy in 2011.[248] Based on this database, the GTAP-BIO model was enhanced with three types of biofuels, corn-ethanol, oilseed-based biodiesel, and sugar-based ethanol, along with the coproducts, DDGS and oil meal.

GTAP-BIO is a static model that simulates scenarios for one time period. GTAP-BIO can currently run simulations using the 2011 GTAP database. Given that GTAP databases are now available for 2014 and 2017, GTAP-BIO is likely to be able to simulate these time periods in the near future. Researchers at Purdue have the ability to manually project a GTAP database forward in time based on macro-economic projections in order to simulate future time periods.[249]

GTAP-BIO has been updated multiple times to add features that are relevant for biofuel GHG modeling. Tyner et al. (2010) included marginal lands and productivity estimates for the potential new cropland based on a biophysical model. Taheripour et al. (2012) used a biophysical model (TEM) and estimated a set of extensification parameters which represent productivity of

[247] Uris, B. L. (2017) Development of GTAP 9 Land Use and Land Cover Data Base for years 2004, 2007 and 2011. GTAP Research Memorandum No. 30

[248] Taheripour, F., et al. (2017). "The impact of considering land intensification and updated data on biofuels land use change and emissions estimates." Biotechnology for Biofuels 10(1): 191. This study includes a summary of GTAP-BIO developments over time.

[249] Dhoubhadel, S., Taheripour, F. and Stockton, M. (2016) Livestock Demand, Global Land Use Changes, and Induced Greenhouse Gas Emissions. Journal of Environmental Protection, 7, 985-995. doi: 10.4236/jep.2016.77087. https://file.scirp.org/Html/2-6702993_67110.htm.

new cropland versus the existing land by AEZ region.[250] Taheripour and Tyner (2013) used a tuning process to differentiate land transformation elasticities by region based on FAO data.[251] Taheripour and Tyner (2013b) modified the land supply tree putting cropland pasture and dedicated energy crops (e.g., switchgrass) in one nest and all other crops in another nest, “to make greater use of cropland pasture (a representative for marginal land) to produce dedicated energy crops.”[252] Taheripour et al. (2016) altered the land use module of GTAP-BIO to include cropland intensification due to multiple cropping or returning idled cropland production, defined a new set of regional intensification parameters and determined, and defined regional yield responses to price based on analysis of regional changes in crop yields.[253] Taheripour et al. (2017) brought all of these modifications into one version of GTAP-BIO using the GTAP database representing 2011.[254]

GTAP-BIO has been used in biofuel GHG analysis to estimate the areas and types of land use change by region. Given that GTAP-BIO does not endogenously estimate land use change GHG emissions, they are estimated using either the AEZ-EF tool or the CCLUB module of GREET, which produce significantly different estimates. The resulting land use change GHG emissions have been added to direct emissions estimates from LCI models such as GREET. Given that GTAP-BIO models all sectors of the economy it may be possible to conduct a full consequential lifecycle GHG analysis with GTAP-BIO, but such an analysis has yet to be published.

Our focus in this section is on the GTAP-BIO model as that has been the most extensively applied GTAP model for biofuel analysis, but there are other versions of GTAP that have been or could potentially be used for biofuel modeling. GDyn-BIO is a recursive-dynamic version of GTAP that has been used to model U.S. corn ethanol land use change GHG impacts.[255] GTAP-DEPS is another recursive-dynamic version of GTAP that has been used to simulate corn ethanol effects, though it does not report GHG emissions.[256] ENVISAGE is another dynamic version of GTAP complemented by an emissions and climate module that links changes in temperature to impacts on economic variables such as agricultural yields. To our knowledge ENVISAGE has not been used for biofuel GHG analysis.[257] Further exploring and

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[250] Taheripour, F., et al. (2012). "Biofuels, cropland expansion, and the extensive margin." Energy, Sustainability and Society 2(1): 25.
[251] Taheripour, F. and W. E. Tyner (2013). "Biofuels and land use change: Applying recent evidence to model estimates." Applied Sciences 3(1): 14-38.
[252] Taheripour, F. and W. E. Tyner (2013). "Induced Land Use Emissions due to First and Second Generation Biofuels and Uncertainty in Land Use Emission Factors." Economics Research International 2013: 12.
[253] Taheripour, F., et al. (2016). An Exploration of Agricultural Land Use Change at Intensive and Extensive Margins. Bioenergy and Land Use Change: 19-37.
[254] Taheripour, F., et al. (2017). "The impact of considering land intensification and updated data on biofuels land use change and emissions estimates." Biotechnology for Biofuels 10(1): 191.
[255] Golub, A. A., et al. (2017). Global Land Use Impacts of U.S. Ethanol: Revised Analysis Using GDyn-BIO Framework. Handbook of Bioenergy Economics and Policy: Volume II: Modeling Land Use and Greenhouse Gas Implications. M. Khanna and D. Zilberman. New York, NY, Springer New York: 183-212.
[256] Oladosu, Gbadebo, and Keith Kline. "A dynamic simulation of the ILUC effects of biofuel use in the USA." Energy policy 61 (2013): 1127-1139.
[257] Van der Mensbrugghe, Dominique. "The environmental impact and sustainability applied general equilibrium (ENVISAGE) model." The World Bank, January (2008): 334934-1193838209522.

comparing the capabilities of these other GTAP models for biofuel analysis is a potential area for future research.

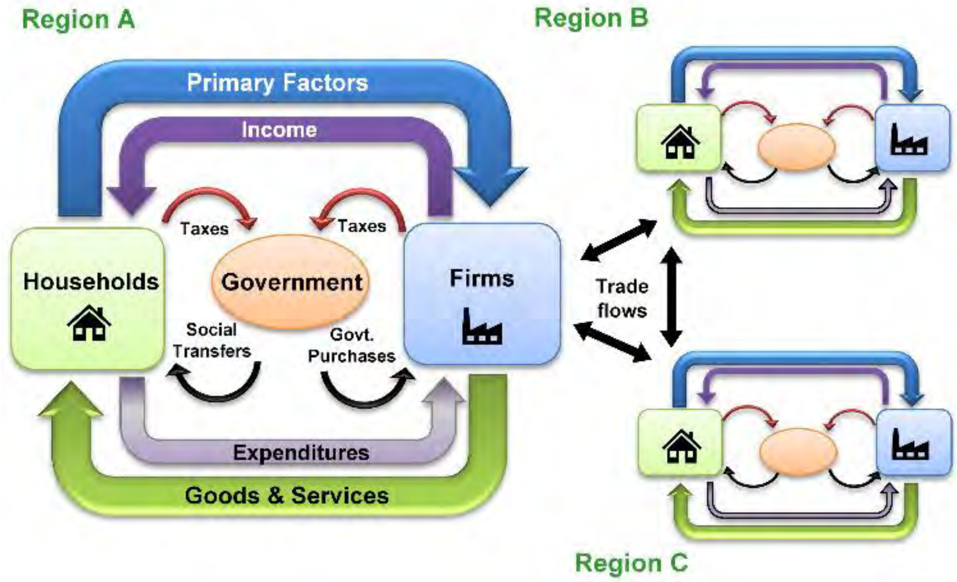
4.2.2.5 The ADAGE Model

The Applied Dynamic Analysis of the Global Economy (ADAGE) model is a multi-region, multi-sector computable general equilibrium (CGE) model developed and maintained by RTI International. The original ADAGE model was a forward-looking model.[258] It was originally developed to examine impacts of climate change mitigation policies and was used to analyze economy-wide impacts of the Waxman-Markey climate change bill and the American Clean Energy and Security Act of 2009. More recently, the ADAGE model has been developed to have additional sectoral detail, particularly in agriculture, bioenergy, and transportation.[259] This version of the ADAGE model (hereinafter referred to as "ADAGE" or "the ADAGE model") is global, rather than national, and is recursive-dynamic, which means that decisions about production, consumption, savings, and investment are based on previous and current economic conditions. There are plans to make ADAGE publicly available.

ADAGE represents the entire economy, including private and public consumption, production, trade, and investment, and follows the classical Arrow-Debreu general equilibrium framework.[260] The model uses nested constant elasticity of substitution (CES) production functions. As illustrated in Figure 4.2.2.5-1, ADAGE includes representative households and firms, and economic flows among households, firms, and government are considered. Bilateral trade is represented using an Armington approach.[261] Dynamics in ADAGE are represented by 1) growth in the available effective labor supply from population growth and changes in labor productivity; 2) capital accumulation through savings and investment; 3) changes in stocks of natural resources; and 4) technological change from improvements in manufacturing, energy efficiency and land productivity, and advanced technologies that become cost competitive.

[258] Ross, M. 2009. *Documentation of the Applied Dynamic Analysis of the Global Economy (ADAGE) Model*. Working paper 09_01. Research Triangle Park, NC: RTI International.
[259] Cai Y., Beach R., Woollacott J., Daenzer K., 2022. *Documentation of the Applied Dynamic Analysis of the Global Economy (ADAGE) model*. Technical Report.
[260] Arrow, K.J., and G. Debreu. 1954. Existence of an equilibrium for a competitive economy. Econometrica 22:265-290.
[261] Armington, P. S. (1969). A Theory of Demand for Products Distinguished by Place of Production. Staff Papers - International Monetary Fund, 16(1), 159–178.

Figure 4.2.2.5-1: Representation of Economic Flows in a CGE model[262]



ADAGE includes energy, industry, food, agriculture, and transportation sectors. It runs in 5-year intervals from 2010 through 2050, and includes 8 global regions (Africa, Brazil, China, EU 27, United States, Rest of Asia, Rest of South America, and Rest of World; Figure 4.2.2.5-2). ADAGE is built off the GTAP v7.1 database,[263] with additional data from other sources such as the International Energy Agency, U.S. Energy Information Administration, and United Nations Food and Agriculture Organization. Many CGE models only track inputs and outputs in monetary units, but ADAGE also tracks physical units (such as energy units of fuel consumption and area of land).

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[262] Cai Y., Beach R., Woollacott J., Daenzer K., 2022. *Documentation of the Applied Dynamic Analysis of the Global Economy (ADAGE) model*. Technical Report.

[263] Narayanan, G. B., and T. L. Walmsley (Eds.). 2008. Global Trade, Assistance, and Production: The GTAP 7 Data Base. West Lafayette, IN: Center for Global Trade Analysis, Purdue University. http://www.gtap.agecon.purdue.edu/databases/v7/v7_doco.asp

Figure 4.2.2.5-2: ADAGE Regional Mapping

ADAGE includes several agricultural commodities: wheat, corn, soybean, sugarcane, sugar beet, rest of cereal grains, rest of oilseeds, and rest of crops, in addition to one livestock category and one forestry category. The agricultural sector in the underlying GTAP v7.1 database is more aggregated, so creating these commodities in ADAGE required disaggregation using information on trade shares, consumption shares, cost shares, and own use shares. [264] This disaggregation was done with software called SplitCom[265] and data from the United Nations Food and Agricultural Organization FAOSTAT database and the United Nations Comtrade Database.[266,267] The "cereal grains" sector in GTAP v7.1 was split into corn and rest of cereal grains, the oil seeds sector was split into soybean and rest of oilseeds, and the combined sugarcane and sugar beet sector was split into sugarcane and sugar beet.

Agricultural sector details in ADAGE enable it to model several kinds of biofuels. ADAGE includes 8 types of first generation biofuels (corn ethanol, wheat ethanol, sugarcane ethanol, sugar beet ethanol, soy biodiesel, rape-mustard biodiesel, palm kernel biodiesel, and corn oil biodiesel) and 5 types of advanced biofuels (ethanol from switchgrass, miscanthus, agricultural residue, forest residue, and forest pulpwood). These biofuels are not included in the GTAP 7.1 database and were split from GTAP v7.1 sectors using the SplitCom software and secondary data from USDA's Economic Research Service, DOE's Energy Information

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[264] Beach, R.H., D.K. Birur, L.M. Davis, and M.T. Ross. 2011. A dynamic general equilibrium analysis of U.S. biofuels production. AAEA & NAREA Joint Annual Meeting, Pittsburgh, PA. https://ageconsearch.umn.edu/bitstream/103965/2/ADAGE-Biofuels_AAEA_Conference_Paper.pdf

[265] Horridge, M., J. Madden, and G. Wittwer. 2005. The impact of the 2002–2003 drought on Australia. Journal of Policy Modeling 27(3):285-308.

[266] Food and Agriculture Organization of the United Nations. 2012. FAOSTAT Database. Rome, Italy: FAO. http://www.fao.org/faostat/en/#data

[267] United Nations. 2012. UN Comtrade Database. http://comtrade.un.org

Administration, and the United Nations Comtrade database.[268,269,270] Corn ethanol and wheat ethanol were split from the "food products sector" in GTAP v7.1, which receives inputs from corn and wheat. Sugarcane ethanol and sugar beet ethanol were split from the chemicals sector. Biodiesel from soybean, rapeseed, and palm oil were split from the vegetable oils and fats sector. Distillers grains with solubles (DGS) and corn oil biodiesel are coproducts of corn ethanol production. An oil meal byproduct was split from the vegetable oil sector in GTAP v7.1. Because ADAGE does not explicitly represent rapeseed and palm oil production, the input shares of "rest of oilseeds" is based on region-specific palm oil and rapeseed biodiesel yields (gallon of biodiesel per ton of feedstock). Advanced biofuels were not included in the 2010 base year in ADAGE but are allowed to enter the market in future years.

The energy sectors of the ADAGE model include coal, natural gas, crude oil, and refined oil, and several categories of electricity generation technologies (conventional coal, conventional natural gas, conventional oil, combined-cycle natural gas, nuclear, hydropower, geothermal, wind, solar, and biomass). The supply of fossil fuels is limited by the availability of natural resources, which is represented as a fixed factor in the model. Crude oil is used as an input for refined oil and enters the production function in a fixed proportion. Electricity generation technologies are combined into a single electricity output.

The transportation sector in ADAGE has been developed to include light duty vehicles, freight trucks, buses, marine, aviation, freight rail and passenger rail. Biofuels can be consumed in on-road transportation (light duty vehicles, buses, and trucks). Alternative fuel options (hybrid, battery electric, fuel cell, and natural gas) are available for on-road vehicles. The GTAP v7.1 database includes three types of transportation (air, water, and rest of transportation) and was disaggregated using data from several sources.[271]

ADAGE includes six land types (cropland, pasture, managed forest, natural forest, natural grassland, and other land[272]). Land use change is represented using a constant elasticity of supply. Each land type has its own endowment, land rent, and usage. Willingness to convert land is represented by an elasticity, and the conversion cost is equal to the difference in land rent between land types. ADAGE models land in physical as well as monetary quantities. Emissions from land use change are based on the differences in carbon stocks (vegetative and soil carbon) between the land types, and emission factors (one for vegetative carbon, and one for soil carbon) that represent the fraction of the change in carbon stock that would occur over 20 years after land conversion. Land use change emissions and sequestration are all reported in the model year in

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[268] U.S. Department of Agriculture (USDA), Economic Research Service (ERS). 2012. U.S. Bioenergy statistics. Washington, DC: U.S. Department of Agriculture. https://www.ers.usda.gov/data-products/us-bioenergy-statistics/
[269] U.S. Department of Energy, Energy Information Administration (EIA). 2012. Petroleum & other liquids. Washington, DC: U.S. Department of Energy. https://www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_epooxe_im0_mbbl_a.htm
[270] United Nations. 2012. UN Comtrade Database. http://comtrade.un.org/
[271] Data sources include GCAM 4.2, the Bureau of Economic Analysis, the Bureau of Transportation Statistics, the International Energy Agency, and the Energy Information Administration. For more details, see Cai Y., Beach R., Woollacott J., Daenzer K., 2022. *Documentation of the Applied Dynamic Analysis of the Global Economy (ADAGE) model*. Technical Report.
[272] "Other land" includes bare ground, wetlands, mangroves, salt marsh, glaciers, and lakes, and is assumed to be constant over time.

which the land use change occurs. Vegetative and soil carbon stocks are based on data from GCAM 3.2, which were aggregated to ADAGE regions using weighted land area.

ADAGE includes six types of greenhouse gases: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), perfluorocarbons (PFCs), hydrofluorocarbons (HFCs), and sulfur hexafluoride (SF_6). CO_2 emissions from fossil fuel combustion are based on emissions factors (kg CO_2/mmBtu) for coal, gas, and oil. The emission factors are differentiated by region and based on data from EIA's International Energy Statistics. CO_2 emission factors from sources other than fossil fuel combustion and land use change are based on data from the Emissions Database for Global Atmospheric Research (EDGAR) version 4.2.[273] Non-CO_2 emission factors are based on data from EPA.[274]

CGE models typically do not have the sectoral detail available in other types of models. However, because CGE models capture the entire economy, they can be useful for determining impacts of environmental policies across sectors and on GDP. In one study, the ADAGE model was used to analyze projected impacts of the RFS on land use, crop production, crop prices, fossil energy use, GHG emissions, and GDP.[275] ADAGE has also been used to study the impact of oil prices on biofuel expansion.[276] In model comparison studies, ADAGE was used to analyze the GHG abatement potential in Latin America,[277] and the impacts of climate policy and agriculture, forestry, and land use emissions.[278]

4.2.2.6 Other Models and Approaches

Other models, besides the ones discussed above, have also been used to estimate land use change and GHG emissions associated with biofuels. We briefly describe some of these models here and focus our discussion on models that were used to produce at least one of the estimates that appear in our literature review. Austin et al. (2022) conducted a literature review of studies that examined U.S. biofuels and land use change.[279] They review studies published before 2019 and, after applying a filtering process, identified 15 economic simulation modeling studies and 14 empirical studies for detailed assessment. In this section, we discuss relevant studies and

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[273] Joint Research Centre at European Commission. 2013. Emission Database for Global Atmospheric Research. http://edgar.jrc.ec.europa.eu/overview.php?v=42FT2010
[274] U.S. Environmental Protection Agency (EPA). 2012. Global Non-CO2 GHG Emissions: 1990-2030. Washington, DC: EPA. https://www.epa.gov/global-mitigation-non-co2-greenhouse-gases/global-non-co2-ghg-emissions-1990-2030
[275] Cai, Y., D.K. Birur, R.H. Beach, and L.M. Davis. (2013, August). Tradeoff of the U.S. Renewable Fuel Standard, a General Equilibrium Analysis. Presented at 2013 AAEA & CAES Joint Annual Meeting, Washington, D.C.
[276] Cai, Y., R.H. Beach, and Y. Zhang. (2014, March). Exploring the Implications of Oil Prices for Global Biofuels, Food Security, and GHG Mitigation. Presented at 2014 AAEA Annual Meeting, Minneapolis, MN.
[277] Clarke L., McFarland J., Octaviano C., van Ruijven B., Beach R., Daenzer K., Herreras Martínez S., Lucena A.F.P., Kitous A., Labriet M., Loboguerrero Rodriguez A.M., Mundra A., van der Zwaan B., 2016. Long-term abatement potential and current policy trajectories in Latin American countries. Energy Econ. 56, 513-525. http://dx.doi.org/10.1016/j.eneco.2016.01.011
[278] Calvin K.V., Beach R., Gurgel A., Labriet M., Loboguerrero Rodriguez A.M., 2016. Agriculture, forestry, and other land-use emissions in Latin America. Energy Econ. 56, 615-624. http://dx.doi.org/10.1016/j.eneco.2015.03.020
[279] Austin, K., et al. (2022). "A review of domestic land use change attributable to US biofuel policy." Renewable and Sustainable Energy Reviews 159: 112181.

models reviewed by Austin et al. (2022). The purpose of this brief overview is to highlight that there are other models, besides the five discussed above, that have some capabilities to evaluate biofuel GHG impacts. We are providing a brief discussion of other models for informational purposes, but we do not think they meet our statutory requirements under the CAA to evaluate all significant direct and indirect emissions. For example, some of the models do not have global coverage, some are not spatially explicit and cannot model land use change emissions, and some do not include GHG emissions. Furthermore, some of these models are difficult to access given their proprietary nature (e.g., they are not open source models).

In their literature review, Austin et al. (2022) considered 14 empirical studies that "derive a statistical relationship between an observed land use conversion response (e.g., non-crop to crop conversion) and a treatment (e.g., ethanol refinery location or capacity)." All of these empirical studies were limited in spatial extent to the contiguous U.S. or a subset of U.S. states (generally the corn belt). Only two of the 14 empirical studies estimated the effects of corn ethanol production on land use for the contiguous U.S. and considered the effects of corn and crop prices changes on land use. The other 12 studies were either limited to a subset of U.S. states, did not consider prices effects, or evaluated price effects in general but not biofuel induced effects. These limitations make these 12 studies potentially useful for informing our understanding, but the models and methods have limited relevance for our purposes. We briefly discuss each of the two studies that met these criteria.

Lark et al. (2022)[280] was widely cited by commenters on our biofuel GHG modeling workshop. This study combines econometric analyses, land use observations, and biophysical models to estimate the effects of increasing U.S. corn ethanol production by 5.5 billion gallons since 2007 compared to a counterfactual scenario. Austin et al. (2022) categorized this as an empirical study as it does not develop an economic simulation model that can be straightforwardly applied to a wide range of scenarios. For GHG emissions attributable to corn ethanol, Lark et al. (2022) report net changes in CO_2 and N_2O emissions from land use and land management changes in the U.S. The reported CO_2 emissions are the result of ecosystem carbon changes (e.g., plowing grassland to produce corn) and the reported N_2O emissions are from increased fertilizer application. Lark et al. (2022) added their estimates of U.S. land use change to the corn ethanol LCA estimates from the 2010 RFS2 rule, GREET and the CARB's analysis for the CA-LCFS. The fact that this study only estimates historical U.S. land use change GHG emissions means that we can only do a limited comparison with estimates from other models that evaluate all lifecycle stages and/or project scenarios into the future.

Brandao (2022) uses a consequential approach to estimate the GHG emissions associated with ramping up U.S. corn ethanol production to 15 billion gallons from 1999 to 2018. This study estimates market-mediated effects without an economic model. Rather it looks at the difference in corn supply over this time period and uses a rules based approach to estimate diversion, direct land use change, and intensification effects of increasing the amount of corn used for ethanol. It then estimates the resulting crop production and land use change emissions. We include this study in the range of estimates for corn ethanol presented below as it provides a full lifecycle estimate.

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[280] Lark, T. J., et al. (2022). "Environmental outcomes of the US Renewable Fuel Standard." Proceedings of the National Academy of Sciences 119(9): e2101084119.

Li et al. (2019) estimated the effects of ethanol capacity, corn prices and crop prices on corn and cropland area at a county level.[281] Unlike Lark et al. (2022), this study did not estimate the influence of ethanol production on corn and crop prices, nor did they estimate GHG emissions or other environmental effects. Combined with exogenous estimates of the effects of ethanol production on corn and crop prices, it is possible to use Li et al. (2019) to estimate corn and cropland area changes at county-scale resolution for comparison with economic modeling estimates. Furthermore, Li et al. (2019) estimated corn and crop area elasticities in response to ethanol capacity and prices, which may be useful as inputs to economic simulation models.

In addition to the economic simulation models discussed above (i.e., GTAP-BIO, GLOBIOM, GCAM, ADAGE), Austin et al. (2022) identified studies that used models called REAP, PEEL-Co, BEPAM, AEPE and an unnamed multi-market equilibrium model. All of these models limit their spatial extent to the U.S., and thus we give them brief treatment. REAP is a price-endogenous mathematical programming model of the U.S. agricultural sector that can simulate changes in soil carbon.[282] PEEL-Co is a stochastic PE land use change allocation model that can estimate domestic land use change emissions associated with corn ethanol production.[283] BEPAM is a PE model that simulates biofuel effects on Conservation Reserve Program and cropland pasture acres, and currently excludes GHG emissions.[284] AEPA is a PE model that examines interactions between agricultural and energy markets and evaluates the consequences of changes in biofuel policies.[285]

In addition to the models discussed in the Austin et. al. paper, another model has been used to evaluate biofuels is the Bio-based circular carbon economy Environmentally-extended Input-Output Model (BEIOM). BEIOM is an economy-wide environmentally extended input-output model using economic transactions data together with emissions inventories to provide a high-level snapshot of the U.S. economy at different points in time.[286] As such it performs a “top-down” assessment linking national-level economic transactions with emissions inventories for specific points in time. However, BEIOM only includes emissions in the U.S., therefore we do not discuss it in more extensive detail.

Finally, while most studies in the literature focus on estimating indirect/induced land use change emissions, other studies estimate “direct” land use change emissions (i.e., the emissions associated with converting the land required for biofuel feedstock production). A relatively early

[281] Li, Y., et al. (2019). "Effects of Ethanol Plant Proximity and Crop Prices on Land-Use Change in the United States." American Journal of Agricultural Economics.
[282] Johansson, Robert C. Regional environment and agriculture programming model. (Technical bulletin (United States. Dept. of Agriculture) ; no. 1916); Malcolm, Scott A., Marcel P. Aillery, and Marca Weinberg. Ethanol and a changing agricultural landscape. No. 1477-2016-121116. 2009.
[283] Elliott, J., et al. (2014). "A Spatial Modeling Framework to Evaluate Domestic Biofuel-Induced Potential Land Use Changes and Emissions." Environmental Science & Technology 48(4): 2488-2496.
[284] Chen, X. and M. Khanna (2018). "Effect of corn ethanol production on Conservation Reserve Program acres in the US." Applied Energy 225: 124-134.
[285] Taheripour, F., et al. (2022). "Economic Impacts of the U.S. Renewable Fuel Standard: An Ex-Post Evaluation." Frontiers in Energy Research 10.
[286] Lamers, P., et al. (2021). "Potential Socioeconomic and Environmental Effects of an Expanding U.S. Bioeconomy: An Assessment of Near-Commercial Cellulosic Biofuel Pathways." Environmental Science & Technology.

study of direct land use change emissions (Fargione et al. 2008) estimated the "land clearing carbon debt" associated with converting a range of natural ecosystems (rainforests, grasslands, savannas) to food crop-based biofuel feedstock production.[287] ICAO (2022) provides a methodology for calculating direct land use change emissions for an "event where feedstocks were sourced from land obtained through land use conversion after 1 January 2008."[288] Given difficulties with measuring direct land use change emissions in cases where the land was converted many years ago, Searchinger et al. (2022) use an alternate approach called "carbon opportunity cost" estimated as either: (1) "the global carbon loss from plants and soils generated by producing each crop to date (the numerator), divided by the global production (the denominator)", or (2) "the quantity of carbon that could be sequestered annually if the average productive capacity of land used to produce a kilogram of each food globally were instead devoted to regenerating forest."[289] Direct land use change does not factor into the rest of our review as it has not been used in recent LCA studies; however, it may deserve additional consideration in the future as it can be estimated with empirical measurements instead of counterfactual modeling.

4.2.2.7 Comparison of Model Characteristics

In this section we compare the characteristics of the five models highlighted above in Chapter 4.2.2.1-5. While there are many models that could potentially be used for biofuel GHG analysis (see Chapter 4.2.2.8), we focus our discussion on these five models for the reasons discussed at the beginning of Chapter 4.2.2. We sometimes bring other models and empirical studies into the discussion as comparison points, but we otherwise set them aside to focus on models that are designed to evaluate hypothetical scenarios and project future effects. We compare the models across several characteristics that are important for biofuel analysis. In the next section (Chapter 4.2.2.8) we also compare published results from these models and discuss the importance of input assumptions relative to model choice. We then outline the goals of the model comparison exercise that we intend to conduct for the final rule.

Table 4.2.2.7-1 summarizes some of the key characteristics of the five models featured in section 4.2.2. Although there are many ways to compare these models, we choose six key characteristics that we believe will help us determine whether the modeling framework meets the statutory requirements for evaluating biofuel lifecycle GHG emissions, including direct and indirect emissions. [290] The models that are the most comprehensive across these key characteristics are more likely to satisfy the statutory requirements, as discussed in Section 4.2.2.1. For example, models that represent all relevant sectors, regions, time periods, GHG emissions sources, and land categories are most likely to capture significant indirect emissions. These six characteristics provide a good starting point for understanding the primary differences across these frameworks. We start our discussion based on these six characteristics before touching on other key aspects of these models for biofuel GHG analysis. While we are not ruling

[287] Fargione, J., et al. (2008). "Land Clearing and the Biofuel Carbon Debt." Science 319(5867): 1235-1238.
[288] ICAO (2022). CORSIA Methodology for Calculating Actual Life Cycle Emissions Values, International Civil Aviation Organization. June 2022.
[289] Searchinger, T. D., et al. (2018). "Assessing the efficiency of changes in land use for mitigating climate change." Nature 564(7735): 249-253.
[290] While not explicitly required as part of the CAA, we also note that open access to the models is an important consideration.

out consideration or future use of other models, based on the biofuel GHG modeling workshop and our review of the literature, we believe the models listed in the table are the most likely to meet our statutory requirements for evaluating lifecycle GHG emissions. In addition, the models selected provide a broad representation of the types of models that can be used for lifecycle analysis.

Table 4.2.2.7-1 Comparison of Key Characteristics Across Models

Characteristic	GREET	GLOBIOM	GTAP-BIO	ADAGE	GCAM
Type of Model	Lifecycle inventory (LCI)	Partial equilibrium (PE)	Computable general equilibrium (CGE)	Computable general equilibrium (CGE)	Integrated assessment model (IAM)
Sectoral Coverage	Fuel supply chains including energy resource and material inputs	Agriculture, forestry and bioenergy	Economy-wide with 57 sectors	Economy-wide with 36 sectors	Energy (conventional and renewable), agriculture, forestry, water
Temporal Representation	Static	Recursive dynamic (10-year time steps)	Comparative static	Recursive dynamic (5-year time steps)	Recursive dynamic (5-year time steps)
Regional Coverage	Customizable (typically U.S. average)	37 economic regions; 10,000 spatial units (grid cell)	19 economic regions; 18 agro-ecological zones	8 economic and spatial regions	32 economic regions; 235 spatial regions (water basins)
GHG Emissions Coverage	Direct supply-chain emissions + indirect land use change from CCLUB module	Crop production, livestock and land use change	Land use change GHGs calculated with CCLUB or AEZ-EF modules	Economy-wide GHGs including land use change	Global GHGs including land use change
Land Representation (Arable land categories considered in biofuel land use change analysis)	Exogenous (Land use change estimates from GTAP-BIO and CCLUB)	Cropland, other agricultural land, grassland, commercial and non-commercial forest, wetlands, other natural land	Cropland (including cropland-pasture), livestock pasture, "accessible" forestry land	Cropland, pasture, commercial forest, non-commercial forest, natural grassland, other land	Cropland, commercial pasture and forest, non-commercial pasture and forest, shrubland, grassland, "protected" non-commercial land

Across the four model types there tends to be a trade-off between scope and detail. The LCI models have the most detailed technological representations but the most limited scope. For example, the GREET model includes detailed representations of many biofuel and energy production processes, but includes no price-induced interactions between supply chains or economic sectors. PE models also tend to have a high level of detail in the agricultural sector, but limited interactions with other sectors. For example, the GLOBIOM model has a detailed representation of crop production, livestock, and land use, but does not include economic interactions between the agricultural and energy sectors (e.g., fertilizer prices are exogenous). CGE models are the broadest in economic scope but tend to lack detail in their physical and technological representations. For example, CGE models are designed to track resources in terms of their monetary value and require subsequent accounting methods to estimate physical quantities. IAMs are the broadest in their representation of the interactions between human (e.g., economic) and Earth (e.g., biophysical) systems but tend to lack detail in their representation of particular sectors (e.g., finance, labor) and technologies (e.g., oil refining is represented with one or two generic technologies).

The modeling frameworks differ substantially in the scope of economic interactions that they represent. Since the Clean Air Act requires us to consider all significant indirect impacts as part of our lifecycle analysis, capturing a wide range of economic interactions is important for understanding the overall GHG impacts of crop-based biofuel production. Based on economic theory, we expect increased consumption of crop-based biofuels to have complex ripple effects through the entire world economy. For example, as the demand for feedstocks increase, we expect the price of these commodities to increase with consequences for food and feed markets not only in the U.S., but around the world. These interactions are complicated by the fact that the major crop-based biofuel feedstocks have co-products (e.g., distiller grains, soybean meal) that are used as livestock feed. Given that producing biofuels requires material (e.g., fertilizer) and energy (e.g., natural gas), increased biofuel production may affect these input commodity markets as well. When biofuels displace gasoline or diesel in the U.S., this change may affect consumer fuel prices and crude oil prices which may in turn affect other sectors of the economy. LCI models such as GREET ignore most of these economic interactions. However, GREET includes agricultural sector interactions to a limited extent through the exogenous addition of land use change GHG estimates. GLOBIOM models economic interactions within and between the agricultural (including crops and livestock) and forestry sectors. GLOBIOM also includes a bioenergy sector with limited economic interactions other than through its consumption of feedstocks from the agricultural and forestry sectors. GCAM models economic interactions within and between the energy, agriculture, forestry, and water systems. The energy system in GCAM is highly developed, including energy production from a broad range of technologies and resources, and energy consumption in the industrial, commercial, residential, transportation, agriculture, and forestry sectors. As CGE models, GTAP-BIO and ADAGE model interactions across the entire economy. Thus, CGE models include economic interactions that the other modeling frameworks take as exogenous or ignore but do so at a highly aggregated level.

Temporal representation, or the treatment of time dynamics, is another important characteristic that differentiates the modeling frameworks. As a general matter, the ability to model temporal dynamics is an important feature given that biofuel land use change emissions occur over time (e.g., soil carbon levels change over multiple decades following land conversion) and biofuel-induced effects are dependent on factors that change over time, such as crop yields and overall demands on land to produce food, feed, and fiber. GREET does not represent time as it is not designed to simulate temporal changes.[291] GTAP-BIO is a comparative static model, meaning it models only one time period and does not project changes over time.[292] GLOBIOM, GCAM and ADAGE are recursive dynamic models whereby production, consumption, and

[291] However, as discussed above, if provided with sufficient data, GREET can estimate supply chain emissions for different time periods

[292] GTAP-BIO can model different time periods if the GTAP database is first manually projected forward (or backward) based on assumptions.

investment decisions are made on the basis of market conditions in each period with dependence on previous model periods through capital and/or resource stocks.

Consistent with the statutory definition of lifecycle GHG emissions, we need to consider significant indirect emissions, and there are many scientific studies showing that such indirect emissions can occur in many different regions of the globe. Thus, models need to represent all of the relevant regions in order to satisfy our needs. Furthermore, regional representation is important due to differing regional conditions related to terrestrial carbon stocks, agricultural yields, energy resources and other factors. PE, CGE and IAM models often distinguish between economic regions and spatial regions. These models use algorithms to find market clearing conditions in, and trade between, each of the economic regions. Spatial regions are often defined separately to allocate the economic activities to physical locations. GTAP-BIO models 19 economic regions and 18 non-contiguous AEZs (see Figure 4.2.2.2-1). GLOBIOM models 37 economic regions and uses a grid-cell approach to represent 10,000 spatial units worldwide. GCAM models 32 economic regions and 235 global water basins—the intersection of the economic regions and water basins produces 384 spatial subregions. A spatial downscaling model called Demeter is able to present GCAM results at higher spatial resolution ($0.05° \times 0.05°$).[293] ADAGE models 8 economic and spatial regions. In contrast, GREET is not a spatial or regional model, but it can be customized to represent biofuel production conditions for particular regions or supply chains. GREET also has modules that are designed to estimate soil carbon and land use change emissions at a regional level. The FD-CIC module allows users to estimate feedstock production emissions at county level, and the CCLUB module estimates indirect land use change emissions based on the spatial regions represented by GTAP-BIO.

There are major differences across the models in their coverage of GHG emissions sources. As such, the biofuel GHG emissions estimates produced from these models are often quite different in their scopes. As mentioned previously, GREET estimates direct GHG emissions from a biofuel production supply chain and ignores indirect market-mediated emissions from other sources and sectors, with the exception of indirect land use change emissions which are added exogenously through the CCLUB module. There are versions of GTAP models that endogenously track GHG emissions from energy and land use. It may be possible to endogenously track GHG emission in GTAP-BIO, but to our knowledge this approach has never been used in peer-reviewed studies on biofuel GHG impacts.[294] GTAP-BIO models the entire economy but, at least in terms of peer-reviewed studies on biofuels, changes in emissions from other sectors of the economy are generally not reported. As discussed above, land use change GHG emissions are estimated from GTAP-BIO's land use change area estimates through the application of static land conversion emissions factors. GLOBIOM endogenously calculates GHG emissions from agriculture, including crop and livestock production, forestry, and land use change. ADAGE endogenously calculates GHG emissions from the entire economy, including land use change, while GCAM endogenously calculates global GHG emissions from the energy, agriculture, forestry and water systems, including from land use changes. Of the five highlighted models, ADAGE, GCAM, and GTAP are the only models that

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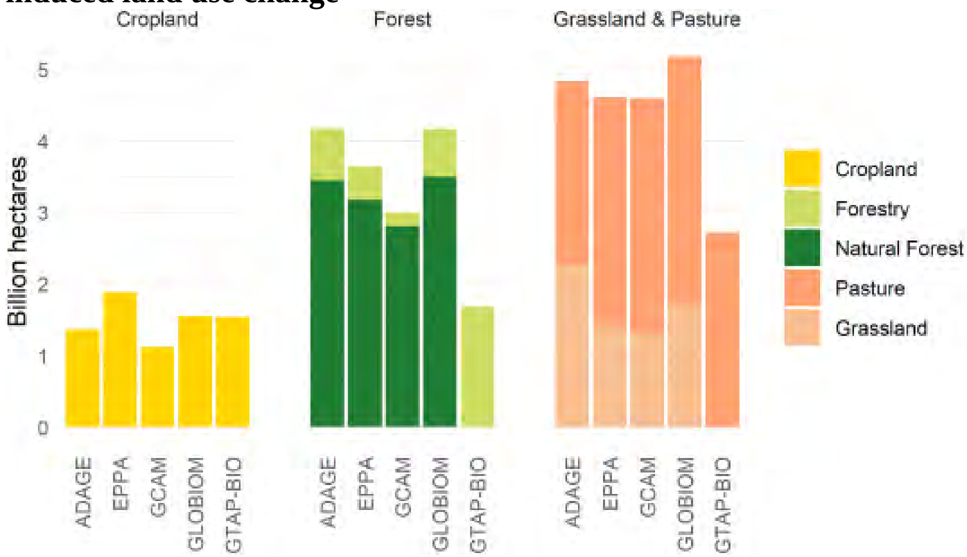
[293] Chen, M., Vernon, C.R., Graham, N.T. et al. Global land use for 2015–2100 at 0.05° resolution under diverse socioeconomic and climate scenarios. Sci Data 7, 320 (2020). https://doi.org/10.1038/s41597-020-00669-x
[294] See for example: https://www.gtap.agecon.purdue.edu/models/energy/default.asp

capture GHG emissions from market-mediated changes within the energy system, though energy sector emissions have not historically been reported in GTAP-BIO LCA calculations.

It is important to note that although GREET, GLOBIOM, ADAGE and GCAM seem to overlap in their coverage of GHG emissions, they estimate GHG impacts associated with very different phenomena. For example, GREET and GLOBIOM both estimate GHG emissions from crop production, but they do so in fundamentally different ways. GREET estimates the GHG emissions associated with producing the crops that are directly used in the biofuel supply chain under evaluation. In contrast, GLOBIOM estimates the GHG emissions associated with the market-mediated marginal changes in crop production stemming from a biofuel shock (i.e., the difference in crop production emissions from a scenario with a given amount of biofuel relative to a scenario absent that biofuel). ADAGE and GCAM represent a further departure from the GREET approach as they include market mediated GHG impacts from yet more economic sectors. A notable example is the inclusion of GHG emissions from transportation fuel market effects in ADAGE and GCAM. When these models are shocked to consume more biofuels in a particular region, they estimate the effects of the shock on transportation fuel prices and consumption, both in the region where the shock occurs and all other regions around the world. Thus, instead of assuming that biofuels displace gasoline or diesel on an energy-equivalent basis, they estimate the global market-mediated changes in gasoline and diesel consumption associated with the biofuel shock and report the resulting GHG emissions changes.

Representation of land is an important, but often overlooked, consideration for land use change modeling. By land representation we mean the way that land is categorized and how much of it is assumed to be unavailable for commercial use. GREET does not explicitly represent land. The other four models estimate interactions between cropland, pasture, and forestry. GLOBIOM, ADAGE and GCAM also model the expansion of commercial cropland, pasture and forestry activities into grassland and forests that are not otherwise used for commercial production. In contrast, GTAP-BIO only allows managed lands in the U.S. and around the world to be used for productive uses, excluding the possibility for “unmanaged” land such as rainforests to be brought into production. As shown in Figure 4.2.2.7-1, this assumption applies to a relatively large share of arable land and means that GTAP-BIO employs a much different representation of land than the other models. Additionally, the share of non-commercial land that is assumed to be protected or unavailable for protected use is also an important assumption. For example, if the modeling assumes that policies will be implemented and enforced to protect natural forests with high carbon stocks, this will likely reduce the land use change GHG estimates by a significant amount.

Figure 4.2.2.7-1: Land available for productive use in five models used to estimate biofuel-induced land use change[295]



There are also significant differences in the data and parameter inputs that are used within models used for biofuel GHG analysis. There have been very few efforts to compare the many assumptions across these models or evaluate how they influence the results. As part of the model comparison exercise that we intend to conduct for the final rule, we will strive, time permitting, to compare some of the key input assumptions. For now, we can make a limited set of observations about which assumptions are likely to be important for biofuel GHG modeling and how they compare across the models.

Assumptions related to crop yields and crop intensification are important for biofuel GHG modeling. Global crop yield data is readily available from FAO; however, there may be differences in how the models map this historical data to the crops and regions they represent. Assumptions about how crop yields may change in the future are also influential and inherently uncertain. Perhaps even more important for biofuel modeling are assumptions about how crop yields may change in response to price changes. Plevin et al. (2015) performed a sensitivity analysis of biophysical and economic inputs to the GTAP-BIO+AEZ-EF modeling framework, and found the elasticity of crop yield with respect to price (YDEL) to be "by far" the most influential parameter in terms of its effect on the estimated ILUC emissions associated with corn ethanol, sugarcane ethanol and soybean oil biodiesel.[296] Later studies confirmed that YDEL is influential in GTAP-BIO and found that other parameters related to crop intensification, such as the parameters that control multi-cropping (i.e., multiple harvest per year on the same land) instead of crop expansion to meet demands, also have a significant effect.[297] However, a

[295] Figure 1 from Plevin, R. J., et al. (2022). "Choices in land representation materially affect modeled biofuel carbon intensity estimates." Journal of Cleaner Production: 131477. For simplicity, shrubland and some other land types (e.g., wetlands) are excluded. Note: GREET is not included in this chart since it does not explicitly model land use change.

[296] Plevin, R. J., et al. (2015). "Carbon Accounting and Economic Model Uncertainty of Emissions from Biofuels-Induced Land Use Change." Environmental Science & Technology 49(5): 2656-2664.

[297] Taheripour, F., et al. (2017). "The impact of considering land intensification and updated data on biofuels land use change and emissions estimates." Biotechnology for Biofuels 10(1): 191

sensitivity analysis with GCAM did not identify crop yield assumptions to be among the most influential parameters determining corn ethanol land use change GHG emissions.[298] This suggests that input parameters that are influential in one model might not be very influential in another model due to structural differences between them. Unfortunately, we do not have sensitivity analyses from GLOBIOM or ADAGE that estimate the most influential parameters on biofuel GHG estimates.

The parameters that control land competition and land transitions within the models may also be important. A sensitivity analysis with GCAM found the parameter controlling ease of transition between cropland, forest, and grassland to be an influential parameter. A sensitivity analysis with GTAP-BIO also found that the assumed elasticity of transformation between managed forest, cropland, and pasture is influential for corn ethanol LUC GHG estimates.[299]

Sensitivity analysis using GCAM found other assumptions to be influential when estimating corn ethanol land use change GHG emission, including the soil carbon density of cropland, ease of transition between crop types, the soil carbon density of grassland and the soil carbon density of other arable land.[300] Other influential assumptions identified through sensitivity analysis with GTAP-BIO include the relative productivity of newly converted cropland, trade elasticities (i.e., ease of substitution among products imported from other countries) and emissions from conversion of cropland pasture.[301]

Sensitivity analyses have shown that other influential assumptions within GTAP-BIO include, but are not limited to, tropical peat soil oxidation and the share of palm oil expansion on peatland for vegetable oil based biofuel modeling, and the share of vegetable oil biofuel feedstock that is supplied through expanded vegetable oil production versus reduced demand and substitutions with other products.[302]

These aspects of vegetable oil market dynamics have led to variation in how different models capture emission impacts of vegetable oils. Most of the mass and value of soybeans for instance comes from the plant matter and goes towards livestock feed. Only about 20 percent of a soybean’s mass goes towards oil. This means that modeling the livestock sector and associated data and parameters are also important considerations for modeling oilseeds. Likewise on the oil side, the number of vegetable oil substitutes and the degree to which people can or want to substitute between these oils for both food and fuel is another important consideration in oilseed modeling. Furthermore, the vegetable oil market dynamics have not been static; over the last

[298] Plevin, R. J., et al. (2022). "Choices in land representation materially affect modeled biofuel carbon intensity estimates." Journal of Cleaner Production: 131477. Figure 7.
[299] Plevin, R. J., et al. (2015). "Carbon Accounting and Economic Model Uncertainty of Emissions from Biofuels-Induced Land Use Change." Environmental Science & Technology 49(5): 2656-2664. Table S9 in the Supplemental Information.
[300] Plevin, R. J., et al. (2022). "Choices in land representation materially affect modeled biofuel carbon intensity estimates." Journal of Cleaner Production: 131477. Figure 7.
[301] Plevin, R. J., et al. (2015). "Carbon Accounting and Economic Model Uncertainty of Emissions from Biofuels-Induced Land Use Change." Environmental Science & Technology 49(5): 2656-2664. Table S9 in the Supplemental Information.
[302] ICAO (2021). CORSIA Eligible Fuels -- Lifecycle Assessment Methodology. CORSIA Supporting Document. Version 3: 155. Section 6.2

decade the relative and absolute prices of vegetable oils have grown and changed from their 2010 values. The data and market structure that underlies how these market interactions are captured differs from model to model.

Another influential assumption in biofuel GHG modeling is the choice of data sets for soil carbon and biomass carbon stocks, and how these data are mapped to land categories and regions to determine the GHG emissions from converting an acre of land from one use to another. The soil and biomass carbon data sources used in each model are discussed in the model descriptions above. Soil carbon data and analysis are active areas of research, and higher resolution datasets have recently been produced using statistical methods and remote sensing data.[303] For example, the SoilGrids250m version 2.0 dataset provides soil carbon estimates for the globe with quantified spatial uncertainty,[304] and Spawn et al. (2020) developed global maps of above and below ground biomass carbon density in the year 2010.[305] With few exceptions,[306] these newer data sets have not yet been incorporated into published estimates of biofuel land use change.

4.2.2.8 Review of Land Use Change GHG Estimates

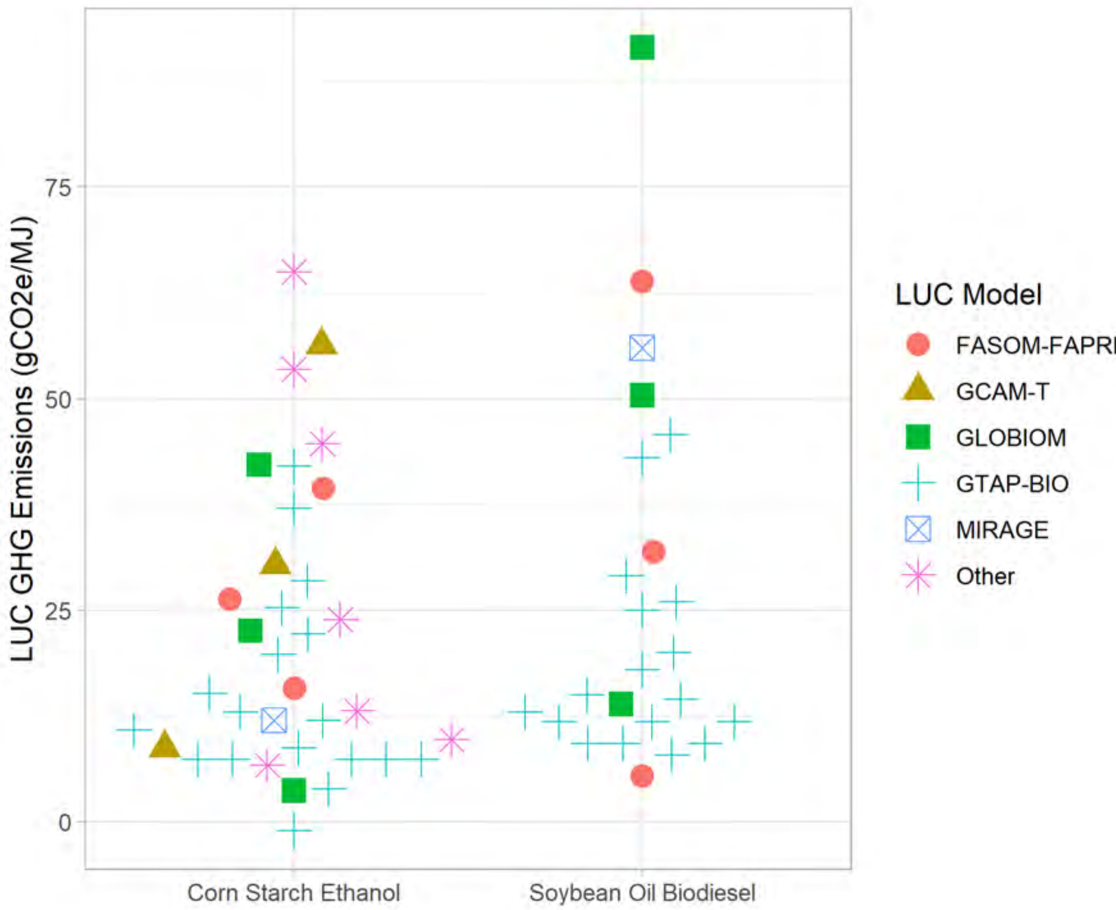
Land use change GHG estimates continues to be a large source of variation between lifecycle GHG estimates for crop-based fuels. In order to further our understanding of available models, we reviewed studies that estimate the land use change GHG emissions associated with corn ethanol and soybean oil biodiesel, which account for the large majority of crop-based biofuel supply in the U.S. This review included journal articles, major reports and studies that informed biofuel-related policies. We reviewed studies that were published after the March 2010 RFS2 rule, as that rule considered the available science at the time. In cases where there were multiple studies that include updates to the same general model and approach, we included only the most recent study. However, we include older estimates from the GTAP-BIO model that are still used for the CA-LCFS or the default assumptions in GREET.

We focused our review on estimates of the average type of each fuel produced in the United States. Many of the studies we reviewed include sensitivity analysis, where many parameters are varied to produce a large number of estimates. In these cases, we include representative high and low estimates. For example, when studies report a 95% confidence interval, we use only the central estimate (usually the default, mean or median estimate) and the estimates at the top and bottom of the confidence interval. This approach simplifies the presentation of results relative to including every estimate in between. We intentionally do not calculate or present any statistics (e.g., mean, median) derived from the estimates, as we do not believe such statistics would be meaningful or appropriate based on the design and purpose of our literature review.

[303] Spawn-Lee, Seth. (2022). “Carbon: Where is it and how can we know?” Presentation for EPA Biofuel GHG Modeling Workshop. February 28, 2022. EPA-HQ-OAR-2021-0921-0022
[304] Poggio, L., de Sousa, L. M., Batjes, N. H., Heuvelink, G. B. M., Kempen, B., Ribeiro, E., and Rossiter, D.: SoilGrids 2.0: producing soil information for the globe with quantified spatial uncertainty, SOIL, 7, 217–240, 2021.
[305] Spawn, S. A., et al. (2020). "Harmonized global maps of above and belowground biomass carbon density in the year 2010." Scientific Data 7(1): 112.
[306] Lark, T. J., et al. (2022). "Environmental outcomes of the US Renewable Fuel Standard." Proceedings of the National Academy of Sciences 119(9): e2101084119.

Figure 4.2.2.8-1 summarizes the land use change GHG estimates from our literature review for corn ethanol and soybean oil biodiesel.[307] All of the estimates in this chart report land use change GHG estimates as carbon dioxide-equivalent (CO_2e) emissions per megajoule (MJ) of fuel consumed. All CO_2e estimates are based on 100-year global warming potential (GWP) from the IPCC.[308] This allows us to compare all of the estimates on a gCO_2e/MJ of fuel basis. However, we stress that many of the studies in this chart do not align in terms of their time horizon, year of analysis, or other factors. Therefore, the estimates reported in this figure give us a sense for the range of estimates, but caution is needed when comparing the points in this figure as the estimates are from evaluations of divergent scenarios and methodologies.

Figure 4.2.2.8-1: Land Use Change GHG Emissions Estimates by Pathway

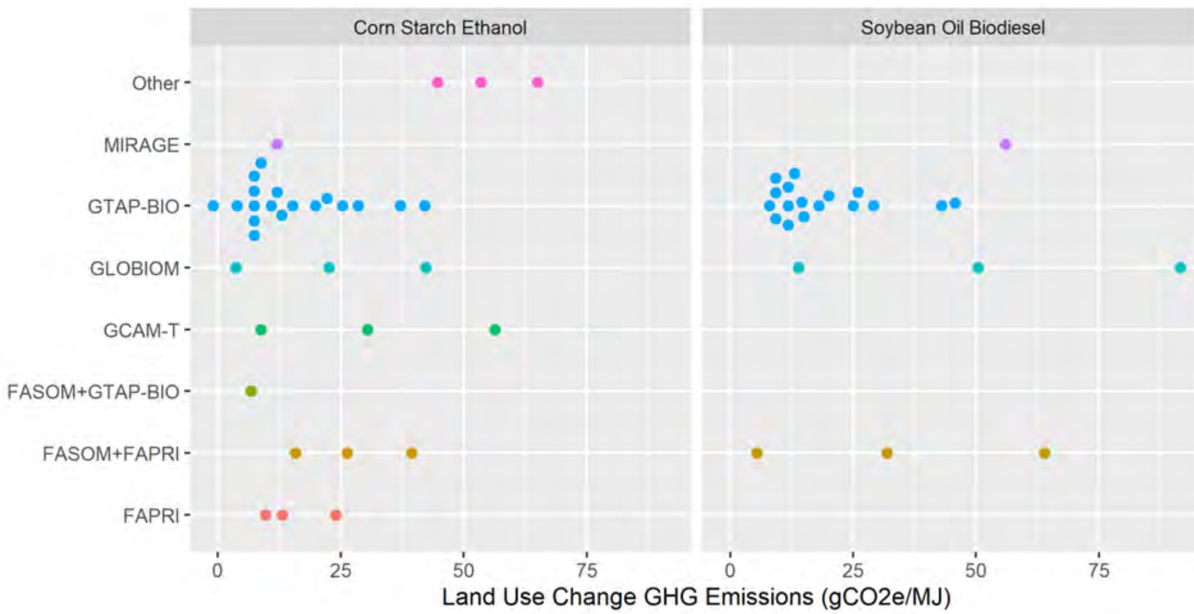


[307] Details on the sourcing of each estimate from our literature review are available in a memo to the docket for this proposed rule titled "Notes on Literature Review of Transportation Fuel Greenhouse Gas (GHG) Lifecycle Analysis (LCA)."

[308] The reviewed estimates use GWP values from the IPCC Second Assessment Report (SAR), Fourth Assessment Report (AR4) or Fifth Assessment Report (AR5). We did not attempt to harmonize GWP assumptions across studies as many studies only reported CO_2e results and not emissions by gas.

Figure 4.2.2.8-1 shows a relatively wide range of land use change GHG estimates, especially for soybean oil-based biodiesel.[309] These findings are consistent with the conclusions of another recent literature review presented at our February 2022 workshop.[310] In order to highlight the influence of model choice on the land use change estimates, Figure 4.2.2.8-2 arranges the data by model. Once again, caution is needed when comparing the estimates in Figure 4.2.2.8-2, as the estimates were produced for different scenarios and contexts. With these qualifications in mind, we can make some general observations from Figure 4.2.2.8-2 about the effect of model choice on land use change estimates.

Figure 4.2.2.8-2: Land Use Change GHG Emissions Estimates by Model[311]



GTAP-BIO is the model with the largest number of estimates in our literature review. This is partly because GTAP-BIO has been used for multiple publications and purposes. For example, GTAP-BIO is used to estimate land use change GHG emissions for the CA-LCFS and the ICAO CORSIA programs. It is also partly due to the way that we filtered and selected estimates for our review. For example, GLOBIOM recently produced 300 different estimates for each pathway, but for practical reasons Figure 4.2.2.8-2 includes only the default estimate and the 2.5% and 97.5% quantile estimates from the Monte Carlo sensitivity analysis.[312] As another example, analysis by Plevin et al (2022) using GCAM-T produced 3,000 estimates of corn

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[309] Some of the estimates in this figure come from studies that only estimate land use change GHG emissions or do not conduct full lifecycle estimates for corn ethanol or soybean oil biodiesel and thus do not factor into the LCA ranges developed below in Chapter 4.2.3. For example, the highest estimate for soybean oil from GLOBIOM does not factor into the range of LCA estimates for soybean oil biodiesel or renewable diesel summarized in Chapter 4.2.3.12 (see Chapter 4.2.3.4 for more information).
[310] Daioglou, V., et al. (2020). "Progress and barriers in understanding and preventing indirect land-use change." Biofuels, Bioproducts and Biorefining 14(5): 924-934.
[311] Details on the sourcing of each estimate from our literature review are available in a memo to the docket for this proposed rule titled “Notes on Literature Review of Transportation Fuel Greenhouse Gas (GHG) Lifecycle Analysis (LCA).”
[312] ICAO (2021). CORSIA Eligible Fuels -- Lifecycle Assessment Methodology. CORSIA Supporting Document. Version 3: 155. Table 67.

ethanol land use emissions in a recent publication, but Figure 4.2.2.8-3 includes only the mean, 5^{th} and 95^{th} percentile results from the Monte Carlo sensitivity analysis conducted for this study.[313] The FASOM+FAPRI estimates in this figure are from the 2010 RFS2 rule; although these estimates are over 10 years old, the figure illustrates that they continue to be within the range of more recent studies. The estimates from the model labeled "Other" in this figure are from Lark et al. (2022). Lark et al. (2022) developed a new model to estimate U.S. land use change GHG emissions, and pairs these estimates with estimates of non-U.S. land use change emissions from other models.

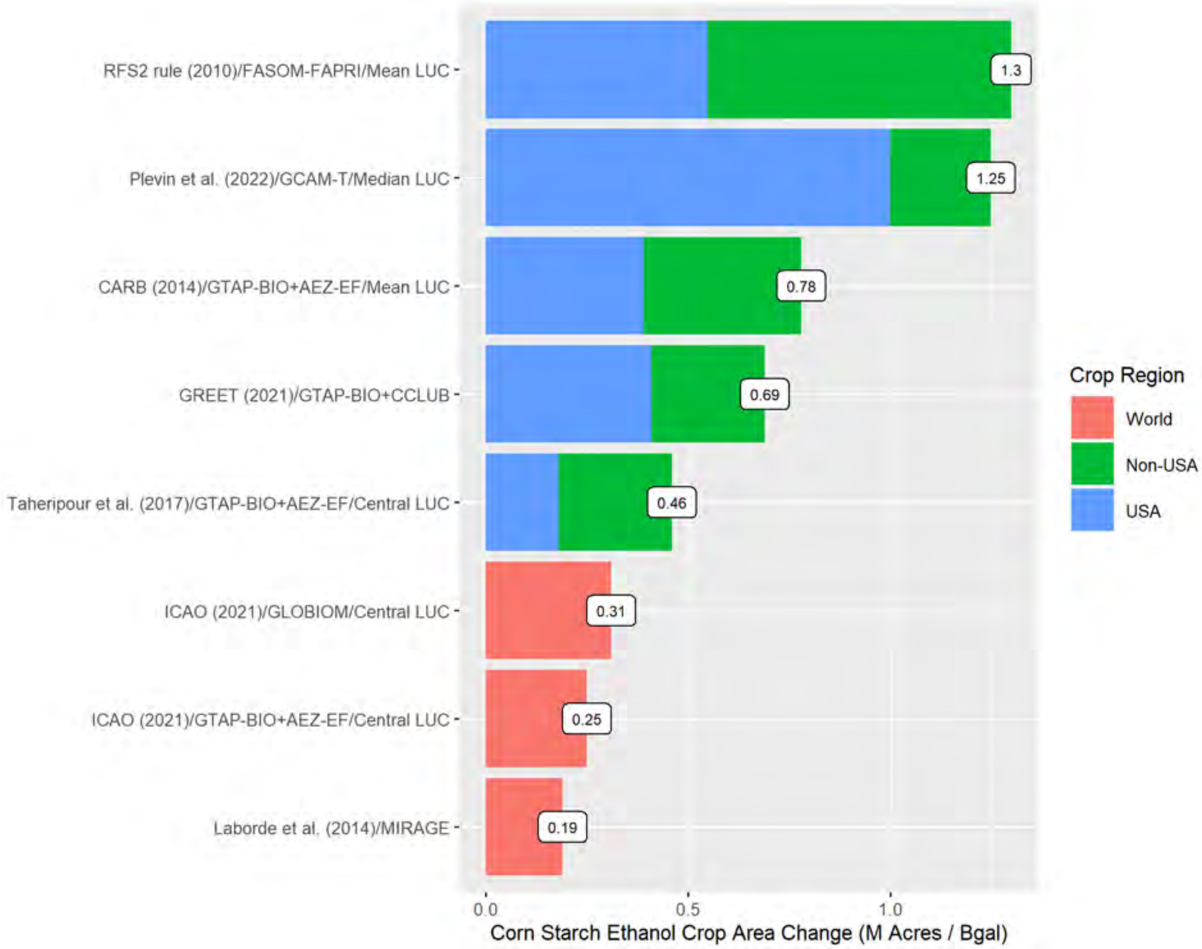
Since Figure 4.2.2.8-2 only reports land use change emissions, we cannot say, based on the estimates in this figure, which models produce the highest or lowest lifecycle GHG estimates. Although many of these models can estimate GHG emissions from other sources (and in some cases all sources), with few exceptions only the land use change GHG emissions have been reported from these models. As part of our model comparison exercise for the final rule, we intend to examine a broader range of GHG emissions estimates from these models. For example, we intend to compare estimates from these models of the GHG emissions associated with changes in crop production, livestock production, and energy supply and consumption. For now, we focus our discussion on the land use change results and what factors may explain differences between estimates.

While there is a large amount of overlap between the range of land use change GHG estimates from each model, many of the GTAP-BIO estimates are clustered at the relatively low end of the range of estimates. GCAM tends to have the highest land use change GHG estimates for corn ethanol, and GLOBIOM tends to have the highest estimates for soybean oil biodiesel (there are no modeling results from GCAM for soybean oil biodiesel available in the literature). Without harmonizing scenarios and assumptions it isn't possible to fully explain the source of the differences. However, based on our current understanding of how these models compare (see previous section), we can identify some of the potential reasons.

There are three broad elements that contribute to land use change GHG estimates per gallon of biofuel production: 1) acres of cropland expansion, 2) types of land displaced by cropland expansion, and 3) GHG emissions per acre of land use change. Comparing these elements for the published estimates in Figure 4.2.2.8-2 helps us better understand the underlying differences between the studies. The next two figures compare cropland area impact estimates across studies for corn ethanol and then soybean oil biodiesel. These studies compared a reference scenario to a scenario with increased corn ethanol or soybean oil biodiesel production. The figures show the change in cropland area between these two scenarios. To facilitate comparison, we normalized the units from all studies to million acres of cropland per billion gallons of biofuel production (Mac/Bgal). For dynamic models, results are reported for the peak year of the biofuel shock. We made no other efforts to harmonize these estimates, and we note that caution is needed when interpreting these figures for many reasons including the divergent scenarios modeled and differences in the definition of cropland between models.

[313] Plevin, R. J., et al. (2022). "Choices in land representation materially affect modeled biofuel carbon intensity estimates." Journal of Cleaner Production: 131477.

Figure 4.2.2.8-3: Cropland Area Change Estimates by Study for Corn Ethanol



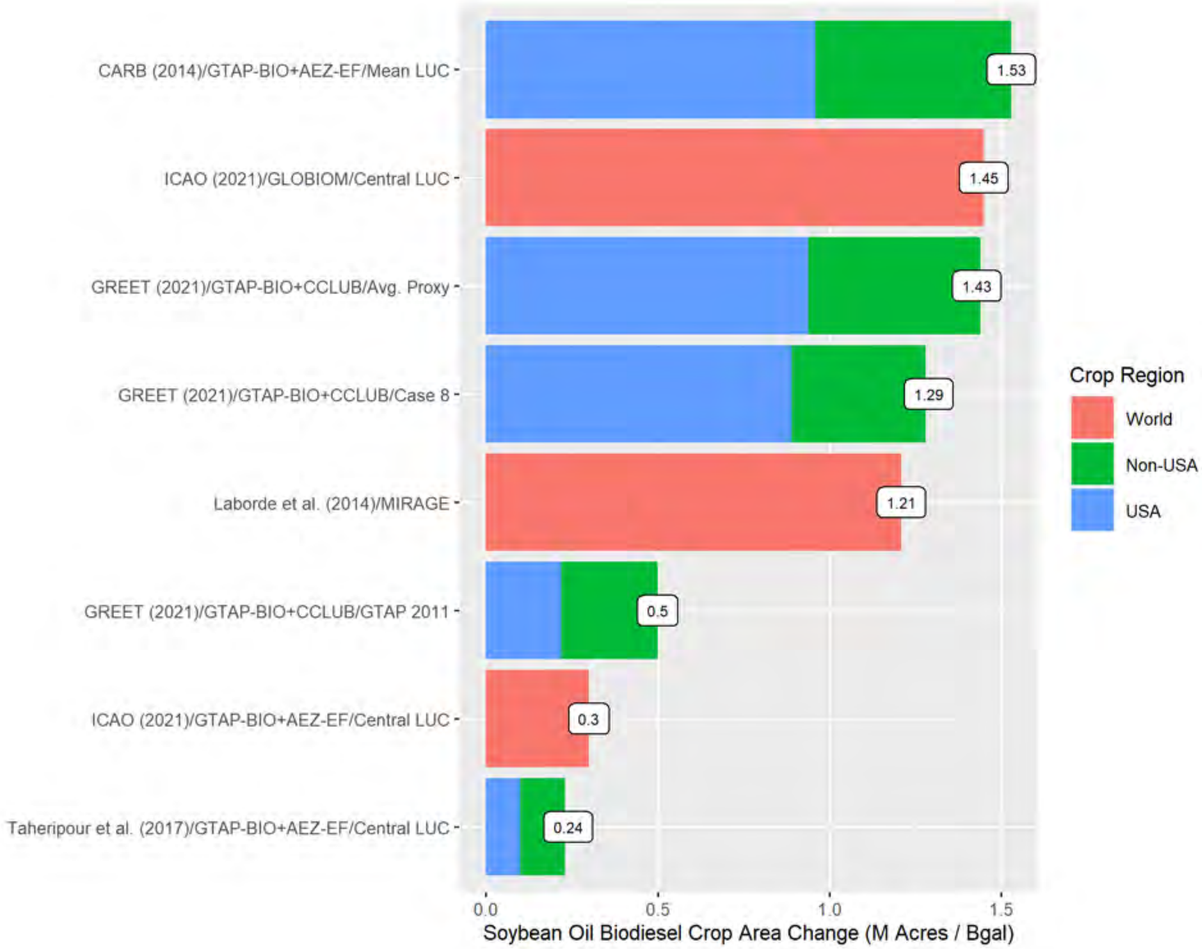
Notes: The name on the y-axis for each bar/estimate includes multiple descriptors separated by "/". In order, these descriptors are the author or other name (e.g., RFS2 rule), the name of the model used to estimate land use change impacts, and a brief descriptor of the scenario modeled. For studies that did not report disaggregated estimates by USA and Non-USA we only report the World total. Scenarios modeled and definitions of cropland differ across studies. ICAO (2021) estimates for corn ethanol to jet fuel were adjusted based on the assumed jet fuel yield.

For corn ethanol, we see relatively wide variation across studies in the amount of cropland expansion estimated per gallon of biofuel production, ranging from approximately 0.2 to 1.5 Mac/Bgal ethanol. The largest estimate comes from the FASOM-FAPRI modeling for the 2010 RFS2 rule. The next largest estimate comes from GCAM-T (Plevin et al. 2022). Estimates from GTAP-BIO straddle the most recent estimate from GLOBIOM. The lowest estimate comes from a 2014 study for the European Commission using the MIRAGE model. Estimates from the same model also show large variations. The estimates from GTAP-BIO range from 0.25 to 0.8 Mac/Bgal. For studies that report cropland area changes by region, there are also large differences in how much of the estimated cropland impacts occur in the U.S. versus other regions. Among these studies, GCAM-T estimates the largest share of cropland impacts in the U.S. (Plevin et al. 2022) and the GTAP-BIO modeling by Taheripour et al. (2017) estimates the lowest share of cropland impacts in the U.S.

The empirical studies reviewed in Austin et al. (2021) provide a point of comparison for the U.S. cropland area estimates in Figure 4.2.2.8-3 which come from economic models. Lark et al. (2022) estimates increased cropland area of 0.9 Mac/Bgal of corn ethanol (95% confidence interval of 0.8 to 1.1). Li et al. (2019) estimates a direct effect of 0.6 Mac/Bgal of corn ethanol capacity (95% confidence range of 0.4 to 0.8), excluding price effects. If we use the Li et al. (2019) elasticity of cropland area to crop price estimated (0.07 +/- 0.02) and assume crop prices increase 1.8% (+/- 0.7%) per Bgal of corn ethanol based on the empirical study by Roberts and Schlenker (2013)[314], we derive an estimate from Li et al. (2019) including crop price effects of 1.0 Mac/Bgal (range of 0.4 to 1.4). This range of 0.4 to 1.4 Mac/Bgal for U.S. cropland encompasses the Lark et al. (2022) estimate and the four highest of the economic model estimates in the figure above. Other estimates from the Austin et al. (2021) review include estimates from a PE model called BEPAM of 0.47 Mac/Bgal (Chen and Khanna 2018),[315] and 0.14 Mac/Bgal (Khanna et al. 2020).[316] Using an unnamed PE model, Bento et al. (2015) estimated 0.33 Mac/Bgal for the period from 2009-2012 and 0.49 Mac/Bgal for 2012-2015. Other estimates reviewed in Austin et al. (2021) either predate the 2010 RFS2 rule analysis or failed to consider price-induced effects. Overall, our review of estimates from PE, CGE, IAM and empirical studies includes a range for the effect of corn ethanol on U.S. cropland spanning from 0.14 to 1.4 Mac/Bgal. There is overlap between empirical and modeled estimates in the range of 0.4 to 1.0 Mac/Bgal, although this includes only two empirical studies. Below we discuss some of the modeling assumptions that influence these cropland area estimates and their implications for land use change GHG estimates.

[314] Roberts, M. J. and W. Schlenker (2013). "Identifying Supply and Demand Elasticities of Agricultural Commodities: Implications for the US Ethanol Mandate." American Economic Review 103(6): 2265-2295.
[315] Chen, X. and M. Khanna (2018). "Effect of corn ethanol production on Conservation Reserve Program acres in the US." Applied Energy 225: 124-134.
[316] Khanna, M., et al. (2020). "Assessing the Additional Carbon Savings with Biofuel." BioEnergy Research 13(4): 1082-1094.

Figure 4.2.2.8-4: Cropland Area Change Estimates by Study for Soy Biodiesel



Notes: The name on the y-axis for each bar/estimate includes multiple descriptors separated by "/". In order, these descriptors are the author or other name (e.g., CARB), the name of the model used to estimate land use change impacts, and in some cases a brief descriptor of the scenario modeled. For studies that did not report disaggregated estimates by USA and Non-USA we only report the World total. Scenarios modeled and definitions of cropland differ across studies. ICAO (2021) estimates for soybean oil to jet fuel were adjusted based on the assumed jet fuel yield relative to biodiesel.

Figure 4.2.2.8-4 summarizes estimated crop area changes associated with soybean oil biodiesel production. The estimates from the 2010 RFS2 rule are excluded from this chart to improve legibility as they project a much larger amount of cropland change (6.6 M Acres/Bgal). As discussed below, the relatively large cropland area impact from FASOM-FAPRI is not accompanied by similarly large land use change GHG estimates due to the way these models estimate other land types to shift in response.[317] There is a group of estimates between 1.2 and 1.5 million acres per billion gallons, including estimates with GLOBIOM, MIRAGE and the GTAP-BIO modeling done with CARB for the CA-LCFS. The lowest group of estimates, 0.2 to 0.5 million acres per billion gallons, all come from the GTAP-BIO model. The most recent

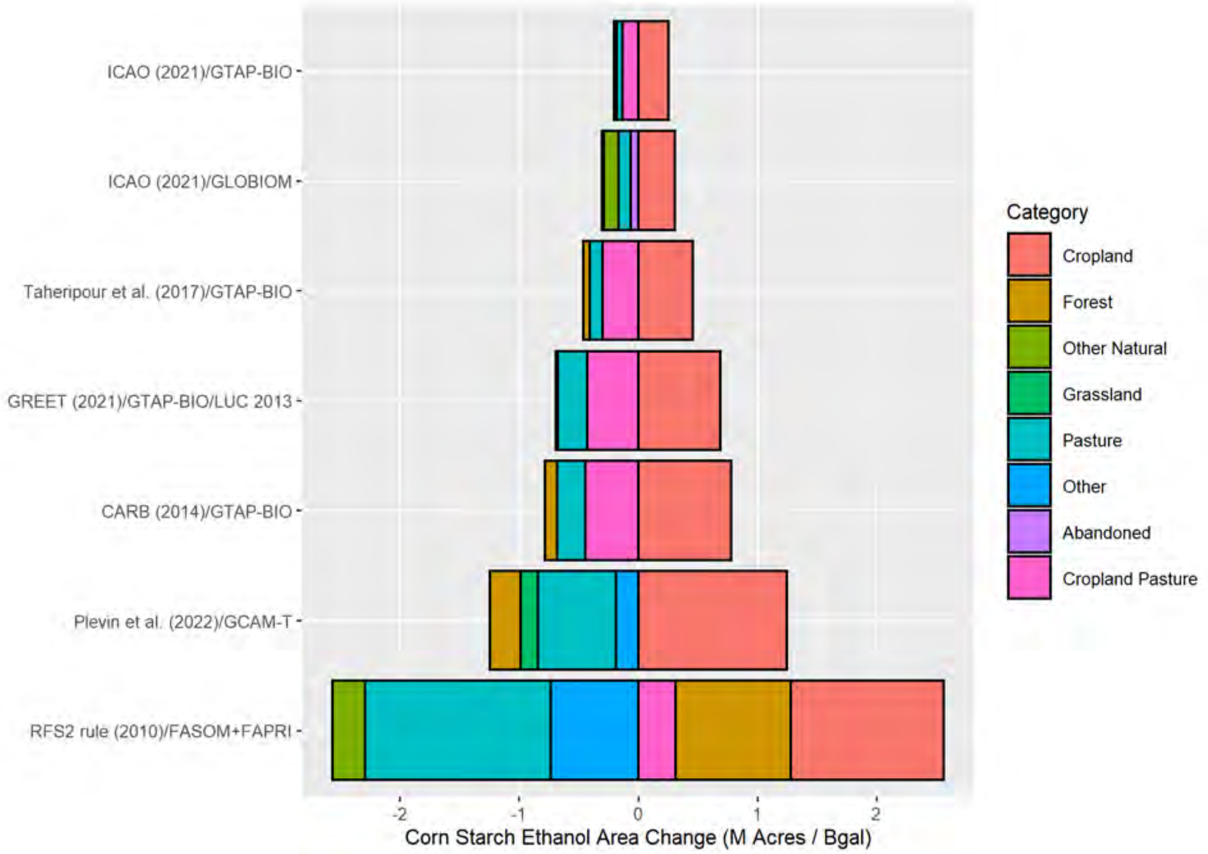
[317] For example, for the U.S. FASOM projected an increase in cropland of 3.5 M acres.Bgal, but the GHG impacts were muted because the cropland increases were accompanied by decreases in idle land (-5.7 M acres/Bgal) and rangeland (-5.4 M acres/Bgal) and increases in forest-pasture land (6.9 M acres/Bgal). For the rest of the world, FAPRI projected a large increase in cropland (3.1 M acres/Bgal) accompanied by a reduction in pasture area (associated with the market-mediated effects of increased soybean meal supplies on livestock producers) and accompanying increases in forest area (0.7 M acres/Bgal) especially in Brazil.

GTAP-BIO estimates are the lowest among the group, at 0.24-0.25 million acres per billion gallons. Between the GTAP-BIO modeling for CARB and the more recent estimates, a number of updates were made to the GTAP-BIO model that lowered the cropland area estimates, including revising the assumptions that determine crop intensification in response to price changes and multi-cropping (Taheripour et al. 2017). Unlike corn ethanol, we did not identify any empirical estimates of cropland area changes attributable to soybean oil biodiesel production. Thus, we do not have any empirical comparisons with the modeled estimates in Figure 3.2.2.8-4. Below we discuss some of the factors that influence these modeled estimates of cropland area impacts and their implications for land use change GHG emissions estimates.

The second broad element that contributes to land use change GHG estimates is the type of land impacted. The next two figures compare area changes in cropland, pasture, forest and other land types across studies for corn ethanol and then soybean oil biodiesel.[318] Similar to the figures above for cropland area impacts, we normalized the estimates per billion gallons of biofuel to facilitate comparison. In some cases, we aggregated or slightly modified the categories of land to facilitate comparison. For example, we aggregated GCAM-T's commercial and non-commercial forest categories and report them as forest. Once again, caution is needed comparing results as we made no other efforts to align scenario design or other factors.

[318] The MIRAGE estimates from Laborde et al. (2014) are also excluded as that study does not report area changes by land type.

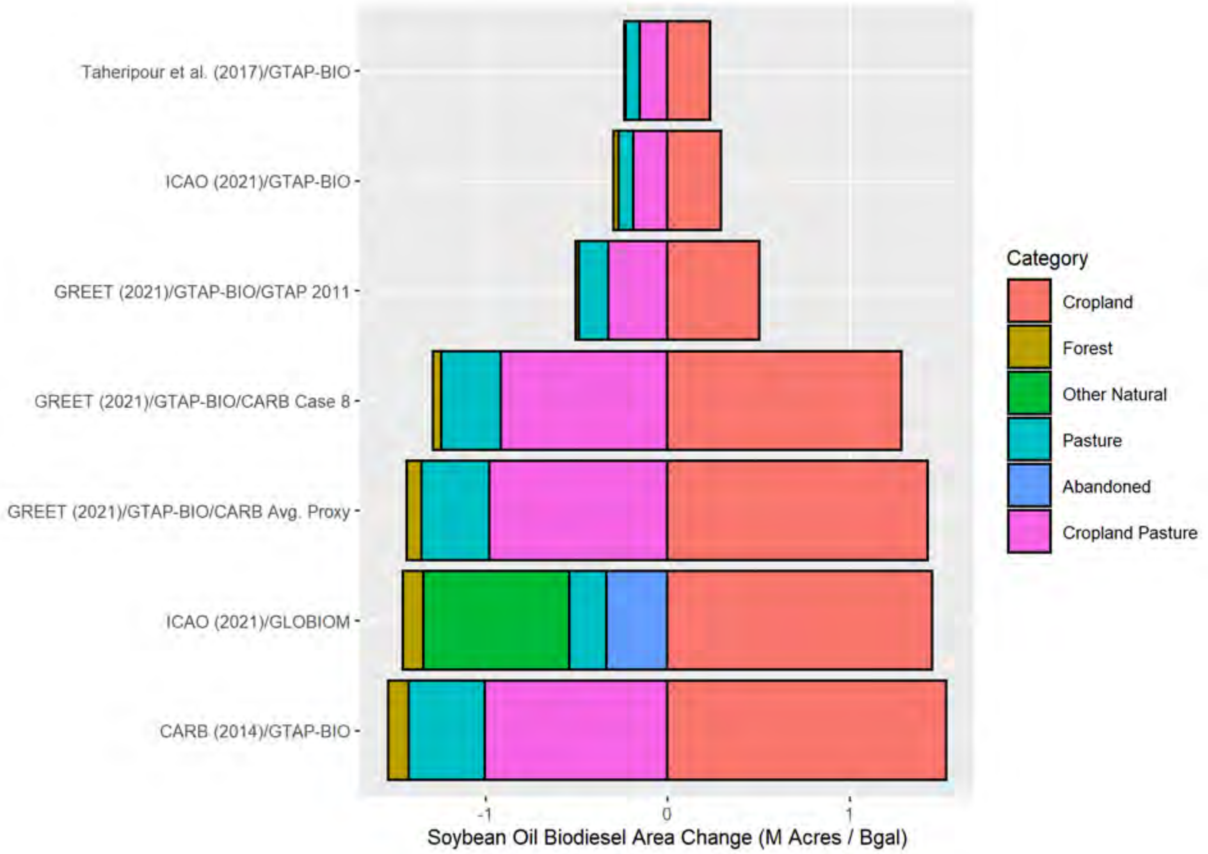
Figure 4.2.2.8-5: Land Use Change Estimates by Study for Corn Ethanol



Notes: The name on the y-axis for each bar/estimate includes multiple descriptors separated by "/". In order, these descriptors are the author or other name (e.g., CARB), the name of the model used to estimate land use change impacts, and in some cases a brief descriptor of the scenario modeled. In some cases, we have aggregated or relabeled land categories to facilitate comparison across estimates. For example, forest pasture in FASOM is reported as forest in this figure. ICAO (2021) estimates for corn ethanol to jet fuel were adjusted based on the assumed jet fuel yield.

All of the estimates in the above figure reported cropland area increases and decreases in other land types in response to additional corn starch ethanol production. However, the types of land displaced by increased cropland differs among the estimates. The estimates with GTAP-BIO have cropland pasture decreasing more than any other land type. As discussed more below, cropland pasture plays an important role in land use change modeling both in terms of how it is represented, and the estimated soil carbon changes associated with its use for crop production. Pasture is modeled separately from cropland pasture, it decreases in area in all of the estimates, and it is the land type that decreases the most in the GCAM-T estimate from Plevin et al. (2022). Most of the estimates include a relatively small amount of forest area decreases, with the GCAM-T estimate reporting the largest decrease. The GCAM-T and GLOBIOM estimates include decreases in other natural land types such as grassland, savannah, and shrubland; the GTAP-BIO estimates do not report decreases in these land types as the model only represents commercially managed land.

Figure 4.2.2.8-6: Land Use Change Estimates by Study for Soybean Oil Biodiesel



Notes: The name on the y-axis for each bar/estimate includes multiple descriptors separated by "/". In order, these descriptors are the author or other name (e.g., RFS2 rule), the name of the model used to estimate land use change impacts, and in some cases a brief descriptor of the scenario modeled. In some cases we have aggregated or relabeled land categories to facilitate comparison across estimates. ICAO (2021) estimates for soybean oil to jet fuel were adjusted based on the assumed jet fuel yield relative to biodiesel.

The land use change estimates for soy biodiesel in Figure 4.2.2.8-6 come from GTAP-BIO and GLOBIOM. There are several estimates from GTAP-BIO as the GREET model gives users multiple choices of which GTAP-BIO estimates to use when estimating soybean oil biodiesel land use change GHG emissions. The GTAP-BIO estimates conducted for the CA-LCFS have much larger areas of cropland expansion than the other more recent GTAP-BIO estimates. However, the pattern of land use change is similar in all the GTAP-BIO estimates, with cropland pasture decreasing the most followed by pasture and managed forest. In contrast, the GLOBIOM estimates have other natural land (e.g., grassland, savannah, shrubland) as the largest category of decline. GLOBIOM does not include cropland pasture as a category, but it includes "abandoned" land that GTAP-BIO does not represent. In all the estimates in this figure, forest declines by a relatively small amount, with the most recent GTAP-BIO estimates by Taheripour et al. (2017) and ICAO (2021) showing very small areas of forest loss. We note once again that caution is needed interpreting these results as the figure above aggregates land categories for comparison across models to facilitate comparison. Land categories are defined and modeled differently across the models.

The RFS2 (2010) estimates are not included in Figure 4.2.2.8-6 because they are different in their size and pattern and would reduce legibility. In the RFS2 (2010) estimates, cropland area increases 6.6 M acres per Bgal, and pasture declines by about the same amount. Although RFS2 (2010) estimates much larger cropland area increases than the other studies, the associated land use change GHG emissions are more similar in size due to the pattern of other land use changes. For example, the RFS2 (2010) results include an increase in forest pasture area in the U.S. (6.9 M acres per Bgal) and an increase in forest area (0.7 M acres per Bgal) outside of the U.S. associated with a reduction in pasture area particular in Brazil. These forest area increases offset the GHG impacts of expanding cropland in the RFS2 (2010) analysis.

The third broad element that contributes to land use change GHG estimates are the emissions factors and formulas that are used to convert areas of land use change to GHG emissions. These emissions factors are developed from data on biomass (above and below ground) and soil carbon for multiple land categories for regions. We do not have sufficient information at this time to summarize these emission factors in a figure the directly and meaningfully compares these inputs assumptions. However, we can make some observations based on our review of the available studies.

At the most basic level, we can clearly say that the land use change emissions factors are an influential part of biofuel GHG modeling. For the GTAP-BIO studies reviewed, two different tools are used to estimate land use change GHG emissions based on the estimated land area changes: the AEZ-EF model[319] and the CCLUB model.[320] These tools essentially apply different emission factors to the land area change outputs from GTAP-BIO. Based on cases where both tools have been applied to the same GTAP-BIO estimates we can see that they have a relatively large effect on the resulting land use change GHG estimates. Our literature review includes 12 corn ethanol land use change GHG estimates from GTAP-BIO+AEZ-EF ranging from 12 to 37 gCO2e/MJ, and 9 estimates from GTAP-BIO+AEZ-EF ranging from -1 to 9 gCO2e/MJ. Chen et al. (2018) applied both CCLUB and AEZ-EF to four sets of GTAP-BIO results. Using AEZ-EF the land use change GHG emissions estimates are 22, 26, 17 and 18 gCO2e/MJ. Applying CCLUB to the same GTAP-BIO results gives land use change GHG estimates of 8, 10, 4 and 6. In these cases, using CCLUB reduced the estimates by 12-16 gCO2e/MJ, or about 67% on average, relative to using AEZ-EF. The data and assumptions within each of these tools are also important. Plevin et al. (2015) conducted a Monte Carlo simulation and found that varying key assumptions within AEZ-EF could increase or decrease corn ethanol and soy biodiesel land use change GHG estimates by about 20% in either direction (95% confidence interval).[321]

In this section (Chapter 4.2.2), we have reviewed available models for biofuel GHG analysis, the main characteristics of these models, and GHG estimates they have produced for corn ethanol and soybean oil biodiesel. Based on this review we have found that there are four different types of models (PE, CGE, IAM, LCI) with fundamentally different structures. These models have large differences in the sectors and GHG emission they cover, the way they

[319] Plevin, R., et al. (2014). Agro ecological Zone Emission Factor (AEZ EF) Model (v52): A model of greenhouse gas emissions from land use change for use with AEZ based economic models.
[320] Kwon, H., et al. (2020). Carbon Calculator for Land Use and Land Management Change from Biofuels Production (CCLUB).
[321] Based on visual inspection of Figure S11.

represent land and time, and many other differences. Our review shows that land use change is an important and uncertain aspect of crop-based biofuel GHG modeling. There continues to be a wide range of available estimates of land use change GHG emission associated with corn ethanol, soybean oil biodiesel and soybean oil renewable diesel. We have made some observations about key factors that are contributing to the differences in these estimates, but we do not have a systematic quantification of which factors are most important across all of the models. Furthermore, in many areas where the models disagree in their assumptions (e.g., crop intensification, soil carbon effects, livestock market effects, fuel market effects) there is disagreement or a lack of information on the most scientifically justifiable values to use for this type of modeling.

A major challenge in our review is that available estimates come from studies that evaluated different scenarios and reported results in different formats and units. In order to provide additional information to inform the final rule, we intend to conduct a model comparison exercise that will address some of these challenges. For the model comparison exercise, we will use a common set of scenarios and align model outputs to the extent possible. We will also attempt to align input assumptions and time permitting conduct sensitivity analyses. We believe this will give us a much greater level of information about the best available biofuel GHG modeling to inform the final rule. Given the complexity of crop-based biofuel GHG modeling, it is likely the model comparison exercise will raise further important questions. While this exercise will focus on comparing economic and lifecycle simulation models, we will also continue to review relevant empirical studies (see Chapter 4.2.2.6) and other science to inform and compare with the modeling.

4.2.3 Range of LCA Estimates by Fuel Pathway for Illustrative Scenario

As discussed at the beginning of Chapter 4.2, our assessment of the climate change impacts of the proposed rule relies on an extrapolation of lifecycle analyses (LCA) of GHG emissions. As we did in the 2020-2022 RVO rulemaking, this approach involves multiplying LCA emissions of individual fuels by the change in the candidate volumes of that fuel to quantify the GHG impacts. We repeat this process for each fuel (e.g., corn ethanol, soybean biodiesel, landfill biogas CNG) to estimate the overall GHG impacts of the candidate volumes. In the 2020-2022 RVO rulemaking, we applied the LCA estimates that we developed in the March 2010 RFS2 rule (75 FR 14670) and in subsequent agency actions. In this rulemaking, we are updating our approach to use a range of LCA emissions estimates that are in the literature. Instead of providing one estimate of the GHG impacts of each candidate volume, we provide a high and low estimate of the potential GHG impacts, which is inclusive of the values we estimated in the 2010 RFS final rule and subsequent agency actions. We then use this range of values for considering the GHG impacts of the candidate renewable fuel volumes that change relative to the No RFS baseline.

In this chapter we present the range of LCA estimates contained within the published literature for each fuel pathway.[322] We conducted a high-level review of relevant literature for

[322] Details on the sourcing of each estimate from our literature compilation are available in a memo to the docket for this proposed rule titled "Notes on Literature Review of Transportation Fuel Greenhouse Gas (GHG) Lifecycle Analysis (LCA)."

the biofuel pathways (combination of biofuel type, feedstock, and production process) that would be most likely to satisfy the candidate renewable fuel volumes. Our literature review was broad and includes studies that estimate the lifecycle GHG emissions associated with the relevant biofuel pathways and the petroleum-based fuels they replace.

We believe the presentation of ranges based on literature review provides important information for readers about the variety of estimates in the scientific literature and illustrates the level of uncertainty in these estimates. In Chapter 4.2.4 we describe how the LCA estimates for each pathway are used to estimate a potential range of GHG impacts associated with the candidate volumes relative to the No RFS baseline for an illustrative 30-year scenario. The chapter that follows (Chapter 4.2.5) describes how the GHG estimates are used to estimate the potential monetized benefits of the GHG impacts associated with the candidate volumes relative to the No RFS baseline for an illustrative 30-year scenario.

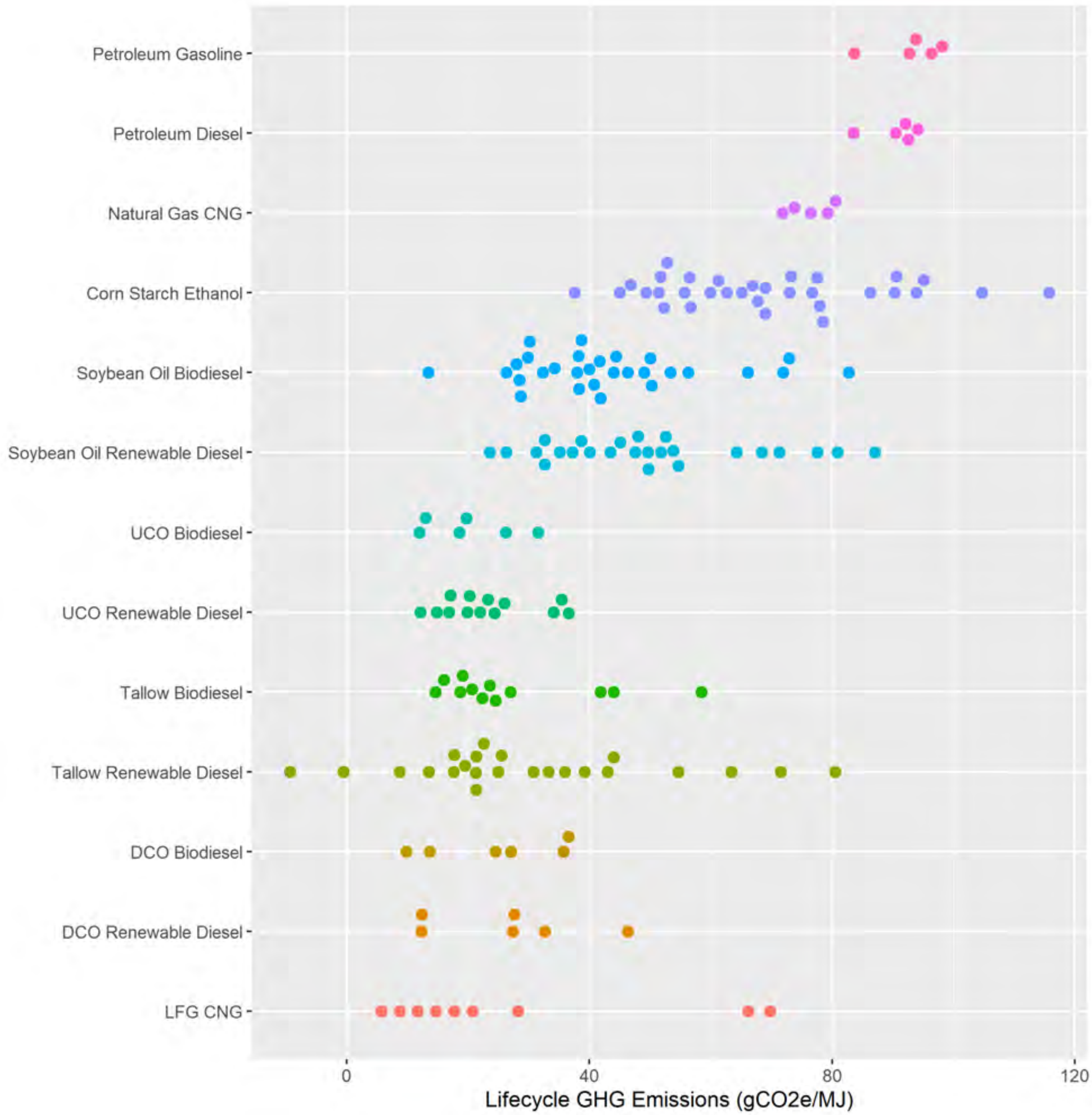
We reviewed relevant literature and identified a range of lifecycle GHG estimates for the biofuel pathways with increased consumption in the candidate volumes scenario relative to the No RFS baseline scenario (see Chapter 3 for description of these scenarios). We also identified a range of lifecycle GHG estimates for the conventional fossil-based fuels that the biofuels are likely to replace. Our compilation includes journal articles, major reports and studies that inform biofuel-related policies. We include estimates from the March 2010 RFS2 rule and studies published after the March 2010 RFS2 rule, as that rule considered the available science at the time. We do not claim that our compilation is fully comprehensive, but we attempted to include relevant studies published before Spring 2022. In cases where there were multiple studies that include updates to the same general model and approach, we included only the most recent study. However, we include a subset of older estimates that are still used for major regulatory programs or that continue to be widely cited for other reasons. We focused our compilation on estimates of the average type of each fuel produced in the United States (e.g., natural gas-fired corn ethanol plants), though we include a discussion at the end of this section (Chapter 4.2.3.12) about how advanced technologies could lead to more significant emissions reductions in the future. In this section (Chapter 4.2.3) we focus on studies that estimate full lifecycle (or “well-to-wheel”) GHG emissions. For crop-based biofuels, there are many studies that only estimate land use change GHG emissions; these studies are discussed in Chapter 4.2.2.8.

Many of the studies we compiled include sensitivity analysis, where many parameters are varied to produce a large number of estimates. In these cases, we include representative high and low estimates. For example, when studies report a 95% confidence interval, we use only the central estimate (usually the default, mean or median estimate) and the estimates at the top and bottom of the confidence interval. This approach simplifies the presentation of results relative to including every estimate in between. We believe this approach is appropriate given that the primary purpose of our literature review is to produce a range (high and low estimate) for each pathway. We intentionally do not calculate or present any statistics (e.g., mean, median) derived from the estimates included in our literature review, as we do not believe such statistics would be meaningful or appropriate based on the design of our literature compilation. As discussed below, in some cases we remove outlier estimates in order to form a range that we believe is representative of the likely upper and lower GHG impacts of each biofuel pathway on a national average basis. We believe this is appropriate as the purpose of our review is to consider national average fuel production, not regional variation or unique conditions that are unlikely to represent the impacts of the candidate volumes relative to the No RFS baseline.

Figure 4.2.3-1 provides an overview of the lifecycle GHG estimates in our literature compilation. This chart only includes studies that report the full well-to-wheel emissions associated with each pathway. All of the pathways in our compilation are included with the exception of compressed natural gas (CNG) produced from manure digester biogas, as some of the estimates for this pathway (e.g., 533 gCO_2e/MJ) are so low that they skew the rest of the chart. All of the estimates in this chart report lifecycle GHG estimates as carbon dioxide-equivalent (CO_2e) emissions per megajoule (MJ) of fuel consumed. All CO_2e estimates are based on 100-year global warming potential (GWP) from the IPCC.[323] This allows us to compare all of the estimates on a gCO_2e/MJ of fuel basis. However, we stress that many of the studies in this chart do not align in terms of their scope, system boundaries, time horizon, year of analysis, or other factors. Therefore, the estimates reported in this figure give us a sense for the range of estimates for each pathway, but we must exercise caution when comparing estimates and drawing conclusions.

[323] The reviewed estimates use GWP values from the IPCC Second Assessment Report (SAR), Fourth Assessment Report (AR4) or Fifth Assessment Report (AR5). We did not attempt to harmonize GWP assumptions across studies as many studies only reported CO_2e results and not emissions by gas.

Figure 4.2.3-1 Lifecycle GHG Emissions Estimates by Pathway



Notes: LFG = landfill gas, CNG = compressed natural gas, DCO = distillers corn oil, UCO = used cooking oil. Other than reporting all estimates in gCO2/MJ no effort has been made to harmonize estimates. Corn starch ethanol and LFG electricity are reported following gasoline as these pathways are more likely to displace gasoline than diesel. The other pathways are reported after petroleum diesel as they are more likely to displace diesel.

Figure 4.2.3-1 shows that, in general, the CI estimates for biofuel pathways tend to be lower than those for petroleum gasoline, diesel, and natural gas. GHG emissions for biofuels produced from corn and soybeans tend to be higher than those produced from used cooking oil, tallow or landfill gas. However, there are some high estimates for the tallow-based pathways when animal production emissions are allocated to the tallow.[324] Most lifecycle GHG estimates are presented as grams of CO_2e emissions per megajoule (gCO_2e/MJ) of additional renewable fuel consumed. These estimates are often called the "carbon intensity" (CI) of the fuel or the well-to-wheel (WTW) GHG emissions associated with the fuel. Below, we summarize the results of this literature review for each of the relevant biofuel pathways. For better legibility we provide a list of references at the end of this section rather than using footnotes.

4.2.3.1 Length of Time Period for Analysis

The time period over which land use change emissions are quantified influences the GHG estimates for crop-based renewable fuels. If increased demand for biofuels leads to land conversion, an initial pulse of emissions would likely be released in the first year, and there would also be foregone sequestration over time based on the carbon that would have been sequestered through plant growth absent the biofuel induced land use change.[325] Over time, if the biofuel production continues, the GHG benefits of displacing fossil fuels may eventually "pay back" the initial increase in GHG emissions from the first year. Thus, when increased biofuel production is expected to result in land conversion, longer analytical time horizons should result in greater GHG reduction estimates than shorter time horizons, provided other assumptions are met. The question of the appropriate time horizon over which to evaluate the net emissions can depend on many factors (e.g., the lifetime of the project, the goals of the program, future projections of renewable fuels use). After considering public comments and the input of an expert peer review panel, in the March 2010 RFS2 rule (75 FR 14670), EPA determined that our lifecycle greenhouse gas emissions analysis for renewable fuels would quantify the GHG impacts over a 30-year period. One of the reasons for using 30 years as a reasonable time horizon for analysis is that biofuel production facilities last multiple decades after they are constructed.

EPA continues to believe that 30 years is an appropriate timeframe for evaluating the lifecycle GHG emissions of renewable fuels for purposes of determining which fuel pathways satisfy the statutory GHG reduction thresholds for qualification under each of the four categories of renewable fuel. With respect to estimating the GHG impacts of this rulemaking specifically, the CAA gives us discretion to choose the appropriate analytical time period. On one hand, this Set rule is part of the broader RFS program that has been in existence since 2005, so there have been long-term market impacts of standards that were set in past individual years. Furthermore, once the cost of clearing and converting land is incurred, and given that global cropland areas are expected to continue expanding, it seems likely that land will continue to be used for agricultural

[324] Seber, G., et al. (2014). "Environmental and economic assessment of producing hydroprocessed jet and diesel fuel from waste oils and tallow." Biomass and Bioenergy 67: 108-118.

[325] The initial pulse of emissions may take longer than one year depending on the fate of the biomass cleared from the land. For example, if the biomass is burned, the emissions will indeed occur in the first year. If it is left on the ground or landfilled the emissions associated with biomass decay may occur over several years. The lifecycle GHG analyses for the March 2010 RFS2 rule allocated international biomass clearing emissions to the first year. We said at the time that this was a simplification that was appropriate for the purposes of the analysis. EPA (2010). Renewable fuel standard program (RFS2) regulatory impact analysis. Washington, DC, US Environmental Protection Agency Office of Transportation Air Quality. EPA-420-R-10-006. Section 2.4.4.2.6.8.

purposes in the future for a period of time.[326] On the other hand, the volumes in this rule do not extend beyond 2025 and making projections about future policies, volume requirements, and renewable fuel use are inherently uncertain. However, since we have chosen to use LCA GHG estimates as the proxy for evaluating the climate change impacts of this rule, it is consistent to use the same 30-year analytical time period for the purposes of estimating the GHG impacts of this rule. Therefore, in the illustrative GHG scenario presented in Chapter 4.2.4, the analyses make the assumption that, in each of the 29 years following the introduction of the final standards, aggregate renewable fuel consumption (and consequent increased demand for agricultural goods) for each category exceeded baseline levels by the same volume as required by this rule.

In order to estimate the monetized social cost or benefit of the candidate biofuel volumes in Chapter 4.2.5, annual streams of emissions are required. In the literature review described below, all the studies that include land use change annualize these emissions over a time period of 20 to 30 years. However, many of these studies do not report annual streams of emissions. Rather, they report average annualized emissions over a 20–30-year period, and it is not possible to produce a credible annual stream of emissions from these estimates based on the information provided. Thus, to develop ranges for purposes of estimating the monetized GHG impacts we must rely on the high and low estimates that report annual streams of emissions. This is discussed further below for each of the crop-based pathways that involve land use change emissions.

4.2.3.2 Petroleum Gasoline and Diesel

The net GHG impacts of the production and use of biofuels depends on the GHG emissions associated with the conventional fuels they displace. For the purposes of conducting the lifecycle GHG emissions analysis and determining which biofuels meet the GHG requirements, CAA Section 211(o)(1)(C) defines baseline lifecycle greenhouse gas emissions as “the average lifecycle greenhouse gas emissions, as determined by the Administrator, after notice and opportunity for comment, for gasoline or diesel (whichever is being replaced by the renewable fuel) sold or distributed as transportation fuel in 2005.” As the baseline lifecycle GHG emissions are used for a specific purpose under the RFS program, we are not required to use it for evaluating the GHG impacts of this proposed rule. Given that this rule involves biofuel production and use in 2022 and beyond, we believe it is appropriate to consider LCA estimates for gasoline and diesel production that occurred more recently than 2005. Furthermore, given that we are developing a range LCA estimates from literature for biofuels, we believe a similar

[326] Globally cropland areas have been expanding, suggesting that once land is put into cultivation it is likely to stay under production. Potapov et al. (2022) report that cropland area increased by 9% globally from 2003 to 2019. Furthermore, integrated assessment modeling of future scenarios suggests that global cropland areas, including bioenergy cropland, are expected to increase through 2100. See for example the figure on page 32 of IPCC (2019). Potapov, P., Turubanova, S., Hansen, M.C. et al. Global maps of cropland extent and change show accelerated cropland expansion in the twenty-first century. Nat Food 3, 19–28 (2022). https://doi.org/10.1038/s43016-021-00429-z; IPCC, 2019: Summary for Policymakers. In: Climate Change and Land: an IPCC special report on climate change, desertification, land degradation, sustainable land management, food security, and greenhouse gas fluxes in terrestrial ecosystems [P.R. Shukla, J. Skea, E. Calvo Buendia, V. Masson-Delmotte, H.- O. Pörtner, D. C. Roberts, P. Zhai, R. Slade, S. Connors, R. van Diemen, M. Ferrat, E. Haughey, S. Luz, S. Neogi, M. Pathak, J. Petzold, J. Portugal Pereira, P. Vyas, E. Huntley, K. Kissick, M. Belkacemi, J. Malley, (eds.)]. In press.

approach is appropriate for the conventional fuels they replace. Thus, our literature review for this proposed rule includes studies that estimate the lifecycle GHG emissions associated with petroleum-based gasoline and diesel.

For the March 2010 RFS2 rule, EPA estimated the lifecycle GHG emissions associated with average 2005 gasoline and diesel. Our review includes the 2010 RFS2 rule and studies that estimated lifecycle GHG emissions for average U.S. gasoline and diesel that were published following the 2010 RFS2 rule. Studies that estimate only the GHG emissions associated with crude oil extraction[327] or refining[328] are excluded from our review, as we require estimates of the full lifecycle GHG emissions. It is not appropriate to simply sum crude oil extraction estimates with refining estimates as the properties of the crude oil from different wells significantly effects the refining emissions.

We recognize that the CI of the average gallon of gasoline and diesel replaced by biofuels may be different than the CI of the marginal gallons replaced. While there is one study that suggests the CI of the marginal oil supplies may be higher than average oil supplies,[329] we did not identify any studies that estimate the full lifecycle GHG emissions of the marginal volumes, including oil extraction, oil transport, refining, fuel distribution and use.

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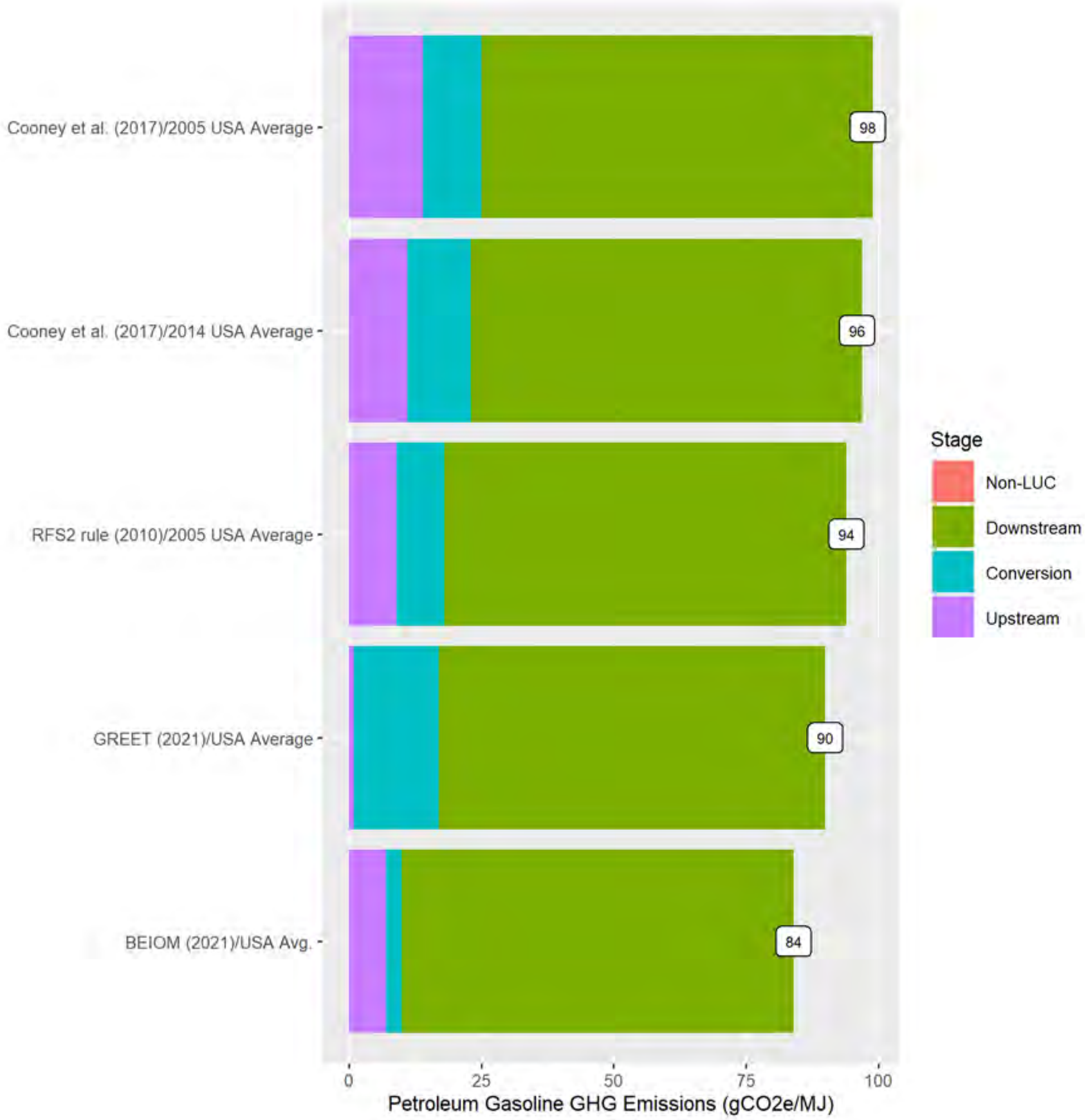
[327] See for example, Masnadi, M. S., et al. (2018). "Global carbon intensity of crude oil production." Science 361(6405): 851-853.

[328] See for example, Jing, L., et al. (2020). "Carbon intensity of global crude oil refining and mitigation potential." Nature Climate Change 10(6): 526-532.

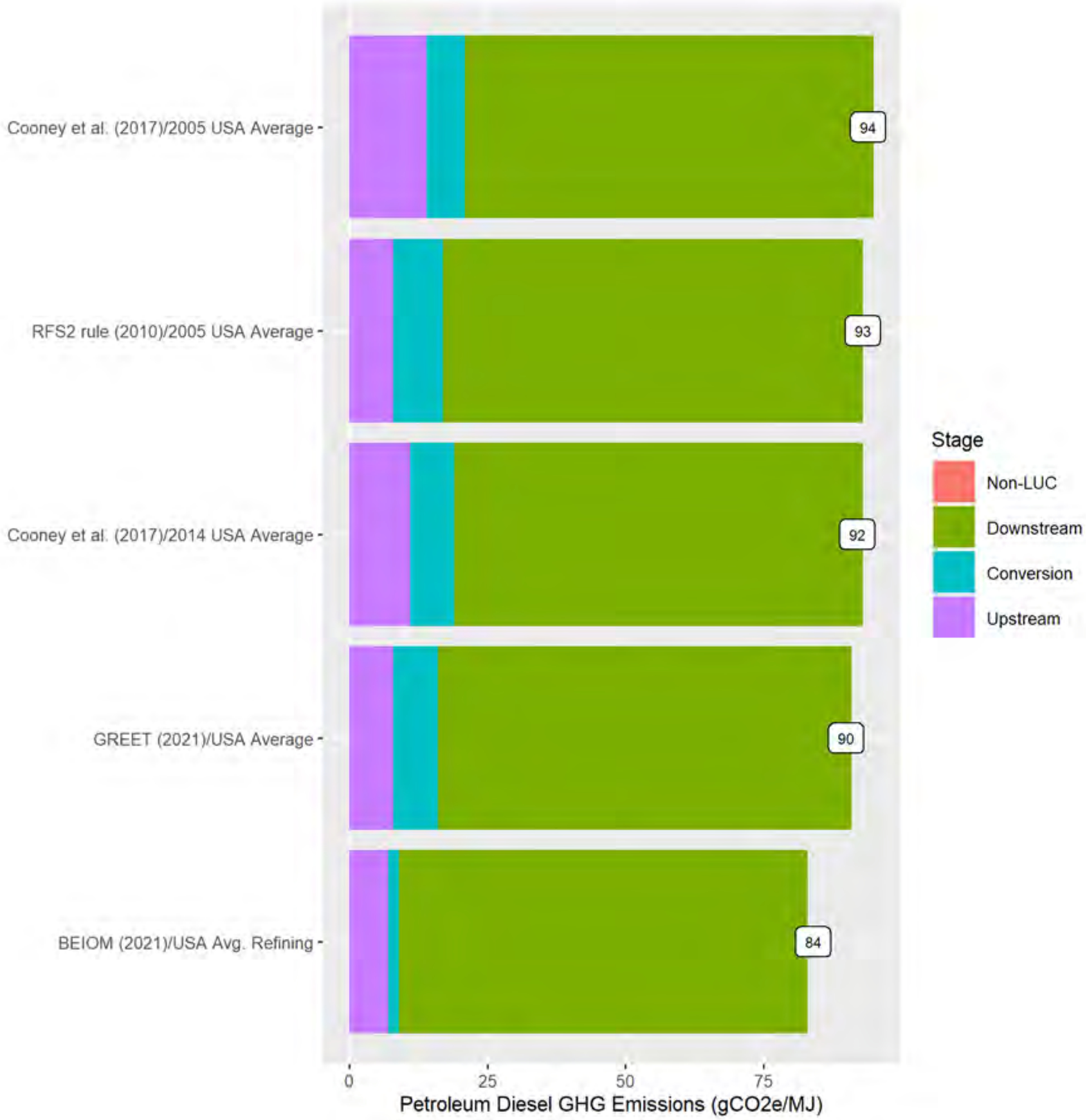
[329] Masnadi, M. S., et al. (2021). "Carbon implications of marginal oils from market-derived demand shocks." Nature 599(7883): 80-84.

Figure 4.2.3.2-1: Petroleum Gasoline Lifecycle GHG Estimates



Notes: The name on the y-axis for each bar/estimate includes multiple descriptors separated by "/". In order, these descriptors are the author or other name (e.g., RFS2 rule) and a brief descriptor of the scenario modeled. The Upstream stage includes all of the emissions associated with extracting, handling and delivering crude oil to the refinery gate. The Conversion stage includes emissions associated with refining. The Downstream stage includes emissions associated with gasoline distribution and tailpipe combustion emissions. The gasoline baseline estimate in the March 2010 RFS2 rule used SAR GWP values. All values in this chart use 100-year AR5 GWP values.

Figure 4.2.3.2-2: Petroleum Diesel Lifecycle GHG Estimates



Notes: The name on the y-axis for each bar/estimate includes multiple descriptors separated by "/". In order, these descriptors are the author or other name (e.g., RFS2 rule) and a brief descriptor of the scenario modeled. The Upstream stage includes all of the emissions associated with extracting, handling and delivering crude oil to the refinery gate. The Conversion stage includes emissions associated with refining. The Downstream stage includes emissions associated with diesel distribution and tailpipe combustion emissions. The diesel baseline estimate in the March 2010 RFS2 rule used SAR GWP values, but all the values in this chart use 100-year AR5 GWP values.

The 2010 RFS2 estimates were largely based on a study by the National Energy Technology Laboratory (NETL).[330] A team of NETL researchers published new estimates of the lifecycle GHG emissions associated with 2005 and 2014 average U.S. gasoline and diesel (Cooney et al. 2017). For 2005 average diesel the Cooney et al. (2017) estimates are very similar to our estimates for the 2010 RFS2 rule. For 2005 average gasoline the Cooney et al. (2017)

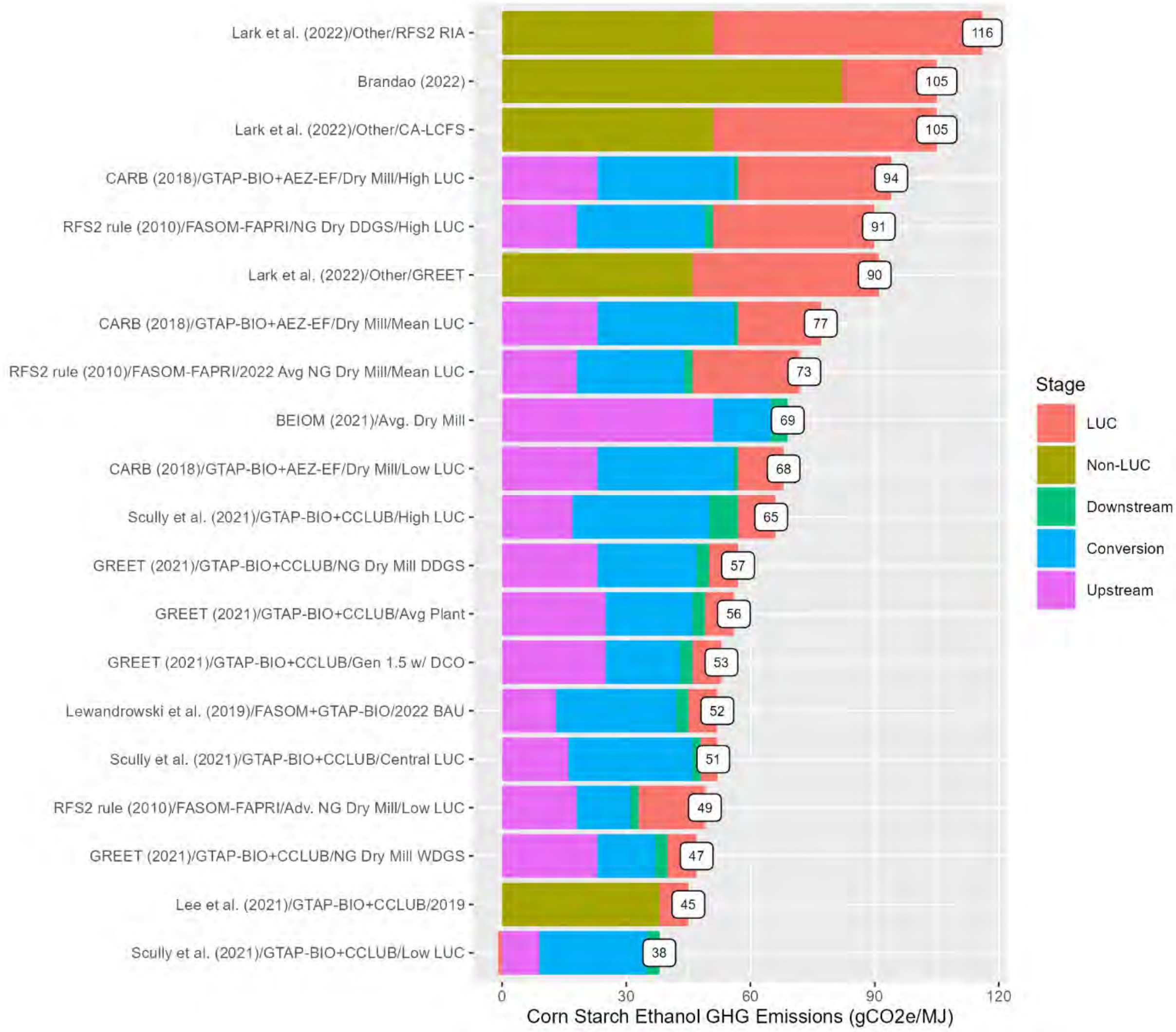
[330] U.S. EPA, (2010). 2005 Petroleum Baseline Lifecycle GHG (Greenhouse Gas) Calculations. U.S. Environmental Protection Agency, EPA-HQ-OAR-2005-0161-3151. Washington DC, January. Available at https://www.regulations.gov/document/EPA-HQ-OAR-2005-0161-3151

estimates are higher by approximately 4 gCO2e/MJ. The Cooney et al. (2017) estimates for 2005 average gasoline and diesel values represent the high end of the range used in our illustrative GHG impacts assessment. The GREET-2021 model estimates lifecycle GHG emissions for average U.S. gasoline and diesel. The GREET estimates for average gasoline and diesel are lower than the estimates from RFS2 rule (2010) and Cooney et al. (2014) but all of these estimates are all within 5 gCO_2e/MJ. The figures above also report results from a study with the BEIOM model (Avelino et al. 2021), an “environmentally extended input-output model.” The BEIOM estimates are significantly lower than those from the other studies. BEIOM’s methodology differs significantly from the other studies in our review and is limited in geographic scope to the United States, which may explain its lower estimates for the carbon intensity of gasoline and diesel. Based on our review of published estimates, we use a range of 84 to 98 gCO2e/MJ for gasoline and for diesel we use a range of 84 to 94 gCO2e/MJ.

4.2.3.3 Corn Starch Ethanol

More studies have been published on the GHG emissions associated with corn starch ethanol than any of the other biofuel pathways considered for this rule. Our literature review includes 9 studies that estimate the lifecycle GHG emissions associated with corn ethanol. Many of these studies include multiple emissions estimates based on different assumptions about the energy efficiency of dry mill ethanol production, co-products and other factors. Some of these studies report a large number of estimates. The figure below includes 19 estimates from these studies that are representative of the range of results that each of them reports.

Figure 4.2.3.3-1: Corn Starch Ethanol Lifecycle Greenhouse Gas Estimates



Notes: The name on the y-axis for each bar/estimate includes multiple descriptors separated by "/". In order, these descriptors are the author or other name (e.g., RFS2 rule) and year of the study; the model used to estimate the LUC emissions; the type of natural gas-fired dry mill used for ethanol production (e.g., 2022 Avg. NG Dry Mill); the LUC estimate case (e.g., Low LUC); and the non-LUC estimate case (e.g., Low CI). The Upstream stage includes all of the emissions associated with corn production and transport upstream of the ethanol production facility. The Conversion stage includes emission associated with fuel production at the ethanol production facility. The Downstream stage includes emissions associated with ethanol transport and non-CO_2 combustion emissions. The LUC stage includes emissions from induced land use changes. For studies that do not report disaggregated results, results are reported as LUC and Non-LUC emissions.

We include estimates for different natural gas-fired dry mill configurations from RFS2 (2010) and GREET-2021 (see Chapter 4.2.2 for more information on the 2010 RFS2 rule modeling and GREET). We include the high, low and mean land use change GHG estimates from RFS2 (2010). The CARB (2018) estimates are based on the default assumptions in the most recent version of the CA-GREET model (version 3.0), a version of GREET developed by CARB for the CA-LCFS. We include a range of land use change emissions for CARB (2018) based on the CARB (2014) report describing the indirect land use change modeling that continues to be used for CA-LCFS implementation. Lewandrowski et al. (2019) is a study that attempts to update the RFS2 (2010) estimates based on more recent data and swaps in land use change estimates from GTAP-BIO. Lee et al. (2021) uses GREET to estimate U.S. corn ethanol carbon intensity from 2005 to 2019. We include the estimate for 2019 and add the default land use change estimate from GREET. The lowest estimate is from Scully et al. (2021), a review paper that developed a range of LCA estimates by combining elements of prior studies. The highest estimates are from Lark et al. (2022), a study that modeled historical U.S. land use change GHG emissions attributable to corn ethanol and added these estimates to the LCA estimates from RFS (2010), CARB (2018) and GREET.[331] We also include the estimate from BEIOM (2021) which uses economic input-output methodology (see Chapter 4.2.2.6 for more information). Finally, we include the estimate from Brandao (2022), a consequential lifecycle analysis of the GHG emissions associated with ramping up ethanol production to 15 billion gallons from 1999-2018.

Among the estimates in the above figure, upstream emissions range from 9 to 51 gCO2e/MJ. These include emissions associated with feedstock production and transport, including non-LUC market-mediated impacts in the agricultural sector. BEIOM reports the highest upstream emissions, with the next highest estimate being 25 gCO2e/MJ from GREET (2021). The lowest estimate comes from Scully et al. (2021), which includes a relatively large credit (-13.5 gCO2e/MJ) for DGS displacing other sources of livestock feed.

We include estimates for ethanol produced at a U.S. dry mill facility using natural gas and electricity for energy,[332] as dry mills produce over 90% of U.S. fuel ethanol and natural gas and electricity account for almost all of the energy use at these facilities.[333] Among the studies in Figure 4.2.3.2-1, conversion emissions range from 13 to 33 gCO2e/MJ.[334] The highest estimates are from CARB (2018) based on the default assumptions used in the CA-GREET3.0 model. The GREET-2021 estimate for "industrial average dry mill corn ethanol production is 21 gCO2e/MJ, and the RFS2 (2010) estimate for a projected 2022 natural gas dry mill facility is 26 gCO2e/MJ. The lowest GHG estimate of 13 gCO2e/MJ for the fuel production stage comes from the most advanced natural gas-fired dry mill facility evaluated in the 2010 RFS2 rule. This advanced facility includes wet DGS, corn oil fractionation, combined heat and power (CHP) and membrane separation technologies.[335]

The largest source of variation between estimates are the land use change emissions, ranging from -1 to 65 gCO2e/MJ in Figure 4.2.3.3-1. The highest land use change estimates are from Lark et al. (2021), which produced new estimates of U.S. land use change attributable to corn ethanol and added the U.S. emission to non-US land use change estimates from RFS2

[331] Lark et al. caveat that incorporating their U.S. land use change emissions into other fuel program estimates is only a partial analysis, and that to accurately assess the carbon intensity of corn ethanol, a full reanalysis is needed to ensure consistent treatment and systems boundaries.
[332] In accordance with CAA 211(o)(2)(A)(i) renewable fuel production from facilities that commenced construction prior to December 19. 2007, are exempt from the 20% GHG reduction requirement to qualify as renewable fuel under the RFS program. Our review in this section focuses on average dry mill corn ethanol production in the U.S. regardless of facility status pursuant to this "grandfathering" exemption.
[333] Lee, U., et al. (2021). "Retrospective analysis of the US corn ethanol industry for 2005–2019: implications for greenhouse gas emission reductions." Biofuels, Bioproducts and Biorefining
[334] This excludes the studies that do not report disaggregated non-LUC emissions.
[335] Including this facility in our review also allows us to include a wider range of RFS2 (2010) estimates which is beneficial for the 30-year illustrative scenario as the RFS2 (2010) estimates are the only ones that report a differentiated 30-year stream of annual emissions. Without this estimate the range used for the illustrative scenario would be further from the full range identified in the literature.

(2010), GREET and CARB. Scully et al. (2021) reports negative land use change emissions in part because they assumed that planting annual crops on land categorized as cropland pasture would result in net sequestration of soil carbon.[336] For more discussion of corn ethanol land use change estimates see Chapter 4.2.2.

Downstream emissions range from 1 to 7 gCO2e/MJ. Downstream emissions are associated with fuel distribution from ethanol production facilities to retail gasoline stations and tailpipe emissions. Some studies also include emissions from production and use of denaturant which is added to ethanol in small volume percentages to render it undrinkable. The highest downstream estimate is from Scully et al. (2021) including emissions associated with denaturant. All of the other estimates are 4 gCO2e/MJ or less.

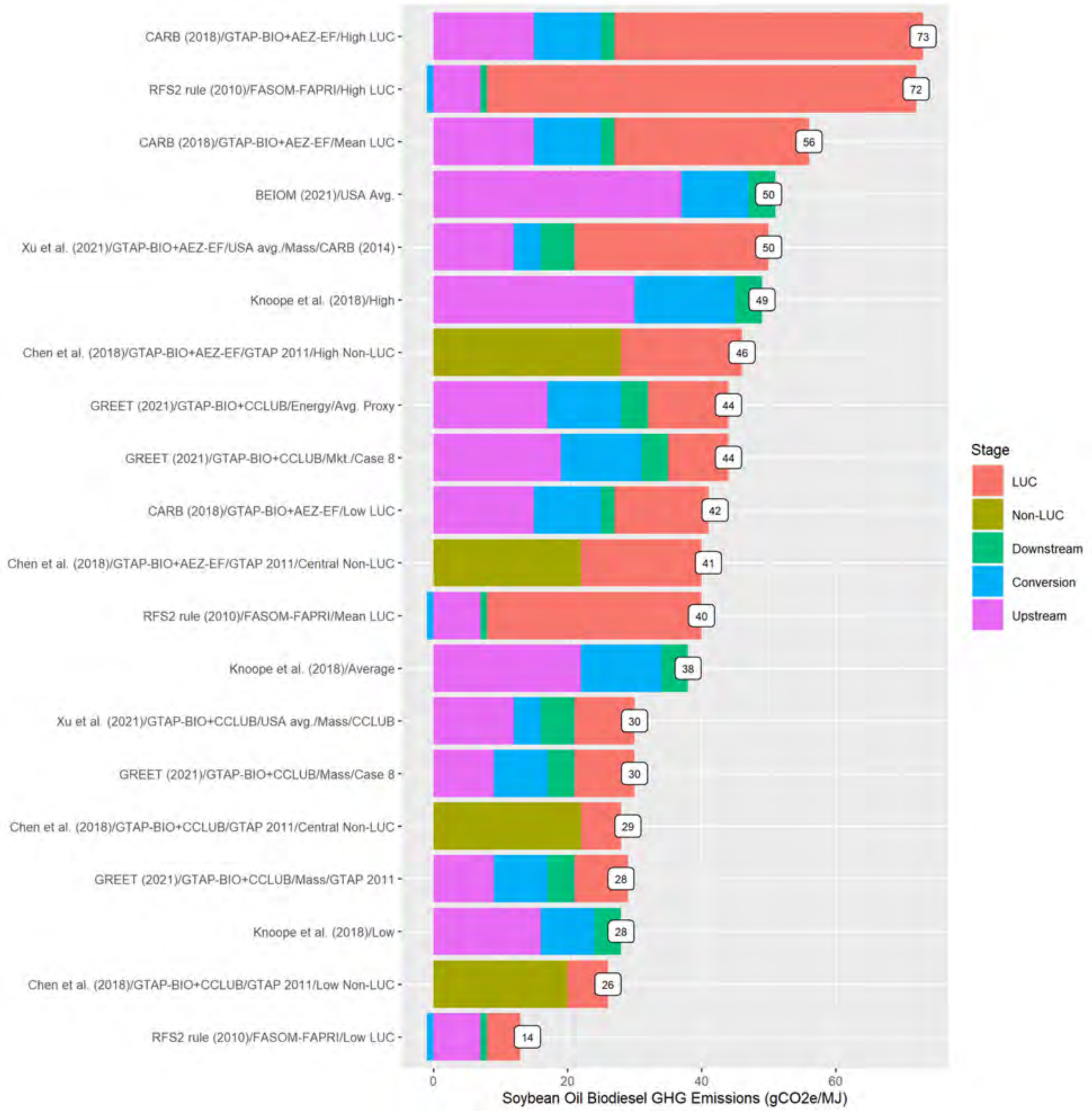
Overall, our literature review of estimates representative of average corn ethanol production at natural gas-fired U.S. dry mills produces a range from 38 to 116 gCO2e/MJ. The largest source of variation across studies continues to be estimated emissions associated with direct and indirect land use change. Although this is already a wide range, corn ethanol can have higher or lower GHG emissions depending on farm specific or facility specific factors. For example, ethanol produced from facilities fired with coal or from corn grown on marginal lands with lower yields produce emissions that are greater than the top end of this range. On the other hand, corn ethanol produced with the adoption of advanced technologies or climate smart agricultural practices can have lower LCA emissions. Corn ethanol facilities produce a highly concentrated stream of CO2 that lends itself to carbon capture and sequestration (CCS). CCS is being deployed at ethanol plants and has the potential to result in negative emissions at the ethanol production facility, especially if mills with CCS use renewable sources of electricity and other advanced technologies to lower their needs for thermal energy. Climate smart practices are being adopted at the feedstock production stage. For example, planting cover crops between corn rotations can build soil organic carbon stocks. Collecting data on and evaluating these trends in corn and ethanol production are areas for additional effort that will inform future LCA estimates for corn ethanol.

4.2.3.4 Soybean Oil Biodiesel

Relative to corn ethanol, there have been fewer studies published on the GHG emissions associated with soybean oil biodiesel. Our literature review includes 8 studies that estimate the lifecycle GHG emissions associated with soybean oil biodiesel. Given that soybeans are approximately 20% oil and 80% meal by dry mass, these studies often include several estimates based on different allocation approaches for the soybean meal coproduct. The figure below includes 20 estimates of the lifecycle GHG emissions associated with soybean oil biodiesel production and use.

[336] Spawn-Lee, S. A., et al. (2021). "Comment on 'Carbon Intensity of corn ethanol in the United States: state of the science'." Environmental Research Letters 16(11): 118001.

Figure 4.2.3.4-1: Soybean Oil Biodiesel Lifecycle Greenhouse Gas Estimates



Notes: The name on the y-axis for each bar/estimate includes multiple descriptors separated by "/". In order, these descriptors are the author or other name (e.g., RFS2 rule) and year of the study; the model used to estimate the LUC emissions; the allocation approach used for soybean meal (e.g., mass, energy); the LUC estimate case (e.g., Low LUC); and the non-LUC estimate case (e.g., Low CI). The Upstream stage includes all of the emissions associated with soybean oil production and transport upstream of the biodiesel production facility. The Conversion stage includes emission associated with fuel production at the biodiesel production facility. The Downstream stage includes emissions associated with biodiesel transport and non-CO_2 combustion emissions. The LUC stage includes emissions from induced land use changes. For studies that do not report disaggregated results, results are reported as LUC and Non-LUC emissions.

RFS2 (2010) estimated uncertainty in land use change GHG emissions and reported a relatively wide range of estimates. The only estimate in our review that is outside the range of estimates from the RFS2 (2010) estimate is from CARB (2018) using CARB's high estimate for soy biodiesel land use change emissions from CARB (2014). GREET-2021 allows users to choose from land use change results from three different GTAP-BIO runs, and four different allocation approaches to account for soybean meal coproduct. We include a range of estimates from GREET-2021 based on different combinations of these factors. Chen et al. (2018) used GREET and the GTAP-BIO model to estimate soy biodiesel carbon intensity. This study uses a range of estimates based on sensitivity analysis on the GREET input parameters as well as multiple prior land use change GHG estimates based on GTAP-BIO. Knoope et al. (2018) is a GREET-style LCA study that excludes land use change GHG emissions and reports a range of estimates based on sensitivity analysis of input parameters. We also include the estimate from BEIOM (2021) which uses economic input-output methodology (see Chapter 4.2.2.6 for more information).

Among the estimates in the above figure, upstream emissions range from 7 to 37 gCO2e/MJ. These include emissions associated with feedstock production and transport, including non-LUC market-mediated impacts in the agricultural sector. Upstream emissions estimates depend on the methodology used to estimate them and the co-product accounting methods applied to the soybean meal co-product. By default, GREET uses mass allocation for the meal co-product, but GREET allows users to select market, energy or displacement approaches. We include the mass, energy and market-based allocation approaches in the figure above.[337] The highest estimate (19 gCO_2e/MJ) uses the market-based allocation approach, and the lowest estimate (9 gCO_2e/MJ) uses the mass-based allocation. Market-based allocation in GREET produces higher estimates based on the assumed prices for soybean oil and meal. The lowest overall estimate for upstream emissions is from RFS2 (2010). RFS2 (2010) is the only study in our review that uses a consequential modeling approach for non-land use change emissions, whereby the GHG impacts were modeled using economic models. The highest estimate is from BEIOM which is also unique in its modeling approach. All of the other studies use an attributional approach to estimates upstream GHG emissions, and most of them apply a mass-based allocation approach to account for the soybean meal co-product.

We include estimates for biodiesel produced at U.S. facilities that use a transesterification process. The range of conversion emissions in Figure 4.2.3.4-1 range from -1 to 15 gCO2e/MJ. Most of the fuel production estimates are from 8-12 gCO2e/MJ. The RFS2 (2010) estimate is -1 gCO2e/MJ based on the assumption that the glycerin co-product from biodiesel production is burned for thermal process energy displacing the use of petroleum residual oil. Most of the other studies use energy, market, or mass-based allocation to account for the glycerin co-product which results in a larger estimate for fuel production GHG emissions.

Similar to corn ethanol, the largest source of variation between soybean oil biodiesel LCA estimates are the land use change emissions, ranging from 5 to 64 gCO2e/MJ in Figure 4.2.3.4-1.[338] The highest and lowest land use change GHG estimates are from RFS2 (2010) based on the upper and lower bounds of the reported 95% confidence interval. The land use change uncertainty analysis for RFS2 (2010) considered uncertainty in land conversion types and emissions factors but did not consider uncertainty in economic model parameters. As discussed,

[337] Using displacement results in upstream emissions of -17 gCO2e/MJ and total LCA emissions of 38 gCO2e/MJ. Although the inclusion of the displacement method provides interesting variation in the estimates for each stage the overall estimate is near the middle of the range, thus we exclude it from Figure 4.2.3.3 to improve legibility.
[338] This excludes Knoope et al. (2021) and BEIOM (2021) which exclude land use change emissions.

in Chapter 4.2.2.8, above, the range of soybean oil biodiesel land use change GHG estimates in the literature is wider when we consider studies that only estimate land use change emissions, ranging from 5 to 80 gCO2e/MJ.

Particular characteristics of soybean oil biodiesel production introduce greater potential for uncertainty relative to corn ethanol. For example, the quantity of biofuel that can be produced from an acre of U.S. soybeans is substantially smaller than that produced from an acre of US corn. Based on data from USDA and GREET, an average acre of U.S. farmland yields about four times as much corn ethanol as soybean oil biodiesel on an energy basis.[339] This difference in per-acre fuel yields means that soybean biodiesel modeling results are far more sensitive to tradeoffs between cropland extensification and other means of obtaining additional soybean oil. For example, every acre of cropland extensification projected in a given soybean oil biodiesel scenario represents four times as much new cropland per megajoule of biodiesel relative to a corn ethanol scenario.

Another key sensitivity for soybean oil is the impact on livestock markets. While soybean oil represents about 19 percent, by mass, of the crush product of soybeans, meal represents about 80 percent of that crush. Soybean meal is an important source of protein in livestock feed diets. Corn ethanol also has a livestock feed co-product in the form of distillers grains. On a weight basis, one MMBTU of soybean oil biodiesel is associated with approximately 4 times as much feed coproduct as one MMBTU of corn ethanol.[340] Soybean meal and distillers grains are used differently in feed rations and their nutritional contents are also not identical. However, even this general comparison demonstrates that the quantity of feed product associated with a given quantity of soybean oil biodiesel is substantially greater than that associated with the same quantity of corn ethanol. The impact of biofuel feed coproducts on GHG emissions is highly complex. As a brief example, to the extent greater production of feed coproducts allows cattle producers to intensify production, reducing the use of grazing lands, these feed coproducts may mitigate LUC emissions. Conversely, to the extent that greater availability of feed products reduces costs for livestock producers, this may lead to increased livestock-related emissions. It is unclear which of these market dynamics may prove dominant in the future, making the net signal of livestock emissions highly uncertain. The larger quantities of feed coproducts associated with the production of soybean oil biodiesel relative to corn ethanol amplify this uncertainty at both ends of the emissions range, contributing to the wider overall range of GHG impacts we observe in the literature.

Another key sensitivity present in the literature is uncertainty about the type of land that will be converted in response to increased soybean oil demand, either to increase production of

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[339] Assumes soybean yield of 3,084 lbs/acre and corn yield of 9,912 lbs/acre, based on 2021 average yields from USDA NASS. Assumes 93.6 lbs of soybean oil per MMBTU of biodiesel output and 163.7 lbs of corn per MMBTU of ethanol based on GREET-2021.Thus, one acre yields 6.26 MMBTU (128.6 gallons ethanol-equivalent) of soybean oil biodiesel, or 60.6 MMBTU (506.2 gallons of ethanol) of corn ethanol. USDA NASS data from QuickStats database, https://quickstats.nass.usda.gov/ (accessed August 3rd, 2022).

[340] For every lb of soybean oil produced, approximately 5.26 lbs of soybean meal are produced. At GREET-2021 average biodiesel yields, production of the one MMBTU of soybean oil biodiesel is associated with the production of approximately 251.4 lbs of soybean meal. For comparison, according to GREET-2021, production of one MMBTU of corn ethanol using the aforementioned dry mill ethanol process coproduces about 60.4 lbs of dried distillers grains (assuming 100 percent drying).

soybeans or through market-mediated impacts on other vegetable oils. Soybean oil is part of the larger global market for vegetable oils and is a good substitute for palm oil in many use cases. Given the potential for marginal palm oil extensification into carbon-rich peat lands in Southeast Asia,[341] the extent to which palm oil backfills for soybean oil diverted to biofuel production from other uses also substantially impacts LUC emissions. In addition, increased demand for soybean oil in the U.S. could lead to land conversion in other large soybean-producing countries such as Argentina and Brazil that have carbon-dense forests and grasslands. Therefore, the potential for these types of impacts on sensitive high-carbon lands creates additional uncertainty in soybean oil biodiesel GHG modeling.

Downstream emissions range from 1 to 4 gCO2e/MJ. Downstream emissions are associated with fuel distribution from biodiesel production facilities to retail gasoline stations and tailpipe emissions. The highest downstream estimates are from GREET and lowest are from RFS2 (2010).

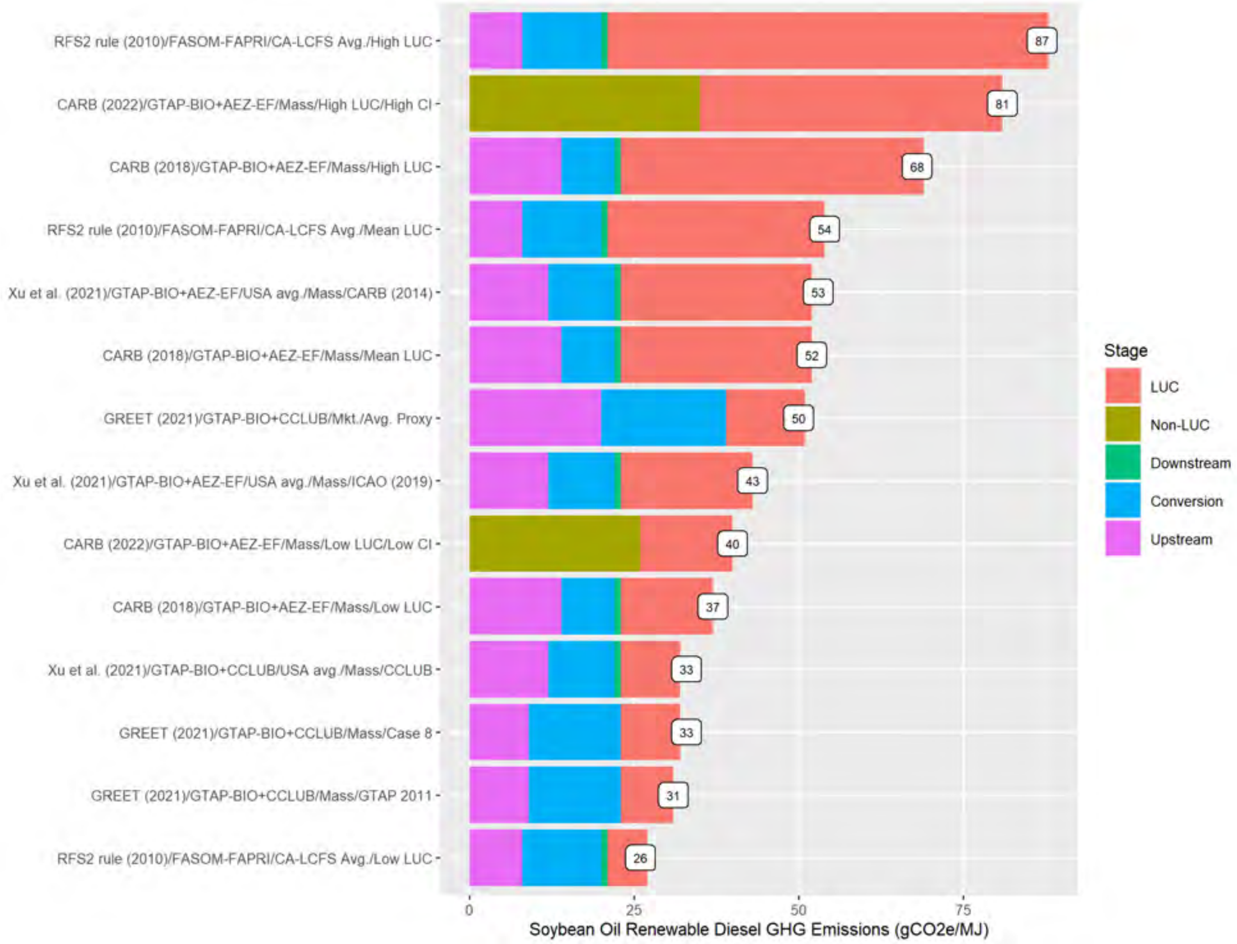
Overall, our literature review of estimates representative of average U.S. soybean oil biodiesel production provides a range from 14 to 73 gCO2e/MJ. The largest source of variation across studies continues to be estimated emissions associated with direct and indirect land use change. Although this is a wide range, biodiesel produced under particular conditions may produce emissions that are outside of this range on a per MJ basis. For example, LCA emissions may be higher if economic conditions result in soybean oil used for biodiesel to be backfilled with palm oil or soybeans grown in tropical regions with high rates of deforestation. It may also be possible to produce soybean oil biodiesel with lower LCA emissions with the adoption of climate smart agricultural practices. For example, planting cover crops between soybean rotations has the potential to build soil organic carbon stocks. Collecting data on and evaluating these trends in soybean production and vegetable oil markets are areas for additional research that will inform future LCA estimates for soybean oil biodiesel.

4.2.3.5 Soybean Oil Renewable Diesel

Relative to soybean oil biodiesel, there have been fewer studies published on the GHG emissions associated with soybean oil renewable diesel. Lifecycle GHG estimates for soybean oil renewable diesel Our literature review includes 5 sources that estimate the GHG emissions associated with soybean oil renewable diesel. These studies include numerous estimates based on different scenarios for land use change and assumptions related to co-product accounting. The figure below includes 13 LCA estimates from 5 studies.

[341] See for example: Austin, K. G., et al. (2017). "Shifting patterns of oil palm driven deforestation in Indonesia and implications for zero-deforestation commitments." Land Use Policy 69: 41-48.

Figure 4.2.3.5-1: Soybean Oil Renewable Diesel Lifecycle Greenhouse Gas Estimates



Notes: The name on the y-axis for each bar/estimate includes multiple descriptors separated by "/". In order, these descriptors are the author or other name (e.g., RFS2 rule) and year of the study; the model used to estimate the LUC emissions; the allocation approach used for soybean meal (e.g., mass, energy); the LUC estimate case (e.g., Low LUC); and the non-LUC estimate case (e.g., Low CI). The Upstream stage includes all of the emissions associated with soybean oil production and transport upstream of the renewable diesel production facility. The Conversion stage includes emission associated with fuel production at the renewable diesel production facility. The Downstream stage includes emissions associated with renewable diesel transport and non-CO_2 combustion emissions. The LUC stage includes emissions from induced land use changes. For studies that do not report disaggregated results, results are reported as LUC and Non-LUC emissions.

The estimates from RFS2 (2010) in the figure above are based on the "upstream" GHG modeling for soybean oil from the 2010 RFS2 rule combined with estimates that EPA published more recently for renewable diesel production and downstream fuel distribution and use.[342] Similar to the review for soybean oil biodiesel, CARB (2018) provides a range of land use change GHG estimates and GREET (2021) includes multiple land use change scenarios and co-product allocation approaches for soybean meal. Given the relative scarcity of LCA estimates for soybean oil renewable diesel, we also include the highest and lowest carbon intensities for individual U.S. facilities as certified by CARB for the CA-LCFS (CARB 2022) using their central land use change GHG estimates.

[342] April 2022 Canola Oil Pathways NPRM (87 FR 22823): https://www.govinfo.gov/content/pkg/FR-2022-04-18/pdf/2022-07598.pdf

Among the estimates in the above figure, upstream emissions range from 8 to 20 gCO2e/MJ. Upstream emissions vary for the same reasons discussed for soybean oil biodiesel, including the methodology used to estimate them and the co-product accounting methods applied to the soybean meal co-product. The lowest upstream emissions estimates are from RFS2 (2010).[343] The highest upstream emissions are from GREET using a market-based allocation approach to account for the meal co-product. Market-based allocation in GREET produces higher estimates for soybean oil than mass- or energy-based allocation based on the assumed prices for soybean oil and meal. Using mass-based allocation, CARB (2018) estimates higher emissions (14 gCO2e/MJ) than GREET-2021 (9 gCO2e/MJ). The lowest upstream estimates are from RFS2 (2010). As discussed above for soybean oil biodiesel, the RFS2 (2010) analysis uses an entirely different methodology than GREET or CARB for estimating GHG emissions associated with feedstock production.

Our review includes estimates representative of U.S. renewable diesel production via a hydrotreating process. The range of conversion emissions in Figure 4.2.3.5-1 range from 8 to 19 gCO2e/MJ. This range does not include the facility-specific carbon intensities from CARB (2022) as this source does not report carbon intensity disaggregated into lifecycle stages. The lowest estimate is from CARB (2018) and the highest estimate is from GREET-2021 using market-based allocation. The RFS2 (2010) estimates in the figure above use hydrotreating processing data provided by CARB representing the average of renewable diesel production facilities registered for the CA-LCFS as of June 2021.[344] The estimate uses an energy allocation approach to account for co-products of renewable diesel production. The lowest estimates come from CARB (2018) based on the default assumptions in CA-GREET version 3.0.

Similar to soybean oil biodiesel, the largest source of variation between soybean oil biodiesel LCA estimates are the land use change emissions. The same factors, discussed above, that introduce additional complexity into LUC modeling for soybean oil biodiesel also apply to soybean oil renewable diesel. For renewable diesel the land use change GHG estimates range from 6 to 67 gCO2e/MJ in Figure 4.2.3.4-1.[345] The highest and lowest land use change GHG estimates are from RFS2 (2010) based on the upper and lower bounds of the reported 95% confidence interval. The land use change uncertainty analysis for RFS2 (2010) considered uncertainty in land conversion types and emissions factors but did not consider uncertainty in economic model parameters. As discussed, in Chapter 4.2.2.8, above, the range of soybean oil biodiesel land use change GHG estimates in the literature is wider when we consider studies that only estimate land use change emissions, ranging from 5 to 80 gCO2e/MJ.

Downstream emissions are associated with fuel distribution from renewable diesel production facilities to retail gasoline stations and tailpipe emissions. For renewable diesel, there is little variation in the review estimates, as they range from 0.5 to 1 gCO2e/MJ.

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[343] The renewable diesel upstream emissions from RFS2(2010) are lower than those for soybean oil biodiesel, because we have updated the soybean oil upstream estimates for renewable diesel using more recent emissions factors from GREET and AR5 GWP values. More details are provided in a technical memo to the docket titled "Notes on Literature Review of Transportation Fuel Greenhouse Gas (GHG) Lifecycle Analysis (LCA)."

[344] For more information on hydrotreating process data evaluated by EPA, see April 2022 Canola Oil Pathways NPRM (87 FR 22823), Section II.C.9.

[345] This excludes Knoope et al. (2021) and BEIOM (2021) which exclude land use change emissions.

Overall, our literature review of estimates representative of average U.S. soybean oil renewable production provides a range from 26 to 87 gCO_2e/MJ. This is a relatively wide range, and the largest source of variation between studies continues to be estimated emissions associated with direct and indirect land use change. Although this is a wide range, renewable diesel produced under particular conditions may produce emissions that are outside of this range on a per MJ basis. Some of the main factors that could result in emissions higher or lower than the literature range are the same as those discussed above for soybean oil biodiesel. Renewable diesel production requires a relatively large amount of hydrogen. Renewable diesel carbon intensities could be reduced by consuming less hydrogen or sourcing the hydrogen from low carbon sources.

It is worth noting that the International Civil Aviation Organization (ICAO) has been conducting similar lifecycle GHG analysis in support of the Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA). Given ICAO's focus on jet fuel, they have not specifically released an LCA value for soybean oil renewable diesel. However, the lifecycle analysis for soybean oil jet fuel is almost identical to an LCA for soybean oil renewable diesel since both are produced through the same hydrotreating process. While most current hydrotreating processes yield renewable diesel with small amounts of naptha and LPG co-products, these facilities can be configured to produce a separate jet fuel stream from the rest of the products produced. Producing jet fuel requires additional refining, therefore jet fuel LCA estimates tend to be slightly more GHG intensive than producing renewable diesel alone. The soybean oil jet fuel results from ICAO (2021) are summarized in the table below.

Table 4.2.3.5-1: U.S. Soybean Oil Jet Fuel Estimates from ICAO (2021) (gCO_2e/MJ)

Estimate	Core[346]	Land Use Change	LCA Value
GLOBIOM LUC (Low end of 95% CI)	40	14	54
GTAP-BIO LUC	40	20	60
ICAO Default	40	25	65
GLOBIOM LUC	40	50	91
GLOBIOM LUC (High end of 95% CI)	40	92	132

Notes: For their default land use change estimate, ICAO uses the GTAP-BIO estimate plus 4.45 gCO2e/MJ, see ICAO (2021) p. 149 for explanation. The GTAP-BIO and central GLOBIOM land use change estimates are from ICAO (2021) Table 67. The low and high GLOBIOM estimates are from ICAO (2021) Table 72. The low estimate is the 2.5% quantile and the high estimate is the 97.5% quantile from sensitivity analysis (300 runs). LCA values in table might not be the sum or core and LUC values due to rounding.

Given the similarities in the hydrotreating process, it is a relatively straightforward adjustment to modify a soybean oil jet fuel LCA to a soybean oil renewable diesel LCA.[347] If the ICAO soybean oil jet fuel LCA was adjusted for the lower energy needs for renewable diesel, the

[346] ICAO (2021) includes estimates from GREET of the direct, or "core," GHG emissions associated with jet fuel produced from soybean oil through a hydrotreating process.

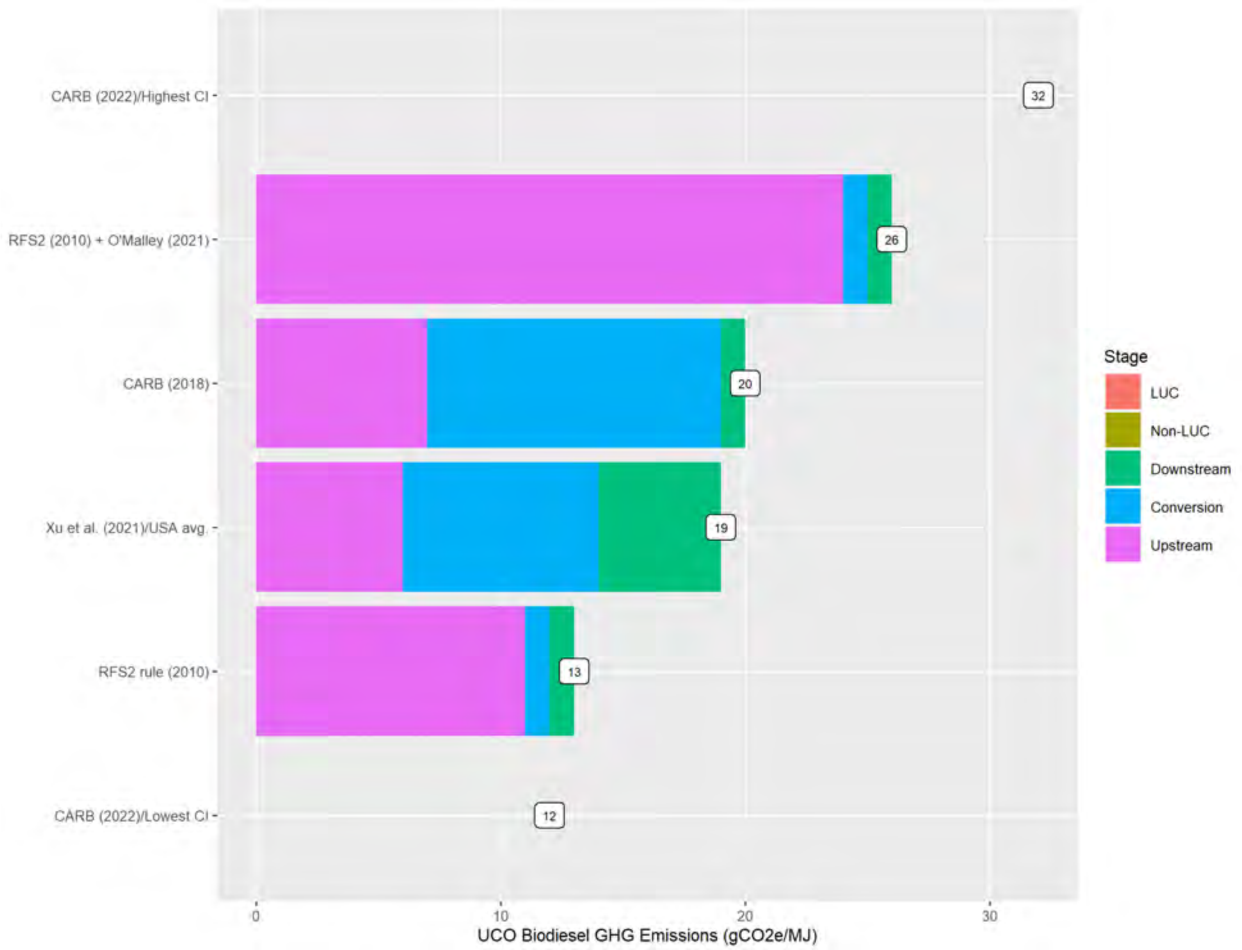
[347] ICAO's core GHG estimates are based on analysis with GREET using an energy allocation approach for co-products. The GREET-2021 core GHG estimate for soybean oil renewable diesel using energy allocation is 36 gCO2e/MJ. This GREET-2021 estimate can be substituted for the 40 gCO2e/MJ core jet fuel value to produce an LCA range for soybean oil renewable diesel.

ICAO estimates for soybean oil renewable diesel would be 50 to 128 gCO_2e/MJ. If the ICAO LCA values were included in Figure 4.2.3.5-1 and Table 4.2.3.12, the overall range of values for soybean oil renewable diesel would be wider (26 gCO_2e/MJ to 128 gCO_2e/MJ).

4.2.3.6 FOG Biodiesel

We reviewed literature on the GHG emissions associated with biodiesel produced from fats, oils and greases (FOG). Specifically, we reviewed estimates for biodiesel produced from used cooking oil (UCO) and animal tallow. Figure 4.2.3.6-1 includes the LCA estimates for UCO biodiesel, and Figure 4.2.3.6-2 includes the LCA estimates for animal tallow biodiesel.

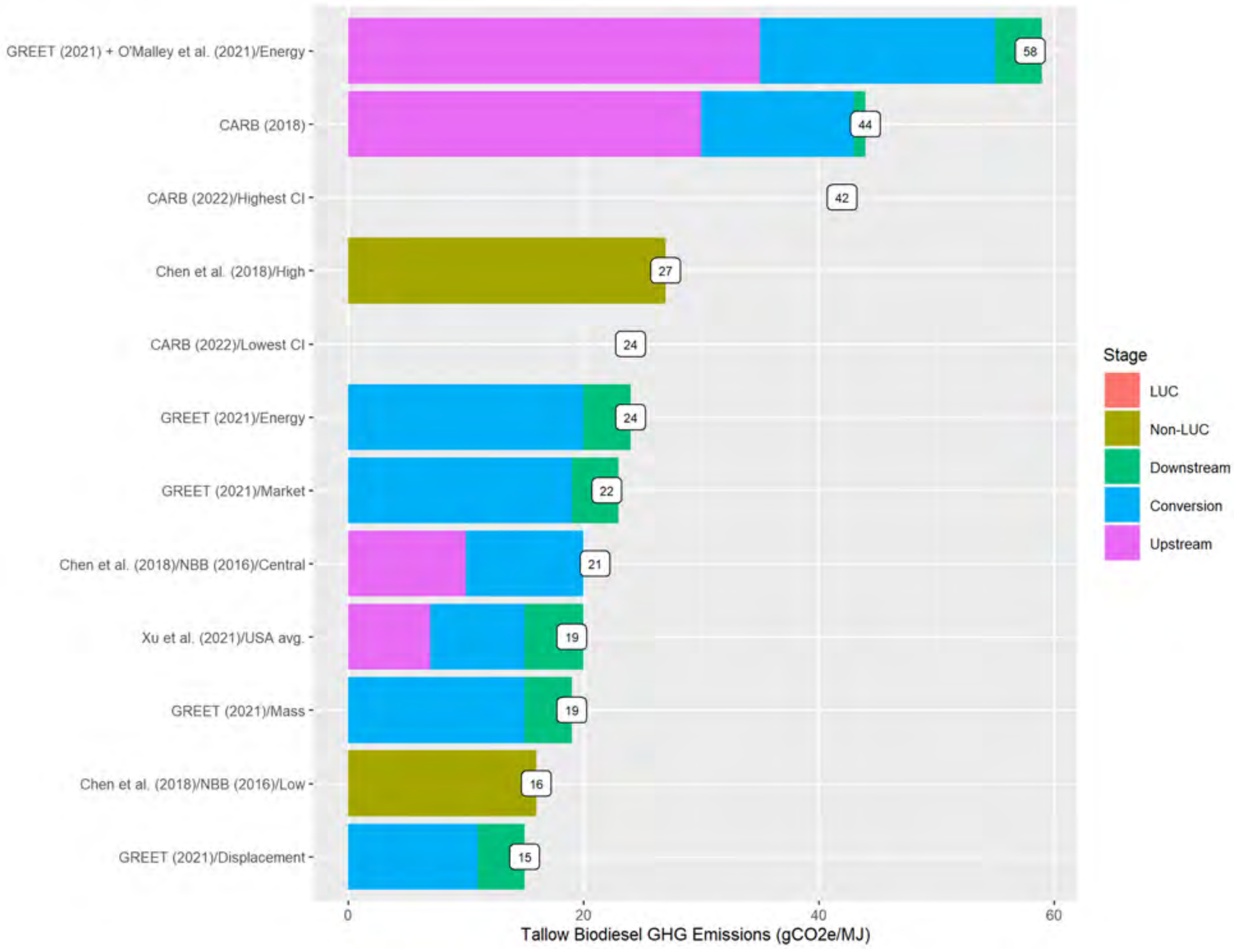
Figure 4.2.3.6-1: UCO Biodiesel Lifecycle Greenhouse Gas Estimates



Notes: The Upstream stage includes all of the emissions associated with UCO pre-treatment/rendering and transport upstream of the biodiesel production facility. O'Malley et al. (2021) also includes indirect GHG emissions in the Upstream stage. The Conversion stage includes emission associated with fuel production at the biodiesel production facility. The Downstream stage includes emissions associated with biodiesel transport and non-CO_2 combustion emissions. Estimates that only report total lifecycle GHG emissions are depicted only with a label and no bars.

Estimates for UCO biodiesel range from 12 to 32 gCO2e/MJ. Given the relative scarcity of LCA studies on UCO biodiesel, we include the highest and lowest certified carbon intensities for individual biodiesel facilities under the CA-LCFS in our review. The highest and lowest estimates come from the CA-LCFS range (CARB 2022). The CARB and RFS2 estimates assume that the only upstream emissions for supplying UCO are associated with rendering/cooking the raw UCO and transporting it to biodiesel production facilities. O'Malley et al. (2021) looked at the current uses for UCO apart from biofuel production and evaluated a case study where UCO diverted from livestock feed and oleochemical uses is backfilled with corn, soybean oil and palm oil. Based on this case study, they estimated potential indirect emissions of 12.2 gCO2e/MJ associated with UCO use for biodiesel. In the figure above, we include the potential indirect emissions estimate from O'Malley et al. (2021) added to the RFS2 (2010) estimates.

Figure 4.2.3.6-2: Animal Tallow Biodiesel Lifecycle Greenhouse Gas Estimates



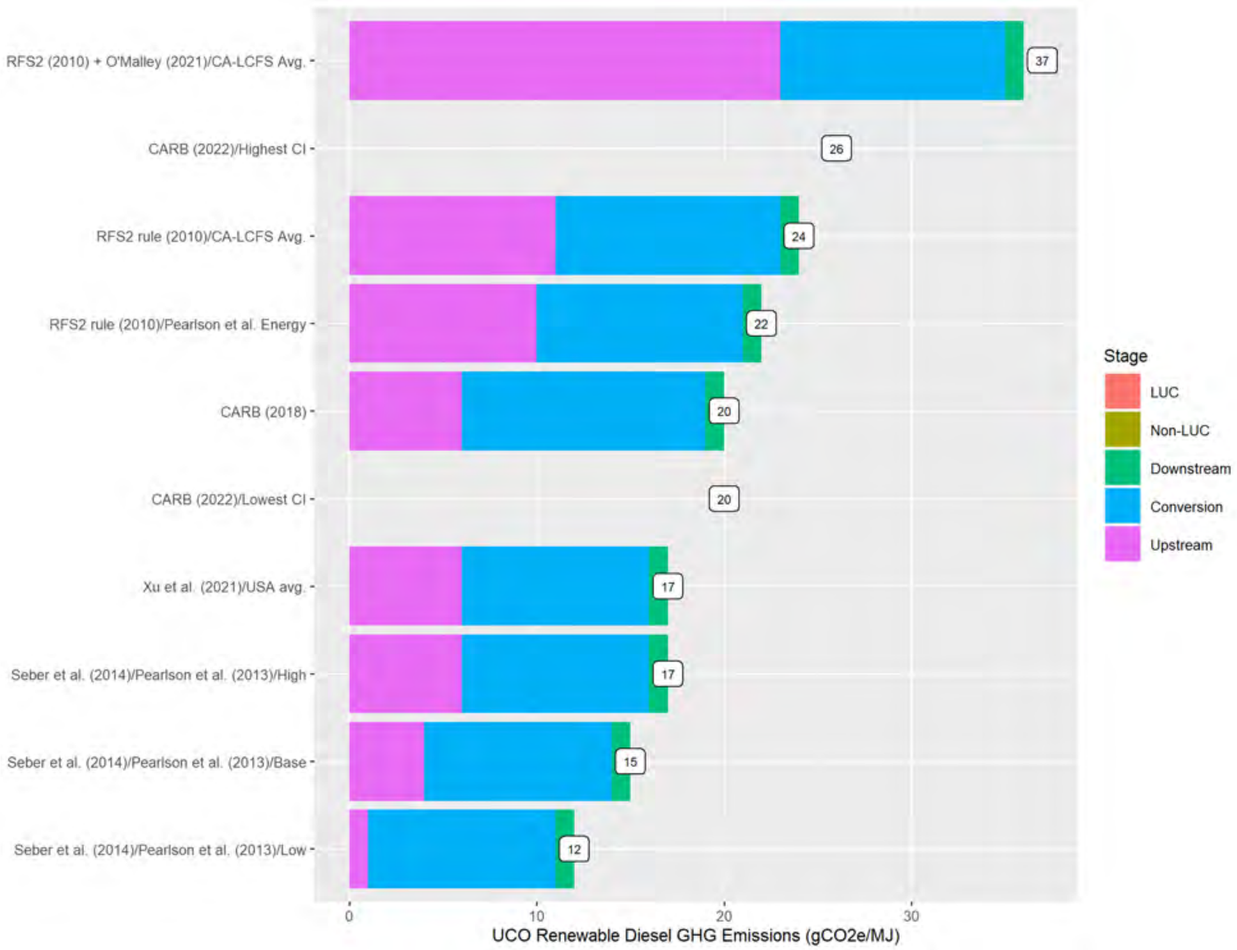
Notes: The Upstream stage includes all of the emissions associated with animal tallow pre-treatment/rendering and transport upstream of the biodiesel production facility. The Conversion stage includes emission associated with fuel production at the biodiesel production facility. The Downstream stage includes emissions associated with biodiesel transport and non-CO_2 combustion emissions. For studies that do not report disaggregated results, results are reported as LUC and Non-LUC emissions. Estimates that only report total lifecycle GHG emissions are depicted only with a label and no bars.

Estimates for tallow biodiesel range from 15 to 58 gCO2e/MJ. Most of the estimates assume that tallow is a byproduct of meat production and assume zero upstream emissions from livestock production allocated to the tallow. For these estimates the ranges are primarily based on different assumptions about the energy requirements for rendering, as well as different assumptions about the co-products from rendering and the accounting methods for these co-products. The exception is the case study by O'Malley et al. (2021) which estimates emissions of 34.8 gCO2e/MJ associated with backfilling tallow used in livestock feed and oleochemical production with corn, soybean oil and palm oil. To inform our range of estimates we add this backfill emissions estimate to the estimates from GREET-2021.

4.2.3.7 FOG Renewable Diesel

We reviewed literature on the GHG emissions associated with renewable diesel produced from FOG. Specifically, we reviewed estimates for renewable diesel produced from used cooking oil (UCO) and animal tallow. Figure 4.2.3.7-1 includes the LCA estimates for UCO biodiesel, and Figure 4.2.3.7-2 includes the LCA estimates for animal tallow biodiesel.

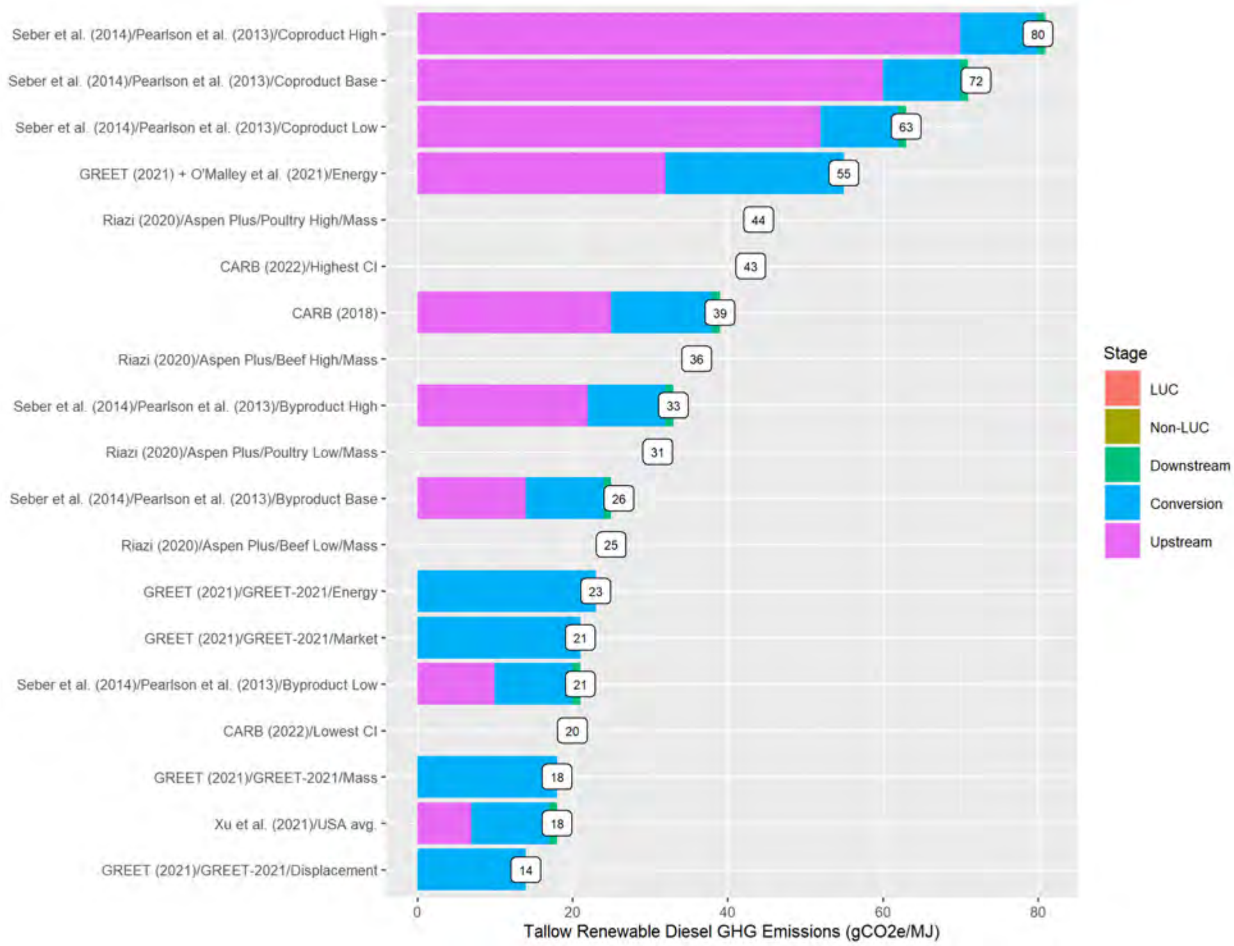
Figure 4.2.3.7-1: UCO Renewable Diesel Lifecycle Greenhouse Gas Estimates



Notes: The Upstream stage includes all of the emissions associated with UCO pre-treatment/rendering and transport upstream of the biodiesel production facility. O'Malley et al. (2021) also includes indirect GHG emissions in the Upstream stage. The Conversion stage includes emission associated with fuel production at the biodiesel production facility. The Downstream stage includes emissions associated with biodiesel transport and non-CO_2 combustion emissions. Estimates that only report total lifecycle GHG emissions are depicted only with a label and no bars.

Estimates for UCO renewable diesel range from 12 to 37 gCO2e/MJ. The CARB and RFS2 estimates assume that the only upstream emissions for supplying UCO are associated with rendering/cooking the raw UCO and transporting it to biodiesel production facilities. O'Malley et al. (2021) looked at the current uses for UCO apart from biofuel production and evaluated a case study where UCO diverted from livestock feed and oleochemical uses is backfilled with corn, soybean oil and palm oil. Based on this case study, they estimated potential indirect emissions of 12.2 gCO2e/MJ associated with UCO use for biodiesel. In the figure above, the highest estimate is based on the sum of the potential indirect emissions estimate from O'Malley et al. (2021) added to the RFS2 (2010) estimate. The lowest estimates are from Seber et al. (2014), which do not include any backfilling emissions.

Figure 4.2.3.7-2: Animal Tallow Renewable Diesel Lifecycle Greenhouse Gas Estimates



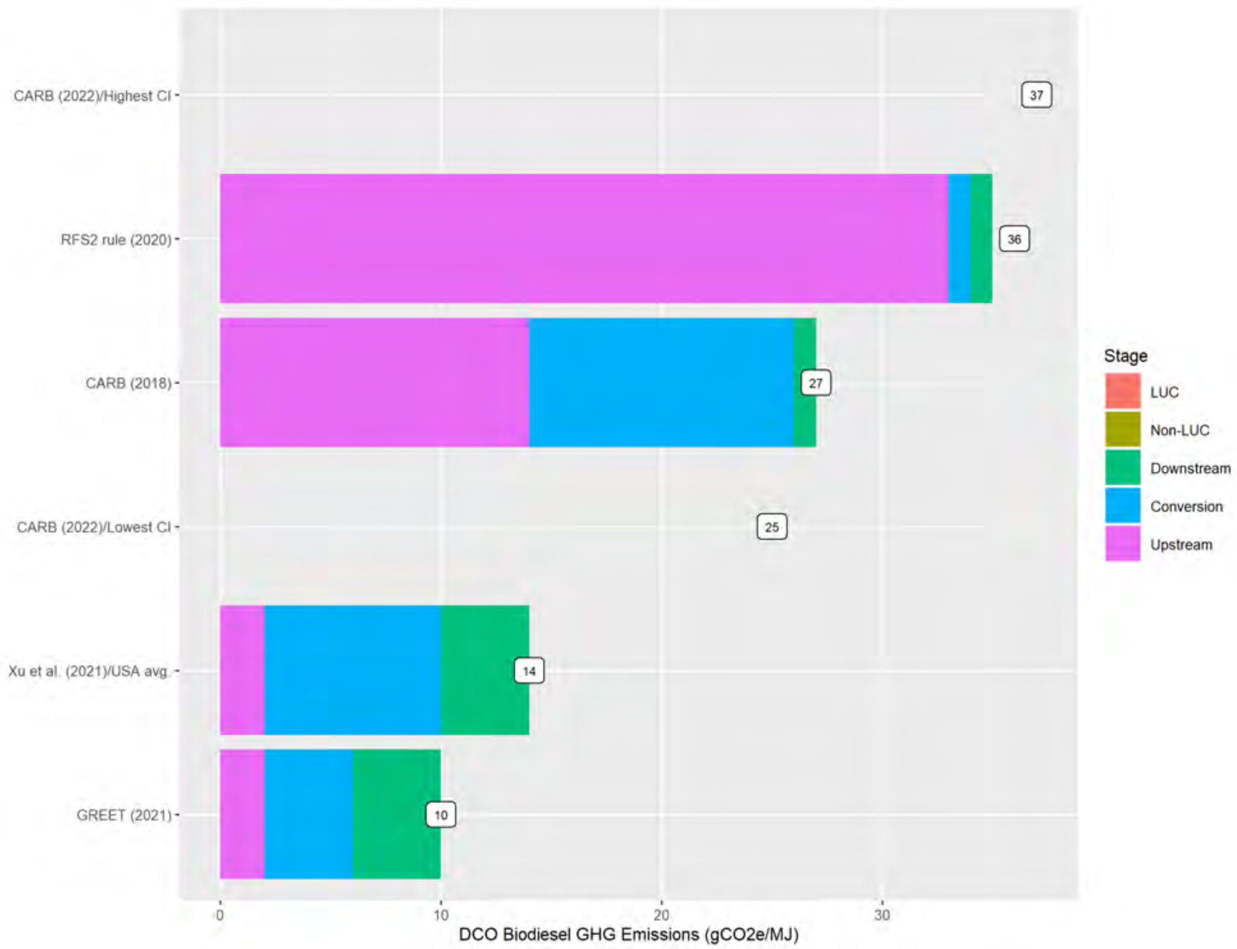
Notes: The Upstream stage includes all of the emissions associated with tallow pre-treatment/rendering and transport upstream of the biodiesel production facility. Seber et al. (2021) also includes livestock production GHG emissions in the Upstream stage. The Conversion stage includes emission associated with fuel production at the biodiesel production facility. The Downstream stage includes emissions associated with biodiesel transport and non-CO_2 combustion emissions. Estimates that only report total lifecycle GHG emissions are depicted only with a label and no bars.

Estimates for tallow renewable diesel range from 14 to 80 gCO2e/MJ. The highest estimates are from Seber et al. (2014). Seber et al. (2014) is the only study that includes scenarios where GHG emission associated with livestock raising and meat production are allocated the tallow. In other words, in these scenarios the tallow is considered a co-product of meat production rather than a byproduct. Our review also includes a case study by O'Malley et al. (2021) that evaluates emission associated with backfilling tallow used in livestock feed and oleochemical production with corn, soybean oil and palm oil. The lowest estimate is from GREET-2021 using a displacement approach for the co-products from tallow rendering.

4.2.3.8 Distillers Corn Oil Biodiesel

We reviewed published estimates of the GHG emissions associated with biodiesel produced from distillers corn oil (DCO). DCO is a co-product from ethanol production whereby oil is removed the DGS before it is sold as livestock feed. The DCO can then be used as a biofuel feedstock or added back into livestock feed at desired levels. Figure 4.2.3.8-1 includes the LCA estimates for DCO biodiesel.

Figure 4.2.3.8-1: DCO Biodiesel Lifecycle Greenhouse Gas Estimates



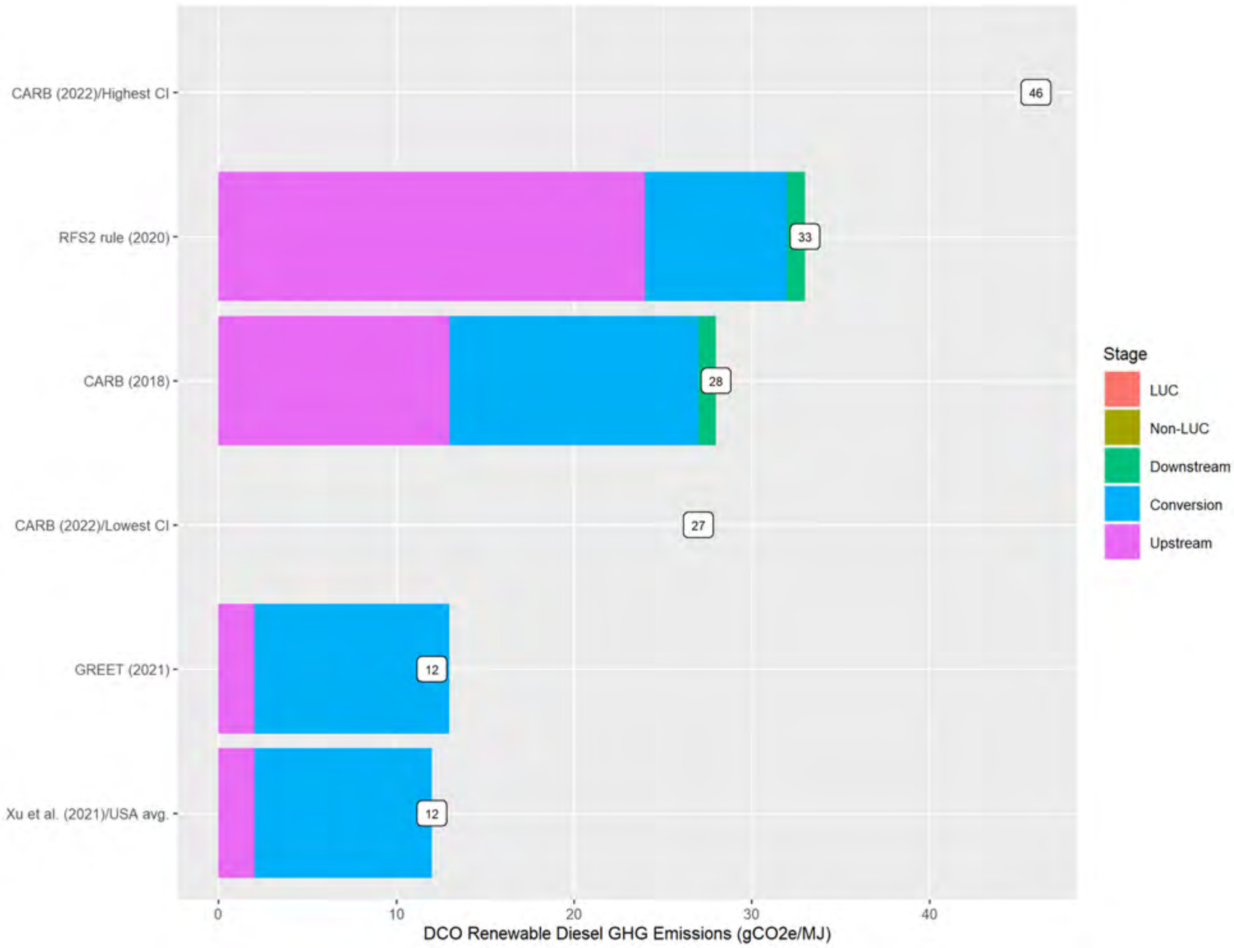
Notes: The Upstream stage includes all of the emissions associated with DCO extraction and in some cases backfilling with corn in livestock feed. The Conversion stage includes emission associated with fuel production at the biodiesel production facility. The Downstream stage includes emissions associated with biodiesel transport and non-CO_2 combustion emissions. Estimates that only report total lifecycle GHG emissions are depicted only with a label and no bars.

DCO biodiesel estimates range from 10 to 37 gCO_2e/MJ. Most of the estimates assume that DCO is a byproduct and assign none of the emissions associated with corn or ethanol production to it. For the 2020 RFS2 rule, we estimated the emissions associated with corn backfilling for DCO in animal feed. As discussed in that rule and a prior rule on distillers sorghum oil, we determined that DCO is used as a source of energy/calories in feed diets and that corn is a likely product to backfill when DCO is used as a biofuel feedstock. The lowest estimate is from GREET-2021.

4.2.3.9 Distillers Corn Oil Renewable Diesel

We reviewed published estimates of the GHG emissions associated with renewable diesel produced from DCO. Figure 4.2.3.9-1 includes the LCA estimates for DCO renewable diesel.

Figure 4.2.3.9-1: DCO Renewable Diesel Lifecycle Greenhouse Gas Estimates



Notes: The Upstream stage includes all of the emissions associated with DCO extraction and in some cases backfilling with corn in livestock feed. The Conversion stage includes emission associated with fuel production at the renewable diesel production facility. The Downstream stage includes emissions associated with biodiesel transport and non-CO_2 combustion emissions. Estimates that only report total lifecycle GHG emissions are depicted only with a label and no bars.

DCO renewable diesel estimates range from 12 to 46 gCO_2e/MJ. Most of the estimates assume that DCO is a byproduct and assign none of the emissions associated with corn or ethanol production to it. For the 2020 RFS2 rule, we estimated the emissions associated with corn backfilling for DCO in animal feed. The lowest estimate is from GREET-2021.

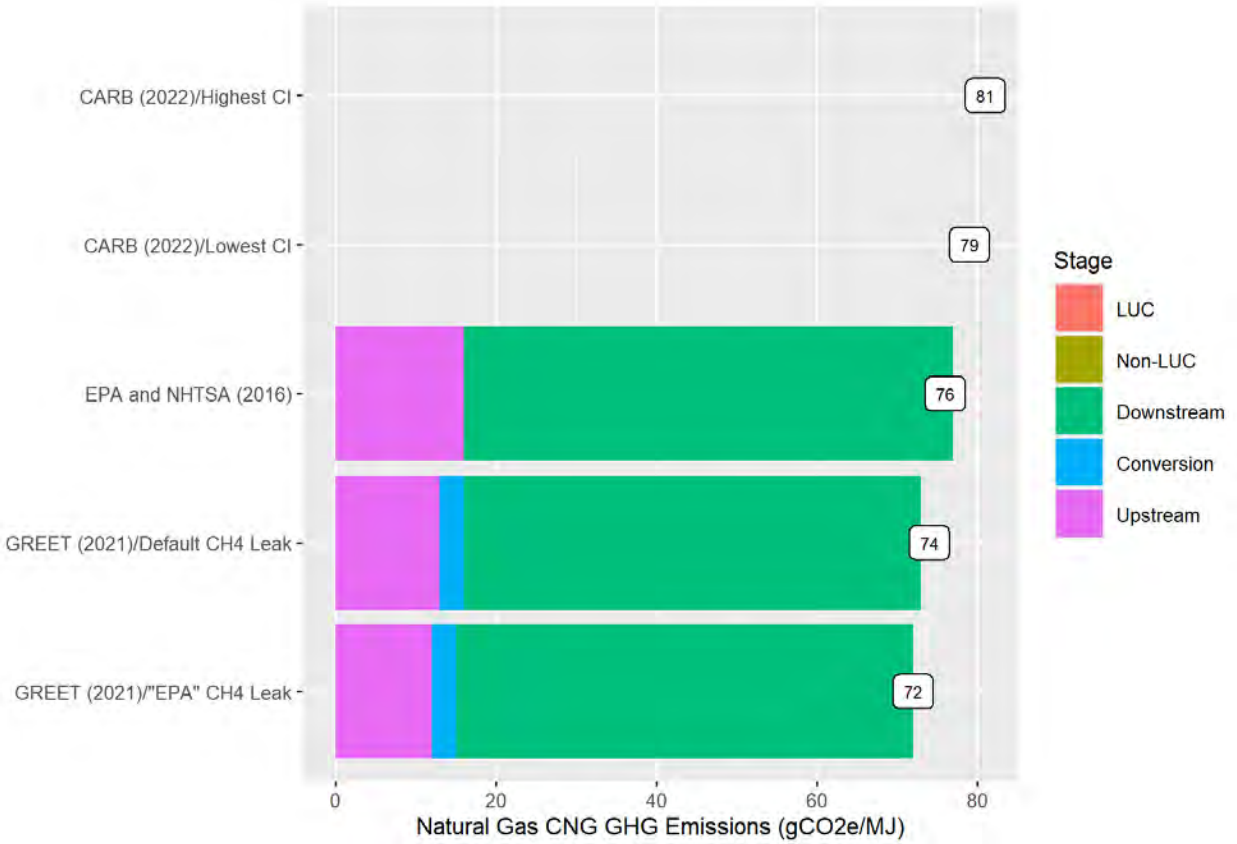
4.2.3.10 Natural Gas CNG

As discussed above for petroleum gasoline and diesel, for the purposes of conducting the lifecycle GHG emissions analysis and determining which biofuels meet the GHG requirements, CAA Section 211(o)(1)(C) defines baseline lifecycle greenhouse gas emissions as "the average lifecycle greenhouse gas emissions, as determined by the Administrator, after notice and opportunity for comment, for gasoline or diesel (whichever is being replaced by the renewable fuel) sold or distributed as transportation fuel in 2005." While the baseline lifecycle GHG emissions are used for a different specific purpose under the RFS program, we are not required to use it here in this analysis for evaluating the GHG impacts of the candidate volumes.

To inform a range of potential GHG impacts associated with renewable CNG we consider two scenarios for the conventional fuels it displaces. In the first scenario we assume that the candidate volumes of renewable CNG, relative to the No RFS baseline, cause some miles traveled with diesel vehicles to be replaced with miles traveled with vehicles that run on renewable CNG. This scenario assumes that the candidate volumes make CNG vehicles more economically attractive than diesel vehicles in some cases, leading to a marginal increase in CNG vehicle miles traveled relative to diesel vehicle miles traveled. In the second scenario, we assume the candidate volumes of renewable CNG do not shift the relative miles traveled for diesel vehicles relative to CNG vehicles, but instead cause CNG vehicles to be fueled with renewable CNG instead of conventional CNG.

Thus, our literature review for this proposed rule includes studies that estimate the lifecycle GHG emissions associated with natural gas CNG. Figure 4.2.3.9-1 includes the natural gas CNG from our review of the literature. Based on our review, LCA estimates for diesel are higher than those for natural gas CNG on a per MJ of fuel basis. For the illustrative 30-year GHG scenario discussed in the next section (Chapter 4.2.4), the scenario where renewable CNG replaces diesel fuel produces a high estimate of the GHG benefits of renewable CNG. The low estimate of renewable CNG GHG benefits is based on the scenario that assumes renewable CNG displaces conventional CNG.

Figure 4.2.3.10-1: Natural Gas CNG Well-to-Wheel Greenhouse Gas Estimates



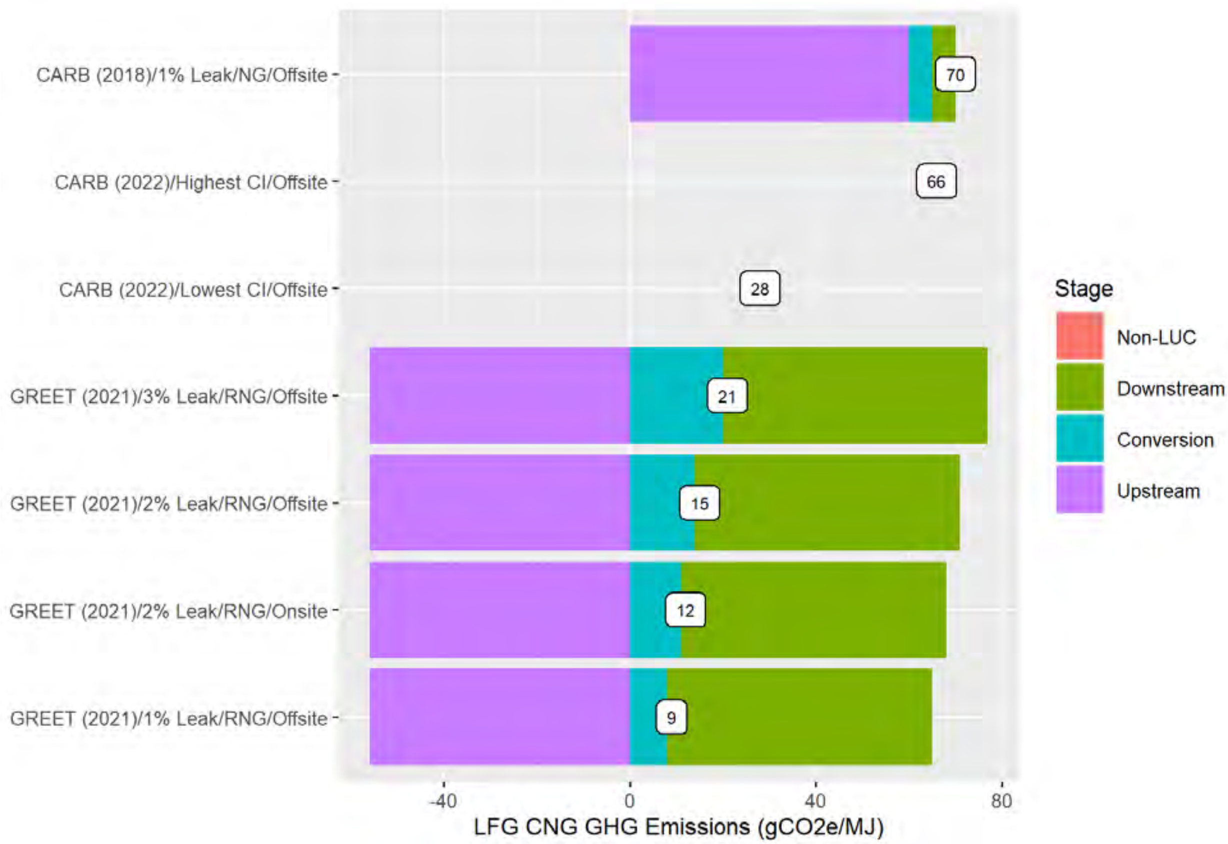
Notes: The name on the y-axis for each bar/estimate includes multiple descriptors separated by "/". In order, these descriptors are the author or other name (e.g., RFS2 rule) and a brief descriptor of the scenario modeled. The Upstream stage includes all of the emissions associated with extracting, processing and delivering natural gas to a compression facility. The Conversion stage includes emissions associated compressing natural gas to CNG. The Downstream stage includes emissions associated with fueling a CNG vehicle and tailpipe combustion emissions. The gasoline baseline estimate in the March 2010 RFS2 rule used SAR GWP values. All values in this chart use 100-year AR5 GWP values. Estimates that only report total lifecycle GHG emissions are depicted only with a label and no bars.

The natural gas CNG estimates in our review range from 72 to 81 gCO_2e/MJ. Our review did not identify many applicable studies, as there are many more studies on the lifecycle emissions associated with natural gas production than natural gas for CNG vehicles. The EPA and NHTSA (2016) estimate is from the RIA for the Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles - Phase 2 rule. It represents lifecycle emissions for CNG used in a 2014 or later dedicated CNG vehicle. The lowest estimates are from GREET-2021. By default, GREET-2021 assumes a set of assumptions for methane leakage during natural gas production. The model also gives users the option of choosing methane leakage assumptions derived from the EPA GHG Inventory. The highest estimates are the natural gas CNG pathways certified under the CA-LCFS program. CNG produced from natural gas that is in turn produced from wells or systems with high leakage rates may have much greater carbon intensity than the estimates in our review. This is an area where additional LCA research would be helpful.

4.2.3.11 Landfill Biogas CNG

Our literature review did not identify many studies on the lifecycle GHG emissions associated with CNG produced from landfill gas (LFG). Our review is limited to estimates derived from the GREET model and estimates by CARB as part of their implementation of the CA-LCFS program. Figure 4.2.3.11-1 includes the LCA estimates for CNG produced from landfill biogas.

Figure 4.2.3.11-1: Landfill Biogas CNG Lifecycle Greenhouse Gas Estimates



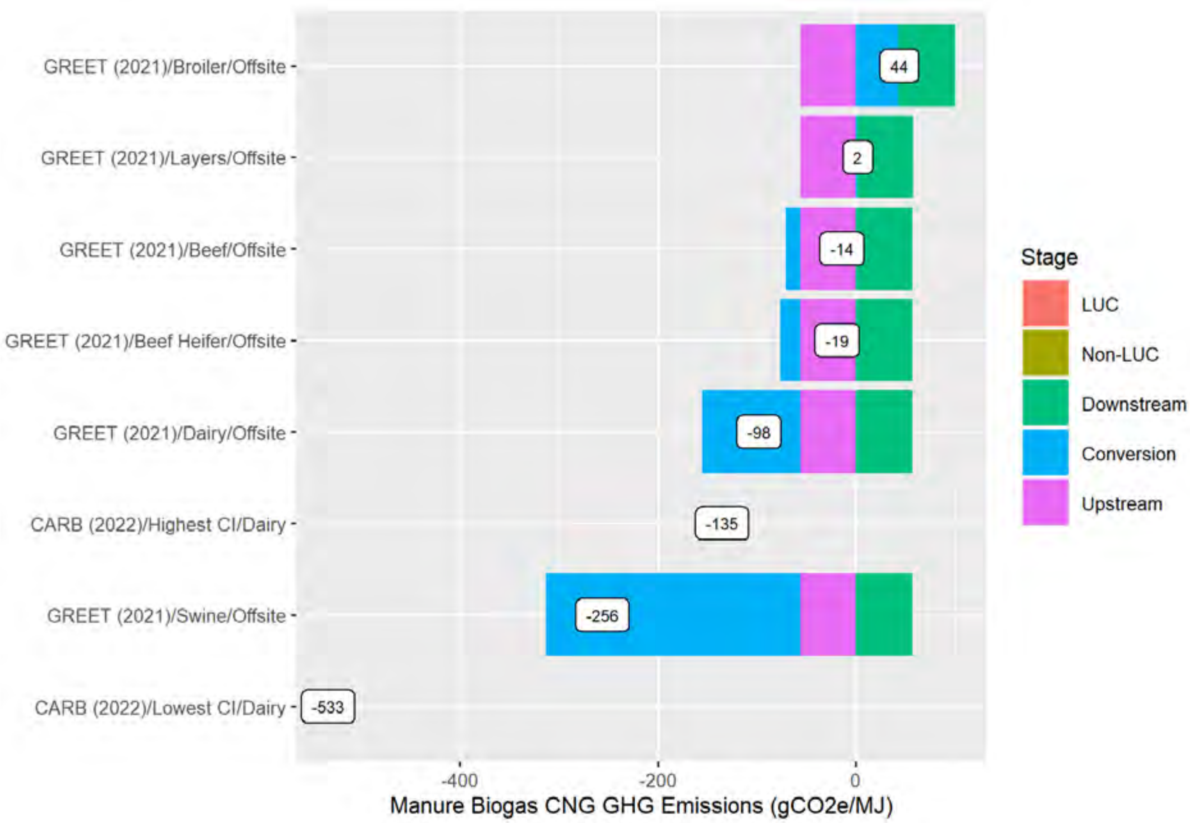
Notes: The Upstream stage includes all of the emissions associated with capturing LFG, processing it to pipeline quality, and transporting it to the fueling location. Downstream emission include tailpipe emissions including CO2 emissions. In most studies upstream emissions are negative because they assume LFG will be flared in the counterfactual baseline scenario. Because reductions in CO2 emissions are included in the Upstream emissions, CO2 tailpipe emissions are included in the Downstream emissions. CARB (2018) reports more disaggregated results and excludes tailpipe CO2 emissions. Estimates that only report total lifecycle GHG emissions are depicted only with a label and no bars.

The range of estimates in Figure 4.2.3.11-1 range from 6 to 70 gCO_2e/MJ. The higher estimates are from CARB and the lower estimates are from GREET-2021. We varied two parameters in GREET-2021 to provide a range of estimates. By default, GREET-2021 assumes a 2% methane leakage rate associated with processing landfill gas to pipeline quality. We include estimates assuming 1% and 3% methane leakage and show that each 1% of additional methane leakage increases the LCA estimates by 6 gCO_2e/MJ. By default, GREET-2021 assumes CNG fueling occurs offsite from where the landfill gas is produced, and the majority of CA-LCFS certified LFG CNG pathways are for offsite CNG fueling. Based on GREET-2021 onsite fueling reduces the LCA estimate by approximately 3 gCO_2e/MJ. The highest estimates are from CARB, with the very highest estimate coming from the default CA-GREET version 3.0 model. GREET-2021 includes negative upstream emissions based on reduced GHG emissions in a baseline scenario absent the use of the LFG as fuel. The CA-GREET model has much larger upstream GHG emissions than GREET-2021 as it does not include the large emissions reductions relative to the baseline. Landfills with high leakage rates associated with capturing and cleaning up the biogas may have much greater carbon intensity than the estimates in our review. This is an area where additional LCA research would be helpful.

4.2.3.12 Manure Digester CNG

Our literature review did not identify many studies on the lifecycle GHG emissions associated with CNG produced from manure digester biogas. Our review is limited to estimates derived from the GREET model and estimates by CARB as part of their implementation of the CA-LCFS program. Figure 4.2.3.12-1 includes the LCA estimates for CNG produced from landfill biogas.

Figure 4.2.3.12-1: Manure Digester CNG Lifecycle Greenhouse Gas Estimates



Notes: The Upstream stage includes all of the emissions associated with capturing LFG, processing it to pipeline quality, and transporting it to the fueling location. Downstream emission include tailpipe emissions including CO2 emissions. In most studies upstream emissions are negative because they assume LFG will be flared in the counterfactual baseline scenario. Because reductions in CO2 emissions are included in the Upstream emissions, CO2 tailpipe emissions are included in the Downstream emissions. CARB (2018) reports more disaggregated results and excludes tailpipe CO2 emissions. Estimates that only report total lifecycle GHG emissions are depicted only with a label and no bars.

There are relatively few studies but a very large range of LCA estimates (-533 to 44 gCO_2e/MJ) for biogas CNG produced from manure digesters. CARB has certified pathways for CNG produced from over 50 different sources of manure biogas. All of these pathways have negative carbon intensities meaning they reduce GHG emissions even before displacing any conventional transportation fuels. The negative emissions are due to the assumed high methane and nitrous oxide emissions in the baseline scenario absent the collection and treatment of animal manure in anaerobic digesters. Consequently, the biggest area of uncertainty in the LCA for manure digester GHG emissions is what level of control is assumed in the baseline. Based on estimates from GREET-2021, CNG produced from poultry manure biogas has positive carbon intensities, as high as 44 gCO2e/MJ.

4.2.3.13 Summary of LCA Ranges

Based on the literature review for each pathway discussed above, the range of LCA estimates are summarized in Table 4.2.3.12-1.

Table 4.2.3.13-1: Lifecycle GHG Ranges Based on Literature Review (gCO_2e/MJ)

Pathway	LCA Range
Petroleum Gasoline	84 to 98
Petroleum Diesel	84 to 94
Corn Starch Ethanol	38 to 116
Soybean Oil Biodiesel	14 to 73
Soybean Oil Renewable Diesel	26 to 87
Used Cooking Oil Biodiesel	12 to 32
Used Cooking Oil Renewable Diesel	12 to 37
Tallow Biodiesel	15 to 58
Tallow Renewable Diesel	14 to 81
Distillers Corn Oil Biodiesel	10 to 37
Distillers Corn Oil Renewable Diesel	12 to 46
Natural Gas CNG	72 to 81
Landfill Gas CNG	9 to 70
Manure Biogas CNG	-533 to 44

In the sections that follow we present a range of monetized climate benefits associated with the candidate volumes for an illustrative 30-year scenario. In order to appropriately monetize GHG impacts over this period an annual stream of net GHG emissions is required. For the non-crop based fuel pathways we assume a constant stream of GHG emissions per MJ over the 30-year period. The land use change emissions associated with crop-based biofuels are highly dynamic, as the majority of emission increases associated with land use changes occur relatively quickly (e.g., in the first few years) with the reduced emissions associated with the biofuel use occuring over time. Thus, for the 30-year illustrative scenario, we use estimates for crop-based biofuels that report an annual stream of land use change emissions. The majority of the land use change GHG estimates in the literature do not report an annual stream. In many cases, these LUC estimates are derived by estimating land conversions induced by the crop-based biofuel production and then multiplying these conversions by emissions factors that estimate the resulting total emissions over a 20-30 year period. The only study identified in our review that does report an annual stream of land use change emissions is the analysis for the 2010 RFS2 rule. The reasons that no other studies report annual emissions are not entirely clear, but many studies use static models to estimate land use change that are not conducive to reporting annual emissions. Other studies use models that have the capability to estimate an annual stream but did not report them for reasons that were not discussed in the publication. Thus, for the illustrative GHG scenario we use the highest and lowest LCA estimates from the 2010 RFS2 rule for the crop-based biofuel pathways. The LCA ranges used for the illustrative 30-year scenario are summarized in the following table. The results for the 30-year scenario are described in the following section.

Table 4.2.3.13-2: Lifecycle GHG Ranges for Illustrative 30-Year Scenario (gCO_2e/MJ)

Pathway	LCA Range
Petroleum Gasoline	84 to 98
Petroleum Diesel	84 to 94
Corn Starch Ethanol	49 to 91
Soybean Oil Biodiesel	14 to 72
Soybean Oil Renewable Diesel	24 to 78
Used Cooking Oil Biodiesel	12 to 32
Used Cooking Oil Renewable Diesel	12 to 37
Tallow Biodiesel	15 to 44
Tallow Renewable Diesel	14 to 81
Distillers Corn Oil Biodiesel	10 to 37
Distillers Corn Oil Renewable Diesel	12 to 46
Natural Gas CNG	72 to 90
Landfill Gas CNG	6 to 70
Manure Biogas CNG	-533 to 44

4.2.3.14 References for LCA Literature Review

For ease of reference, the following is the list of references cited in Chapter 4.2.3, unless otherwise cited with the footnote:

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4.2.4 GHG Results for Illustrative Scenario

For each of the 2023, 2024, and 2025 standards, we estimate a 30-year stream of changes in GHG emissions for renewable fuel volumes above the No RFS baseline for each analyzed fuel using the carbon intensity analyses discussed above. While the standards proposed in this rulemaking only apply in individual years, this analysis portrays what might be expected if, in each of the ensuing 29 years, aggregate renewable fuel consumption for each category exceeded baseline levels by the same volume as required by the rule.

Table 4.2.4-2 summarizes the annual low biofuel emission estimates and high petroleum baseline emission estimates in grams CO_2e per megajoule (Table 4.2.4-4 does the same for high biofuel and low petroleum baseline estimates). Table 4.2.4-3 presents the high petroleum subtracted from the low biofuel emission estimates to show net emissions from displacing petroleum fuels with biofuels on a per fuel-equivalent megajoule basis (Table 4.2.4-5 does the same for high biofuel and low petroleum baseline estimates). GHG benefits from biofuels displacing fossil fuel use include the GHG emissions associated with biofuel production and use, including land use change emissions relative to the baseline scenario.

Emissions streams based on the 2023 through 2025 standards are presented in Tables 4.2.4-6 through 4.2.4-8 for low biofuel/high petroleum lifecycle analysis estimates, and Tables 4.2.4-10 through 4.2.4-12 for high biofuel/low petroleum lifecycle analysis estimates respectively, both compared to the No RFS baseline. These are derived by first converting the net emission streams presented in Tables 4.2.4-3 and 4.2.4-5 from grams CO_2e per megajoule to million metric tons CO_2e per megajoule, then multiplying these streams of emissions factors by changes in renewable fuel volumes. The volume changes in 2023 reflect the difference between the target volumes and the No RFS baseline as presented in Table 4.2.4-1. As discussed in Section 4.2.3.1, our GHG analysis of the 2023 standard assumes that the target volumes will produce GHG benefits for the subsequent 29 years due to ongoing use of renewable fuels (and their consequent displacement of fossil fuels). In analyzing the GHG impacts of the 2024 standard we only consider the difference in volumes between the 2024 standard and 2023 standard because the emissions benefits of the increase in use of renewable fuels to meet the 2023 standards are already accounted for in the 29 years following 2023 (i.e., 2023-2053). Thus, we only attribute emissions to the 2024 standard for the volumes that have changed compared to the previous year (2023). Similarly, for 2024, we only include the emission impact for volumes that have changed from the 2024 levels. These resulting annual sequences of emissions for the 2023 through 2025 standards are then summed, resulting in a combined stream of estimated annual emissions from 2023 through 2054. These are presented in Tables 4.2.4-9 and 4.2.4-13 respectively below.

Table 4.2.4-1: Volume Changes Used for Illustrative GHG Scenario

		Landfill Biogas CNG/ LNG[348]	Agricultural Digester Biogas CNG/LNG	Wood Waste/ MSW Diesel/Jet Fuel	Soybean/ Canola Oil Biodiesel	Fats/Oils/ Greases Biodiesel	Corn Oil Biodiesel	Soybean Oil Renewable Diesel	Fats/Oils/ Greases Renewable Diesel	Corn Oil Renewable Diesel	Corn Starch Ethanol
Volume Changes Relative to No RFS Baseline [Table 3.2-3] (million gallons)	2023	44	44	-	968	200	120	901	275	80	706
	2024	91	91	3	935	200	120	1,048	329	86	776
	2025	145	145	6	901	200	120	1,054	388	91	840
Volume Changes Relative to Previous Year (million gallons)	2023	44	44	-	968	200	120	901	275	80	706
	2024	48	48	3	(33)	-	-	147	53	6	70
	2025	54	54	3	(33)	-	-	6	60	6	65

Table 4.2.4-5 shows positive net GHG emissions for the corn ethanol and soybean oil renewable diesel and biodiesel volumes in 2023 due to the initial pulse of land use change emissions in the estimates used for this illustrative scenario. For corn ethanol, volumes relative to the No RFS baseline increase in years 2024 and 2025, therefore there are positive emissions in all three years. Conversely as shown in Table 4.2.4-6, soybean oil renewable diesel and biodiesel volumes are negative in 2024 because those volumes decrease relative to the previous year's (2023) volume increases from the No RFS baseline. As noted above, this scenario assumes that the biofuel production continues for 30 years, irrespective of volume mandates in future years.

We separately estimate a 30-year stream of changes in GHG emissions for renewable fuel volumes from the supplemental volume requirement proposed in this rulemaking as described in

[348] Table 3.2-3 presents total volume changes for CNG/LNG from biogas. We assume for purposes of this illustrative GHG scenario that half of that biogas is sourced from landfills and half from agricultural digesters.

Chapter 3.3. As shown in Table 3.3-1, the supplemental volume requirement of 250 million ethanol-equivalent gallons is represented by an energy-equivalent 147 million soybean oil renewable diesel gallons in 2023.[349] Table 4.2.4-14 shows the illustrative GHG scenario using the same process described above for both low biofuel/high petroleum and high biofuel/low petroleum lifecycle analysis estimates for the supplemental volumes.

[349] See Chapter 3.3 for more details.

Table 4.2.4-2: Gross low biofuel/high petroleum annual lifecycle analysis estimates for individual biofuels, presented in grams CO_2e per megajoule of fuel.[350]

	Landfill Biogas CNG/ LNG	Ag. Digester Biogas CNG/LNG	Wood Waste/ MSW Diesel/Jet Fuel[351]	Soybean/ Canola Oil Biodiesel	Fats/Oils/ Greases Biodiesel	Corn Oil Biodiesel	Soybean Oil Renewable Diesel	Fats/Oils/ Greases Renewable Diesel	Corn Oil Renewable Diesel	Corn Starch Ethanol	Gasoline (High Estimate)	Diesel (High Estimate)
Year 0	8.7	(532.7)	37.6	710.3	13.0	9.9	755.9	12.8	12.4	395.0	98.1	94.1
Year 1	8.7	(532.7)	37.6	(20.0)	13.0	9.9	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 2	8.7	(532.7)	37.6	(20.0)	13.0	9.9	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 3	8.7	(532.7)	37.6	(20.0)	13.0	9.9	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 4	8.7	(532.7)	37.6	(20.0)	13.0	9.9	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 5	8.7	(532.7)	37.6	(20.0)	13.0	9.9	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 6	8.7	(532.7)	37.6	(20.0)	13.0	9.9	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 7	8.7	(532.7)	37.6	(20.0)	13.0	9.9	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 8	8.7	(532.7)	37.6	(20.0)	13.0	9.9	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 9	8.7	(532.7)	37.6	(20.0)	13.0	9.9	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 10	8.7	(532.7)	37.6	(20.0)	13.0	9.9	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 11	8.7	(532.7)	37.6	(20.0)	13.0	9.9	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 12	8.7	(532.7)	37.6	(20.0)	13.0	9.9	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 13	8.7	(532.7)	37.6	(20.0)	13.0	9.9	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 14	8.7	(532.7)	37.6	(20.0)	13.0	9.9	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 15	8.7	(532.7)	37.6	(20.0)	13.0	9.9	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 16	8.7	(532.7)	37.6	(20.0)	13.0	9.9	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 17	8.7	(532.7)	37.6	(20.0)	13.0	9.9	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 18	8.7	(532.7)	37.6	(20.0)	13.0	9.9	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 19	8.7	(532.7)	37.6	(20.0)	13.0	9.9	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 20	8.7	(532.7)	37.6	7.5	13.0	9.9	19.9	12.8	12.4	34.5	98.1	94.1
Year 21	8.7	(532.7)	37.6	7.5	13.0	9.9	19.9	12.8	12.4	34.5	98.1	94.1
Year 22	8.7	(532.7)	37.6	7.5	13.0	9.9	19.9	12.8	12.4	34.5	98.1	94.1
Year 23	8.7	(532.7)	37.6	7.5	13.0	9.9	19.9	12.8	12.4	34.5	98.1	94.1
Year 24	8.7	(532.7)	37.6	7.5	13.0	9.9	19.9	12.8	12.4	34.5	98.1	94.1
Year 25	8.7	(532.7)	37.6	7.5	13.0	9.9	19.9	12.8	12.4	34.5	98.1	94.1
Year 26	8.7	(532.7)	37.6	7.5	13.0	9.9	19.9	12.8	12.4	34.5	98.1	94.1
Year 27	8.7	(532.7)	37.6	7.5	13.0	9.9	19.9	12.8	12.4	34.5	98.1	94.1
Year 28	8.7	(532.7)	37.6	7.5	13.0	9.9	19.9	12.8	12.4	34.5	98.1	94.1
Year 29	8.7	(532.7)	37.6	7.5	13.0	9.9	19.9	12.8	12.4	34.5	98.1	94.1

[350] Parentheses indicate a reduction in GHG emissions.
[351] Wood waste/MSW diesel and jet fuels are comprised of a wide variety of feedstocks and represent a small volume of fuels in this rule. We have made a simplifying assumption that these fuels meet a 60% GHG reduction (equal to the cellulosic threshold) compared to the diesel GHG estimate shown in this table.

Table 4.2.4-3: Net low biofuel/high petroleum (low biofuel minus high petroleum baseline) annual lifecycle analysis estimates for individual biofuels, presented in grams CO_2e per megajoule of fuel.[352]

	Landfill Biogas CNG/LNG	Agricultural Digester Biogas CNG/LNG	Wood Waste/ MSW Diesel/Jet Fuel	Soybean/ Canola Oil Biodiesel	Fats/Oils/ Greases Biodiesel	Corn Oil Biodiesel	Soybean Oil Renewable Diesel	Fats/Oils/ Greases Renewable Diesel	Corn Oil Renewable Diesel	Corn Starch Ethanol
Year 0	(85.4)	(626.8)	(56.5)	616.2	(81.1)	(84.2)	661.8	(81.3)	(81.7)	296.9
Year 1	(85.4)	(626.8)	(56.5)	(114.1)	(81.1)	(84.2)	(102.8)	(81.3)	(81.7)	(59.2)
Year 2	(85.4)	(626.8)	(56.5)	(114.1)	(81.1)	(84.2)	(102.8)	(81.3)	(81.7)	(59.2)
Year 3	(85.4)	(626.8)	(56.5)	(114.1)	(81.1)	(84.2)	(102.8)	(81.3)	(81.7)	(59.2)
Year 4	(85.4)	(626.8)	(56.5)	(114.1)	(81.1)	(84.2)	(102.8)	(81.3)	(81.7)	(59.2)
Year 5	(85.4)	(626.8)	(56.5)	(114.1)	(81.1)	(84.2)	(102.8)	(81.3)	(81.7)	(59.2)
Year 6	(85.4)	(626.8)	(56.5)	(114.1)	(81.1)	(84.2)	(102.8)	(81.3)	(81.7)	(59.2)
Year 7	(85.4)	(626.8)	(56.5)	(114.1)	(81.1)	(84.2)	(102.8)	(81.3)	(81.7)	(59.2)
Year 8	(85.4)	(626.8)	(56.5)	(114.1)	(81.1)	(84.2)	(102.8)	(81.3)	(81.7)	(59.2)
Year 9	(85.4)	(626.8)	(56.5)	(114.1)	(81.1)	(84.2)	(102.8)	(81.3)	(81.7)	(59.2)
Year 10	(85.4)	(626.8)	(56.5)	(114.1)	(81.1)	(84.2)	(102.8)	(81.3)	(81.7)	(59.2)
Year 11	(85.4)	(626.8)	(56.5)	(114.1)	(81.1)	(84.2)	(102.8)	(81.3)	(81.7)	(59.2)
Year 12	(85.4)	(626.8)	(56.5)	(114.1)	(81.1)	(84.2)	(102.8)	(81.3)	(81.7)	(59.2)
Year 13	(85.4)	(626.8)	(56.5)	(114.1)	(81.1)	(84.2)	(102.8)	(81.3)	(81.7)	(59.2)
Year 14	(85.4)	(626.8)	(56.5)	(114.1)	(81.1)	(84.2)	(102.8)	(81.3)	(81.7)	(59.2)
Year 15	(85.4)	(626.8)	(56.5)	(114.1)	(81.1)	(84.2)	(102.8)	(81.3)	(81.7)	(59.2)
Year 16	(85.4)	(626.8)	(56.5)	(114.1)	(81.1)	(84.2)	(102.8)	(81.3)	(81.7)	(59.2)
Year 17	(85.4)	(626.8)	(56.5)	(114.1)	(81.1)	(84.2)	(102.8)	(81.3)	(81.7)	(59.2)
Year 18	(85.4)	(626.8)	(56.5)	(114.1)	(81.1)	(84.2)	(102.8)	(81.3)	(81.7)	(59.2)
Year 19	(85.4)	(626.8)	(56.5)	(114.1)	(81.1)	(84.2)	(102.8)	(81.3)	(81.7)	(59.2)
Year 20	(85.4)	(626.8)	(56.5)	(86.6)	(81.1)	(84.2)	(74.2)	(81.3)	(81.7)	(63.6)
Year 21	(85.4)	(626.8)	(56.5)	(86.6)	(81.1)	(84.2)	(74.2)	(81.3)	(81.7)	(63.6)
Year 22	(85.4)	(626.8)	(56.5)	(86.6)	(81.1)	(84.2)	(74.2)	(81.3)	(81.7)	(63.6)
Year 23	(85.4)	(626.8)	(56.5)	(86.6)	(81.1)	(84.2)	(74.2)	(81.3)	(81.7)	(63.6)
Year 24	(85.4)	(626.8)	(56.5)	(86.6)	(81.1)	(84.2)	(74.2)	(81.3)	(81.7)	(63.6)
Year 25	(85.4)	(626.8)	(56.5)	(86.6)	(81.1)	(84.2)	(74.2)	(81.3)	(81.7)	(63.6)
Year 26	(85.4)	(626.8)	(56.5)	(86.6)	(81.1)	(84.2)	(74.2)	(81.3)	(81.7)	(63.6)
Year 27	(85.4)	(626.8)	(56.5)	(86.6)	(81.1)	(84.2)	(74.2)	(81.3)	(81.7)	(63.6)
Year 28	(85.4)	(626.8)	(56.5)	(86.6)	(81.1)	(84.2)	(74.2)	(81.3)	(81.7)	(63.6)
Year 29	(85.4)	(626.8)	(56.5)	(86.6)	(81.1)	(84.2)	(74.2)	(81.3)	(81.7)	(63.6)

[352] Parentheses indicate a net reduction in GHG emissions.

Table 4.2.4-4: Gross high biofuel/low petroleum annual lifecycle analysis estimates for individual biofuels, presented in grams CO_2e per megajoule of fuel.

	Landfill Biogas CNG/ LNG	Ag. Digester Biogas CNG/LNG	Wood Waste/ MSW Diesel/Jet Fuel[353]	Soybean/ Canola Oil Biodiesel	Fats/Oils/ Greases Biodiesel	Corn Oil Biodiesel	Soybean Oil Renewable Diesel	Fats/Oils/ Greases Renewable Diesel	Corn Oil Renewable Diesel	Corn Starch Ethanol	Gasoline (Low Estimate)	Diesel (Low Estimate)	Natural Gas (Low Estimate)
Year 0	69.8	44.0	33.4	1,044.0	42.3	36.6	1,102.7	54.2	46.3	665.1	83.6	83.5	71.9
Year 1	69.8	44.0	33.4	54.2	42.3	36.6	68.4	54.2	46.3	79.8	83.6	83.5	71.9
Year 2	69.8	44.0	33.4	54.2	42.3	36.6	68.4	54.2	46.3	79.8	83.6	83.5	71.9
Year 3	69.8	44.0	33.4	54.2	42.3	36.6	68.4	54.2	46.3	79.8	83.6	83.5	71.9
Year 4	69.8	44.0	33.4	54.2	42.3	36.6	68.4	54.2	46.3	79.8	83.6	83.5	71.9
Year 5	69.8	44.0	33.4	54.2	42.3	36.6	68.4	54.2	46.3	79.8	83.6	83.5	71.9
Year 6	69.8	44.0	33.4	54.2	42.3	36.6	68.4	54.2	46.3	79.8	83.6	83.5	71.9
Year 7	69.8	44.0	33.4	54.2	42.3	36.6	68.4	54.2	46.3	79.8	83.6	83.5	71.9
Year 8	69.8	44.0	33.4	54.2	42.3	36.6	68.4	54.2	46.3	79.8	83.6	83.5	71.9
Year 9	69.8	44.0	33.4	54.2	42.3	36.6	68.4	54.2	46.3	79.8	83.6	83.5	71.9
Year 10	69.8	44.0	33.4	54.2	42.3	36.6	68.4	54.2	46.3	79.8	83.6	83.5	71.9
Year 11	69.8	44.0	33.4	54.2	42.3	36.6	68.4	54.2	46.3	79.8	83.6	83.5	71.9
Year 12	69.8	44.0	33.4	54.2	42.3	36.6	68.4	54.2	46.3	79.8	83.6	83.5	71.9
Year 13	69.8	44.0	33.4	54.2	42.3	36.6	68.4	54.2	46.3	79.8	83.6	83.5	71.9
Year 14	69.8	44.0	33.4	54.2	42.3	36.6	68.4	54.2	46.3	79.8	83.6	83.5	71.9
Year 15	69.8	44.0	33.4	54.2	42.3	36.6	68.4	54.2	46.3	79.8	83.6	83.5	71.9
Year 16	69.8	44.0	33.4	54.2	42.3	36.6	68.4	54.2	46.3	79.8	83.6	83.5	71.9
Year 17	69.8	44.0	33.4	54.2	42.3	36.6	68.4	54.2	46.3	79.8	83.6	83.5	71.9
Year 18	69.8	44.0	33.4	54.2	42.3	36.6	68.4	54.2	46.3	79.8	83.6	83.5	71.9
Year 19	69.8	44.0	33.4	54.2	42.3	36.6	68.4	54.2	46.3	79.8	83.6	83.5	71.9
Year 20	69.8	44.0	33.4	8.4	42.3	36.6	20.9	54.2	46.3	53.6	83.6	83.5	71.9
Year 21	69.8	44.0	33.4	8.4	42.3	36.6	20.9	54.2	46.3	53.6	83.6	83.5	71.9
Year 22	69.8	44.0	33.4	8.4	42.3	36.6	20.9	54.2	46.3	53.6	83.6	83.5	71.9
Year 23	69.8	44.0	33.4	8.4	42.3	36.6	20.9	54.2	46.3	53.6	83.6	83.5	71.9
Year 24	69.8	44.0	33.4	8.4	42.3	36.6	20.9	54.2	46.3	53.6	83.6	83.5	71.9
Year 25	69.8	44.0	33.4	8.4	42.3	36.6	20.9	54.2	46.3	53.6	83.6	83.5	71.9
Year 26	69.8	44.0	33.4	8.4	42.3	36.6	20.9	54.2	46.3	53.6	83.6	83.5	71.9
Year 27	69.8	44.0	33.4	8.4	42.3	36.6	20.9	54.2	46.3	53.6	83.6	83.5	71.9
Year 28	69.8	44.0	33.4	8.4	42.3	36.6	20.9	54.2	46.3	53.6	83.6	83.5	71.9
Year 29	69.8	44.0	33.4	8.4	42.3	36.6	20.9	54.2	46.3	53.6	83.6	83.5	71.9

[353] Wood waste/MSW diesel and jet fuels are comprised of a wide variety of feedstocks and represent a small volume of fuels in this rule. We have made a simplifying assumption that these fuels meet a 60% GHG reduction (equal to the cellulosic threshold) compared to the diesel GHG estimate shown in this table.

Table 4.2.4-5: Net high biofuel/low petroleum (high biofuel minus low petroleum baseline) annual lifecycle analysis estimates for individual biofuels, presented in grams CO_2e per megajoule of fuel.[354]

	Landfill Biogas CNG/LNG	Agricultural Digester Biogas CNG/LNG	Wood Waste/ MSW Diesel/Jet Fuel	Soybean/ Canola Oil Biodiesel	Fats/Oils/ Greases Biodiesel	Corn Oil Biodiesel	Soybean Oil Renewable Diesel	Fats/Oils/ Greases Renewable Diesel	Corn Oil Renewable Diesel	Corn Starch Ethanol
Year 0	(2.1)	(27.8)	(50.1)	960.5	(41.2)	(46.9)	1,019.2	(29.4)	(37.2)	581.5
Year 1	(2.1)	(27.8)	(50.1)	(29.3)	(41.2)	(46.9)	(15.1)	(29.4)	(37.2)	(3.8)
Year 2	(2.1)	(27.8)	(50.1)	(29.3)	(41.2)	(46.9)	(15.1)	(29.4)	(37.2)	(3.8)
Year 3	(2.1)	(27.8)	(50.1)	(29.3)	(41.2)	(46.9)	(15.1)	(29.4)	(37.2)	(3.8)
Year 4	(2.1)	(27.8)	(50.1)	(29.3)	(41.2)	(46.9)	(15.1)	(29.4)	(37.2)	(3.8)
Year 5	(2.1)	(27.8)	(50.1)	(29.3)	(41.2)	(46.9)	(15.1)	(29.4)	(37.2)	(3.8)
Year 6	(2.1)	(27.8)	(50.1)	(29.3)	(41.2)	(46.9)	(15.1)	(29.4)	(37.2)	(3.8)
Year 7	(2.1)	(27.8)	(50.1)	(29.3)	(41.2)	(46.9)	(15.1)	(29.4)	(37.2)	(3.8)
Year 8	(2.1)	(27.8)	(50.1)	(29.3)	(41.2)	(46.9)	(15.1)	(29.4)	(37.2)	(3.8)
Year 9	(2.1)	(27.8)	(50.1)	(29.3)	(41.2)	(46.9)	(15.1)	(29.4)	(37.2)	(3.8)
Year 10	(2.1)	(27.8)	(50.1)	(29.3)	(41.2)	(46.9)	(15.1)	(29.4)	(37.2)	(3.8)
Year 11	(2.1)	(27.8)	(50.1)	(29.3)	(41.2)	(46.9)	(15.1)	(29.4)	(37.2)	(3.8)
Year 12	(2.1)	(27.8)	(50.1)	(29.3)	(41.2)	(46.9)	(15.1)	(29.4)	(37.2)	(3.8)
Year 13	(2.1)	(27.8)	(50.1)	(29.3)	(41.2)	(46.9)	(15.1)	(29.4)	(37.2)	(3.8)
Year 14	(2.1)	(27.8)	(50.1)	(29.3)	(41.2)	(46.9)	(15.1)	(29.4)	(37.2)	(3.8)
Year 15	(2.1)	(27.8)	(50.1)	(29.3)	(41.2)	(46.9)	(15.1)	(29.4)	(37.2)	(3.8)
Year 16	(2.1)	(27.8)	(50.1)	(29.3)	(41.2)	(46.9)	(15.1)	(29.4)	(37.2)	(3.8)
Year 17	(2.1)	(27.8)	(50.1)	(29.3)	(41.2)	(46.9)	(15.1)	(29.4)	(37.2)	(3.8)
Year 18	(2.1)	(27.8)	(50.1)	(29.3)	(41.2)	(46.9)	(15.1)	(29.4)	(37.2)	(3.8)
Year 19	(2.1)	(27.8)	(50.1)	(29.3)	(41.2)	(46.9)	(15.1)	(29.4)	(37.2)	(3.8)
Year 20	(2.1)	(27.8)	(50.1)	(75.1)	(41.2)	(46.9)	(62.6)	(29.4)	(37.2)	(30.0)
Year 21	(2.1)	(27.8)	(50.1)	(75.1)	(41.2)	(46.9)	(62.6)	(29.4)	(37.2)	(30.0)
Year 22	(2.1)	(27.8)	(50.1)	(75.1)	(41.2)	(46.9)	(62.6)	(29.4)	(37.2)	(30.0)
Year 23	(2.1)	(27.8)	(50.1)	(75.1)	(41.2)	(46.9)	(62.6)	(29.4)	(37.2)	(30.0)
Year 24	(2.1)	(27.8)	(50.1)	(75.1)	(41.2)	(46.9)	(62.6)	(29.4)	(37.2)	(30.0)
Year 25	(2.1)	(27.8)	(50.1)	(75.1)	(41.2)	(46.9)	(62.6)	(29.4)	(37.2)	(30.0)
Year 26	(2.1)	(27.8)	(50.1)	(75.1)	(41.2)	(46.9)	(62.6)	(29.4)	(37.2)	(30.0)
Year 27	(2.1)	(27.8)	(50.1)	(75.1)	(41.2)	(46.9)	(62.6)	(29.4)	(37.2)	(30.0)
Year 28	(2.1)	(27.8)	(50.1)	(75.1)	(41.2)	(46.9)	(62.6)	(29.4)	(37.2)	(30.0)
Year 29	(2.1)	(27.8)	(50.1)	(75.1)	(41.2)	(46.9)	(62.6)	(29.4)	(37.2)	(30.0)

[354] Parentheses indicate a net reduction in GHG emissions.

Table 4.2.4-6: 30-year stream of emissions for 2023 standards using low biofuel/high petroleum lifecycle analysis estimates for individual biofuels, relative to the No RFS baseline, presented in millions of metric tons CO_2e.[355]

	Landfill Biogas CNG/LNG	Agricultural Digester Biogas CNG/LNG	Wood Waste/ MSW Diesel/Jet Fuel	Soybean/ Canola Oil Biodiesel	Fats/Oils/ Greases Biodiesel	Corn Oil Biodiesel	Soybean Oil Renewable Diesel	Fats/Oils/ Greases Renewable Diesel	Corn Oil Renewable Diesel	Corn Starch Ethanol
2023	(0.3)	(2.2)	-	75.2	(2.0)	(1.3)	77.3	(2.9)	(0.8)	16.9
2024	(0.3)	(2.2)	-	(13.9)	(2.0)	(1.3)	(12.0)	(2.9)	(0.8)	(3.4)
2025	(0.3)	(2.2)	-	(13.9)	(2.0)	(1.3)	(12.0)	(2.9)	(0.8)	(3.4)
2026	(0.3)	(2.2)	-	(13.9)	(2.0)	(1.3)	(12.0)	(2.9)	(0.8)	(3.4)
2027	(0.3)	(2.2)	-	(13.9)	(2.0)	(1.3)	(12.0)	(2.9)	(0.8)	(3.4)
2028	(0.3)	(2.2)	-	(13.9)	(2.0)	(1.3)	(12.0)	(2.9)	(0.8)	(3.4)
2029	(0.3)	(2.2)	-	(13.9)	(2.0)	(1.3)	(12.0)	(2.9)	(0.8)	(3.4)
2030	(0.3)	(2.2)	-	(13.9)	(2.0)	(1.3)	(12.0)	(2.9)	(0.8)	(3.4)
2031	(0.3)	(2.2)	-	(13.9)	(2.0)	(1.3)	(12.0)	(2.9)	(0.8)	(3.4)
2032	(0.3)	(2.2)	-	(13.9)	(2.0)	(1.3)	(12.0)	(2.9)	(0.8)	(3.4)
2033	(0.3)	(2.2)	-	(13.9)	(2.0)	(1.3)	(12.0)	(2.9)	(0.8)	(3.4)
2034	(0.3)	(2.2)	-	(13.9)	(2.0)	(1.3)	(12.0)	(2.9)	(0.8)	(3.4)
2035	(0.3)	(2.2)	-	(13.9)	(2.0)	(1.3)	(12.0)	(2.9)	(0.8)	(3.4)
2036	(0.3)	(2.2)	-	(13.9)	(2.0)	(1.3)	(12.0)	(2.9)	(0.8)	(3.4)
2037	(0.3)	(2.2)	-	(13.9)	(2.0)	(1.3)	(12.0)	(2.9)	(0.8)	(3.4)
2038	(0.3)	(2.2)	-	(13.9)	(2.0)	(1.3)	(12.0)	(2.9)	(0.8)	(3.4)
2039	(0.3)	(2.2)	-	(13.9)	(2.0)	(1.3)	(12.0)	(2.9)	(0.8)	(3.4)
2040	(0.3)	(2.2)	-	(13.9)	(2.0)	(1.3)	(12.0)	(2.9)	(0.8)	(3.4)
2041	(0.3)	(2.2)	-	(13.9)	(2.0)	(1.3)	(12.0)	(2.9)	(0.8)	(3.4)
2042	(0.3)	(2.2)	-	(13.9)	(2.0)	(1.3)	(12.0)	(2.9)	(0.8)	(3.4)
2043	(0.3)	(2.2)	-	(10.6)	(2.0)	(1.3)	(8.7)	(2.9)	(0.8)	(3.6)
2044	(0.3)	(2.2)	-	(10.6)	(2.0)	(1.3)	(8.7)	(2.9)	(0.8)	(3.6)
2045	(0.3)	(2.2)	-	(10.6)	(2.0)	(1.3)	(8.7)	(2.9)	(0.8)	(3.6)
2046	(0.3)	(2.2)	-	(10.6)	(2.0)	(1.3)	(8.7)	(2.9)	(0.8)	(3.6)
2047	(0.3)	(2.2)	-	(10.6)	(2.0)	(1.3)	(8.7)	(2.9)	(0.8)	(3.6)
2048	(0.3)	(2.2)	-	(10.6)	(2.0)	(1.3)	(8.7)	(2.9)	(0.8)	(3.6)
2049	(0.3)	(2.2)	-	(10.6)	(2.0)	(1.3)	(8.7)	(2.9)	(0.8)	(3.6)
2050	(0.3)	(2.2)	-	(10.6)	(2.0)	(1.3)	(8.7)	(2.9)	(0.8)	(3.6)
2051	(0.3)	(2.2)	-	(10.6)	(2.0)	(1.3)	(8.7)	(2.9)	(0.8)	(3.6)
2052	(0.3)	(2.2)	-	(10.6)	(2.0)	(1.3)	(8.7)	(2.9)	(0.8)	(3.6)
2053	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-

[355] This analysis portrays what might be expected if, in each of the ensuing 29 years, aggregate renewable fuel consumption for each category exceeded baseline levels by the same volume as required by the rule. Parentheses indicate a net reduction in GHG emissions.

Table 4.2.4-7: 30-year stream of emissions for 2024 standards using low biofuel/high petroleum lifecycle analysis estimates for individual biofuels, relative to the No RFS baseline, presented in millions of metric tons CO_2e.[356]

	Landfill Biogas CNG/LNG	Agricultural Digester Biogas CNG/LNG	Wood Waste/ MSW Diesel/Jet Fuel	Soybean/ Canola Oil Biodiesel	Fats/Oils/ Greases Biodiesel	Corn Oil Biodiesel	Soybean Oil Renewable Diesel	Fats/Oils/ Greases Renewable Diesel	Corn Oil Renewable Diesel	Corn Starch Ethanol
2023	-	-	-	-	-	-	-	-	-	-
2024	(0.3)	(2.4)	(0.0)	(2.6)	-	-	12.6	(0.6)	(0.1)	1.7
2025	(0.3)	(2.4)	(0.0)	0.5	-	-	(2.0)	(0.6)	(0.1)	(0.3)
2026	(0.3)	(2.4)	(0.0)	0.5	-	-	(2.0)	(0.6)	(0.1)	(0.3)
2027	(0.3)	(2.4)	(0.0)	0.5	-	-	(2.0)	(0.6)	(0.1)	(0.3)
2028	(0.3)	(2.4)	(0.0)	0.5	-	-	(2.0)	(0.6)	(0.1)	(0.3)
2029	(0.3)	(2.4)	(0.0)	0.5	-	-	(2.0)	(0.6)	(0.1)	(0.3)
2030	(0.3)	(2.4)	(0.0)	0.5	-	-	(2.0)	(0.6)	(0.1)	(0.3)
2031	(0.3)	(2.4)	(0.0)	0.5	-	-	(2.0)	(0.6)	(0.1)	(0.3)
2032	(0.3)	(2.4)	(0.0)	0.5	-	-	(2.0)	(0.6)	(0.1)	(0.3)
2033	(0.3)	(2.4)	(0.0)	0.5	-	-	(2.0)	(0.6)	(0.1)	(0.3)
2034	(0.3)	(2.4)	(0.0)	0.5	-	-	(2.0)	(0.6)	(0.1)	(0.3)
2035	(0.3)	(2.4)	(0.0)	0.5	-	-	(2.0)	(0.6)	(0.1)	(0.3)
2036	(0.3)	(2.4)	(0.0)	0.5	-	-	(2.0)	(0.6)	(0.1)	(0.3)
2037	(0.3)	(2.4)	(0.0)	0.5	-	-	(2.0)	(0.6)	(0.1)	(0.3)
2038	(0.3)	(2.4)	(0.0)	0.5	-	-	(2.0)	(0.6)	(0.1)	(0.3)
2039	(0.3)	(2.4)	(0.0)	0.5	-	-	(2.0)	(0.6)	(0.1)	(0.3)
2040	(0.3)	(2.4)	(0.0)	0.5	-	-	(2.0)	(0.6)	(0.1)	(0.3)
2041	(0.3)	(2.4)	(0.0)	0.5	-	-	(2.0)	(0.6)	(0.1)	(0.3)
2042	(0.3)	(2.4)	(0.0)	0.5	-	-	(2.0)	(0.6)	(0.1)	(0.3)
2043	(0.3)	(2.4)	(0.0)	0.5	-	-	(2.0)	(0.6)	(0.1)	(0.3)
2044	(0.3)	(2.4)	(0.0)	0.4	-	-	(1.4)	(0.6)	(0.1)	(0.4)
2045	(0.3)	(2.4)	(0.0)	0.4	-	-	(1.4)	(0.6)	(0.1)	(0.4)
2046	(0.3)	(2.4)	(0.0)	0.4	-	-	(1.4)	(0.6)	(0.1)	(0.4)
2047	(0.3)	(2.4)	(0.0)	0.4	-	-	(1.4)	(0.6)	(0.1)	(0.4)
2048	(0.3)	(2.4)	(0.0)	0.4	-	-	(1.4)	(0.6)	(0.1)	(0.4)
2049	(0.3)	(2.4)	(0.0)	0.4	-	-	(1.4)	(0.6)	(0.1)	(0.4)
2050	(0.3)	(2.4)	(0.0)	0.4	-	-	(1.4)	(0.6)	(0.1)	(0.4)
2051	(0.3)	(2.4)	(0.0)	0.4	-	-	(1.4)	(0.6)	(0.1)	(0.4)
2052	(0.3)	(2.4)	(0.0)	0.4	-	-	(1.4)	(0.6)	(0.1)	(0.4)
2053	(0.3)	(2.4)	(0.0)	0.4	-	-	(1.4)	(0.6)	(0.1)	(0.4)
2054	-	-	-	-	-	-	-	-	-	-

[356] This analysis portrays what might be expected if, in each of the ensuing 29 years, aggregate renewable fuel consumption for each category exceeded baseline levels by the same volume as required by the rule. Parentheses indicate a net reduction in GHG emissions.

Table 4.2.4-8: 30-year stream of emissions for 2025 standards using low biofuel/high petroleum lifecycle analysis estimates for individual biofuels, relative to the No RFS baseline, presented in millions of metric tons CO_2e.[357]

	Landfill Biogas CNG/LNG	Agricultural Digester Biogas CNG/LNG	Wood Waste/ MSW Diesel/Jet Fuel	Soybean/ Canola Oil Biodiesel	Fats/Oils/ Greases Biodiesel	Corn Oil Biodiesel	Soybean Oil Renewable Diesel	Fats/Oils/ Greases Renewable Diesel	Corn Oil Renewable Diesel	Corn Starch Ethanol
2023	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-
2025	(0.4)	(2.7)	(0.0)	(2.6)	-	-	0.5	(0.6)	(0.1)	1.5
2026	(0.4)	(2.7)	(0.0)	0.5	-	-	(0.1)	(0.6)	(0.1)	(0.3)
2027	(0.4)	(2.7)	(0.0)	0.5	-	-	(0.1)	(0.6)	(0.1)	(0.3)
2028	(0.4)	(2.7)	(0.0)	0.5	-	-	(0.1)	(0.6)	(0.1)	(0.3)
2029	(0.4)	(2.7)	(0.0)	0.5	-	-	(0.1)	(0.6)	(0.1)	(0.3)
2030	(0.4)	(2.7)	(0.0)	0.5	-	-	(0.1)	(0.6)	(0.1)	(0.3)
2031	(0.4)	(2.7)	(0.0)	0.5	-	-	(0.1)	(0.6)	(0.1)	(0.3)
2032	(0.4)	(2.7)	(0.0)	0.5	-	-	(0.1)	(0.6)	(0.1)	(0.3)
2033	(0.4)	(2.7)	(0.0)	0.5	-	-	(0.1)	(0.6)	(0.1)	(0.3)
2034	(0.4)	(2.7)	(0.0)	0.5	-	-	(0.1)	(0.6)	(0.1)	(0.3)
2035	(0.4)	(2.7)	(0.0)	0.5	-	-	(0.1)	(0.6)	(0.1)	(0.3)
2036	(0.4)	(2.7)	(0.0)	0.5	-	-	(0.1)	(0.6)	(0.1)	(0.3)
2037	(0.4)	(2.7)	(0.0)	0.5	-	-	(0.1)	(0.6)	(0.1)	(0.3)
2038	(0.4)	(2.7)	(0.0)	0.5	-	-	(0.1)	(0.6)	(0.1)	(0.3)
2039	(0.4)	(2.7)	(0.0)	0.5	-	-	(0.1)	(0.6)	(0.1)	(0.3)
2040	(0.4)	(2.7)	(0.0)	0.5	-	-	(0.1)	(0.6)	(0.1)	(0.3)
2041	(0.4)	(2.7)	(0.0)	0.5	-	-	(0.1)	(0.6)	(0.1)	(0.3)
2042	(0.4)	(2.7)	(0.0)	0.5	-	-	(0.1)	(0.6)	(0.1)	(0.3)
2043	(0.4)	(2.7)	(0.0)	0.5	-	-	(0.1)	(0.6)	(0.1)	(0.3)
2044	(0.4)	(2.7)	(0.0)	0.5	-	-	(0.1)	(0.6)	(0.1)	(0.3)
2045	(0.4)	(2.7)	(0.0)	0.4	-	-	(0.1)	(0.6)	(0.1)	(0.3)
2046	(0.4)	(2.7)	(0.0)	0.4	-	-	(0.1)	(0.6)	(0.1)	(0.3)
2047	(0.4)	(2.7)	(0.0)	0.4	-	-	(0.1)	(0.6)	(0.1)	(0.3)
2048	(0.4)	(2.7)	(0.0)	0.4	-	-	(0.1)	(0.6)	(0.1)	(0.3)
2049	(0.4)	(2.7)	(0.0)	0.4	-	-	(0.1)	(0.6)	(0.1)	(0.3)
2050	(0.4)	(2.7)	(0.0)	0.4	-	-	(0.1)	(0.6)	(0.1)	(0.3)
2051	(0.4)	(2.7)	(0.0)	0.4	-	-	(0.1)	(0.6)	(0.1)	(0.3)
2052	(0.4)	(2.7)	(0.0)	0.4	-	-	(0.1)	(0.6)	(0.1)	(0.3)
2053	(0.4)	(2.7)	(0.0)	0.4	-	-	(0.1)	(0.6)	(0.1)	(0.3)
2054	(0.4)	(2.7)	(0.0)	0.4	-	-	(0.1)	(0.6)	(0.1)	(0.3)

[357] This analysis portrays what might be expected if, in each of the ensuing 29 years, aggregate renewable fuel consumption for each category exceeded baseline levels by the same volume as required by the rule. Parentheses indicate a net reduction in GHG emissions.

Table 4.2.4-9: 30-year stream of emissions for combined 2023-2025 standards using low biofuel/high petroleum lifecycle analysis estimates for individual biofuels, relative to the No RFS baseline, presented in millions of metric tons CO_2e.[358]

	Landfill Biogas CNG/LNG	Agricultural Digester Biogas CNG/LNG	Wood Waste/ MSW Diesel/Jet Fuel	Soybean/ Canola Oil Biodiesel	Fats/Oils/ Greases Biodiesel	Corn Oil Biodiesel	Soybean Oil Renewable Diesel	Fats/Oils/ Greases Renewable Diesel	Corn Oil Renewable Diesel	Corn Starch Ethanol
2023	(0.3)	(2.2)	-	75.2	(2.0)	(1.3)	77.3	(2.9)	(0.8)	16.9
2024	(0.6)	(4.6)	(0.0)	(16.5)	(2.0)	(1.3)	0.6	(3.5)	(0.9)	(1.7)
2025	(1.0)	(7.3)	(0.0)	(16.0)	(2.0)	(1.3)	(13.5)	(4.1)	(1.0)	(2.2)
2026	(1.0)	(7.3)	(0.0)	(13.0)	(2.0)	(1.3)	(14.0)	(4.1)	(1.0)	(4.0)
2027	(1.0)	(7.3)	(0.0)	(13.0)	(2.0)	(1.3)	(14.0)	(4.1)	(1.0)	(4.0)
2028	(1.0)	(7.3)	(0.0)	(13.0)	(2.0)	(1.3)	(14.0)	(4.1)	(1.0)	(4.0)
2029	(1.0)	(7.3)	(0.0)	(13.0)	(2.0)	(1.3)	(14.0)	(4.1)	(1.0)	(4.0)
2030	(1.0)	(7.3)	(0.0)	(13.0)	(2.0)	(1.3)	(14.0)	(4.1)	(1.0)	(4.0)
2031	(1.0)	(7.3)	(0.0)	(13.0)	(2.0)	(1.3)	(14.0)	(4.1)	(1.0)	(4.0)
2032	(1.0)	(7.3)	(0.0)	(13.0)	(2.0)	(1.3)	(14.0)	(4.1)	(1.0)	(4.0)
2033	(1.0)	(7.3)	(0.0)	(13.0)	(2.0)	(1.3)	(14.0)	(4.1)	(1.0)	(4.0)
2034	(1.0)	(7.3)	(0.0)	(13.0)	(2.0)	(1.3)	(14.0)	(4.1)	(1.0)	(4.0)
2035	(1.0)	(7.3)	(0.0)	(13.0)	(2.0)	(1.3)	(14.0)	(4.1)	(1.0)	(4.0)
2036	(1.0)	(7.3)	(0.0)	(13.0)	(2.0)	(1.3)	(14.0)	(4.1)	(1.0)	(4.0)
2037	(1.0)	(7.3)	(0.0)	(13.0)	(2.0)	(1.3)	(14.0)	(4.1)	(1.0)	(4.0)
2038	(1.0)	(7.3)	(0.0)	(13.0)	(2.0)	(1.3)	(14.0)	(4.1)	(1.0)	(4.0)
2039	(1.0)	(7.3)	(0.0)	(13.0)	(2.0)	(1.3)	(14.0)	(4.1)	(1.0)	(4.0)
2040	(1.0)	(7.3)	(0.0)	(13.0)	(2.0)	(1.3)	(14.0)	(4.1)	(1.0)	(4.0)
2041	(1.0)	(7.3)	(0.0)	(13.0)	(2.0)	(1.3)	(14.0)	(4.1)	(1.0)	(4.0)
2042	(1.0)	(7.3)	(0.0)	(13.0)	(2.0)	(1.3)	(14.0)	(4.1)	(1.0)	(4.0)
2043	(1.0)	(7.3)	(0.0)	(9.6)	(2.0)	(1.3)	(10.7)	(4.1)	(1.0)	(4.3)
2044	(1.0)	(7.3)	(0.0)	(9.7)	(2.0)	(1.3)	(10.2)	(4.1)	(1.0)	(4.3)
2045	(1.0)	(7.3)	(0.0)	(9.8)	(2.0)	(1.3)	(10.1)	(4.1)	(1.0)	(4.3)
2046	(1.0)	(7.3)	(0.0)	(9.8)	(2.0)	(1.3)	(10.1)	(4.1)	(1.0)	(4.3)
2047	(1.0)	(7.3)	(0.0)	(9.8)	(2.0)	(1.3)	(10.1)	(4.1)	(1.0)	(4.3)
2048	(1.0)	(7.3)	(0.0)	(9.8)	(2.0)	(1.3)	(10.1)	(4.1)	(1.0)	(4.3)
2049	(1.0)	(7.3)	(0.0)	(9.8)	(2.0)	(1.3)	(10.1)	(4.1)	(1.0)	(4.3)
2050	(1.0)	(7.3)	(0.0)	(9.8)	(2.0)	(1.3)	(10.1)	(4.1)	(1.0)	(4.3)
2051	(1.0)	(7.3)	(0.0)	(9.8)	(2.0)	(1.3)	(10.1)	(4.1)	(1.0)	(4.3)
2052	(1.0)	(7.3)	(0.0)	(9.8)	(2.0)	(1.3)	(10.1)	(4.1)	(1.0)	(4.3)
2053	(0.7)	(5.1)	(0.0)	0.7	-	-	(1.5)	(1.2)	(0.1)	(0.7)
2054	(0.4)	(2.7)	(0.0)	0.4	-	-	(0.1)	(0.6)	(0.1)	(0.3)

[358] This analysis portrays what might be expected if, in each of the ensuing 29 years, aggregate renewable fuel consumption for each category exceeded baseline levels by the same volume as required by the rule. Parentheses indicate a net reduction in GHG emissions.

Table 4.2.4-10: 30-year stream of emissions for 2023 standards using high biofuel/low petroleum lifecycle analysis estimates for individual biofuels, relative to the No RFS baseline, presented in millions of metric tons CO_2e.[359]

	Landfill Biogas CNG/LNG	Agricultural Digester Biogas CNG/LNG	Wood Waste/ MSW Diesel/Jet Fuel	Soybean/ Canola Oil Biodiesel	Fats/Oils/ Greases Biodiesel	Corn Oil Biodiesel	Soybean Oil Renewable Diesel	Fats/Oils/ Greases Renewable Diesel	Corn Oil Renewable Diesel	Corn Starch Ethanol
2023	(0.0)	(0.1)	-	117.3	(1.0)	(0.7)	119.0	(1.0)	(0.4)	33.1
2024	(0.0)	(0.1)	-	(3.6)	(1.0)	(0.7)	(1.8)	(1.0)	(0.4)	(0.2)
2025	(0.0)	(0.1)	-	(3.6)	(1.0)	(0.7)	(1.8)	(1.0)	(0.4)	(0.2)
2026	(0.0)	(0.1)	-	(3.6)	(1.0)	(0.7)	(1.8)	(1.0)	(0.4)	(0.2)
2027	(0.0)	(0.1)	-	(3.6)	(1.0)	(0.7)	(1.8)	(1.0)	(0.4)	(0.2)
2028	(0.0)	(0.1)	-	(3.6)	(1.0)	(0.7)	(1.8)	(1.0)	(0.4)	(0.2)
2029	(0.0)	(0.1)	-	(3.6)	(1.0)	(0.7)	(1.8)	(1.0)	(0.4)	(0.2)
2030	(0.0)	(0.1)	-	(3.6)	(1.0)	(0.7)	(1.8)	(1.0)	(0.4)	(0.2)
2031	(0.0)	(0.1)	-	(3.6)	(1.0)	(0.7)	(1.8)	(1.0)	(0.4)	(0.2)
2032	(0.0)	(0.1)	-	(3.6)	(1.0)	(0.7)	(1.8)	(1.0)	(0.4)	(0.2)
2033	(0.0)	(0.1)	-	(3.6)	(1.0)	(0.7)	(1.8)	(1.0)	(0.4)	(0.2)
2034	(0.0)	(0.1)	-	(3.6)	(1.0)	(0.7)	(1.8)	(1.0)	(0.4)	(0.2)
2035	(0.0)	(0.1)	-	(3.6)	(1.0)	(0.7)	(1.8)	(1.0)	(0.4)	(0.2)
2036	(0.0)	(0.1)	-	(3.6)	(1.0)	(0.7)	(1.8)	(1.0)	(0.4)	(0.2)
2037	(0.0)	(0.1)	-	(3.6)	(1.0)	(0.7)	(1.8)	(1.0)	(0.4)	(0.2)
2038	(0.0)	(0.1)	-	(3.6)	(1.0)	(0.7)	(1.8)	(1.0)	(0.4)	(0.2)
2039	(0.0)	(0.1)	-	(3.6)	(1.0)	(0.7)	(1.8)	(1.0)	(0.4)	(0.2)
2040	(0.0)	(0.1)	-	(3.6)	(1.0)	(0.7)	(1.8)	(1.0)	(0.4)	(0.2)
2041	(0.0)	(0.1)	-	(3.6)	(1.0)	(0.7)	(1.8)	(1.0)	(0.4)	(0.2)
2042	(0.0)	(0.1)	-	(3.6)	(1.0)	(0.7)	(1.8)	(1.0)	(0.4)	(0.2)
2043	(0.0)	(0.1)	-	(9.2)	(1.0)	(0.7)	(7.3)	(1.0)	(0.4)	(1.7)
2044	(0.0)	(0.1)	-	(9.2)	(1.0)	(0.7)	(7.3)	(1.0)	(0.4)	(1.7)
2045	(0.0)	(0.1)	-	(9.2)	(1.0)	(0.7)	(7.3)	(1.0)	(0.4)	(1.7)
2046	(0.0)	(0.1)	-	(9.2)	(1.0)	(0.7)	(7.3)	(1.0)	(0.4)	(1.7)
2047	(0.0)	(0.1)	-	(9.2)	(1.0)	(0.7)	(7.3)	(1.0)	(0.4)	(1.7)
2048	(0.0)	(0.1)	-	(9.2)	(1.0)	(0.7)	(7.3)	(1.0)	(0.4)	(1.7)
2049	(0.0)	(0.1)	-	(9.2)	(1.0)	(0.7)	(7.3)	(1.0)	(0.4)	(1.7)
2050	(0.0)	(0.1)	-	(9.2)	(1.0)	(0.7)	(7.3)	(1.0)	(0.4)	(1.7)
2051	(0.0)	(0.1)	-	(9.2)	(1.0)	(0.7)	(7.3)	(1.0)	(0.4)	(1.7)
2052	(0.0)	(0.1)	-	(9.2)	(1.0)	(0.7)	(7.3)	(1.0)	(0.4)	(1.7)
2053	-	-	-	-	-	-	-	-	-	-
2054	-	-	-	-	-	-	-	-	-	-

[359] This analysis portrays what might be expected if, in each of the ensuing 29 years, aggregate renewable fuel consumption for each category exceeded baseline levels by the same volume as required by the rule. Parentheses indicate a net reduction in GHG emissions.

Table 4.2.4-11: 30-year stream of emissions for 2024 standards using high biofuel/low petroleum lifecycle analysis estimates for individual biofuels, relative to the No RFS baseline, presented in millions of metric tons CO_2e.[360]

	Landfill Biogas CNG/LNG	Agricultural Digester Biogas CNG/LNG	Wood Waste/ MSW Diesel/Jet Fuel	Soybean/ Canola Oil Biodiesel	Fats/Oils/ Greases Biodiesel	Corn Oil Biodiesel	Soybean Oil Renewable Diesel	Fats/Oils/ Greases Renewable Diesel	Corn Oil Renewable Diesel	Corn Starch Ethanol
2023	-	-	-	-	-	-	-	-	-	-
2024	(0.0)	(0.1)	(0.0)	(4.0)	-	-	19.4	(0.2)	(0.0)	3.3
2025	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.3)	(0.2)	(0.0)	(0.0)
2026	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.3)	(0.2)	(0.0)	(0.0)
2027	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.3)	(0.2)	(0.0)	(0.0)
2028	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.3)	(0.2)	(0.0)	(0.0)
2029	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.3)	(0.2)	(0.0)	(0.0)
2030	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.3)	(0.2)	(0.0)	(0.0)
2031	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.3)	(0.2)	(0.0)	(0.0)
2032	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.3)	(0.2)	(0.0)	(0.0)
2033	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.3)	(0.2)	(0.0)	(0.0)
2034	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.3)	(0.2)	(0.0)	(0.0)
2035	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.3)	(0.2)	(0.0)	(0.0)
2036	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.3)	(0.2)	(0.0)	(0.0)
2037	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.3)	(0.2)	(0.0)	(0.0)
2038	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.3)	(0.2)	(0.0)	(0.0)
2039	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.3)	(0.2)	(0.0)	(0.0)
2040	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.3)	(0.2)	(0.0)	(0.0)
2041	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.3)	(0.2)	(0.0)	(0.0)
2042	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.3)	(0.2)	(0.0)	(0.0)
2043	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.3)	(0.2)	(0.0)	(0.0)
2044	(0.0)	(0.1)	(0.0)	0.3	-	-	(1.2)	(0.2)	(0.0)	(0.2)
2045	(0.0)	(0.1)	(0.0)	0.3	-	-	(1.2)	(0.2)	(0.0)	(0.2)
2046	(0.0)	(0.1)	(0.0)	0.3	-	-	(1.2)	(0.2)	(0.0)	(0.2)
2047	(0.0)	(0.1)	(0.0)	0.3	-	-	(1.2)	(0.2)	(0.0)	(0.2)
2048	(0.0)	(0.1)	(0.0)	0.3	-	-	(1.2)	(0.2)	(0.0)	(0.2)
2049	(0.0)	(0.1)	(0.0)	0.3	-	-	(1.2)	(0.2)	(0.0)	(0.2)
2050	(0.0)	(0.1)	(0.0)	0.3	-	-	(1.2)	(0.2)	(0.0)	(0.2)
2051	(0.0)	(0.1)	(0.0)	0.3	-	-	(1.2)	(0.2)	(0.0)	(0.2)
2052	(0.0)	(0.1)	(0.0)	0.3	-	-	(1.2)	(0.2)	(0.0)	(0.2)
2053	(0.0)	(0.1)	(0.0)	0.3	-	-	(1.2)	(0.2)	(0.0)	(0.2)
2054	-	-	-	-	-	-	-	-	-	-

[360] This analysis portrays what might be expected if, in each of the ensuing 29 years, aggregate renewable fuel consumption for each category exceeded baseline levels by the same volume as required by the rule. Parentheses indicate a net reduction in GHG emissions.

Table 4.2.4-12: 30-year stream of emissions for 2025 standards using high biofuel/low petroleum lifecycle analysis estimates for individual biofuels, relative to the No RFS baseline, presented in millions of metric tons CO_2e.[361]

	Landfill Biogas CNG/LNG	Agricultural Digester Biogas CNG/LNG	Wood Waste/ MSW Diesel/Jet Fuel	Soybean/ Canola Oil Biodiesel	Fats/Oils/ Greases Biodiesel	Corn Oil Biodiesel	Soybean Oil Renewable Diesel	Fats/Oils/ Greases Renewable Diesel	Corn Oil Renewable Diesel	Corn Starch Ethanol
2023	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-
2025	(0.0)	(0.1)	(0.0)	(4.0)	-	-	0.8	(0.2)	(0.0)	3.0
2026	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.0)	(0.2)	(0.0)	(0.0)
2027	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.0)	(0.2)	(0.0)	(0.0)
2028	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.0)	(0.2)	(0.0)	(0.0)
2029	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.0)	(0.2)	(0.0)	(0.0)
2030	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.0)	(0.2)	(0.0)	(0.0)
2031	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.0)	(0.2)	(0.0)	(0.0)
2032	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.0)	(0.2)	(0.0)	(0.0)
2033	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.0)	(0.2)	(0.0)	(0.0)
2034	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.0)	(0.2)	(0.0)	(0.0)
2035	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.0)	(0.2)	(0.0)	(0.0)
2036	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.0)	(0.2)	(0.0)	(0.0)
2037	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.0)	(0.2)	(0.0)	(0.0)
2038	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.0)	(0.2)	(0.0)	(0.0)
2039	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.0)	(0.2)	(0.0)	(0.0)
2040	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.0)	(0.2)	(0.0)	(0.0)
2041	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.0)	(0.2)	(0.0)	(0.0)
2042	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.0)	(0.2)	(0.0)	(0.0)
2043	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.0)	(0.2)	(0.0)	(0.0)
2044	(0.0)	(0.1)	(0.0)	0.1	-	-	(0.0)	(0.2)	(0.0)	(0.0)
2045	(0.0)	(0.1)	(0.0)	0.3	-	-	(0.0)	(0.2)	(0.0)	(0.2)
2046	(0.0)	(0.1)	(0.0)	0.3	-	-	(0.0)	(0.2)	(0.0)	(0.2)
2047	(0.0)	(0.1)	(0.0)	0.3	-	-	(0.0)	(0.2)	(0.0)	(0.2)
2048	(0.0)	(0.1)	(0.0)	0.3	-	-	(0.0)	(0.2)	(0.0)	(0.2)
2049	(0.0)	(0.1)	(0.0)	0.3	-	-	(0.0)	(0.2)	(0.0)	(0.2)
2050	(0.0)	(0.1)	(0.0)	0.3	-	-	(0.0)	(0.2)	(0.0)	(0.2)
2051	(0.0)	(0.1)	(0.0)	0.3	-	-	(0.0)	(0.2)	(0.0)	(0.2)
2052	(0.0)	(0.1)	(0.0)	0.3	-	-	(0.0)	(0.2)	(0.0)	(0.2)
2053	(0.0)	(0.1)	(0.0)	0.3	-	-	(0.0)	(0.2)	(0.0)	(0.2)
2054	(0.0)	(0.1)	(0.0)	0.3	-	-	(0.0)	(0.2)	(0.0)	(0.2)

[361] This analysis portrays what might be expected if, in each of the ensuing 29 years, aggregate renewable fuel consumption for each category exceeded baseline levels by the same volume as required by the rule. Parentheses indicate a net reduction in GHG emissions.

Table 4.2.4-13: 30-year stream of emissions for combined 2023-2025 standards using high biofuel/low petroleum lifecycle analysis estimates for individual biofuels, relative to the No RFS baseline, presented in millions of metric tons CO_2e.[362]

	Landfill Biogas CNG/LNG	Agricultural Digester Biogas CNG/LNG	Wood Waste/ MSW Diesel/Jet Fuel	Soybean/ Canola Oil Biodiesel	Fats/Oils/ Greases Biodiesel	Corn Oil Biodiesel	Soybean Oil Renewable Diesel	Fats/Oils/ Greases Renewable Diesel	Corn Oil Renewable Diesel	Corn Starch Ethanol
2023	(0.0)	(0.1)	-	117.3	(1.0)	(0.7)	119.0	(1.0)	(0.4)	33.1
2024	(0.0)	(0.2)	(0.0)	(7.6)	(1.0)	(0.7)	17.7	(1.3)	(0.4)	3.1
2025	(0.0)	(0.3)	(0.0)	(7.5)	(1.0)	(0.7)	(1.3)	(1.5)	(0.4)	2.8
2026	(0.0)	(0.3)	(0.0)	(3.3)	(1.0)	(0.7)	(2.1)	(1.5)	(0.4)	(0.3)
2027	(0.0)	(0.3)	(0.0)	(3.3)	(1.0)	(0.7)	(2.1)	(1.5)	(0.4)	(0.3)
2028	(0.0)	(0.3)	(0.0)	(3.3)	(1.0)	(0.7)	(2.1)	(1.5)	(0.4)	(0.3)
2029	(0.0)	(0.3)	(0.0)	(3.3)	(1.0)	(0.7)	(2.1)	(1.5)	(0.4)	(0.3)
2030	(0.0)	(0.3)	(0.0)	(3.3)	(1.0)	(0.7)	(2.1)	(1.5)	(0.4)	(0.3)
2031	(0.0)	(0.3)	(0.0)	(3.3)	(1.0)	(0.7)	(2.1)	(1.5)	(0.4)	(0.3)
2032	(0.0)	(0.3)	(0.0)	(3.3)	(1.0)	(0.7)	(2.1)	(1.5)	(0.4)	(0.3)
2033	(0.0)	(0.3)	(0.0)	(3.3)	(1.0)	(0.7)	(2.1)	(1.5)	(0.4)	(0.3)
2034	(0.0)	(0.3)	(0.0)	(3.3)	(1.0)	(0.7)	(2.1)	(1.5)	(0.4)	(0.3)
2035	(0.0)	(0.3)	(0.0)	(3.3)	(1.0)	(0.7)	(2.1)	(1.5)	(0.4)	(0.3)
2036	(0.0)	(0.3)	(0.0)	(3.3)	(1.0)	(0.7)	(2.1)	(1.5)	(0.4)	(0.3)
2037	(0.0)	(0.3)	(0.0)	(3.3)	(1.0)	(0.7)	(2.1)	(1.5)	(0.4)	(0.3)
2038	(0.0)	(0.3)	(0.0)	(3.3)	(1.0)	(0.7)	(2.1)	(1.5)	(0.4)	(0.3)
2039	(0.0)	(0.3)	(0.0)	(3.3)	(1.0)	(0.7)	(2.1)	(1.5)	(0.4)	(0.3)
2040	(0.0)	(0.3)	(0.0)	(3.3)	(1.0)	(0.7)	(2.1)	(1.5)	(0.4)	(0.3)
2041	(0.0)	(0.3)	(0.0)	(3.3)	(1.0)	(0.7)	(2.1)	(1.5)	(0.4)	(0.3)
2042	(0.0)	(0.3)	(0.0)	(3.3)	(1.0)	(0.7)	(2.1)	(1.5)	(0.4)	(0.3)
2043	(0.0)	(0.3)	(0.0)	(8.9)	(1.0)	(0.7)	(7.6)	(1.5)	(0.4)	(1.7)
2044	(0.0)	(0.3)	(0.0)	(8.7)	(1.0)	(0.7)	(8.5)	(1.5)	(0.4)	(1.9)
2045	(0.0)	(0.3)	(0.0)	(8.5)	(1.0)	(0.7)	(8.6)	(1.5)	(0.4)	(2.0)
2046	(0.0)	(0.3)	(0.0)	(8.5)	(1.0)	(0.7)	(8.6)	(1.5)	(0.4)	(2.0)
2047	(0.0)	(0.3)	(0.0)	(8.5)	(1.0)	(0.7)	(8.6)	(1.5)	(0.4)	(2.0)
2048	(0.0)	(0.3)	(0.0)	(8.5)	(1.0)	(0.7)	(8.6)	(1.5)	(0.4)	(2.0)
2049	(0.0)	(0.3)	(0.0)	(8.5)	(1.0)	(0.7)	(8.6)	(1.5)	(0.4)	(2.0)
2050	(0.0)	(0.3)	(0.0)	(8.5)	(1.0)	(0.7)	(8.6)	(1.5)	(0.4)	(2.0)
2051	(0.0)	(0.3)	(0.0)	(8.5)	(1.0)	(0.7)	(8.6)	(1.5)	(0.4)	(2.0)
2052	(0.0)	(0.3)	(0.0)	(8.5)	(1.0)	(0.7)	(8.6)	(1.5)	(0.4)	(2.0)
2053	(0.0)	(0.2)	(0.0)	0.6	-	-	(1.2)	(0.4)	(0.1)	(0.3)
2054	(0.0)	(0.1)	(0.0)	0.3	-	-	(0.0)	(0.2)	(0.0)	(0.2)

[362] This analysis portrays what might be expected if, in each of the ensuing 29 years, aggregate renewable fuel consumption for each category exceeded baseline levels by the same volume as required by the rule. Parentheses indicate a net reduction in GHG emissions.

Table 4.2.4-14: 30-year stream of lifecycle analysis estimates for volume changes from 2023 supplemental volume requirement, represented by soybean renewable diesel compared to petroleum diesel, presented in millions of metric tons CO_2e.[363]

	Low Biofuel/High Petroleum	High Biofuel/Low Petroleum
2023	12.6	19.4
2024	(2.0)	(0.3)
2025	(2.0)	(0.3)
2026	(2.0)	(0.3)
2027	(2.0)	(0.3)
2028	(2.0)	(0.3)
2029	(2.0)	(0.3)
2030	(2.0)	(0.3)
2031	(2.0)	(0.3)
2032	(2.0)	(0.3)
2033	(2.0)	(0.3)
2034	(2.0)	(0.3)
2035	(2.0)	(0.3)
2036	(2.0)	(0.3)
2037	(2.0)	(0.3)
2038	(2.0)	(0.3)
2039	(2.0)	(0.3)
2040	(2.0)	(0.3)
2041	(2.0)	(0.3)
2042	(2.0)	(0.3)
2043	(1.4)	(1.2)
2044	(1.4)	(1.2)
2045	(1.4)	(1.2)
2046	(1.4)	(1.2)
2047	(1.4)	(1.2)
2048	(1.4)	(1.2)
2049	(1.4)	(1.2)
2050	(1.4)	(1.2)
2051	(1.4)	(1.2)
2052	(1.4)	(1.2)
2053	-	-
2054	-	-

[363] This analysis portrays what might be expected if, in each of the ensuing 29 years, aggregate renewable fuel consumption for each category exceeded baseline levels by the same volume as required by the rule. Parentheses indicate a net reduction in GHG emissions.

4.2.5 Monetized GHG Impacts

4.2.5.1 Social Cost of Greenhouse Gases

For assessing GHG impacts in this illustrative scenario, we rely upon past biofuel emissions reductions estimates that are available in CO_2e—carbon equivalent emissions using the global warming potentials utilized in those analyses.[364] We estimate the social benefits of GHG reductions in this illustrative scenario using estimates of the social cost of greenhouse gases (SC-GHG)[365], specifically using the SC-CO_2 estimates presented in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (hereinafter the "February 2021 TSD").[366] The SC-GHG is the monetary value of the net harm to society associated with a marginal increase in GHG emissions in a given year, or the benefit of avoiding that increase. In principle, SC-GHG includes the value of all climate change impacts (both negative and positive), including (but not limited to) changes in net agricultural productivity, human health effects, property damage from increased flood risk and natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. The SC-GHG therefore, reflects the societal value of reducing emissions of the gas in question by one metric ton. The SC-GHG is the theoretically appropriate value to use in conducting benefit-cost analyses of policies that affect GHG emissions. In practice, data and modeling limitations naturally restrain the ability of SC-GHG estimates to include all the important physical, ecological, and economic impacts of climate change, such that the estimates are a partial accounting of climate change impacts and will therefore, tend to be underestimates of the marginal benefits of abatement.

We have evaluated the SC-GHG estimates in the February 2021 TSD and have determined that these estimates are appropriate for use in estimating the social benefits of GHG reductions in this illustrative scenario. These SC-GHG estimates are interim values developed for use in benefit-cost analyses until updated estimates of the impacts of climate change can be developed based on the best available science and economics. After considering the TSD, and the issues and studies discussed therein, EPA finds that these estimates, while likely an underestimate, are the best currently available SC-GHG estimates.

EPA and other federal agencies began regularly incorporating SC-CO_2 estimates in benefit-cost analyses conducted under Executive Order (E.O.) 12866[367] in 2008, following a court ruling in which an agency was ordered to consider the value of reducing CO_2 emissions in a

[364] It would be preferable to use estimates for each gas (e.g., CO_2, CH_4, N_2O), but we use CO2e estimates for this illustrative scenario as they are the most readily available biofuel carbon intensity estimates.

[365] Estimates of the social cost of greenhouse gases are gas specific (e.g., social cost of carbon (SC-CO_2), social cost of methane (SC-CH_4), social cost of nitrous oxide (SC-N_2O)), but collectively they are referenced as the social cost of greenhouse gases (SC-GHG).

[366] Interagency Working Group on Social Cost of Greenhouse Gases (IWG). 2021. Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990. February. United States Government. Available at: https://www.whitehouse.gov/briefing-room/blog/2021/02/26/a-return-to-science-evidence-based-estimates-of-the-benefits-of-reducing-climate-pollution/.

[367] Under E.O. 12866, agencies are required, to the extent permitted by law and where applicable, "to assess both the costs and the benefits of the intended regulation and, recognizing that some costs and benefits are difficult to quantify, propose or adopt a regulation only upon a reasoned determination that the benefits of the intended regulation justify its costs."

rulemaking process. The SC-CO_2 estimates presented here were developed over many years, using a transparent process, peer-reviewed methodologies, the best science available at the time of that process, and with input from the public. Specifically, in 2009, an interagency working group (IWG) that included the EPA and other executive branch agencies and offices was established to develop estimates relying on the best available science for agencies to use. The IWG published SC-CO_2 estimates in 2010 that were developed from an ensemble of three widely cited integrated assessment models (IAMs) that estimate global climate damages using highly aggregated representations of climate processes and the global economy combined into a single modeling framework. The three IAMs were run using a common set of input assumptions in each model for future population, economic, and CO_2 emissions growth, as well as equilibrium climate sensitivity (ECS)—a measure of the globally averaged temperature response to increased atmospheric CO_2 concentrations. These estimates were updated in 2013 based on new versions of each IAM.[368,369,370] In August 2016 the IWG published estimates of the social cost of methane (SC-CH_4) and nitrous oxide (SC-N_2O) using methodologies that are consistent with the methodology underlying the SC-CO_2 estimates. In 2015, as part of the response to public comments received to a 2013 solicitation for comments on the SC-CO_2 estimates, the IWG announced a National Academies of Sciences, Engineering, and Medicine review of the SC-CO_2 estimates to offer advice on how to approach future updates to ensure that the estimates continue to reflect the best available science and methodologies. In January 2017, the National Academies released their final report, *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide*, and recommended specific criteria for future updates to the SC-CO_2 estimates, a modeling framework to satisfy the specified criteria, and both near-term updates and longer-term research needs pertaining to various components of the estimation process.[371] Shortly thereafter, in March 2017, President Trump issued Executive Order 13783, which disbanded the IWG, withdrew the previous TSDs, and directed agencies to ensure SC-CO_2 estimates used in regulatory analyses are consistent with the guidance contained in OMB's Circular A-4, "including with respect to the consideration of domestic versus international impacts and the consideration of appropriate discount rates" (E.O. 13783, Section 5(c)). Benefit-cost analyses following E.O. 13783 used SC-CO_2 estimates that attempted to focus on the U.S. specific share of climate change damages as estimated by the models and were calculated using two discount rates recommended by Circular A-4, 3 percent and 7 percent. All other methodological decisions and model versions used in SC- CO_2 calculations remained the same as those used by the IWG in 2010 and 2013, respectively.

On January 20, 2021, President Biden issued Executive Order 13990, which re-established the IWG and directed it to develop updated estimates of the social cost of carbon and other greenhouse gases that reflect the best available science and the recommendations of the National Academies. The IWG was tasked with first reviewing the SC-GHG estimates currently used in Federal analyses and publishing interim estimates within 30 days of the E.O. that reflect the full impact of GHG emissions, including by taking global damages into account.

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[368] Dynamic Integrated Climate and Economy (DICE) 2010 (Nordhaus 2010).
[369] Climate Framework for Uncertainty, Negotiation, and Distribution (FUND) 3.8 (Anthoff and Tol 2013a, 2013b)
[370] Policy Analysis of the Greenhouse Gas Effect (PAGE) 2009 (Hope 2013).
[371] National Academies of Sciences, Engineering, and Medicine (National Academies). 2017. Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide. Washington, D.C.: National Academies Press.

As noted above, EPA participated in the IWG but has also independently evaluated the interim SC-CO_2 estimates published in the February 2021 TSD and determined they are appropriate to use here to estimate the climate benefits associated with this illustrative scenario. EPA and other agencies intend to undertake a fuller update of the SC-GHG estimates that takes into consideration the advice of the National Academies (2017) and other recent scientific literature. The EPA has also evaluated the supporting rationale of the February 2021 TSD, including the studies and methodological issues discussed therein, and concludes that it agrees with the rationale for these estimates presented in the TSD and summarized below.

In particular, the IWG found that the SC-GHG estimates used under E.O. 13783 fail to reflect the full impact of GHG emissions in multiple ways. First, the IWG concluded that those estimates fail to capture many climate impacts that can affect the welfare of U.S. citizens and residents. Examples of affected interests include direct effects on U.S. citizens and assets located abroad, international trade, and tourism, and spillover pathways such as economic and political destabilization and global migration that can lead to adverse impacts on U.S. national security, public health, and humanitarian concerns. Those impacts are better captured within global measures of the social cost of greenhouse gases.

In addition, assessing the benefits of U.S. GHG mitigation activities requires consideration of how those actions may affect mitigation activities by other countries, as those international mitigation actions will provide a benefit to U.S. citizens and residents by mitigating climate impacts that affect U.S. citizens and residents. A wide range of scientific and economic experts have emphasized the issue of reciprocity as support for considering global damages of GHG emissions. Using a global estimate of damages in U.S. analyses of regulatory actions allows the U.S. to continue to actively encourage other nations, including emerging major economies, to take significant steps to reduce emissions. The only way to achieve an efficient allocation of resources for emissions reduction on a global basis—and so benefit the U.S. and its citizens—is for all countries to base their policies on global estimates of damages.

Therefore, in this illustrative analysis, EPA centers attention on a global measure of SC-GHG. This approach is the same as that taken in EPA regulatory analyses over 2009 through 2016. A robust estimate of climate damages to U.S. citizens and residents that accounts for the myriad of ways that global climate change reduces the net welfare of U.S. populations does not currently exist in the literature. As explained in the February 2021 TSD, existing estimates are both incomplete and an underestimate of total damages that accrue to the citizens and residents of the U.S. because they do not fully capture the regional interactions and spillovers discussed above, nor do they include all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature, as discussed further below. EPA, as a member of the IWG, will continue to review developments in the literature, including more robust methodologies for estimating the magnitude of the various damages to U.S. populations from climate impacts and reciprocal international mitigation activities, and explore ways to better inform the public of the full range of carbon impacts.

Second, the IWG concluded that the use of the social rate of return on capital (7 percent under current OMB Circular A-4 guidance) to discount the future benefits of reducing GHG emissions inappropriately underestimates the impacts of climate change for the purposes of estimating the SC-GHG. Consistent with the findings of the National Academies and the economic literature, the IWG continued to conclude that the consumption rate of interest is the theoretically appropriate discount rate in an intergenerational context, and recommended that discount rate uncertainty and relevant aspects of intergenerational ethical considerations be accounted for in selecting future discount rates.[372,373,374,375,376] Furthermore, the damage estimates developed for use in the SC-GHG are estimated in consumption-equivalent terms, and so an application of OMB Circular A-4's guidance for regulatory analysis would then use the consumption discount rate to calculate the SC-GHG. EPA agrees with this assessment and will continue to follow developments in the literature pertaining to this issue. EPA also notes that while OMB Circular A-4, as published in 2003, recommends using 3% and 7% discount rates as "default" values, Circular A-4 also reminds agencies that "different regulations may call for different emphases in the analysis, depending on the nature and complexity of the regulatory issues and the sensitivity of the benefit and cost estimates to the key assumptions." On discounting, Circular A-4 recognizes that "special ethical considerations arise when comparing benefits and costs across generations," and Circular A-4 acknowledges that analyses may appropriately "discount future costs and consumption benefits…at a lower rate than for intragenerational analysis." In the 2015 Response to Comments on the Social Cost of Carbon for Regulatory Impact Analysis, OMB, EPA, and the other IWG members recognized that "Circular A-4 is a living document" and "the use of 7 percent is not considered appropriate for intergenerational discounting. There is wide support for this view in the academic literature, and it is recognized in Circular A-4 itself." Thus, EPA concludes that a 7% discount rate is not an appropriate value to apply to the social cost of greenhouse gases in this analysis. In this analysis, to calculate the present and annualized values of climate benefits, EPA uses the same discount rate as the rate used to discount the value of damages from future GHG emissions, for internal consistency. That approach to discounting follows the same approach that the February 2021 TSD recommends "to ensure internal consistency—i.e., future damages from climate change using the SC-GHG at 2.5 percent should be discounted to the base year of the analysis using the same 2.5 percent rate." EPA has also consulted the National Academies' 2017 recommendations

[372] GHG emissions are stock pollutants, where damages are associated with what has accumulated in the atmosphere over time, and they are long lived such that subsequent damages resulting from emissions today occur over many decades or centuries depending on the specific greenhouse gas under consideration. In calculating the SC-GHG, the stream of future damages to agriculture, human health, and other market and non-market sectors from an additional unit of emissions are estimated in terms of reduced consumption (or consumption equivalents). Then that stream of future damages is discounted to its present value in the year when the additional unit of emissions was released. Given the long time horizon over which the damages are expected to occur, the discount rate has a large influence on the present value of future damages.

[373] Interagency Working Group on Social Cost of Carbon (IWG). 2010. Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866. February. United States Government.

[374] Interagency Working Group on Social Cost of Carbon (IWG). 2013. Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866. May. United States Government.

[375] Interagency Working Group on Social Cost of Greenhouse Gases (IWG). 2016a. Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866. August. United States Government.

[376] Interagency Working Group on the Social Cost of Greenhouse Gases. 2016b. Addendum to Technical Support Document on Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866: Application of the Methodology to Estimate the Social Cost of Methane and the Social Cost of Nitrous Oxide. August. United Stated Government. Available at: https://www.epa.gov/sites/production/files/2016-12/documents/addendum_to_sc-ghg_tsd_august_2016.pdf (accessed February 5, 2021).

on how SC-GHG estimates can "be combined in RIAs with other cost and benefits estimates that may use different discount rates." The National Academies reviewed "several options," including "presenting all discount rate combinations of other costs and benefits with [SC-GHG] estimates."

While the IWG works to assess how best to incorporate the latest, peer reviewed science to develop an updated set of SC-GHG estimates, it recommended the interim estimates to be the most recent estimates developed by the IWG prior to the group being disbanded in 2017. The estimates rely on the same models and harmonized inputs and are calculated using a range of discount rates. As explained in the February 2021 TSD, the IWG has concluded that it is appropriate for agencies to revert to the same set of four values drawn from the SC-GHG distributions based on three discount rates as were used in regulatory analyses between 2010 and 2016 and subject to public comment. For each discount rate, the IWG combined the distributions across models and socioeconomic emissions scenarios (applying equal weight to each) and then selected a set of four values for use in agency analyses: an average value resulting from the model runs for each of three discount rates (2.5 percent, 3 percent, and 5 percent), plus a fourth value, selected as the 95th percentile of estimates based on a 3 percent discount rate. The fourth value was included to provide information on potentially higher-than-expected economic impacts from climate change, conditional on the 3 percent estimate of the discount rate. As explained in the February 2021 TSD, this update reflects the immediate need to have an operational SC-GHG that was developed using a transparent process, peer-reviewed methodologies, and the science available at the time of that process.

Table 4.2.5.1-1 summarizes the interim SC-CO_2 estimates for the years 2023–2054.[377] These estimates are reported in 2020 dollars in the IWG's 2021 TSD but are otherwise identical to those presented in the IWG's 2016 TSD. For purposes of capturing uncertainty around the SC-CO_2 estimates in analyses, the February 2021 TSD emphasizes the importance of considering all four of the SC-CO_2 values. The SC-CO_2 increases over time within the models (i.e., the societal harm from one metric ton emitted in 2030 is higher than the harm caused by one metric ton emitted in 2025) because future emissions produce larger incremental damages as physical and economic systems become more stressed in response to greater climatic change, and because GDP is growing over time and many damage categories are modeled as proportional to GDP.

[377] The February 2021 TSD provides SC-GHG estimates through emissions year 2050. Estimates were extended for the period 2051 to 2054 using the IWG methods, assumptions, and parameters identical to the 2020-2050 estimates. Specifically, 2051-2054 SC-GHG estimates were calculated in Mimi.jl, an open-source modular computing platform used for creating, running, and performing analyses on IAMs (www.mimiframework.org). For CO_2, the 2051-2054 SC-GHG values were calculated by linearly interpolating between the 2050 TSD values and the 2055 Mimi-based values.

Table 4.2.5.1-1: Interim Social Cost of Carbon Values, 2023-2054 (2021$/Metric Ton CO_2)[378]

Emissions Year	Discount Rate and Statistic			
	5% Average	3% Average	2.5% Average	3% 95th Percentile
2023	$16	$55	$81	$164
2024	$17	$56	$82	$167
2025	$17	$57	$84	$171
2026	$18	$58	$85	$174
2027	$18	$59	$86	$178
2028	$19	$60	$88	$181
2029	$19	$61	$89	$185
2030	$20	$62	$90	$189
2031	$20	$64	$92	$192
2032	$21	$65	$93	$196
2033	$21	$66	$95	$200
2034	$22	$67	$96	$204
2035	$23	$68	$97	$208
2036	$23	$69	$99	$212
2037	$24	$70	$100	$216
2038	$24	$72	$101	$219
2039	$25	$73	$103	$223
2040	$25	$74	$104	$227
2041	$26	$75	$105	$231
2042	$27	$76	$107	$234
2043	$27	$77	$108	$238
2044	$28	$79	$110	$241
2045	$29	$80	$111	$245
2046	$29	$81	$112	$248
2047	$30	$82	$114	$252
2048	$31	$83	$115	$255
2049	$31	$84	$116	$259
2050	$32	$86	$118	$263
2051	$33	$86	$119	$263
2052	$33	$87	$120	$264
2053	$34	$88	$121	$265
2054	$35	$89	$123	$266

Note: The 2023-2050 SC-CO_2 values are identical to those reported in the 2016 TSD (IWG 2016a) adjusted for inflation to 2021 dollars using the annual GDP Implicit Price Deflator values in the U.S. Bureau of Economic

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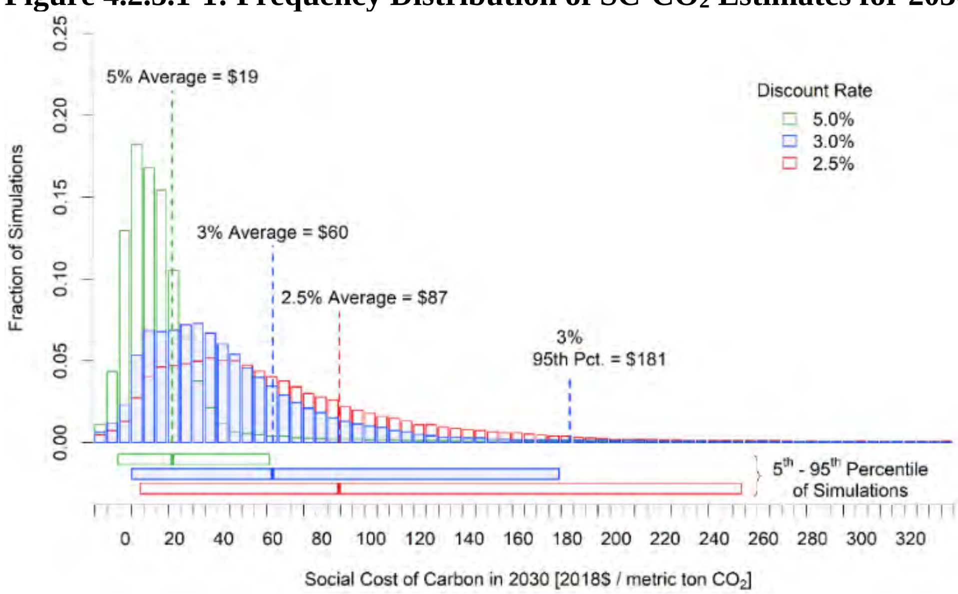
[378] Interagency Working Group on Social Cost of Greenhouse Gases (IWG). 2021. Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990. February. United States Government. Available at: https://www.whitehouse.gov/briefing-room/blog/2021/02/26/a-return-to-science-evidence-based-estimates-of-the-benefits-of-reducing-climate-pollution

Analysis' (BEA) NIPA Table 1.1.9 (U.S. BEA 2021). This table displays the values rounded to the nearest dollar; the annual unrounded values used in the calculations in this analysis are available on OMB's website: https://www.whitehouse.gov/omb/information-regulatory-affairs/regulatory-matters/#scghgs.
The estimates were extended for the period 2051 to 2054 using methods, assumptions, and parameters identical to the 2020-2050 estimates. The values are stated in $/metric ton CO2 and vary depending on the year of CO2 emissions.

There are a number of limitations and uncertainties associated with the SC- CO_2 estimates presented in Table 4.2.5.1-1. Some uncertainties are captured within the analysis, while other areas of uncertainty have not yet been quantified in a way that can be modeled. Figure 4.2.5.1-1 presents the quantified sources of uncertainty in the form of frequency distributions for the SC-CO_2 estimates for emissions in 2030 (in 2018$). The distribution of the SC-CO_2 estimate reflects uncertainty in key model parameters such as the equilibrium climate sensitivity, as well as uncertainty in other parameters set by the original model developers. To highlight the difference between the impact of the discount rate and other quantified sources of uncertainty, the bars below the frequency distributions provide a symmetric representation of quantified variability in the SC-CO_2 estimates for each discount rate. As illustrated by the figure, the assumed discount rate plays a critical role in the ultimate estimate of the SC-CO_2. This is because CO_2 emissions today continue to impact society far out into the future, so with a higher discount rate, costs that accrue to future generations are weighted less, resulting in a lower estimate. As discussed in the February 2021 TSD, there are other sources of uncertainty that have not yet been quantified and are thus not reflected in these estimates.

Figure 4.2.5.1-1: Frequency Distribution of SC-CO_2 Estimates for 2030[379]



In addition, the interim SC-CO_2 estimates presented in Table 4.2.5.1-1 have a number of other limitations. First, the current scientific and economic understanding of discounting

379 Although the distributions and numbers are based on the full set of model results (150,000 estimates for each discount rate and gas), for display purposes the horizontal axis is truncated with 0.02 to 0.68 percent of the estimates falling below the lowest bin displayed and 0.12 to 3.11 percent of the estimates falling above the highest bin displayed, depending on the discount rate and GHG.

approaches suggests discount rates appropriate for intergenerational analysis in the context of climate change are likely to be less than 3 percent, near 2 percent or lower. Second, the IAMs used to produce these interim estimates do not include all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature and the science underlying their “damage functions” (i.e., the core parts of the IAMs that map global mean temperature changes and other physical impacts of climate change into economic (both market and nonmarket) damages) lags behind the most recent research. For example, limitations include the incomplete treatment of catastrophic and non-catastrophic impacts in the integrated assessment models, their incomplete treatment of adaptation and technological change, the incomplete way in which inter-regional and intersectoral linkages are modeled, uncertainty in the extrapolation of damages to high temperatures, and inadequate representation of the relationship between the discount rate and uncertainty in economic growth over long time horizons. Likewise, the socioeconomic and emissions scenarios used as inputs to the models do not reflect new information from the last decade of scenario generation or the full range of projections.

The modeling limitations do not all work in the same direction in terms of their influence on the SC- CO_2 estimates. However, as discussed in the February 2021 TSD, the IWG has recommended that, taken together, the limitations suggest that the SC- CO_2 estimates used in this rule likely underestimate the damages from GHG emissions. In particular, the Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report, which was the most current IPCC assessment available at the time when the IWG decision over the ECS input was made, concluded that SC-CO_2 estimates “very likely…underestimate the damage costs” due to omitted impacts.[380] Since then, the peer-reviewed literature has continued to support this conclusion, as noted in the IPCC’s Fifth Assessment report and other recent scientific

[380] Intergovernmental Panel on Climate Change (IPCC). 2007. Core Writing Team; Pachauri, R.K; and Reisinger, A. (ed.), Climate Change 2007: Synthesis Report, Contribution of Working Groups I, II and III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, IPCC, ISBN 92-9169-122-4.

assessments.[381,382,383,384,385,386,387,388] These assessments confirm and strengthen the science, updating projections of future climate change and documenting and attributing ongoing changes. For example, sea level rise projections from the IPCC's Fourth Assessment report ranged from 18 to 59 centimeters by the 2090s relative to 1980-1999, while excluding any dynamic changes in ice sheets due to the limited understanding of those processes at the time. A decade later, the Fourth National Climate Assessment projected a substantially larger sea level rise of 30 to 130 centimeters by the end of the century relative to 2000, while not ruling out even more extreme outcomes. The February 2021 TSD briefly previews some of the recent advances in the scientific and economic literature that the IWG is actively following and that could provide guidance on, or methodologies for, addressing some of the limitations with the interim SC-GHG estimates. EPA has reviewed and considered the limitations of the models used to estimate the interim SC-GHG estimates, and concurs with the February 2021 TSD's assessment that, taken together, the limitations suggest that the interim SC-CO_2 estimates likely underestimate the damages from CO_2 emissions. The IWG, of which EPA is a member, is currently working on a comprehensive update of the SC-GHG estimates taking into consideration recommendations from the National Academies of Sciences, Engineering and Medicine, recent scientific literature, and public comments received on the February 2021 TSD.

Tables 4.2.4-6 through Tables 4.2.4-13 show the estimated changes in CO_2e for the volume changes analyzed in each year, 2023-2025. This analysis portrays what might be

381 Intergovernmental Panel on Climate Change (IPCC). 2014. Climate Change 2014: Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Core Writing Team, R.K. Pachauri and L.A. Meyer (eds.)]. IPCC, Geneva, Switzerland, 151 pp.

382 Intergovernmental Panel on Climate Change (IPCC). 2018. Global Warming of 1.5°C. An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty [Masson-Delmotte, V., P. Zhai, H.-O. Pörtner, D. Roberts, J. Skea, P.R. Shukla, A. Pirani, W. Moufouma-Okia, C. Péan, R. Pidcock, S. Connors, J.B.R. Matthews, Y. Chen, X. Zhou, M.I. Gomis, E. Lonnoy, T. Maycock, M. Tignor, and T. Waterfield (eds.)].

383 Intergovernmental Panel on Climate Change (IPCC). 2019a. Climate Change and Land: an IPCC special report on climate change, desertification, land degradation, sustainable land management, food security, and greenhouse gas fluxes in terrestrial ecosystems [P.R. Shukla, J. Skea, E. Calvo Buendia, V. Masson-Delmotte, H.-O. Pörtner, D. C. Roberts, P. Zhai, R. Slade, S. Connors, R. van Diemen, M. Ferrat, E. Haughey, S. Luz, S. Neogi, M. Pathak, J. Petzold, J. Portugal Pereira, P. Vyas, E. Huntley, K. Kissick, M. Belkacemi, J. Malley, (eds.)].

384 Intergovernmental Panel on Climate Change (IPCC). 2019b. IPCC Special Report on the Ocean and Cryosphere in a Changing Climate [H.-O. Pörtner, D.C. Roberts, V. Masson-Delmotte, P. Zhai, M. Tignor, E. Poloczanska, K. Mintenbeck, A. Alegría, M. Nicolai, A. Okem, J. Petzold, B. Rama, N.M. Weyer (eds.)].

385 U.S. Global Change Research Program (USGCRP). 2016. The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment. Crimmins, A., J. Balbus, J.L. Gamble, C.B. Beard, J.E. Bell, D. Dodgen, R.J. Eisen, N. Fann, M.D. Hawkins, S.C. Herring, L. Jantarasami, D.M. Mills, S. Saha, M.C. Sarofim, J. Trtanj, and L. Ziska, Eds. U.S. Global Change Research Program, Washington, DC, 312 pp. https://dx.doi.org/10.7930/J0R49NQX.

386 U.S. Global Change Research Program (USGCRP). 2018. Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 1515 pp. doi: 10.7930/NCA4.2018.

387 National Academies of Sciences, Engineering, and Medicine (National Academies). 2016b. Attribution of Extreme Weather Events in the Context of Climate Change. Washington, DC: The National Academies Press. https://doi.org/10.17226/21852.

388 National Academies of Sciences, Engineering, and Medicine (National Academies). 2019. Climate Change and Ecosystems. Washington, DC: The National Academies Press. https://doi.org/10.17226/25504.

expected if, in each of the ensuing 29 years, aggregate renewable fuel consumption for each category exceeded baseline levels by the same volume associated with the rule. EPA estimated the dollar value of these GHG-related effects for each analysis year between 2023 through 2054 by applying the SC-CO_2 estimates, shown in Table 4.2.5.1-1, to the estimated changes in GHG emissions inventories resulting from the candidate volumes. EPA then calculated the present value and annualized benefits from the perspective of each year by discounting each year-specific value to that year using the same discount rate used to calculate the SC-CO_2.

4.2.5.2 Results

For this illustrative scenario, the interim estimates for carbon dioxide from the February 2021 TSD, presented in Table 4.2.5.1-1, were used to estimate the social benefits of the estimated 30-year stream of GHG impacts presented in Chapter 4.2.4. For each year, the total of emissions changes presented in Tables 4.2.4-6 through 4.2.4-13 are multiplied by each of the four SC-CO_2 values for the same year. Values for each year and discount rate statistic are then converted to present value using the corresponding discount rates. The resulting streams of estimated social benefits of the biofuel volume changes assumed in this illustrative scenario for the 2023-2025 standards are presented in Tables 4.2.5.2-1 through 4.2.5.2-8.[389] Note that in these tables, volume changes for the 2023-2025 standards are relative to the No RFS baseline. We separately estimate the social benefits of the biofuel volume changes assumed in this illustrative scenario from the supplemental volume requirement proposed in this rulemaking as described in

[389] According to OMB's Circular A-4 (2003), an "analysis should focus on benefits and costs that accrue to citizens and residents of the United States", and international effects should be reported separately. Circular A-4 also reminds analysts that "[d]ifferent regulations may call for different emphases in the analysis, depending on the nature and complexity of the regulatory issues." To correctly assess the total climate damages to U.S. citizens and residents, an analysis should account for all the ways climate impacts affect the welfare of U.S. citizens and residents, including how U.S. GHG mitigation activities affect mitigation activities by other countries, and spillover effects from climate action elsewhere. The SC-GHG estimates used in regulatory analysis under revoked E.O. 13783 were a limited approximation of some of the U.S. specific climate damages from GHG emissions (e.g., \$7/mtCO_2 (2021 dollars) and \$12/mtCO_2 using a 3% discount rate for emissions occurring in 2020 and 2050, respectively). As discussed at length in the February 2021 TSD, these estimates are an underestimate of the benefits of CO_2 mitigation accruing to U.S. citizens and residents, as well as being subject to a considerable degree of uncertainty due to the manner in which they are derived. In particular, as discussed in this analysis, EPA concurs with the assessment in the February 2021 TSD that the estimates developed under revoked E.O. 13783 did not capture significant regional interactions, spillovers, and other effects and so are incomplete underestimates. As the U.S. Government Accountability Office (GAO) concluded in a June 2020 report examining the SC-GHG estimates developed under E.O. 13783, the models "were not premised or calibrated to provide estimates of the social cost of carbon based on domestic damages" (U.S. GAO 2020, p. 29). Further, the report noted that the National Academies found that country-specific social costs of carbon estimates were "limited by existing methodologies, which focus primarily on global estimates and do not model all relevant interactions among regions" (U.S. GAO 2020, p. 26). It is also important to note that the SC-GHG estimates developed under E.O. 13783 were never peer reviewed, and when their use in a specific regulatory action was challenged, the U.S. District Court for the Northern District of California determined that use of those values had been "soundly rejected by economists as improper and unsupported by science," and that the values themselves omitted key damages to U.S. citizens and residents including to supply chains, U.S. assets and companies, and geopolitical security. The Court found that by omitting such impacts, those estimates "fail[ed] to consider…important aspect[s] of the problem" and departed from the "best science available" as reflected in the global estimates. *California v. Bernhardt*, 472 F. Supp. 3d 573, 613-14 (N.D.Cal. 2020). EPA continues to center attention in this analysis on the global measures of the SC-GHG as the appropriate estimates given the flaws in the U.S. specific estimates, and as necessary for all countries to use to achieve an efficient allocation of resources for emissions reduction on a global basis, and so benefit the U.S. and its citizens.

Section 3.3. We present the results for these supplemental volumes in Tables 4.2.5.2-9 and 4.2.5.2-10. All calculations are available in a spreadsheet in the docket for this rule.[390]

Table 4.2.5.2-1: Present value of 30-year stream of climate benefits for 2023 standards, using low biofuel/high petroleum lifecycle analysis estimates, relative to the No RFS baseline, presented with four values for the social cost of carbon (SC-CO_2) (millions of 2021$)[a]

Year	Rate: 5%	Rate: 3%	Rate: 2.5%	Rate: 3% 95th percentile
2023	$(2,778)	$(9,461)	$(14,001)	$(28,257)
2024	$645	$2,216	$3,285	$6,633
2025	$633	$2,193	$3,256	$6,576
2026	$620	$2,170	$3,227	$6,517
2027	$607	$2,146	$3,197	$6,456
2028	$594	$2,121	$3,167	$6,393
2029	$581	$2,096	$3,136	$6,328
2030	$568	$2,071	$3,105	$6,261
2031	$557	$2,048	$3,075	$6,203
2032	$546	$2,025	$3,045	$6,143
2033	$535	$2,001	$3,015	$6,082
2034	$523	$1,977	$2,984	$6,019
2035	$512	$1,952	$2,953	$5,954
2036	$500	$1,927	$2,922	$5,888
2037	$488	$1,902	$2,890	$5,821
2038	$477	$1,877	$2,859	$5,752
2039	$465	$1,852	$2,827	$5,683
2040	$453	$1,827	$2,795	$5,613
2041	$443	$1,801	$2,762	$5,534
2042	$432	$1,776	$2,729	$5,455
2043	$350	$1,451	$2,235	$4,457
2044	$341	$1,430	$2,208	$4,391
2045	$332	$1,408	$2,180	$4,326
2046	$324	$1,387	$2,153	$4,261
2047	$315	$1,366	$2,126	$4,195
2048	$307	$1,345	$2,099	$4,130
2049	$298	$1,324	$2,071	$4,066
2050	$290	$1,303	$2,044	$4,001
2051	$284	$1,273	$2,023	$3,898
2052	$275	$1,250	$1,991	$3,797
2053	$-	$-	$-	$-
2054	$-	$-	$-	$-

[a] This analysis portrays what might be expected if, in each of the ensuing 29 years, aggregate renewable fuel consumption for each category exceeded baseline levels by the same volume as required by the rule. EPA's lifecycle

[390] See "GHG Scenario for 2023-25 Set Rule (NPRM).xlsx," available in the docket for this rule.

analysis methodology includes GHG impacts for biofuels over a 30-year period based on public comment and the input of an expert peer review panel as described in the March 2010 RFS2 rule (75 FR 14670). Parentheses indicate negative values. Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the SC-CO_2 (model average at 2.5 percent, 3 percent, and 5 percent discount rates; and 95th percentile at 3 percent discount rate). We emphasize the importance and value of considering the benefits calculated using all four estimates. As discussed in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (IWG 2021), a consideration of climate benefits calculated using lower discount rates are also warranted when discounting intergenerational impacts.

Table 4.2.5.2-2: Present value of 30-year stream of climate benefits for 2024 standards, using low biofuel/high petroleum lifecycle analysis estimates, relative to the No RFS baseline, presented with four values for the social cost of carbon ($SC\text{-}CO_2$) (millions of 2021$)[a]

Year	Rate: 5%	Rate: 3%	Rate: 2.5%	Rate: 3% 95th percentile
2023	$-	$-	$-	$-
2024	$69	$237	$352	$710
2025	$50	$173	$257	$520
2026	$49	$171	$255	$515
2027	$48	$170	$253	$510
2028	$47	$168	$250	$505
2029	$46	$166	$248	$500
2030	$45	$164	$245	$495
2031	$44	$162	$243	$490
2032	$43	$160	$241	$485
2033	$42	$158	$238	$481
2034	$41	$156	$236	$476
2035	$40	$154	$233	$470
2036	$40	$152	$231	$465
2037	$39	$150	$228	$460
2038	$38	$148	$226	$455
2039	$37	$146	$223	$449
2040	$36	$144	$221	$444
2041	$35	$142	$218	$437
2042	$34	$140	$216	$431
2043	$33	$138	$213	$425
2044	$34	$142	$220	$437
2045	$33	$140	$217	$431
2046	$32	$138	$214	$424
2047	$31	$136	$212	$418
2048	$31	$134	$209	$411
2049	$30	$132	$206	$405
2050	$29	$130	$204	$398
2051	$28	$127	$201	$388
2052	$27	$124	$198	$378
2053	$27	$122	$195	$368
2054	$-	$-	$-	$-

[a] This analysis portrays what might be expected if, in each of the ensuing 29 years, aggregate renewable fuel consumption for each category exceeded baseline levels by the same volume as required by the rule. EPA's lifecycle analysis methodology includes GHG impacts for biofuels over a 30-year period based on public comment and the input of an expert peer review panel as described in the March 2010 RFS2 rule (75 FR 14670). Parentheses indicate negative values. Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the $SC\text{-}CO_2$ (model average at 2.5 percent, 3 percent, and 5 percent discount rates; and 95th

percentile at 3 percent discount rate). We emphasize the importance and value of considering the benefits calculated using all four estimates. As discussed in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (IWG 2021), a consideration of climate benefits calculated using lower discount rates are also warranted when discounting intergenerational impacts.

Table 4.2.5.2-3: Present value of 30-year stream of climate benefits for 2025 standards, using low biofuel/high petroleum lifecycle analysis estimates, relative to the No RFS baseline, presented with four values for the social cost of carbon (SC-CO_2) (millions of 2021$)[a]

Year	Rate: 5%	Rate: 3%	Rate: 2.5%	Rate: 3% 95th percentile
2023	$-	$-	$-	$-
2024	$-	$-	$-	$-
2025	$67	$233	$346	$698
2026	$56	$196	$292	$590
2027	$55	$194	$289	$584
2028	$54	$192	$287	$579
2029	$53	$190	$284	$573
2030	$51	$187	$281	$567
2031	$50	$185	$278	$561
2032	$49	$183	$276	$556
2033	$48	$181	$273	$551
2034	$47	$179	$270	$545
2035	$46	$177	$267	$539
2036	$45	$174	$264	$533
2037	$44	$172	$262	$527
2038	$43	$170	$259	$521
2039	$42	$168	$256	$514
2040	$41	$165	$253	$508
2041	$40	$163	$250	$501
2042	$39	$161	$247	$494
2043	$38	$158	$244	$487
2044	$37	$156	$241	$479
2045	$37	$159	$246	$487
2046	$36	$156	$243	$480
2047	$35	$154	$239	$473
2048	$35	$152	$236	$465
2049	$34	$149	$233	$458
2050	$33	$147	$230	$451
2051	$32	$143	$228	$439
2052	$31	$141	$224	$428
2053	$30	$138	$221	$417
2054	$29	$136	$217	$406

[a] This analysis portrays what might be expected if, in each of the ensuing 29 years, aggregate renewable fuel consumption for each category exceeded baseline levels by the same volume as required by the rule. EPA's lifecycle analysis methodology includes GHG impacts for biofuels over a 30-year period based on public comment and the input of an expert peer review panel as described in the March 2010 RFS2 rule (75 FR 14670). Parentheses indicate negative values. Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the SC-CO_2 (model average at 2.5 percent, 3 percent, and 5 percent discount rates; and 95th

percentile at 3 percent discount rate). We emphasize the importance and value of considering the benefits calculated using all four estimates. As discussed in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (IWG 2021), a consideration of climate benefits calculated using lower discount rates are also warranted when discounting intergenerational impacts.

Table 4.2.5.2-4: Present value of 30-year stream of climate benefits for the combined 2023-2025 standards, using low biofuel/high petroleum lifecycle analysis estimates, relative to the No RFS baseline, presented with four values for the social cost of carbon (SC-CO_2) (millions of 2021$)[a]

Year	Rate: 5%	Rate: 3%	Rate: 2.5%	Rate: 3% 95th percentile
2023	$(2,778)	$(9,461)	$(14,001)	$(28,257)
2024	$714	$2,454	$3,637	$7,342
2025	$750	$2,600	$3,859	$7,794
2026	$725	$2,538	$3,774	$7,622
2027	$710	$2,510	$3,739	$7,550
2028	$695	$2,481	$3,703	$7,476
2029	$679	$2,452	$3,667	$7,400
2030	$664	$2,422	$3,631	$7,323
2031	$651	$2,395	$3,596	$7,255
2032	$638	$2,368	$3,561	$7,185
2033	$625	$2,340	$3,526	$7,113
2034	$612	$2,312	$3,490	$7,039
2035	$598	$2,283	$3,454	$6,963
2036	$585	$2,254	$3,417	$6,886
2037	$571	$2,225	$3,380	$6,807
2038	$558	$2,196	$3,343	$6,728
2039	$544	$2,166	$3,306	$6,647
2040	$530	$2,136	$3,269	$6,565
2041	$518	$2,107	$3,230	$6,473
2042	$506	$2,077	$3,192	$6,380
2043	$421	$1,748	$2,692	$5,368
2044	$412	$1,728	$2,669	$5,308
2045	$403	$1,707	$2,643	$5,244
2046	$392	$1,682	$2,610	$5,165
2047	$382	$1,656	$2,577	$5,086
2048	$372	$1,630	$2,544	$5,007
2049	$361	$1,605	$2,511	$4,928
2050	$351	$1,580	$2,478	$4,850
2051	$344	$1,543	$2,452	$4,725
2052	$334	$1,515	$2,414	$4,603
2053	$57	$260	$416	$785
2054[b]	$29	$136	$217	$406

[a] This analysis portrays what might be expected if, in each of the ensuing 29 years, aggregate renewable fuel consumption for each category exceeded baseline levels by the same volume as required by the rule. EPA's lifecycle analysis methodology includes GHG impacts for biofuels over a 30-year period based on public comment and the input of an expert peer review panel as described in the March 2010 RFS2 rule (75 FR 14670). Parentheses indicate negative values. Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the SC-CO_2 (model average at 2.5 percent, 3 percent, and 5 percent discount rates; and 95th

percentile at 3 percent discount rate). We emphasize the importance and value of considering the benefits calculated using all four estimates. As discussed in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (IWG 2021), a consideration of climate benefits calculated using lower discount rates are also warranted when discounting intergenerational impacts.
[b] Combined impacts presented in Table 4.2.5.2-4 are the sum of the three thirty-year streams of impacts for the 2023 through 2025 standards presented in Tables 4.2.5.2-1, 4.2.5.2-2, and 4.2.5.2-3. Because we assess thirty years of impacts for each year standards, the period of analysis for the 2023 standards extends to 2052.

Table 4.2.5.2-5: Present value of 30-year stream of climate benefits for 2023 standards, using high biofuel/low petroleum lifecycle analysis estimates, relative to the No RFS baseline, presented with four values for the social cost of carbon ($SC\text{-}CO_2$) (millions of 2021$)[a]

Year	Rate: 5%	Rate: 3%	Rate: 2.5%	Rate: 3% 95th percentile
2023	$(4,599)	$(15,662)	$(23,178)	$(46,778)
2024	$144	$496	$735	$1,484
2025	$142	$491	$728	$1,471
2026	$139	$485	$722	$1,458
2027	$136	$480	$715	$1,444
2028	$133	$475	$708	$1,430
2029	$130	$469	$701	$1,415
2030	$127	$463	$694	$1,400
2031	$125	$458	$688	$1,387
2032	$122	$453	$681	$1,374
2033	$120	$448	$674	$1,361
2034	$117	$442	$668	$1,346
2035	$114	$437	$661	$1,332
2036	$112	$431	$654	$1,317
2037	$109	$426	$647	$1,302
2038	$107	$420	$639	$1,287
2039	$104	$414	$632	$1,271
2040	$101	$409	$625	$1,256
2041	$99	$403	$618	$1,238
2042	$97	$397	$610	$1,220
2043	$234	$972	$1,497	$2,985
2044	$228	$958	$1,479	$2,941
2045	$223	$943	$1,460	$2,897
2046	$217	$929	$1,442	$2,854
2047	$211	$915	$1,424	$2,810
2048	$205	$901	$1,406	$2,766
2049	$200	$887	$1,387	$2,723
2050	$194	$873	$1,369	$2,680
2051	$190	$853	$1,355	$2,611
2052	$184	$837	$1,334	$2,543
2053	$-	$-	$-	$-
2054	$-	$-	$-	$-

[a] This analysis portrays what might be expected if, in each of the ensuing 29 years, aggregate renewable fuel consumption for each category exceeded baseline levels by the same volume as required by the rule. EPA's lifecycle analysis methodology includes GHG impacts for biofuels over a 30-year period based on public comment and the input of an expert peer review panel as described in the March 2010 RFS2 rule (75 FR 14670). Parentheses indicate negative values. Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the $SC\text{-}CO_2$ (model average at 2.5 percent, 3 percent, and 5 percent discount rates; and 95th

percentile at 3 percent discount rate). We emphasize the importance and value of considering the benefits calculated using all four estimates. As discussed in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (IWG 2021), a consideration of climate benefits calculated using lower discount rates are also warranted when discounting intergenerational impacts.

Table 4.2.5.2-6: Present value of 30-year stream of climate benefits for 2024 standards, using high biofuel/low petroleum lifecycle analysis estimates, relative to the No RFS baseline, presented with four values for the social cost of carbon (SC-CO_2) (millions of 2021$)[a]

Year	Rate: 5%	Rate: 3%	Rate: 2.5%	Rate: 3% 95th percentile
2023	$-	$-	$-	$-
2024	$19	$67	$99	$200
2025	$4	$14	$21	$43
2026	$4	$14	$21	$42
2027	$4	$14	$21	$42
2028	$4	$14	$21	$42
2029	$4	$14	$20	$41
2030	$4	$13	$20	$41
2031	$4	$13	$20	$40
2032	$4	$13	$20	$40
2033	$3	$13	$20	$39
2034	$3	$13	$19	$39
2035	$3	$13	$19	$39
2036	$3	$13	$19	$38
2037	$3	$12	$19	$38
2038	$3	$12	$19	$37
2039	$3	$12	$18	$37
2040	$3	$12	$18	$36
2041	$3	$12	$18	$36
2042	$3	$12	$18	$35
2043	$3	$11	$18	$35
2044	$2	$9	$14	$28
2045	$2	$9	$14	$28
2046	$2	$9	$14	$27
2047	$2	$9	$14	$27
2048	$2	$9	$13	$26
2049	$2	$8	$13	$26
2050	$2	$8	$13	$25
2051	$2	$8	$13	$25
2052	$2	$8	$13	$24
2053	$2	$8	$12	$24
2054	$-	$-	$-	$-

[a] This analysis portrays what might be expected if, in each of the ensuing 29 years, aggregate renewable fuel consumption for each category exceeded baseline levels by the same volume as required by the rule. EPA's lifecycle analysis methodology includes GHG impacts for biofuels over a 30-year period based on public comment and the input of an expert peer review panel as described in the March 2010 RFS2 rule (75 FR 14670). Parentheses indicate negative values. Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the SC-CO_2 (model average at 2.5 percent, 3 percent, and 5 percent discount rates; and 95th

percentile at 3 percent discount rate). We emphasize the importance and value of considering the benefits calculated using all four estimates. As discussed in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (IWG 2021), a consideration of climate benefits calculated using lower discount rates are also warranted when discounting intergenerational impacts.

Table 4.2.5.2-7: Present value of 30-year stream of climate benefits for 2025 standards, using high biofuel/low petroleum lifecycle analysis estimates, relative to the No RFS baseline, presented with four values for the social cost of carbon (SC-CO_2) (millions of 2021$)[a]

Year	Rate: 5%	Rate: 3%	Rate: 2.5%	Rate: 3% 95th percentile
2023	$-	$-	$-	$-
2024	$-	$-	$-	$-
2025	$10	$35	$51	$103
2026	$5	$17	$25	$50
2027	$5	$16	$25	$50
2028	$5	$16	$24	$49
2029	$4	$16	$24	$49
2030	$4	$16	$24	$48
2031	$4	$16	$24	$48
2032	$4	$16	$23	$47
2033	$4	$15	$23	$47
2034	$4	$15	$23	$46
2035	$4	$15	$23	$46
2036	$4	$15	$22	$45
2037	$4	$15	$22	$45
2038	$4	$14	$22	$44
2039	$4	$14	$22	$44
2040	$3	$14	$21	$43
2041	$3	$14	$21	$42
2042	$3	$14	$21	$42
2043	$3	$13	$21	$41
2044	$3	$13	$20	$41
2045	$3	$12	$19	$37
2046	$3	$12	$19	$37
2047	$3	$12	$18	$36
2048	$3	$12	$18	$36
2049	$3	$11	$18	$35
2050	$3	$11	$18	$35
2051	$2	$11	$18	$34
2052	$2	$11	$17	$33
2053	$2	$11	$17	$32
2054	$2	$10	$17	$31

[a] This analysis portrays what might be expected if, in each of the ensuing 29 years, aggregate renewable fuel consumption for each category exceeded baseline levels by the same volume as required by the rule. EPA's lifecycle analysis methodology includes GHG impacts for biofuels over a 30-year period based on public comment and the input of an expert peer review panel as described in the March 2010 RFS2 rule (75 FR 14670). Parentheses indicate negative values. Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the SC-CO_2 (model average at 2.5 percent, 3 percent, and 5 percent discount rates; and 95th

percentile at 3 percent discount rate). We emphasize the importance and value of considering the benefits calculated using all four estimates. As discussed in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (IWG 2021), a consideration of climate benefits calculated using lower discount rates are also warranted when discounting intergenerational impacts.

Table 4.2.5.2-8: Present value of 30-year stream of climate benefits for the combined 2023-2025 standards, using high biofuel/low petroleum lifecycle analysis estimates, relative to the No RFS baseline, presented with four values for the social cost of carbon ($SC\text{-}CO_2$) (millions of 2021$)[a]

Year	Rate: 5%	Rate: 3%	Rate: 2.5%	Rate: 3% 95th percentile
2023	$(4,599)	$(15,662)	$(23,178)	$(46,778)
2024	$164	$563	$834	$1,684
2025	$156	$539	$801	$1,617
2026	$148	$516	$768	$1,550
2027	$144	$510	$760	$1,536
2028	$141	$505	$753	$1,521
2029	$138	$499	$746	$1,505
2030	$135	$493	$738	$1,489
2031	$132	$487	$731	$1,475
2032	$130	$482	$724	$1,461
2033	$127	$476	$717	$1,447
2034	$124	$470	$710	$1,432
2035	$122	$464	$702	$1,416
2036	$119	$458	$695	$1,401
2037	$116	$453	$687	$1,385
2038	$113	$447	$680	$1,368
2039	$111	$441	$672	$1,352
2040	$108	$434	$665	$1,335
2041	$105	$428	$657	$1,316
2042	$103	$422	$649	$1,298
2043	$240	$997	$1,535	$3,061
2044	$234	$980	$1,513	$3,010
2045	$228	$964	$1,493	$2,962
2046	$222	$950	$1,474	$2,918
2047	$216	$936	$1,456	$2,873
2048	$210	$921	$1,437	$2,829
2049	$204	$907	$1,419	$2,784
2050	$199	$892	$1,400	$2,740
2051	$194	$872	$1,385	$2,669
2052	$188	$856	$1,364	$2,600
2053	$4	$18	$29	$56
2054[b]	$2	$10	$17	$31

[a] This analysis portrays what might be expected if, in each of the ensuing 29 years, aggregate renewable fuel consumption for each category exceeded baseline levels by the same volume as required by the rule. EPA's lifecycle analysis methodology includes GHG impacts for biofuels over a 30-year period based on public comment and the input of an expert peer review panel as described in the March 2010 RFS2 rule (75 FR 14670). Parentheses indicate negative values. Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the $SC\text{-}CO_2$ (model average at 2.5 percent, 3 percent, and 5 percent discount rates; and 95th

percentile at 3 percent discount rate). We emphasize the importance and value of considering the benefits calculated using all four estimates. As discussed in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (IWG 2021), a consideration of climate benefits calculated using lower discount rates are also warranted when discounting intergenerational impacts.

[b] Combined impacts presented in Table 4.2.5.2-8 are the sum of the three thirty-year streams of impacts for the 2023 through 2025 standards presented in Tables 4.2.5.2-5, 4.2.5.2-6, and 4.2.5.2-7. Because we assess thirty years of impacts for each year standards, the period of analysis for the 2023 standards extends to 2052.

Table 4.2.5.2-9: Present value of 30-year stream of climate benefits for 2023 supplemental volume requirement, using low biofuel/high petroleum lifecycle analysis estimates, presented with four values for the social cost of carbon ($SC-CO_2$) (millions of 2021$)[a]

Year	Rate: 5%	Rate: 3%	Rate: 2.5%	Rate: 3% 95th percentile
2023	$(203)	$(692)	$(1,024)	$(2,066)
2024	$31	$106	$158	$318
2025	$30	$105	$156	$316
2026	$30	$104	$155	$313
2027	$29	$103	$153	$310
2028	$29	$102	$152	$307
2029	$28	$101	$150	$304
2030	$27	$99	$149	$300
2031	$27	$98	$148	$298
2032	$26	$97	$146	$295
2033	$26	$96	$145	$292
2034	$25	$95	$143	$289
2035	$25	$94	$142	$286
2036	$24	$92	$140	$283
2037	$23	$91	$139	$279
2038	$23	$90	$137	$276
2039	$22	$89	$136	$273
2040	$22	$88	$134	$269
2041	$21	$86	$133	$266
2042	$21	$85	$131	$262
2043	$15	$61	$93	$186
2044	$14	$60	$92	$184
2045	$14	$59	$91	$181
2046	$14	$58	$90	$178
2047	$13	$57	$89	$175
2048	$13	$56	$88	$173
2049	$12	$55	$87	$170
2050	$12	$54	$85	$167
2051	$12	$53	$85	$163
2052	$12	$52	$83	$159
2053	$-	$-	$-	$-
2054	$-	$-	$-	$-

[a] This analysis portrays what might be expected if, in each of the ensuing 29 years, aggregate renewable fuel consumption for each category exceeded baseline levels by the same volume as required by the rule. EPA's lifecycle analysis methodology includes GHG impacts for biofuels over a 30-year period based on public comment and the input of an expert peer review panel as described in the March 2010 RFS2 rule (75 FR 14670). Parentheses indicate negative values. Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the $SC-CO_2$ (model average at 2.5 percent, 3 percent, and 5 percent discount rates; and 95th percentile at 3 percent discount rate). We emphasize the importance and value of considering the benefits calculated

using all four estimates. As discussed in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (IWG 2021), a consideration of climate benefits calculated using lower discount rates are also warranted when discounting intergenerational impacts.

Table 4.2.5.2-10: Present value of 30-year stream of climate benefits for 2023 supplemental volume requirement, using high biofuel/low petroleum lifecycle analysis estimates, presented with four values for the social cost of carbon (SC-CO_2) (millions of 2021$)[a]

Year	Rate: 5%	Rate: 3%	Rate: 2.5%	Rate: 3% 95th percentile
2023	$(313)	$(1,065)	$(1,577)	$(3,182)
2024	$5	$16	$23	$47
2025	$4	$15	$23	$46
2026	$4	$15	$23	$46
2027	$4	$15	$23	$46
2028	$4	$15	$22	$45
2029	$4	$15	$22	$45
2030	$4	$15	$22	$44
2031	$4	$14	$22	$44
2032	$4	$14	$21	$43
2033	$4	$14	$21	$43
2034	$4	$14	$21	$42
2035	$4	$14	$21	$42
2036	$4	$14	$21	$41
2037	$3	$13	$20	$41
2038	$3	$13	$20	$41
2039	$3	$13	$20	$40
2040	$3	$13	$20	$40
2041	$3	$13	$19	$39
2042	$3	$13	$19	$38
2043	$12	$51	$79	$157
2044	$12	$50	$78	$155
2045	$12	$50	$77	$153
2046	$11	$49	$76	$150
2047	$11	$48	$75	$148
2048	$11	$47	$74	$146
2049	$11	$47	$73	$143
2050	$10	$46	$72	$141
2051	$10	$45	$71	$138
2052	$10	$44	$70	$134
2053	$-	$-	$-	$-
2054	$-	$-	$-	$-

[a] This analysis portrays what might be expected if, in each of the ensuing 29 years, aggregate renewable fuel consumption for each category exceeded baseline levels by the same volume as required by the rule. EPA's lifecycle analysis methodology includes GHG impacts for biofuels over a 30-year period based on public comment and the

input of an expert peer review panel as described in the March 2010 RFS2 rule (75 FR 14670). Parentheses indicate negative values. Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the SC-CO_2 (model average at 2.5 percent, 3 percent, and 5 percent discount rates; and 95th percentile at 3 percent discount rate). We emphasize the importance and value of considering the benefits calculated using all four estimates. As discussed in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (IWG 2021), a consideration of climate benefits calculated using lower discount rates are also warranted when discounting intergenerational impacts.

We note that the methodology underlying the SC-CO_2 estimates used in this analysis has been subject to public comment in the context of dozens of proposed rulemakings as well as in a dedicated public comment period in 2013. We note that there is an ongoing interagency process to update the SC-GHG estimates, and there will be further opportunity to provide public input on the SC-GHG methodology through that process.[391] As part of that separate process, the EPA welcomes the opportunity to continually improve its understanding through public input on the analytical issues associated with the presentation of anticipated costs, benefits, and other impacts of its actions, as done through RIAs.

4.3 Conversion of Wetlands, Ecosystems, and Wildlife Habitats

The Second Triennial Report to Congress on Biofuels[392] summarized the numerous studies that have examined changes in wetlands, ecosystems, and wildlife habitats. The Report noted, for example, there has been an observed increase in acreage planted with soybeans and corn between the decade leading up to enactment of EISA and the decade following enactment. Evidence from observations of land use change suggests that some of this increase in acreage and crop use is a consequence of increased biofuel production. It is likely that the environmental and natural resource impacts associated with land use change are, at least in part, due to increased biofuel production and use. However, at this time we cannot quantify the amount of land with increased intensity of cultivation nor confidently estimate the portion of crop land expansion that is due to the market for biofuels. (see Second Triennial Report to Congress on Biofuels Sections 2 and 4.2). Often these changes are ascribed to agricultural expansion for biofuel production, and in some cases even to the RFS program itself, but, in reality, such a causal connection is difficult to make with confidence (see Second Triennial Report to Congress on Biofuels Section 2). Moreover, as discussed in Section 2 of the Second Triennial Report to Congress on Biofuels, these land use change studies vary widely in approach and scope, making comparison inherently difficult. It can also be seen in section 4.2.2 of this section the wide range of estimates for the area and types of land use change depending on feedstock, model choice, scenario design and input assumptions. This section focuses on impacts related to the domestic production of renewable fuels and their underlying feedstocks. Effects from the end use of renewable fuel (i.e., retail station storage and dispensing, and combustion of renewable fuel in

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[391] For example, EPA, on behalf of the IWG, published a Federal Register notice on January 25, 2022, to solicit public nominations of scientific experts for the upcoming peer review the forthcoming update. *See* https://www.federalregister.gov/documents/2022/01/25/2022-01387/request-for-nominations-of-experts-for-the-review-of-technical-support-document-for-the-social-cost. EPA has a webpage where additional information regarding the peer review process will be posted as it becomes available: https://www.epa.gov/environmental-economics/scghg-tsd-peer-review. There will be a separate Federal Register notice for the public comment period on the forthcoming SC-GHG technical support document once it is released.

[392] U.S. EPA (2018). Biofuels and the Environment: Second Triennial Report to Congress. U.S. Environmental Protection Agency, EPA/600/R-18/195: 159 pp. Washington, DC, June 2018.

vehicles and engines) are mostly from air quality effects (Chapter 4.1), climate effects (Chapter 4.2), and possible leakage from underground storage tanks (Chapter 4.4.4). Insofar as there are impacts of renewable fuel on the conversion of wetlands, ecosystems, and wildlife habitats, they are associated with crop-based feedstocks rather than waste fats, oils, and greases, biogas, or biogas electricity. Discussion of the impacts of the candidate volumes in many of these chapters will be related to the 2022 baseline as a substitute to the No RFS baseline as land use change would not be drastically affected by the removal of the RFS program as referenced in Chapter 2. Additionally, as stated in Chapter 4.1.3 the proposed electricity volume requirements are expected to be met with existing renewable electricity production. We note that to the extent the RFS standards in this proposed rule are associated with increased palm oil production, either as a biofuel feedstock or for other purposes (e.g., backfilling of soybean oil that has been diverted to biofuel production), there is strong evidence that palm oil production is linked with degradation of wetlands, ecosystems and wildlife habitats outside of the U.S., and other adverse environmental impacts on air quality, soil quality and water quality outside of the U.S. Tropical forests are carbon sinks, and their conversion for oil palm production results in both sequestered carbon emissions and foregone future carbon sequestration. These impacts mitigate the potential GHG benefit otherwise provided by biofuel displacement of conventional fuels.[393]

[393] Austin, K. G., A. Schwantes, Y. Gu and P. S. Kasibhatla (2019). "What causes deforestation in Indonesia?" Environmental Research Letters 14(2): 024007; Austin, K. G., M. González-Roglich, D. Schaffer-Smith, A. M. Schwantes and J. J. Swenson (2017). "Trends in size of tropical deforestation events signal increasing dominance of industrial-scale drivers." Environmental Research Letters 12(5); Austin, K. G., A. Mosnier, J. Pirker, I. McCallum, S. Fritz and P. S. Kasibhatla (2017). "Shifting patterns of oil palm driven deforestation in Indonesia and implications for zero-deforestation commitments." Land Use Policy 69: 41-48; Babel, M. S., B. Shrestha and S. R. Perret (2011). "Hydrological impact of biofuel production: A case study of the Khlong Phlo Watershed in Thailand." Agricultural Water Management 101(1): 8-26.; Carlson, K. M., L. M. Curran, G. P. Asner, A. M. Pittman, S. N. Trigg and J. M. Adeney (2013). "Carbon emissions from forest conversion by Kalimantan oil palm plantations." Nature Climate Change 3(3): 283-287; Gatto, M., M. Wollni and M. Qaim (2015). "Oil palm boom and land-use dynamics in Indonesia: The role of policies and socioeconomic factors." Land Use Policy 46: 292-303; Gaveau, D. L. A., D. Sheil, M. A. Salim, S. Arjasakusuma, M. Ancrenaz, P. Pacheco and E. Meijaard (2016). "Rapid conversions and avoided deforestation: Examining four decades of industrial plantation expansion in Borneo." Scientific reports 6(1): 1-13; Gunarso, P., M. E. Hartoyo, F. Agus and T. J. Killeen (2013). Oil palm and land use change in Indonesia, Malaysia and Papua New Guinea. Reports from the Technical Panels of the 2nd greenhouse gas working Group of the Roundtable on Sustainable Palm Oil (RSPO). the Netherlands, Tropenbos International: 29-63; Hooijer, A., S. Page, J. Jauhiainen, W. A. Lee, X. X. Lu, A. Idris and G. Anshari (2012). "Subsidence and carbon loss in drained tropical peatlands." Biogeosciences 9(3): 1053; Koh, L. P., J. Miettinen, S. C. Liew and J. Ghazoul (2011). "Remotely sensed evidence of tropical peatland conversion to oil palm." Proc Natl Acad Sci U S A 108(12): 5127-5132; Koh, L. P. and D. S. Wilcove (2008). "Is oil palm agriculture really destroying tropical biodiversity?" Conservation letters 1(2): 60-64; Luskin, M. S., J. S. Brashares, K. Ickes, I.-F. Sun, C. Fletcher, S. Wright and M. D. Potts (2017). "Cross-boundary subsidy cascades from oil palm degrade distant tropical forests." Nature communications 8(1): 1-7; Miettinen, J., C. Shi and S. C. Liew (2016). "Land cover distribution in the peatlands of Peninsular Malaysia, Sumatra and Borneo in 2015 with changes since 1990." Global Ecology and Conservation 6: 67-78; Miettinen, J., A. Hooijer, D. Tollenaar, S. Page, C. Malins, R. Vernimmen, C. Shi and S. C. Liew (2012). "Historical analysis and projection of oil palm plantation expansion on peatland in Southeast Asia." ICCT White Paper 17; Mukherjee, I. and B. K. Sovacool (2014). "Palm oil-based biofuels and sustainability in southeast Asia: A review of Indonesia, Malaysia, and Thailand." Renewable and sustainable energy reviews 37: 1-12; Omar, W., N. Aziz, A. T. Mohammed, M. H. Harun and A. K. Din (2010). "Mapping of oil palm cultivation on peatland in Malaysia." MPOB Information Series; Vijay, V., S. L. Pimm, C. N. Jenkins and S. J. Smith (2016). "The impacts of oil palm on recent deforestation and biodiversity loss." PLoS One 11(7): e0159668.

4.3.1 Wetlands

There are several federal reports that describe the status and trends of U.S. wetlands,[394] including the U.S. Fish and Wildlife Service (USFWS) Status and Trends of Wetlands in the Conterminous United States,[395] the USFWS and NOAA Status and Trends of Wetlands in the Coastal Watersheds of the Coterminous United States,[396] the USFWS Status and Trends of Prairie Wetlands in the United States,[397] EPA's National Wetland Condition Assessment[398] (NWCA), and USDA's Natural Resources Inventory (NRI).[399] The USGS NWALT (National Water-Quality Assessment (NAWQA) Program's Wall-to-Wall Anthropogenic Land Use Trends) series does not model changes in wetlands.[400] Although these federal wetland reports are a wealth of information on wetland status and trends in the U.S., many of them are unfortunately not particularly useful in evaluating the impact of biofuels or the RFS program. The most recent versions of the three USFWS reports only cover up to 2009, and, therefore, are of limited utility given that EISA was enacted in 2007 and the RFS2 program was promulgated in 2010. The 2011 NCWA was the first in the series, thus, trends cannot be inferred from that report alone. The second field sampling for NWCA was conducted in 2016 and may be used to infer trends once the report is available.

The most pertinent federal program that monitors and reports the status and trends of U.S. wetlands in the context of biofuels is the USDA NRI.[401] Wetlands are not an independent land cover class in the NRI, but are overlaid on other land cover types (e.g., wetlands on forested lands made up 66,053,800 acres in 2007). The changes in wetland acres between 2007 and 2017 are shown in Table 4.3.1-1. There was an overall reduction by roughly 52,800 acres between 2007 and 2012, and a further reduction of 64,300 acres between 2012 and 2017. Over the full 2007 to 2017 timeframe, these changes represent a reduction of 0.11%. These reductions were mostly from losses of wetlands on cropland and rangeland, which were partly offset by gains in

394 Summarized and listed here: https://www.epa.gov/wetlands/how-does-epa-keep-track-status-and-trends-wetlands-us

395 Dahl, T.E. 2011. Status and trends of wetlands in the conterminous United States 2004 to 2009. U.S. Department of the Interior; Fish and Wildlife Service, Washington, D.C. 108 pp.

396 T.E. Dahl and S.M. Stedman. 2013. Status and trends of wetlands in the coastal watersheds of the Conterminous United States 2004 to 2009. U.S. Department of the Interior, Fish and Wildlife Service and National Oceanic and Atmospheric Administration, National Marine Fisheries Service. (46 p.)

397 Dahl, T.E. 2014. Status and trends of prairie wetlands in the United States 1997 to 2009. U.S. Department of the Interior; Fish and Wildlife Service, Ecological Services, Washington, D.C. (67 pages).

398 NATIONAL WETLAND CONDITION ASSESSMENT 2011: A Collaborative Survey of the Nation's Wetlands. U.S. Environmental Protection Agency Office of Wetlands, Oceans and Watersheds Office of Research and Development Washington, DC 20460. EPA-843-R-15-005. May 2016

399 U.S. Department of Agriculture. 2020. *Summary Report: 2017 National Resources Inventory*, Natural Resources Conservation Service, Washington, DC, and Center for Survey Statistics and Methodology, Iowa State University, Ames, Iowa. https://www.nrcs.usda.gov/sites/default/files/2022-10/2017NRISummary_Final.pdf (accessed November 30, 2022).

400 Falcone JA (2015). U.S. conterminous wall-to-wall anthropogenic land use trends (NWALT), 1974–2012. U.S. Geological Survey: 33 pp. Washington, DC.

401 *See* Table 7 – Changes in land use/cover between 2012 and 2017, U.S. Department of Agriculture. 2020. *Summary Report: 2017 National Resources Inventory*, Natural Resources Conservation Service, Washington, DC, and Center for Survey Statistics and Methodology, Iowa State University, Ames, Iowa. https://www.nrcs.usda.gov/sites/default/files/2022-10/2017NRISummary_Final.pdf (accessed November 30, 2022).

developed and water areas.[402] The report does not provide the information needed to determine the portion of wetland acres lost in order to grow feedstocks for biofuels, nor does it attempt to identify the portion of lost wetland acres attributable to the RFS program.

Table 4.3.1-1: Changes in palustrine[403] and estuarine[404] wetlands on different land use/cover types between 2007, 2012, and 2017[405]

	Acres (in thousands)				
Wetlands on	**2007**	**2012**	**2017**	**Change (2017 - 2007)**	**Change (%)**
Cropland, pastureland, & CRP land	17,623.5	17,552.5	17,426.4	–197.1	–1.12
Rangeland	7,969.2	7,913.0	7,876.8	–92.4	–1.16
Forest land	66,053.8	66,035.9	65,983.6	–70.2	–0.11
Other rural land	14,731.1	14,736.6	14,801.5	70.4	0.48
Developed land	1,411.0	1,450.9	1,486.5	75.5	5.35
Water areas	3,556.0	3,602.9	3,652.7	96.7	2.72
Total	111,344.6	111,291.8	111,227.5	–117.1	–0.11

There are several other regional studies examining changes in wetland area, including several from the Prairie Pothole Region.[406] In the only other national assessment to date, Wright et al. (2017) found that within 50 miles of an ethanol biorefinery there was a 14,000-acre loss of wetland between 2008 and 2012. While one might infer a causal connection between proximity to an ethanol biorefinery and loss of wetlands (a question that was not investigated directly), this study nevertheless does not demonstrate a connection to the RFS program specifically. As discussed in Chapter 1, there are and have been numerous other drivers for ethanol use in the U.S., most significantly the economic benefits of using ethanol in E10 blends. Additionally, a

402 "Water areas" are defined in the USDA NRI as "[a] broad land cover/use category comprising water bodies and streams that are permanent open water."

403 The NRI defines "palustrine wetlands" as "[w]etlands occurring in the Palustrine System, one of five systems in the classification of wetlands and deepwater habitats (Cowardin et al. 1979). Palustrine wetlands include all nontidal wetlands dominated by trees, shrubs, persistent emergent plants, or emergent mosses or lichens, as well as small, shallow open water ponds or potholes. Palustrine wetlands are often called swamps, marshes, potholes, bogs, or fens." *NRI Glossary*, available at https://www.nrcs.usda.gov/wps/portal/nrcs/detail/national/technical/nra/nri/processes/?cid=nrcs143_014127 (last accessed May 6, 2021).

404 The NRI defines "estuarine wetlands" as "[w]etlands occurring in the Estuarine System, one of five systems in the classification of wetlands and deepwater habitats (Cowardin et al. 1979). Estuarine wetlands are tidal wetlands that are usually semienclosed by land but have open, partly obstructed or sporadic access to the open ocean, and in which ocean water is at least occasionally diluted by freshwater runoff from the land. The most common example is where a river flows into the ocean." *NRI Glossary*, available at https://www.nrcs.usda.gov/wps/portal/nrcs/detail/national/technical/nra/nri/processes/?cid=nrcs143_014127 (last accessed May 6, 2021).

405 U.S. Department of Agriculture. 2020. *Summary Report: 2017 National Resources Inventory*, Natural Resources Conservation Service, Washington, DC, and Center for Survey Statistics and Methodology, Iowa State University, Ames, Iowa. https://www.nrcs.usda.gov/wps/portal/nrcs/main/national/technical/nra/nri/results.

406 Johnston, C. A. (2013). "Wetland losses due to row crop expansion in the Dakota Prairie Pothole Region." *Wetlands* 33(1): 175-182. Johnston, C. A. (2014). "Agricultural expansion: land use shell game in the U.S. Northern Plains." *Landscape Ecology* 29(1): 81-95: 10.1007/s10980-013-9947-0.

significant portion of U.S. ethanol production is exported and therefore cannot be attributed to the RFS program.

There are also many differences between Wright et al. (2017) and the NRI that make direct comparison of these two studies not relevant. These differences stem from numerous sources, including the geographic extent (the entire contiguous U.S. for the NRI versus only areas in the contiguous U.S. within 100 miles of a biorefinery in Wright et al. (2017)), and source data (fixed random points in the NRI versus satellite-derived data from the USDA's Cropland Data Layer in Wright et al. (2017)). Reconciling these estimates is beyond the scope of this rulemaking. Nonetheless, when we consider these two national assessments and the other studies cited above overall, they demonstrate that agricultural extensification may affect wetlands,[407] but any losses are relatively small compared with the total amount of wetland. Moreover, as stated above, where these studies were directed at the potential impacts of biofuels they considered the impact of increased biofuel production generally, not the incremental impact in biofuel production attributable to the RFS program or the volumes being proposed in this proposed rule. As discussed in further detail in Chapter 2, much of the biofuel projected to be used in 2023–2025 would be expected to be used even in the absence of the RFS volume requirements. Any land use change associated with biofuels that would be used in the absence of the RFS volume requirements is therefore not attributable to this proposed rule.

In the most recent NRI, the USDA reported that there was a decrease of 24,300 acres in the total wetland and deepwater habitat area, including palustrine and estuarine wetlands and other aquatic habitats, between 2012 and 2017.[408] The bulk of the wetland losses were in the Prairie Pothole region, as reported elsewhere,[409] with some very high rates (i.e., >15%, Wright et al. 2017). The conversion reported by Wright, Larson et al. (2017) explicitly included only lands that had not been in cropland for at least 20 years; although these areas may not represent pristine habitats, they are expected to represent habitats that are in a relatively natural state.

The studies discussed above show that total wetland acres in the contiguous U.S. have been decreasing since 2007. However, additional information is needed in order to draw any conclusions with confidence as to whether biofuel production is a driving factor in that loss, as well as the extent to which the annual volume requirements under the RFS program cause changes in biofuel production and in particular the candidate volumes. The volume increases for 2023-2025 compared to the No RFS baseline that are described in Chapter 3 due to biofuels produced from agricultural feedstocks (especially corn and soybeans) would suggest the

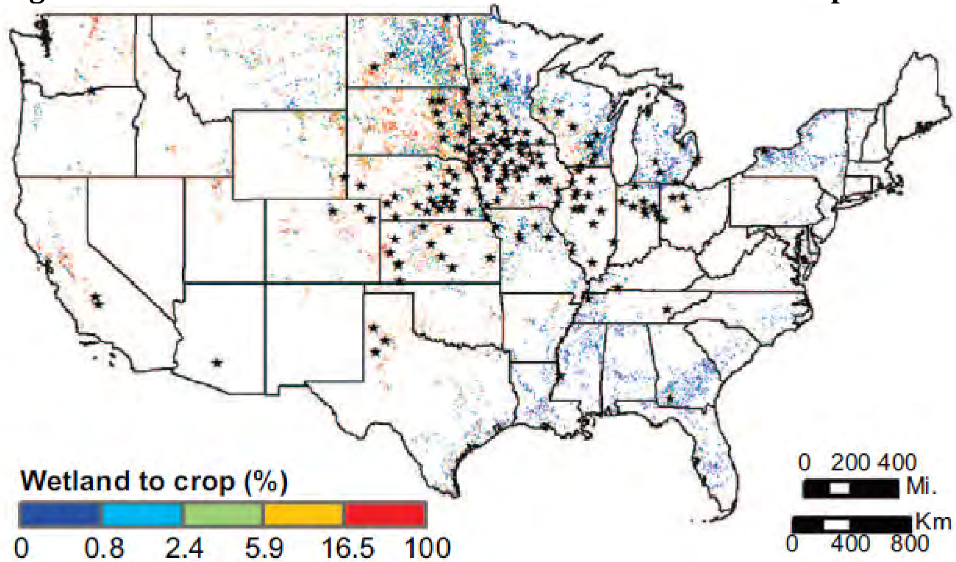
[407] Agricultural extensification is the expansion of agricultural land onto previously uncultivated land. U.S. EPA (2018). Biofuels and the Environment: Second Triennial Report to Congress. U.S. Environmental Protection Agency, EPA/600/R-18/195: 159 pp. Washington, DC, June.

[408] U.S. Department of Agriculture. 2020. *Summary Report: 2017 National Resources Inventory*, Natural Resources Conservation Service, Washington, DC, and Center for Survey Statistics and Methodology, Iowa State University, Ames, Iowa, at Table 18. https://www.nrcs.usda.gov/sites/default/files/2022-10/2017NRISummary_Final.pdf (accessed November 30, 2022). *See also* USDA, 2017 National Resources Inventory, at https://www.nrcs.usda.gov/Internet/NRCS_RCA/reports/nri_wet_nat.html. (Last accessed on April 12, 2021). The National Wetlands table shows a total area of wetlands and aquatic habitat on water areas and non-federal land as 160,755,900 acres in 2012 and 160,731,600 acres in 2017.

[409] Johnston, C. A. (2013). "Wetland losses due to row crop expansion in the Dakota Prairie Pothole Region." *Wetlands* **33**(1): 175-182. Johnston, C. A. (2014). "Agricultural expansion: land use shell game in the U.S. Northern Plains." *Landscape Ecology* 29(1): 81-95.

potential for an associated increase in crop production. As such, they may be associated with increased pressure to convert wetlands into cropland or otherwise impact wetlands. However, if we consider the potential impacts relative to the current situation in 2022 (i.e., the 2022 baseline discussed in Chapter 2.2) there would be much less potential impact. Additional information on land use change from corn and soybean can be located in Chapter 4.2. The main proposed volume changes are from biofuel produced from biogas (CNG/LNG and electricity) which are anticipated to be supplied from existing facilities. Therefore, no effect from this change would be anticipated on wetlands as no additional land is needed to meet these candidate volumes. More information is needed to assess the degree to which the volume requirements impact land use and management decisions in order to estimate the magnitude of their impacts on wetland loss. However, such analysis would be expansive and could not be performed on the timeline of this rulemaking.

Figure 4.3.1-1: Relative conversion rates from wetland to cropland from 2008 to 2012



Rates are relativized by type of ecosystem within a 3.5-mile spatial grid (modified from [410]). Stars denote the location of biorefineries in the analysis.

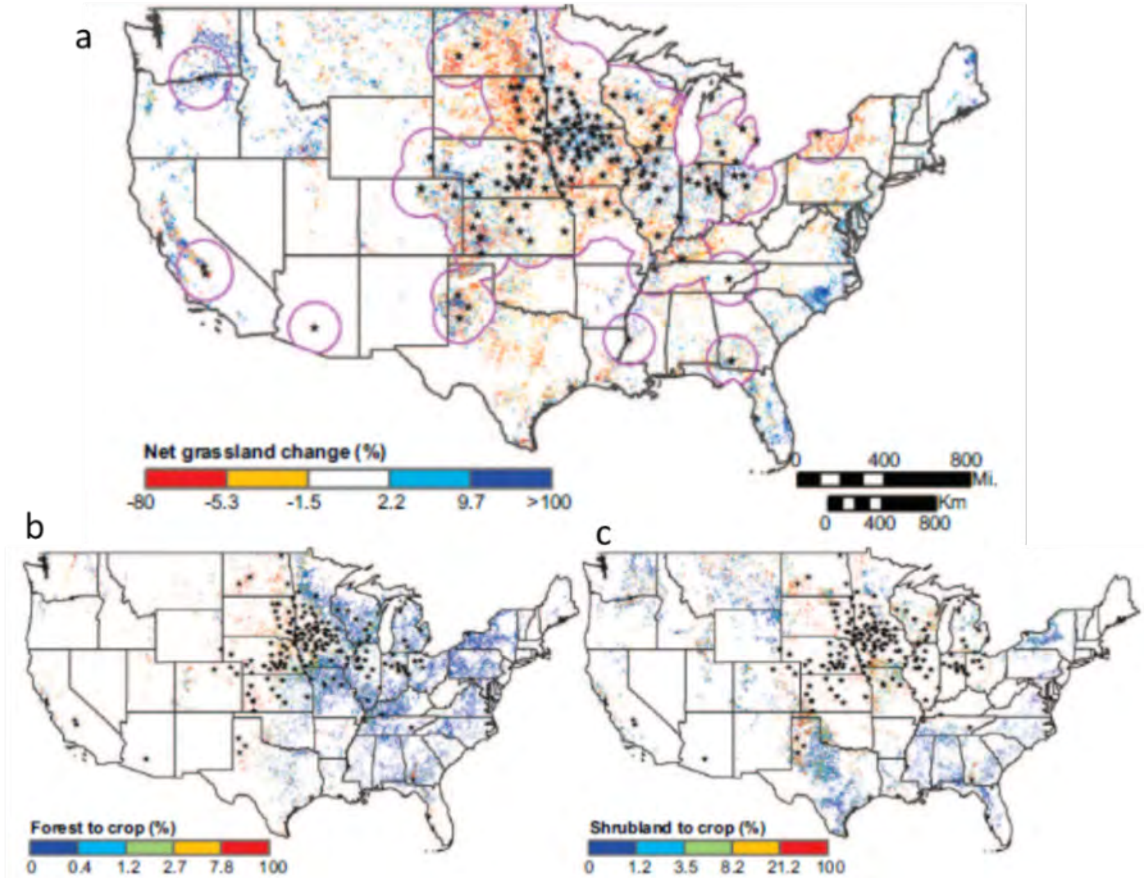
4.3.2 Ecosystems Other Than Wetlands

There are many ecosystems other than wetlands that may be affected by biofuel production and use, including grasslands, forests, and aquatic habitats downstream of corn and soybean production areas. Impacts on aquatic habitats, such as from runoff of fertilizer and pesticides, as well as changes in hydrology from tilling, are discussed in Chapter 4.4. As with other land use changes and associated environmental effects, attributing the fraction of these changes to biofuels is not currently possible with any degree of confidence. Consequently, attribution to the RFS annual volumes is also not currently possible, and such an analysis would be expansive and could not be conducted in time to be included in this rulemaking. The conversion of these ecosystems to other uses, including agriculture, is summarized below.

[410] Wright, C. K., et al. (2017). "Recent grassland losses are concentrated around US ethanol refineries." Environmental Research Letters 12(4).

In addition to wetlands, Wright et al. (2017) also reported on the losses of grasslands, shrublands, and forests within 50 miles of a biorefinery in their study.[411] Wright et al. (2017) estimated much larger reductions of grassland (2 million acres), forests (60,000 acres), and shrublands (52,000 acres), than in wetland reductions (estimated 14,000 acre reduction) (Figure 4.3.2-1). The bulk of the grassland conversions occurred in South Dakota (348,000 acres), Iowa (297,000 acres), Kansas (256,000 acres), Missouri (239,000 acres), Nebraska (213,000 acres), and North Dakota (176,000 acres).[412]

Figure 4.3.2-1: Relative conversion rates to cropland from either (a) grassland, (b) forest, or (c) shrubland from 2008 to 2012



Rates are relativized by type of ecosystem within a 3.5-mile spatial grid (modified from [413]). Stars denote the location of biorefineries, and the 100 mile radius from all biorefineries is included in (a) for reference (purple outline).

The 2 million acre reduction in grassland described in Wright et al. (2017) between 2008 and 2012 is comparable to the 1.475 million acre reduction in rangeland reported in the USDA NRI between 2007 and 2012.[414] The NRI defines rangeland as a land use/land cover that is more

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[411] Id.
[412] Id.
[413] Id.
[414] U.S. Department of Agriculture. 2020. *Summary Report: 2017 National Resources Inventory*, Natural Resources Conservation Service, Washington, DC, and Center for Survey Statistics and Methodology, Iowa State University, Ames, Iowa. https://www.nrcs.usda.gov/sites/default/files/2022-10/2017NRISummary_Final.pdf (accessed November 30, 2022).

lightly managed than pastureland,[415] and, as such, is probably the NRI land use/land cover most comparable to the grassland in Wright et al. (2017). The biggest reduction in rangeland was from conversion to cropland (743,400 acres), followed by developed land (535,800 acres), and then conversion to other land uses by smaller amounts. The NRI does not parse out individual crops within the cropland category, making it impossible to draw specific conclusions about the impact of crop production for biofuels on grassland habitat. This reduction in rangeland acreage between 2007 and 2012 was reported to continue between 2012 and 2017, with an additional reduction of over 2.4 million acres of rangeland, again with the largest conversion to cropland (754,600 acres).[416]

The Conservation Reserve Program (CRP) is especially relevant to the land use change and impacts to ecosystems. CRP lands are often grassland habitat that are entered into contract for 10-15 years, and provide a range of ecosystem services over that period, including carbon sequestration, nutrient capture, and habitat for birds.[417] CRP lands are formerly agricultural lands, and, once they have left the CRP, could be used for the production of biofuel feedstocks. However, they are often not used for production because the lands are often of lower quality, and the guaranteed rental rate from admission to the CRP program is more attractive to farmers than the uncertainty of growing crop on marginal lands.[418] Despite the rental payment incentive to farmers, enrollment in the CRP has been shrinking since 2007.[419] This is due to specifications in the Farm Bills, with a reduction from 36.8 million acres in 2007 to 21.9 million acres in 2020.[420] The 2020 NRI reported a net reduction of CRP land by 8.7 million acres between 2007 and 2012, mostly to cropland (66.5%) and pastureland (38%).[421] These reductions continued from 2012 to 2017, with a reduction of 7.8 million acres between 2012 and 2017, again mostly to cropland (63%) and pasture (37%). A detailed study from a 12-state area in the Midwest found that 30% of the CRP land that left the program between 2010 and 2013 went into five principal crops (i.e.,

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[415] The 2020 NRI defines rangeland as "A broad land cover/use category on which the climax or potential plant cover is composed principally of native grasses, grass-like plants, forbs or shrubs suitable for grazing and browsing, and introduced forage species that are managed like rangeland. This would include areas where introduced hardy and persistent grasses, such as crested wheatgrass, are planted and such practices as deferred grazing, burning, chaining, and rotational grazing are used, with little or no chemicals or fertilizer being applied. Grasslands, savannas, many wetlands, some deserts, and tundra are considered to be rangeland. Certain communities of low forbs and shrubs, such as mesquite, chaparral, mountain shrub, and pinyon-juniper, are also included as rangeland."

[416] U.S. Department of Agriculture. 2020. *Summary Report: 2017 National Resources Inventory*, Natural Resources Conservation Service, Washington, DC, and Center for Survey Statistics and Methodology, Iowa State University, Ames, Iowa. https://www.nrcs.usda.gov/sites/default/files/2022-10/2017NRISummary_Final.pdf (accessed November 30, 2022).

[417] USDA Farm Services Agency (FSA). 2016. The Conservation Reserve Program: 49th Signup Results, https://www.fsa.usda.gov/Assets/USDA-FSA-Public/usdafiles/Conservation/PDF/SU49Book_State_final1.pdf

[418] Gray, B. J., & Gibson, J. W. (2013). "Actor-networks, farmer decisions, and identity." *Culture, Agriculture, Food and Environment*, **35**(2), 82e101. Brown, J. C., et al. (2014). "Ethanol plant location and intensification vs. extensification of corn cropping in Kansas." *Applied Geography* 53: 141-148.

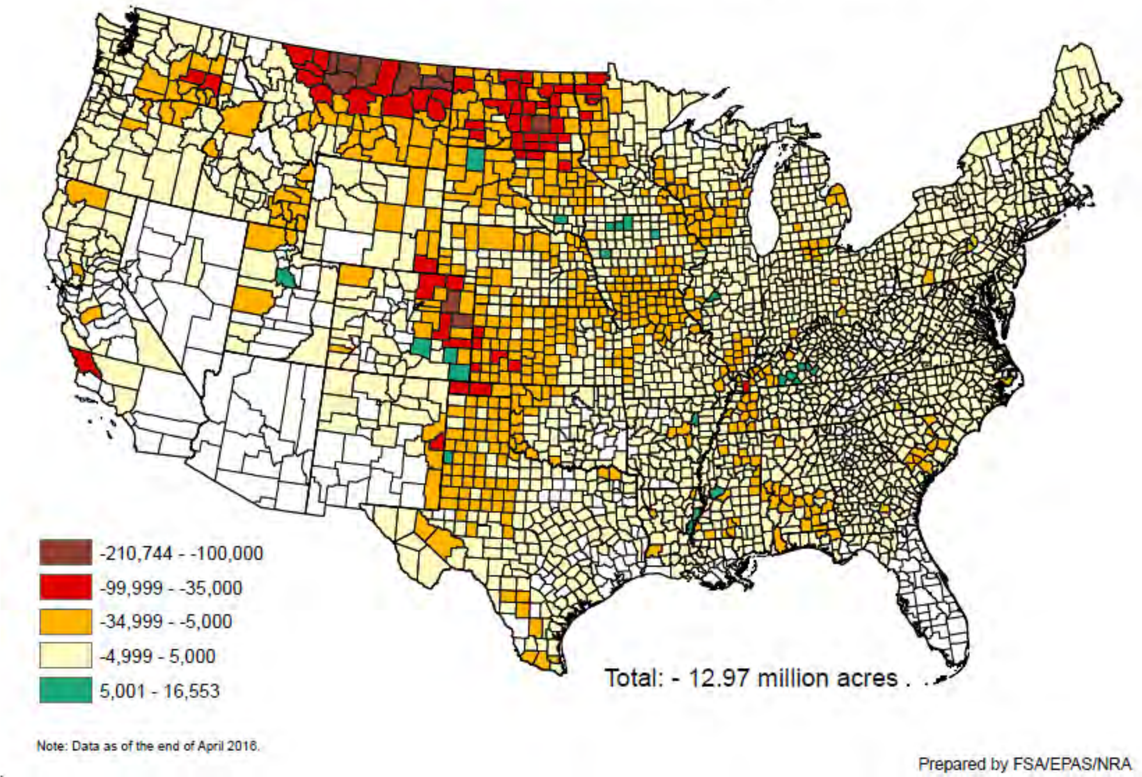
[419] Data from the USDA Farm Service Agency (FSA), available at https://www.fsa.usda.gov/programs-and-services/conservation-programs/reports-and-statistics/conservation-reserve-program-statistics/index (last accessed on April 12, 2021).

[420] USDA FSA, FY 2020 Annual Summary. Data from the USDA Farm Service Agency (FSA), available at https://www.fsa.usda.gov/programs-and-services/conservation-programs/reports-and-statistics/conservation-reserve-program-statistics/index (last accessed on May 5, 2021).

[421] U.S. Department of Agriculture. 2020. *Summary Report: 2017 National Resources Inventory*, Natural Resources Conservation Service, Washington, DC, and Center for Survey Statistics and Methodology, Iowa State University, Ames, Iowa, at 3-45. https://www.nrcs.usda.gov/wps/portal/nrcs/main/national/technical/nra/nri/results/.

corn, soybean, winter wheat, spring wheat, and sorghum), with the majority of that to corn and soybean.[422] Reconciling these studies suggests that, of the land that leaves the CRP and goes into the generic category of cropland in the NRI, at least half of that cropland is devoted to row crops. The change in CRP enrollment is not uniform across the country (Figure 4.3.2-2), with much of the reduction in the western and northern plains, the same areas experiencing losses of grassland and increases in agriculture.

Figure 4.3.2-2: Change in CRP enrollment between 2007 and 2016.[423]



Reductions in forested areas to grow corn or soybeans does not appear to be occurring in large amounts. As noted above, Wright et al. (2017) reported a net conversion of roughly 60,000 acres of forest within 50 miles of biorefineries. The NRI reported an overall increase of forestland between 2007 and 2012 (+672,400 acres) which continued between 2012 and 2017 (+1,099,700 acres). Most of the new forest land in both periods came from conversion of pastureland, which offset smaller losses of forest land to predominantly developed lands.[424]

[422] Morefield, P. E., et al. (2016). "Grasslands, wetlands, and agriculture: the fate of land expiring from the Conservation Reserve Program in the Midwestern United States." Environmental Research Letters 11(9): 094005.
[423] Data from the USDA Farm Services Agency (https://www.fsa.usda.gov/programs-and-services/conservation-programs/reports-and-statistics/conservation-reserve-program-statistics/index).
[424] The increase in forest land between 2007 and 2012 came mostly from addition of pastureland (+2.5 million acres), which offset losses to developed land (-1.4 million acres). These trends continued between 2012 and 2017, with an increase in forestland from pasture (+2.3 million acres) offsetting losses to developed land (-1.2 million acres). There were many other smaller changes that occurred simultaneously.

Thus, even though some forest land did convert to cropland according to the NRI,[425] these conversions appear small and to be offset by reforestation of pastureland.

The volume increases for the 2023-2025 years compared to the No RFS baseline described in Chapter 2 due to biofuel production from agricultural feedstock (notably soybean oil for renewable diesel) suggests the potential for an associated increase in crop production. As renewable diesel growth continues, it is expected that demand for soybean crush with rise. Thus the 2023-2025 volumes will have a potential to adversely impact grassland and other non-wetland ecosystems. However, if we consider the potential impacts relative to the current situation in 2022 (i.e., the 2022 baseline discussed in Chapter 2.2) there would be little impact, as the overall volume increase for biodiesel and renewable diesel is much smaller and expected to be met with expanded waste fats, oils, and greases supply. Additional information on the factors driving grassland to cropland conversion is needed in order to estimate the direction and magnitude of any impact the RFS volumes may have on those land use/land cover changes.

4.3.3 Wildlife

There are many subsequent potential impacts to wildlife from these changes in wetlands and other ecosystems, which were also summarized in the Second Triennial Report to Congress on Biofuels.[426] The potential impacts and their severity vary depending on such factors as crop type, geographic location, and land management practices. The CRP, in particular, provides incentives for maintaining many of these habitats, including practices that target pollinators (e.g., Conservation Practice (CP) 42, and CP2), ducks (e.g., CP 37), and other wildlife (e.g., CP4B, 4D, 33).[427] Here we focus on potential impacts to terrestrial wildlife, including primarily birds and insects, which have been the most studied to date. Impacts to aquatic wildlife are described in Chapter 4.4.2.3.

There are many bird species that use patches of grassland, wetland, pasture, and other lightly managed areas as habitat within largely agricultural areas. Conversion of wetlands to row crops is associated with reduced duck habitat and productivity of duck food sources, including aquatic plants and invertebrates.[428] However, studies of the effects of bioenergy feedstock production suggest that grassland bird species of conservation concern are more likely to be affected by increased corn production than are more common species of birds.[429] Evidence suggests that the direct effects of increasing cultivation of corn and soybean for biofuel production are coming mostly from the conversion of grasslands to cropland, rather than other

[425] The 2020 NRI reports that 292,200, and 265,600 acres of forest land converted to cropland between 2007-2012, and 2012-2017, respectively.
[426] U.S. EPA (2018). Biofuels and the Environment: Second Triennial Report to Congress. U.S. Environmental Protection Agency, EPA/600/R-18/195: 159 pp. Washington, DC, June.
[427] Listed here: https://www.fsa.usda.gov/programs-and-services/conservation-programs/crp-practices-library/index.
[428] Gleason, R.A., Euliss, N.H., Tangen, B.A., Laubhan, M.K., and Browne, B.A. (2011). "USDA conservation program and practice effects on wetland ecosystem services in the Prairie Pothole Region." *Ecological Applications* 21: S65–S81.
[429] Fletcher, R.J., Robertson, B.A., Evans, J., Doran, P.J., Alavalapati, J.R.R., and Schemske, D.W. (2011). "Biodiversity conservation in the era of biofuels: risks and opportunities." *Frontiers in Ecology and the Environment* 9(3): 161-168: 10.1890/090091. Blank PJ, Sample DW, Williams CL and Turner MG (2014). "Bird Communities and Biomass Yields in Potential Bioenergy Grasslands." *PLOS ONE* 9(10): e109989: 10.1371/journal.pone.0109989.

habitat types (e.g., wetlands, forests, shrublands). Thus, it is likely that the wildlife species with the largest potential risk are grassland species, including bird species and various insect species. However, other types of land use change may also occur, with evidence from the NRI suggesting roughly 50,000 acres of wetland converted to cropland between 2012 and 2017.

While the impacts of land use and management on wildlife have been studied, such as in Tudge et al (2021), the impacts of the RFS program specifically have not.[430] Evans et al. (2015) conducted a detailed assessment of trends in the populations of 22 grassland bird species across an 11-state area using the USGS Breeding Bird Survey.[431] The 22 species examined were a subset of the 28 identified by the USGS as grassland birds. Six species were excluded because their breeding ranges were outside of the 11-state study area. Evans et al. (2015) found that observations of six species were negatively associated with primary crop area, while observations for five species were positively associated with primary crop area.[432] All of the bird species with negative associations were on the U.S. FWS list of species of conservation concern, while none of the species exhibiting positive responses were on the list of conservation concern.[433] Although the above results using Ordinary Least Squares regression analysis were statistically significant, associations were weaker when random or fixed effects were included. When using random or fixed effects, only two species of conservation concern retained a negative association with crop area (Bobolink [*Dolichonyx oryzivorus*] and Henslow's Sparrow [*Ammodramus henslowii*]). Furthermore, when the marginal trends from primary crop increases were compared with overall trends, the magnitudes of effect were modest. The effects from land use change of primary crops led to a –0.20% to +0.15% effect, compared to the overall trends which ranged from –2.74% to +10.66%, or a 10- to 100-fold larger overall effect.[434]

Potential harm to insects, especially insect pollinators, has also been of particular concern. One study estimated that bees contributed an estimated $14.6 billion toward agricultural production in 2009, or 11% of the nation's agricultural gross domestic product.[435] Roughly 20% of these pollination services are estimated from wild populations which depend on local habitat for food and nesting sites.[436] A 2016 modeling study suggests that wild bee populations decreased by 23% across the U.S. between 2008 and 2013.[437] The causes of these reductions are

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[430] Tudge, S.J., Purvis, A. & De Palma, A. "The impacts of biofuel crops on local biodiversity: a global synthesis." *Biodivers Conserv* 30, 2863–2883 (2021). https://doi.org/10.1007/s10531-021-02232-5

[431] Evans, S.G. and Potts, M.D. (2015). "Effect of agricultural commodity prices on species abundance of US grassland birds." *Environmental and Resource Economics*, 62(3), pp.549-565.

[432] Primary crops were defined as corn, soybeans, and wheat.

[433] Evans, S.G. and Potts, M.D. (2015). "Effect of agricultural commodity prices on species abundance of US grassland birds." *Environmental and Resource Economics*, 62(3), pp.549-565.

[434] Id.

[435] Lautenbach, S., Seppelt, R., Liebscher, J., Dormann, C.F. (2012). "Spatial and temporal trends of global pollination benefit." *PLoS One* 7(4):e35954. Morse, R.A., Calderone, N.W. (2000). "The value of honey bees as pollinators of U.S. crops in 2000." *Bee Culture* 128:1–15. Koh, I., Lonsdorf, E.V., Williams, N.M., Brittain, C., Isaacs, R., Gibbs, J., and Ricketts, T.H. (2016). "Modeling the status, trends, and impacts of wild bee abundance in the United States." *Proceedings of the National Academy of Sciences* 113(1): 140-145: 10.1073/pnas.1517685113.

[436] Losey, J.E., Vaughan, M. (2006). "The economic value of ecological services provided by insects." *Bioscience* 56(4):311–323.

[437] Koh, I., Lonsdorf, E.V., Williams, N.M., Brittain, C., Isaacs, R., Gibbs, J., and Ricketts, T.H. (2016). "Modeling the status, trends, and impacts of wild bee abundance in the United States." *Proceedings of the National Academy of Sciences* 113(1): 140-145: 10.1073/pnas.1517685113.

complex, but include land use change, pesticides, and disease.[438] Subsequent effects from reductions in local bee populations are possible, including reductions in pollinator-dependent crops grown in the area,[439] as well as natural pollination services provided to wild habitat and associated ecological effects.

In the most comprehensive study to date, Hellerstein et al. (2017) found that when averaged across the United States, the forage suitability index for pollinators increased from 1982 to 2002 and declined slightly from 2002 to 2012—though in important honey bee regions (such as Central North and South Dakota), the decline from 2002 to 2012 was more pronounced.[440] The Dakota's are the summer grounds for many managed honey bee colonies, and thus the reduction in forage quality in these areas may have impacts. Although the largest stressors to honey bee populations remains the varroa mites, rather than pesticides from nearby crops, the presence of high quality forage nearby colonies is thought to improve the resilience and health of colonies by supplementing feeding.

In a series of recent reviews, researchers concluded that there is evidence of adverse impacts to pollinators due to neonicotinoid pesticide exposure.[441] But also that the evidence is mixed, and major gaps remain in our understanding of how pollinator colony-level (for social bees) and population processes may dampen or amplify the lethal or sublethal effects. EPA's preliminary assessment of the risk to bees from imidacloprid, clothianidin, and thiamethoxam found on-field risk to be low for these pesticides applied to corn, which is the dominant use pattern for this crop.[442] For soybeans, risks were considered uncertain at the time and are currently undergoing re-evaluation by EPA. Neonicotinoids, like all pesticides, are approved for use under specific conditions that are designed to protect ecosystems and human health. Recently, EPA expanded its pesticide risk assessment process specifically for bees to quantify or measure exposures and relate them to effects at the individual and colony level.[443] Because of the uncertainty surrounding the impacts of neonicotinoid use in soybean cultivation on pollinators, it is difficult to state with any certainty that the RFS standards in this action will have an impact on pollinators.

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[438] Goulson, D., Nicholls, E., Botías, C., Rotheray, E.L. (2015). "Bee declines driven by combined stress from parasites, pesticides, and lack of flowers." *Science* 347(6229):1255957.
[439] For example, USDA NASS data for 2017 show that even though most apples (which are highly dependent on pollinators) are grown in Washington (165,000 acres), smaller acreages are also grown in Michigan (33,000 acres), Ohio (4,000 acres) and Illinois (1,700 acres). If 20% of these pollination services are provided by wild insects as estimated by Losey et al. (2006), that could have effects on local apple production.
[440] Hellerstein, Daniel, Claudia Hitaj, David Smith, and Amélie Davis. *Land Use, Land Cover, and Pollinator Health: A Review and Trend Analysis,* ERR-232, U.S. Department of Agriculture, Economic Research Service, June 2017.
[441] Godfray, H., Charles, J., Tjeerd Blacquiere, Linda M. Field, Rosemary S. Hails, Gillian Petrokofsky, Simon G. Potts, Nigel E. Raine, Adam J. Vanbergen, and Angela R. McLean. (2014) "A restatement of the natural science evidence base concerning neonicotinoid insecticides and insect pollinators." *Proceedings of the Royal Society B: Biological Sciences* 281, no. 1786: 20140558.
[442] EPA (2016). Preliminary Aquatic Risk Assessment to Support the Registration Review of Imidacloprid. U.S. Environmental Protection Agency Office of Chemical Safety and Pollution Prevention, EPA-HQ-OPP-2008-0844-1086: 219 pp. Washington, DC, December 22. EPA (2017). Preliminary Bee Risk Assessment to Support the Registration Review of Clothianidin and Thiamethoxam. Office of Pesticide Programs, EPA-HQ-OPP-2011-0865-0173: 414 pp. Washington, DC.
[443] U.S. EPA (2018), "How We Assess Risks to Pollinators." Available at https://www.epa.gov/pollinator-protection/how-we-assess-risks-pollinators (last accessed April 12, 2021).

At present it is not possible to confidently estimate the fraction of wildlife habitat loss that is attributable to biofuel production or use. Thus, we cannot confidently estimate the impacts to date on wildlife from biofuels generally nor from the candidate volumes, specifically. Attributing such impacts to the RFS program generally, let alone the specific candidate volumes being analyzed in this action, is even more difficult (see Second Triennial Report to Congress on Biofuels Sections 4.4.3.2 and 2.4.4). EPA is in the process of conducting a Biological Evaluation which will evaluate impacts on endangered species from the RFS Program. More information on the estimated impact to species in the affected region on the RFS program will be available when the evaluation is concluded.

4.3.4 Potential Future Impacts of Annual Volume Requirements

The volume increases for 2023-2025 described in Chapter 3 due to biofuels produced from agricultural feedstocks (especially corn and soybeans) would suggest the potential for an associated increase in crop production. As such, they may be associated with increased pressure to convert grasslands and wetlands into cropland, and, therefore, also increased pressure on wildlife habitats. There exists substantial uncertainty in projecting changes in land use and management associated with corn, soybeans, and other crops. Additional information and modeling are needed to fully assess changes in habitat areas and effects on wildlife, both for crop expansion and pesticide use. Modeling and discussion on the estimates for land use change are further discussed in Chapter 4.2. Changes as a result of biofuel to electricity are not excepted to impact grasslands and wetlands as it is believed that existing CNG/LNG production will be transferred to meet these volumes.

4.4 Soil and Water Quality

Soil and water quality are addressed together here as they are in many ways intertwined, with effects on soil often directly altering water quality (e.g., soil erosion leading to sedimentation). Soil quality, also referred to as soil health, is the capacity of a soil to function, including the ability to sustain plant growth.[444] It can be affected by biofuel feedstock production through changes in soil erosion, soil organic matter (SOM),[445] and soil nutrients, among other characteristics. Soil erosion can negatively impact soil quality by disproportionately removing

[444] The USDA Natural Resources Conservation Service (NRCS) defines soil health or soil quality as "The capacity of a specific kind of soil to function, within natural or managed ecosystem boundaries, to sustain plant and animal productivity, maintain or enhance water and air quality, and support human health and habitation. In short, the capacity of the soil to function" USDA-NRCS. (2017). "Soil health glossary." Retrieved 5/1, 2017, from https://www.nrcs.usda.gov/wps/portal/nrcs/detailfull/soils/health/?cid=nrcs142p2_053848. In this section, "soil quality" is used as a general term, independent of area—it is used both to describe effects on single soil types and cumulative effects across large areas and multiple soil types.

[445] Soil organic matter is defined by Brady, N. and R. Weil (2000). Elements of the Nature and Properties of Soils. Upper Saddle River, NJ, USA, Prentice-Hall, Inc. as "[t]he organic fraction of the soil that includes plant and animal residues at various stages of decomposition, cells and tissues of soil organisms, and substances synthesized by the soil population." Brady N and Weil R (2000). Elements of the Nature and Properties of Soils. Upper Saddle River, NJ, USA, Prentice-Hall, Inc. The USDA NRCS similarly defines soil organic matter as "[t]he total organic matter in the soil. It can be divided into three general pools: living biomass of microorganisms, fresh and partially decomposed residues (the active fraction), and the well-decomposed and highly stable organic material. Surface litter is generally not included as part of soil organic material." (USDA-NRCS 2021).

the finest soil particles generally higher in organic matter, plant nutrients, and water-holding capacity than the remaining soil. Soil organic matter is critical to soil quality because it provides nutrients to plants, facilitates water retention in the soil, promotes soil structure, and reduces erosion, while also sequestering carbon from the atmosphere. Soil nutrients (e.g., nitrogen, phosphorus) are necessary for plant growth. Too little of these nutrients can reduce crop yields; too much can negatively affect water quality via runoff or leaching.

Water quality is the condition of water to serve human or ecological needs.[446] Crop-based biofuel feedstock production can affect water quality through associated changes in nutrients, dissolved oxygen, sediment, and chemical loadings.[447] Nutrient releases from cropland into nearby waterways can result in excessive algal growth (i.e., algal blooms), leading to low dissolved oxygen levels (i.e., hypoxia) in some cases. Increased sediment and total dissolved solids can make water unsuitable for consumption and irrigation, and also have negative impacts on aquatic species. In addition, chemical releases or biofuel leaks and spills from above-ground, underground, and transport tanks can be detrimental to water quality leading to ground, surface, and drinking water contamination (see Chapter 4.4.2).[448] Water quality impacts are presented as either proximal (i.e., geographically close) or downstream, although effects can span both. We discuss sediment and chemical loadings under proximal effects, and nutrients and hypoxia due to algal blooms in both coastal and non-coastal waters under downstream effects.

4.4.1 The Role of Biofuels

Corn starch ethanol and soybean oil biodiesel account for most of the biofuel volumes produced to date. As a result, the majority of soil and water quality impacts from biofuels thus far have come from the production of corn and soybeans. There have also been notable quantities of biogas from landfills that is cleaned and compressed to be used in compressed natural gas (CNG) vehicles, and waste fats, oils and greases (FOG) that is used to produce biodiesel. As of this proposed rule, electricity from biogas will also be biofuel source. However, they are not sourced from crop-based feedstocks and thus have only a tenuous connection to soil and water quality. Additionally, products such as CNG/LNG and electricity from biofuel are not anticipated to have any land affecting production changes. Canola oil is also used for biodiesel production, though in considerably smaller quantities than soybean oil and FOG, and it is a crop-based feedstock that could potentially impact soil and water quality. However, few studies focus on canola oil.

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[446] EPA (2003). National Management Measures to Control Nonpoint Pollution from Agriculture. U.S. Environmental Protection Agency Office of Water, EPA-841-B-03-004. Washington, DC, July.
EPA (2011). Biofuels and the Environment: First Triennial Report to Congress. U.S. Environmental Protection Agency, EPA/600/R-10/183F: 220 pp. Washington, DC, December.

[447] The USDA NRCS Environmental Technical Note No. MT-1 (2011) defines these water quality parameters and their significance.

[448] This section focuses on the non-point source, water quality effects of feedstock production and spills. Any direct point source discharges from biofuel production facilities are expected to be effectively controlled by existing environmental statutes under the Clean Water Act (EPA 2011). Biofuels and the Environment: First Triennial Report to Congress. Office of Research and Development, National Center for Environmental Assessment, Washington, DC; EPA/600/R-10/183F).

Since 2007, grasslands, including CRP grasslands, have been converted to corn and soybeans, in a process termed extensification (see Chapter 4.4.2.1). Corn and soybeans have also replaced other kinds of cropland. By contrast, the use of other crop-based feedstocks for biofuel production has been much more limited. For example, use of corn stover has been attempted at a couple of locations.[449] To date, other feedstocks, such as perennial grasses, woody biomass, and algae, have generally not yet materialized, with a few exceptions (e.g., algal biofuels for the U.S. Navy), though there is a substantial amount of literature available on the impacts of perennial grasses on soil and water quality.[450] For that reason, we have included those feedstocks in this analysis, though they are not widely used. Finally, outside the U.S., palm oil production for biodiesel is an established industry in countries such an Indonesia, Malaysia, and Thailand, with production occurring mainly for export, including to the U.S. As noted in Chapter 4.3, there is strong evidence that expanded palm oil production would adversely affect soil and water quality, in addition to carbon sequestration, outside of the U.S.

4.4.2 Impacts to Date

4.4.2.1 Soil and Proximal Water Quality Effects

Primarily, the magnitude of the impacts to soil and water quality depend upon the feedstock grown and land use—i.e., the type of land used for growing the biofuel feedstock and the management implemented on that land. For a given acre of cropland, planting corn or soybeans onto grasslands (extensification) can be expected to have greater negative effects on soil and water quality relative to the conversion of other existing cropland, such as wheat, to corn or soybeans (intensification). Grassland-to-annual-crop conversion typically impacts soil quality negatively because it increases erosion and the loss of soil nutrients and SOM, including soil carbon loss to the atmosphere.[451] In a meta-analysis, Qin et al. (2016) found that replacing grasslands with corn decreased soil carbon by approximately 20% on average.[452] The effects of converting grasslands to soybeans are likely greater on erosion, SOM, and soil carbon than converting to corn, since corn generally inputs more organic matter and carbon into the soil than soybeans, when both crops are managed using the same tillage practice (tillage practices are discussed in greater detail later in this section).[453] Increased erosion from conversion, in turn, can

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[449] 81 FR 89746 (December 12, 2016).
[450] Ziolkowska, J.R., and Simon, L. (2014). "Recent developments and prospects for algae-based fuels in the US." *Renewable & Sustainable Energy Reviews* 29: 847-853: 10.1016/j.rser.2013.09.021.
[451] Gregorich, E.G., and Anderson, D.W. (1985). "Effects of cultivation and erosion on soils of four toposequences in the Canadian prairies." *Geoderma* 36(3-4): 343-354: 10.1016/0016-7061(85)90012-6. Gelfand, I., Zenone, T., Jasrotia, P., Chen, J.Q., Hamilton, S.K., and Robertson, G.P. (2011). "Carbon debt of Conservation Reserve Program (CRP) grasslands converted to bioenergy production." *Proceedings of the National Academy of Sciences of the United States of America* 108(33): 13864-13869: 10.1073/pnas.1017277108. Qin, Z.C., Dunn, J.B., Kwon, H.Y., Mueller, S., and Wander, M.M. (2016). "Soil carbon sequestration and land use change associated with biofuel production: empirical evidence." *Global Change Biology Bioenergy* 8(1): 66-80: 10.1111/gcbb.12237. Lal, R. (2003). "Soil erosion and the global carbon budget." *Environment International* 29(4): 437-450: 10.1016/s0160-4120(02)00192-7.
[452] Qin, Z.C., Dunn, J.B., Kwon, H.Y., Mueller, S., and Wander, M.M. (2016). "Soil carbon sequestration and land use change associated with biofuel production: empirical evidence." *Global Change Biology Bioenergy* 8(1): 66-80: 10.1111/gcbb.12237.
[453] Johnson, J.M.-F., Allmaras, R.R., and Reicosky, D.C. (2006). "Estimating source carbon from crop residues, roots and rhizodeposits using the national grain-yield database." *Agronomy Journal* 98:622-636.

negatively impact water quality through increased sediment and nutrient loadings to waterways.[454]

Corn and soybeans additionally affect water quality through increased chemical usage, some of which moves as runoff or leaching to surface waterways or groundwater. Table 4.4.2.1-1 summarizes the most recent USDA National Agricultural Statistics Service (NASS) Agricultural Chemical Use Survey results for domestic corn and soybean acreage, as well as domestic wheat acreage for comparison. In general, soybean acreage receives substantially less fertilizer than corn, particularly nitrogen, because soybeans can attain nitrogen from the atmosphere via symbiotic nitrogen fixation whereas corn cannot. Thus, as an example, multiplying 1.94 million acres of extensification in the U.S. attributed to corn[455] by the average nitrogen fertilizer rate corn receives (149 lbs N/acre) yields an increase of approximately 289 million pounds of additional nitrogen added per year. Likewise, from the most recent surveys by the USDA NASS, 97% of planted corn acres were treated with herbicides, 13% with insecticides, and 17% with fungicides (Table 4.4.2.1-1). Atrazine was the top active ingredient among herbicides applied to the planted corn acres, applied to 65% of planted acres, followed by mesotrione, applied to 42% of planted acres.[456] For planted soybean acres, 99% were treated with herbicides, 16% with insecticides, and 15% with fungicides.[457] Glyphosate isopropylamine salt and glyphosate potassium salt were the top active ingredients among herbicides applied to planted soybean acres.[458] Due to the widespread nutrient and pesticide usage on corn and soybeans, it can be inferred that runoff and/or leaching of these chemicals from corn and soybean acres are contributing in part to proximal water quality impacts. For instance, in a modeling study of the continental U.S., Garcia et al. (2017) estimated that increased corn production (up to 18 billion gallons of corn ethanol) between 2002 and 2022 would increase nitrate groundwater contamination (above or equal to 5 mg/L), particularly in areas with irrigated corn on sandy or loamy soils.[459]

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[454] Yasarer, L.M.W., Sinnathamby, S., and Sturm, B.S.M. (2016). "Impacts of biofuel-based land-use change on water quality and sustainability in a Kansas watershed." *Agricultural Water Management* 175: 4-14: 10.1016/j.agwat.2016.05.002.

[455] Lark, T.J., Salmon, J.M., and Gibbs, H.K. (2015). "Cropland expansion outpaces agricultural and biofuel policies in the United States." *Environmental Research Letters* 10(4): 10.1088/1748-9326/10/4/044003.

[456] USDA NASS (2019). 2018 Agricultural Chemical Use Survey: Corn. Available at https://www.nass.usda.gov/Surveys/Guide_to_NASS_Surveys/Chemical_Use/2018_Peanuts_Soybeans_Corn/ChemUseHighlights_Corn_2018.pdf (last accessed April 13, 2021).

[457] USDA NASS (2019). 2018 Agricultural Chemical Use Survey: Soybeans. Available at https://www.nass.usda.gov/Surveys/Guide_to_NASS_Surveys/Chemical_Use/2018_Peanuts_Soybeans_Corn/ChemUseHighlights_Soybeans_2018.pdf (last accessed April 13, 2021).

[458] USDA NASS (2019). 2018 Agricultural Chemical Use Survey: Soybeans. Available at https://www.nass.usda.gov/Surveys/Guide_to_NASS_Surveys/Chemical_Use/2018_Peanuts_Soybeans_Corn/ChemUseHighlights_Soybeans_2018.pdf (last accessed April 13, 2021).

[459] Garcia, V., Cooter, E., Crooks, J., Hinckley, B., Murphy, M., and Xing, X. (2017). "Examining the impacts of increased corn production on groundwater quality using a coupled modeling system." *Science of The Total Environment* 586: 16-24: https://doi.org/10.1016/j.scitotenv.2017.02.009.

Table 4.4.2.1-1: Summary of Chemical Use for Corn, Soybeans, and Wheat Acreage in the U.S. based on 2018 and 2019 USDA NASS Chemical Use Surveys[460,461,462]

	Corn	Soybeans	Winter wheat	Spring wheat	Durum wheat
Nitrogen Fertilizer Applied: % of Planted Acres	98	29	88	97	98
Average Application Rate for Year for Acres with Nitrogen Fertilizer Applied (lbs N/acre)	149	17	73	102	83
Phosphate Fertilizer Applied: % of Planted Acres	79	42	63	89	84
Average Application Rate for Year for Acres with Phosphate Fertilizer Applied (lbs P_2O_5/acre)	69	55	31	39	29
Atrazine Applied: % of Planted Acres	65	Not Reported	Not Reported	Not Reported	Not Reported
Average Application Rate for Year for Acres with Atrazine Applied (lbs/acre)	1.037	Not Reported	Not Reported	Not Reported	Not Reported
Glyphosate Potassium Salt: % of Planted Acres	Not Reported	28	Not Reported	Not Reported	Not Reported
Average Application Rate for Year for Acres with Glyphosate Potassium Salt Applied (lbs/acre)[463]	Not Reported	1.527	Not Reported	Not Reported	Not Reported
Glyphosate Isopropylamine Salt: % of Planted Acres	34	47	Not Reported	Not Reported	46
Average Application Rate for Year for Acres with Glyphosate Isopropylamine Salt Applied (lbs/acre) [464]	0.993	1.202	Not Reported	Not Reported	0.555

There are a couple of factors that can mitigate impacts on soil and water quality, at least in part. First, the type of CRP lands, conservation lands, or other grasslands that are converted to cropland can affect soil quality. In a modeling study, LeDuc et al. (2017) simulated that greater erosion and loss of soil carbon and nitrogen occurs from converting low productivity, highly sloped CRP grasslands compared to those with higher productivity soils and lower slopes.[465] In turn, higher erosion results in greater sedimentation and nutrient loading to waterways. Second, the effects can also depend upon land management and production practices, like different tilling

[460] USDA NASS (2019). 2018 Agricultural Chemical Use Survey: Corn. Available at https://www.nass.usda.gov/Surveys/Guide_to_NASS_Surveys/Chemical_Use/2018_Peanuts_Soybeans_Corn/ChemUseHighlights_Corn_2018.pdf (last accessed April 13, 2021).
[461] USDA NASS (2019). 2018 Agricultural Chemical Use Survey: Soybeans. Available at https://www.nass.usda.gov/Surveys/Guide_to_NASS_Surveys/Chemical_Use/2018_Peanuts_Soybeans_Corn/ChemUseHighlights_Soybeans_2018.pdf (last accessed April 13, 2021).
[462] USDA NASS (2020). 2019 Agricultural Chemical Use Survey: Wheat. Available at https://www.nass.usda.gov/Surveys/Guide_to_NASS_Surveys/Chemical_Use/2019_Field_Crops/chem-highlights-wheat-2019.pdf (last accessed April 13, 2021).
[463] This is expressed in acid equivalent.
[464] This is expressed in acid equivalent.
[465] LeDuc SD, Zhang XS, Clark CM and Izaurralde RC (2017). Cellulosic feedstock production on Conservation Reserve Program land: potential yields and environmental effects. Global Change Biology Bioenergy 9(2): 460-468: 10.1111/gcbb.12352.

practices. About 60-70% of corn and soybeans are grown using conservation tillage.[466,467] Conservation tillage, including no-till, reduces soil erosion and increases SOM content relative to conventional tillage.[468,469] (Cassel, Raczkowski et al. 1995, West and Post 2002) (Cassel, Raczkowski et al. 1995, West and Post 2002) (Cassel, Raczkowski et al. 1995, West and Post 2002) (Cassel, Raczkowski et al. 1995, West and Post 2002) (Cassel, Raczkowski et al. 1995, West and Post 2002) (Cassel, Raczkowski et al. 1995, West and Post 2002) (Cassel, Raczkowski et al. 1995, West and Post 2002) (Cassel, Raczkowski et al. 1995, West and Post 2002) (Cassel, Raczkowski et al. 1995, West and Post 2002) (Cassel, Raczkowski et al. 1995, West and Post 2002) (Cassel, Raczkowski et al. 1995, West and Post 2002) (Cassel, Raczkowski et al. 1995, West and Post 2002) (Cassel, Raczkowski et al. 1995, West and Post 2002) (Cassel, Raczkowski et al. 1995, West and Post 2002)

The soil and water quality effects of converting to corn or soybeans from other crops, such as wheat, are generally less than those of the conversion of grasslands.[470] Zuber et al. (2015) observed similar soil effects of no-till, continuous corn rotations, and corn-soybean-wheat rotations on fine textured soils with high organic matter content.[471] From this evidence, Zuber et

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[466] Claassen, R., Bowman, M., McFadden, J., Smith, D., & Wallander, S. (2018, September). Tillage Intensity and Conservation Cropping in the United States. (EIB-197). U.S. Department of Agriculture, Economic Research Service.

[467] Conservation tillage is defined as any tillage practice leaving at least 30% of the soil surface covered by crop residues; whereas conventional tillage leaves less than 15% of the ground covered by crop residues Lal, R. (1997). "Residue management, conservation tillage and soil restoration for mitigating greenhouse effect by CO2-enrichment." Soil & Tillage Research **43**(1-2): 81-107. No-till management, a subset of conservation tillage, disturbs the soil marginally by cutting a narrow planting strip. Nationally, approximately 30% and 45% of the area planted to corn and soybeans, respectively, are under no-till Wade, T., R. Claassen and S. Wallander (2015). Conservation-practice adoption rates vary widely by crop and region, EIB-147, US Department of Agriculture Economic Research Service. Since 2000, there has been a general trend toward greater percent residue remaining after planting for both crops (USDA-ERS 2018 https://data.ers.usda.gov/reports.aspx?ID=17883; data accessed 2/15/2018). Lal R (1997). Residue management, conservation tillage and soil restoration for mitigating greenhouse effect by CO2-enrichment. Soil & Tillage Research 43(1-2): 81-107. USDA-NRCS (2010). Assessment of the effects of conservation practices on cultivated cropland in the Upper Mississippi River Basin. N. R. C. S. United States Department of Agriculture. Available at https://www.nrcs.usda.gov/wps/portal/nrcs/detail/national/technical/nra/ceap/pub/?cid=nrcs143_014161 (last accessed April 13, 2021).
Wade T, Claassen R and Wallander S (2015). Conservation-practice adoption rates vary widely by crop and region, EIB-147, U.S. Department of Agriculture Economic Research Service.

[468] Cassel DK, Raczkowski CW and Denton HP (1995). Tillage effects on corn production and soil physical conditions. Soil Science Society of America Journal 59(5): 1436-1443. West TO and Post WM (2002). Soil organic carbon sequestration rates by tillage and crop rotation: A global data analysis. Soil Science Society of America Journal 66(6): 1930-1946.

[469] Follett RF, Varvel GE, Kimble JM and Vogel KP (2009). No-Till Corn after Bromegrass: Effect on Soil Carbon and Soil Aggregates. Agronomy Journal 101(2): 261-268: 10.2134/agronj2008.0107.
Gelfand I, Zenone T, Jasrotia P, Chen JQ, Hamilton SK and Robertson GP (2011). Carbon debt of Conservation Reserve Program (CRP) grasslands converted to bioenergy production. Proceedings of the National Academy of Sciences of the United States of America 108(33): 13864-13869: 10.1073/pnas.1017277108.

[470] Zuber SM, Behnke GD, Nafziger ED and Villamil MB (2015). Crop Rotation and Tillage Effects on Soil Physical and Chemical Properties in Illinois. Agronomy Journal 107(3): 971-978: 10.2134/agronj14.0465.
Qin ZC, Dunn JB, Kwon HY, Mueller S and Wander MM (2016). Soil carbon sequestration and land use change associated with biofuel production: empirical evidence. Global Change Biology Bioenergy 8(1): 66-80: 10.1111/gcbb.12237. Yasarer LMW, Sinnathamby S and Sturm BSM (2016). Impacts of biofuel-based land-use change on water quality and sustainability in a Kansas watershed. Agricultural Water Management 175: 4-14: 10.1016/j.agwat.2016.05.002.

[471] Zuber SM, Behnke GD, Nafziger ED and Villamil MB (2015). Crop Rotation and Tillage Effects on Soil Physical and Chemical Properties in Illinois. Agronomy Journal 107(3): 971-978: 10.2134/agronj14.0465.

al. (2015) suggests a movement from wheat to corn may not materially affect soil quality, provided a shift from no-till to conventional tillage does not occur concomitantly. In a meta-analysis, Qin, Dunn et al. (2016) found that corn replacing other cropland (e.g., soybean, wheat) increased soil organic carbon, whereas the opposite occurred when corn replaced grassland or forest land.[472] Notably, the percent increase in soil organic carbon of other cropland moving to corn was exceeded in magnitude by the percent decrease in soil organic carbon by the conversion of grassland to corn. For water quality, an increase in corn at the expense of other crops is likely to lead to greater nutrient loadings. In a global meta-analysis, Zhou and Butterbach-Bahl (2014) found that average nitrate losses from leaching from corn (57.4 kg N/ha) exceeded those of wheat (29 kg N/ha), suggesting that a replacement of wheat by corn would lead to higher nitrate leaching to waterways.[473] Between 2003 and 2010, Plourde et al. (2013) found that the practice of rotating corn and soybeans decreased, while corn mono-cropping, or continuous corn, increased.[474] In a modeling study, Secchi et al. (2011) concluded that this intensification[475] of corn would likely lead to higher nitrogen and phosphorus loads in the Upper Mississippi River Basin.[476]

Beyond corn and soy, the production of cellulosic feedstocks for biofuels, such as corn stover and perennial grasses, may also affect soil and water quality. Partial stover removal can increase corn yields in some locations, in part by reducing nitrogen uptake from the soil by microorganisms and potentially by increasing soil temperatures in no-till systems.[477] Corn stover collection in areas with high rates of production also facilitates no-till land management (compared to conventional tillage), which can reduce erosion, nutrient losses, and thereby improve soil and water quality.[478] Yet too much stover removal can increase soil erosion, decrease SOM and soil nutrients, and ultimately decrease corn yields.[479] Whether corn stover can be harvested sustainably, and at what removal rate, depends on many site-specific factors, including yields, topography, soil characteristics, climate, and tillage practices. In a study across multiple locations in seven states, stover harvesting increased corn grain yields slightly, although

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[472]Qin ZC, Dunn JB, Kwon HY, Mueller S and Wander MM (2016). Soil carbon sequestration and land use change associated with biofuel production: empirical evidence. Global Change Biology Bioenergy 8(1): 66-80: 10.1111/gcbb.12237.
[473] Zhou and Butterbach-Bahl (2014). “Assessment of nitrate leaching loss on a yield-scaled basis from maize and wheat cropping systems.” *Plant Soil* 374: 977-991: 10.1007/s11104-013-1876-9.
[474] Plourde, J.D., Pijanowski, B.C., and Pekin, B.K. (2013). “Evidence for increased monoculture cropping in the Central United States.” *Agriculture, ecosystems & environment* 165: 50-59.
[475] Agricultural intensification is the increased production from the land without an increase in acreage. U.S. EPA (2018). Biofuels and the Environment: Second Triennial Report to Congress. U.S. Environmental Protection Agency, EPA/600/R-18/195: 159 pp. Washington, DC, June.
[476] Secchi, S., Gassman, P.W., Jha, M., Kurkalova, L., and Kling, C.L. (2011). “Potential water quality changes due to corn expansion in the Upper Mississippi River Basin.” *Ecological Applications* 21(4): 1068-1084.
[477] Coulter, J.A. and Naftiger, E.D. (2008). “Continuous Corn Response to Residue Management and Nitrogen Fertilization.” *Agronomy Journal* 100(6): 1774-1780: 10.2134/agronj2008.0170. Karlen, D.L., Birrell, S.J., Johnson, J.M.F., Osborne, S.L., Schumacher, T.E., Varvel, G.E., Ferguson, R.B., Novak, J.M., Fredrick, J.R., Baker, J.M., Lamb, J.A., Adler, P.R., Roth, G.W., and Nafziger, E.D. (2014). “Multilocation Corn Stover Harvest Effects on Crop Yields and Nutrient Removal.” *Bioenergy Research* 7(2): 528-539: 10.1007/s12155-014-9419-7.
[478] Dale, V.H., Kline, K.L., Richard, T.L., Karlen, D.L., and Belden, W.W. (2017). “Bridging biofuel sustainability indicators and ecosystem services through stakeholder engagement.” *Biomass and Bioenergy*. Also available at https://doi.org/10.1016/j.biombioe.2017.09.016 (last accessed April 13, 2021).
[479] EPA (2011). Biofuels and the Environment: First Triennial Report to Congress. U.S. Environmental Protection Agency, EPA/600/R-10/183F: 220 pp. Washington, DC, December.

the authors cautioned against extrapolating these results to other sites and noted that there is a need to conduct site-specific planning with soil testing.[480] Additional research is needed to understand effects on soil and water quality if soil conservation methods are employed while harvesting corn stover.

Perennial grasses are a potential cellulosic feedstock that is not currently used at the commercial scale. But, like other feedstocks, their impacts on soil and water quality would likely depend upon the type of land use replaced and the management practices employed. Replacing grasslands with intensively managed perennial feedstocks could have negative soil and water quality effects, while replacing annual crops would likely lead to improvements.[481] The scientific literature continues to emphasize that perennial grasses or woody biomass grown on marginal lands (e.g., abandoned agricultural land) can help restore soil quality.[482] Notably, however, the effects of these perennial feedstocks can depend upon the plant species grown and the type of land converted.[483] Additionally, the literature definitions of what constitutes marginal land and estimates of its extent vary widely.[484] For water quality, a modeling study found partially replacing annual crops with Miscanthus and switchgrass—two perennial grasses—could reduce inorganic nitrogen loadings by roughly 15% and 20%, respectively, in the Mississippi-Atchafalaya River Basin.[485] Alternative feedstock production (e.g., switchgrass) requires less fertilizer than corn, thereby reducing nutrient runoff.[486] One recent modeling study for the state of Iowa estimated that converting 12% and 37% of cropland to switchgrass would reduce leached nitrate-nitrogen (NO_3-N) by 18% and 38%, respectively, statewide.[487] Another modeling study estimated cropland conversion to switchgrass and stover harvest could greatly reduce suspended sediment, total nitrogen, and phosphorus by 54 to 57%, 30 to 32%, and 7 to 17%, respectively, in the South Fork Iowa River (SFIR) watershed if accompanied by best management practices (e.g., riparian buffers and cover crops).[488]

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[480] Karlen, D.L., Birrell, S.J., Johnson, J.M.F., Osborne, S.L., Schumacher, T.E., Varvel, G.E., Ferguson, R.B., Novak, J.M., Fredrick, J.R., Baker, J.M., Lamb, J.A., Adler, P.R., Roth, G.W., and Nafziger, E.D. (2014). "Multilocation Corn Stover Harvest Effects on Crop Yields and Nutrient Removal." *Bioenergy Research* 7(2): 528-539: 10.1007/s12155-014-9419-7.
[481] Ha, M., Z. Zhang, M. Wu (2017). Biomass production in the Lower Mississippi River Basin: Mitigating associated nutrient and sediment discharge to the Gulf of Mexico. Science of the Total Environment, DOI: 10.1016/j.scitotenv.2018.03.184.
[482] Blanco-Canqui H (2016). Growing Dedicated Energy Crops on Marginal Lands and Ecosystem Services. Soil Science Society of America Journal 80(4): 845-858: 10.2136/sssaj2016.03.0080.
[483] Robertson GP, Hamilton SK, Barham BL, Dale BE, Izaurralde RC, Jackson RD, Landis DA, Swinton SM, Thelen KD and Tiedje JM (2017). Cellulosic biofuel contributions to a sustainable energy future: Choices and outcomes. Science 356(6345): 10.1126/science.aal2324.
[484] Emery I, Mueller S, Qin Z and Dunn JB (2016). Evaluating the potential of marginal land for cellulosic feedstock production and carbon sequestration in the United States. Environmental Science & Technology 51: 733-741.
[485] VanLoocke A, Twine TE, Kucharik CJ and Bernacchi CJ (2017). Assessing the potential to decrease the Gulf of Mexico hypoxic zone with Midwest US perennial cellulosic feedstock production. GCB Bioenergy 9(5): 858-875: 10.1111/gcbb.12385.
[486] Parish ES, Hilliard MR, Baskaran LM, Dale VH, Griffiths NA, Mulholland PJ, Sorokine A, Thomas NA, Downing ME and Middleton RS (2012). Multimetric spatial optimization of switchgrass plantings across a watershed. Biofuels, Bioproducts and Biorefining 6(1): 58-72: 10.1002/bbb.342.
[487] Brandes E (2018). Targeted subfield switchgrass integration could improve the farm economy, water quality, and bioenergy feedstock production. GCB Bioenergy 10: 199–212, doi: 10.1111/gcbb.12481.
[488] Ha, M. and M. Wu (2017). Land management strategies for improving water quality in biomass production under changing climate. Environ. Res. Lett. 12 (3), 034015.

4.4.2.2 Downstream Water Quality Effects

Increased corn and soybean cultivation may also affect downstream surface water and aquatic systems, which can lead to aquatic life effects (see Chapter 4.4.2.3).[489] Fertilizer runoff, in addition to other factors (e.g., temperature and precipitation) and conservation practices, influence downstream eutrophication,[490] algal blooms, and hypoxia in fresh and coastal waters. In freshwater systems, weather conditions and agricultural activity can increase nutrient runoff, as observed in 2011 in western Lake Erie with dissolved reactive phosphorus.[491] Total nitrogen in lake water is also strongly correlated to the probability of detecting the cyanobacterium *Microcystis* in lakes, in addition to the percentage of agricultural land cover within a given lake's ecoregion.[492]

In coastal systems, nutrient loadings affect hypoxic zone size, which is also a function of climate, weather (e.g., storms), basin[493] morphology, circulation patterns, water retention time, freshwater inflows, stratification, and mixing, as seen in the Gulf of Mexico.[494] Conservation practices (e.g., filter strips, cover crops, riparian buffers) can help mitigate downstream water quality effects due to nutrients. Additionally, studies suggest that land conversion to perennial

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[489] LaBeau MB, Robertson DM, Mayer AS, Pijanowski BC and Saad DA (2014). Effects of future urban and biofuel crop expansions on the riverine export of phosphorus to the Laurentian Great Lakes. Ecological Modelling 277: 27-37: https://doi.org/10.1016/j.ecolmodel.2014.01.016. Jarvie HP, Sharpley AN, Flaten D, Kleinman PJA, Jenkins A and Simmons T (2015). The pivotal role of phosphorus in a resilient water–energy–food security nexus. Journal of Environmental Quality 44(4): 1049-1062: 10.2134/jeq2015.01.0030.

[490] EPA defines eutrophication as "[a] reduction in the amount of oxygen dissolved in water. The symptoms of eutrophication include blooms of algae (both toxic and non-toxic), declines in the health of fish and shellfish, loss of seagrass and coral reefs, and ecological changes in food webs." EPA, Vocabulary Catalog: Acid Rain Glossary, available at https://sor.epa.gov/sor_internet/registry/termreg/searchandretrieve/glossariesandkeywordlists/search.do?details=&glossaryName=Acid%20Rain%20Glossary (last accessed April 14, 2021).

[491] Michalak AM, Anderson EJ, Beletsky D, Boland S, Bosch NS, Bridgeman TB, Chaffin JD, Cho K, Confesor R, Daloğlu I, DePinto JV, Evans MA, Fahnenstiel GL, He L, Ho JC, Jenkins L, Johengen TH, Kuo KC, LaPorte E, Liu X, McWilliams MR, Moore MR, Posselt DJ, Richards RP, Scavia D, Steiner AL, Verhamme E, Wright DM and Zagorski MA (2013). Record-setting algal bloom in Lake Erie caused by agricultural and meteorological trends consistent with expected future conditions. Proceedings of the National Academy of Sciences 110(16): 6448-6452: 10.1073/pnas.1216006110.

[492] Taranu ZE, Gregory-Eaves I, Steele RJ, Beaulieu M and Legendre P (2017). Predicting microcystin concentrations in lakes and reservoirs at a continental scale: A new framework for modelling an important health risk factor. Global Ecology and Biogeography.

[493] EPA defines basin as "[a]n area of land that drains into a particular river, lake, bay or other body of water. Also called a watershed." EPA, Vocabulary Catalog: Chesapeake Bay Glossary, available at https://sor.epa.gov/sor_internet/registry/termreg/searchandretrieve/glossariesandkeywordlists/search.do?details=&glossaryName=Chesapeake%20Bay%20Glossary (last accessed April 14, 2021).

[494] Dale VH, Kling C, Meyer JL, Sanders J, Stallworth H, Armitage T, Wangsness D, Bianchi TS, Blumberg A, Boynton W, Conley DJ, Crumpton W, David MB, Gilbert D, Howarth RW, Lowrance R, Mankin K, Opaluch J, Paerl H, Reckhow K, Sharpley AN, Simpson TW, Snyder C and Wright. D (2010). Hypoxia in the Northern Gulf of Mexico. New York, Springer. Turner RE and Rabalais NN (2016). 2016 forecast: Summer hypoxic zone size Northern Gulf of Mexico. Louisiana Universities Marine Consortium: 14 pp.

grasses such as switchgrass and Miscanthus, even with manure application, could significantly reduce phosphorus runoff into water bodies.[495]

4.4.2.3 Aquatic Life Effects

According to the Second Triennial Report to Congress on Biofuels, the impacts of biofuel crop production on aquatic ecosystems is understudied compared to the impacts on terrestrial ecosystems.[496] However, it has been shown that increased corn and soybean cultivation may affect downstream aquatic communities, chiefly through runoff or leaching of nutrients and pesticides, though changes in land use and land cover also impact aquatic ecosystems, particularly through conversion of wetlands that provide ecosystem services like improving surface water flow, groundwater recharge, and sediment control.[497] Aquatic organisms interact within a food web and contribute to many ecosystem services. The aquatic food web includes microorganisms (bacteria, fungi, and algae), macroinvertebrates and macrophytes (submerged and floating aquatic plants), and larger animals such as fish and marine mammals. When increased corn and soybean cultivation changes the flow of water, nutrients, and other chemicals to downstream systems, aquatic communities change in assemblage composition, typically in favor of organisms that can tolerate nutrient and chemical pollution. Sensitive organisms that decrease in abundance in response to these changes may be important food resources or key species in aquatic chemical and biological processes, such as nutrient uptake or fish production.

Inputs of nutrients are a leading cause of impairment of freshwater and coastal ecosystems, in part due to corn and soybean production.[498] Corn production requires greater application of nitrogen fertilizer compared to soy production because soy plants develop root nodules with bacteria that can fix nitrogen from the atmosphere (Table 4.4.2.1-1). EPA's National Aquatic Resource Surveys assess the quality of the nation's freshwater and coastal ecosystems, including biological condition usually derived from the abundance of pollution-tolerant and pollution-sensitive benthic macroinvertebrate taxa[499] and fish.[500] As of 2014, nearly half (44%) of the nation's river- and stream-miles were in poor biological condition and about 30% were in good condition based on benthic macroinvertebrate indicators, and while 37% were

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[495] Muenich RL, Kalcic M and Scavia D (2016). Evaluating the Impact of Legacy P and Agricultural Conservation Practices on Nutrient Loads from the Maumee River Watershed. Environmental Science & Technology 50(15): 8146-8154.
[496] U.S. EPA (2018). Biofuels and the Environment: Second Triennial Report to Congress. U.S. Environmental Protection Agency, EPA/600/R-18/195: 159 pp. Washington, DC, June.
[497] Ibid.
[498] Ibid
[499] Benthic macroinvertebrate taxa are small, bottom-dwelling, aquatic animals and the aquatic larval stages of insects. EPA, National Aquatic Resource Survey: Indicators: Benthic Macroinvertebrates, available at https://www.epa.gov/national-aquatic-resource-surveys/indicators-benthic-macroinvertebrates#:~:text=What%20are%20benthic%20macroinvertebrates%3F,snails%2C%20worms%2C%20and%20beetles (last accessed April 14, 2021).
[500] USEPA (2020). National Rivers and Streams Assessment 2013-2014: A collaborative Survey. EPA 841-R-19-001. Washington, DC. Available at https://www.epa.gov/national-aquatic-resource-surveys/nrsa (last accessed April 14, 2021).

in poor condition and 26% were in good condition based on fish species indicators.[501] The leading problems contributing to poor biological condition were excess nutrients (especially phosphorus), loss of shoreline vegetation, and excess sediments.[502] For rivers and streams, sites with a condition rating of poor because of excess nutrients were most prevalent in the mid-continent ecoregions[503] of the nation compared to the eastern and western regions.[504] Agriculture is the dominant land use in the Mississippi River basin. As of 2012, 31% of the nation's lakes were rated as having poor biological condition, over 35% had excess nutrient concentrations, and nearly 10% of lakes had greater concentrations of cyanobacterial cells and the algal toxin microcystin compared to 2007.[505] For lakes, disturbance by nutrients varied by ecoregion (Figure 4.4.2.3-1). Northern Plains and Southern Appalachian ecoregions had a higher proportion (67-80% of within-ecoregion lakes) of sites classified as most disturbed by phosphorus pollution and there was a statistically significant increase from 2007 to 2014 in the number of most disturbed lakes in the Northern Appalachian ecoregion. For coastal and Great Lakes nearshore waters (Figure 4.4.2.3-1), phosphorus was again a widespread problem (rating of poor in 21% of sites) and biological condition was poorest along the Northeast coast (rating of poor in 27% of sites), followed by the Great Lakes nearshore waters (rating of poor in 18% of sites).[506] By 2014, the greatest reduction in number of fish species occurred in portions of the Midwest and the Great Lakes, where several watersheds have lost more than 20 species known to occur in those locations prior to 1970.[507]

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[501] USEPA (2020). National Rivers and Streams Assessment 2013-2014: A collaborative Survey. EPA 841-R-19-001. Washington, DC. Available at https://www.epa.gov/national-aquatic-resource-surveys/nrsa (last accessed April 14, 2021).

[502] USEPA (2020). National Rivers and Streams Assessment 2013-2014: A collaborative Survey. EPA 841-R-19-001. Washington, DC. Available at https://www.epa.gov/national-aquatic-resource-surveys/nrsa (last accessed April 14, 2021).

[503] The National Rivers and Streams Assessment 2013-2014 defines "ecoregion" as "geographic areas that display similar environmental characteristics, such as climate, vegetation, type of soil, and geology." USEPA (2020). National Rivers and Streams Assessment 2013-2014: A collaborative Survey. EPA 841-R-19-001. Washington, DC. Available at https://www.epa.gov/national-aquatic-resource-surveys/nrsa (last accessed April 14, 2021).

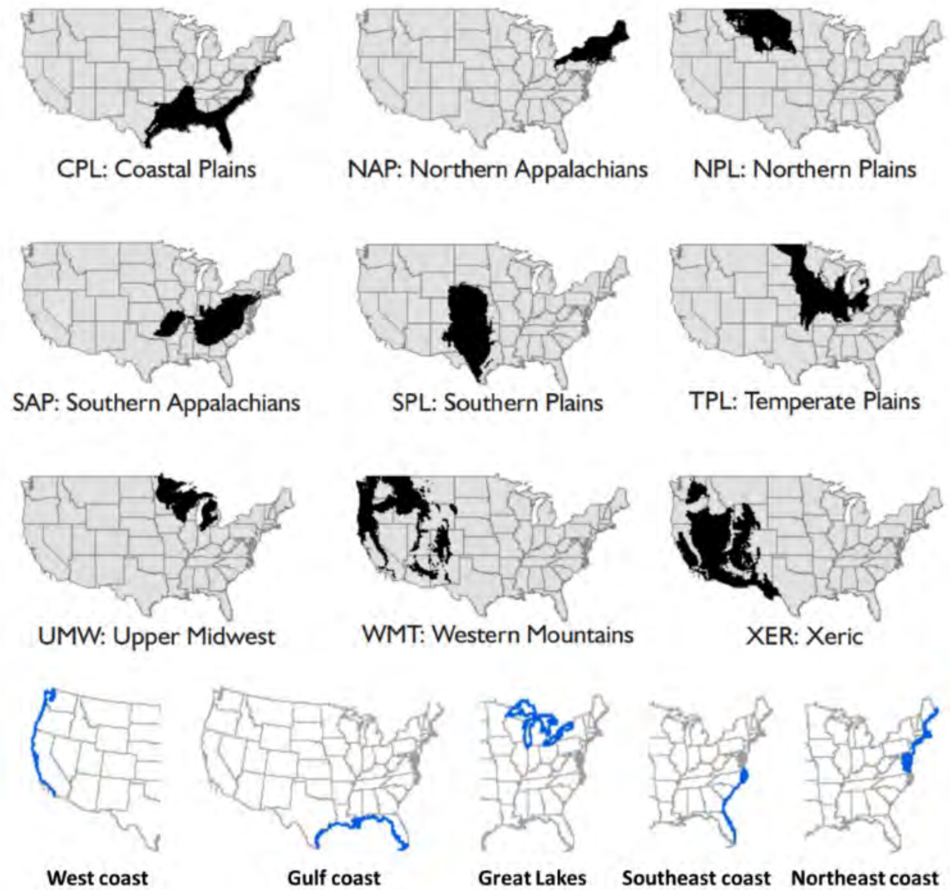
[504] USEPA (2020). National Rivers and Streams Assessment 2013-2014: A collaborative Survey. EPA 841-R-19-001. Washington, DC. Available at https://www.epa.gov/national-aquatic-resource-surveys/nrsa (last accessed April 14, 2021).

[505] USEPA (2016). National Lakes Assessment 2012: A Collaborative Survey of Lakes in the United States. EPA 841-R-16-113. U.S. Environmental Protection Agency, Washington, DC. Available at https://www.epa.gov/sites/default/files/2016-12/documents/nla_report_dec_2016.pdf (last accessed September 14, 2021).

[506] USEPA (2015). Office of Water and Office of Research and Development. National Coastal Condition Assessment. EPA 841-R-15-006. U.S. Environmental Protection Agency, Washington, DC. Available at TO10_NCCA_2010_Summary_Report_Review_Draft_ES_20101029 (epa.gov) (last accessed September 14, 2021).

[507] USEPA (2015). Report on the Environment. Fish Faunal Intactness. https://cfpub.epa.gov/roe/indicator.cfm?i=84

Figure 4.4.2.3-1: Locations of ecoregions and coastal areas defined by the USEPA's National Aquatic Resource Surveys.[508]



Excess nutrients (both nitrogen and phosphorus)[509] in waterbodies can also result in harmful algal blooms, some of which can produce toxins. Algal blooms, especially cyanobacteria, can create surface scums that block sunlight and reduce the growth of other algae and aquatic plants. Because of potential toxin production and composition of fatty acids in their cells, cyanobacteria are lower quality food for aquatic insects and fish compared to other algae such as diatoms. Lakes and reservoirs with excess nutrient loads are susceptible to recurring algal blooms. The western Lake Erie is a good example as it receives nutrient loads from a drainage area dominated by agricultural land use. Larger streams and rivers are often associated with nutrient loading from nearby agricultural activities, as well as slower water flow rates and longer residence times favorable for algal blooms.

In both freshwater and coastal marine systems, algal blooms terminate with microbial decomposition of algal cells resulting in oxygen depletion or hypoxic zones. The 2017 Gulf of

[508] Figures modified from Figure 5.1 in Ecoregions at a Glance in the National Lakes Assessment 2012. USEPA (2016). National Lakes Assessment 2012. EPA 841-R-16-113 and from USEPA (2015) National Coastal Condition Assessments 2010. EPA 841-R-15-006. U.S. Environmental Protection Agency, Washington, DC.

[509] Paerl, H.W., Scott, J.T., McCarthy, M.J., Newell, S.E., Gardner, W.S., Havens, K.E., Hoffman, D.K., Wilhelm, S.W. and Wurtsbaugh, W.A. (2016). It takes two to tango: When and where dual nutrient (N & P) reductions are needed to protect lakes and downstream ecosystems. Environmental science & technology, 50(20): 10805-10813.

Mexico hypoxic zone was the largest size measured since 1985, spanning 8,776 square miles.[510] Hypoxic zones result in the death of fish and other organisms that need oxygen to live. Along lake shorelines, blooms of filamentous green algae such as *Cladophora* harbor potentially pathogenic bacteria and foul recreational beaches when the algae proliferate and decay.[511] While fertilizer use by current agricultural practices contribute to much of the nutrient loading that stimulates algal responses in many waterbodies, the total nutrient budgets[512] of some waterbodies also include internal nutrient recycling of legacy inputs.[513]

In addition to nutrients, pesticides from corn and soybeans can also have deleterious effects on aquatic life. Toxicological studies of glyphosate on fish have measured mainly sublethal effects, such as DNA damage[514] in organ tissues and altered muscle and brain function.[515] Some bacteria can use glyphosate for growth, enhancing microbial proliferation.[516] There are cyanobacteria with natural tolerance to glyphosate[517] and certain concentrations of glyphosate can stimulate photosynthesis in a common bloom-forming taxon, *Microcystis aeruginosa*.[518] There is a notable link between glyphosate and phosphorus because more than 18% of glyphosate acid by mass is phosphorus. Glyphosate has chemical similarities with phosphate ions (competing for the same sorption sites in soil), and glyphosate rapidly degrades in water and releases phosphorus compounds easily used by organisms for growth. Glyphosate-derived phosphorus has now reached levels in aquatic systems similar to phosphorus derived from detergents prior to legislation banning these products, in part because of negative impacts on aquatic life.[519] In 2014, 58% of U.S. rivers and streams were given a rating of poor for the

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[510] Louisiana Universities Marine Consortium (2017). August 2, 2017 Summary. Shelfwide Cruise: July 24 - July 31. https://gulfhypoxia.net/research/shelfwide-cruise/?y=2017&p=press_release. USNOAA (2019). Large 'dead zone' measured in Gulf of Mexico. Available at https://www.noaa.gov/media-release/large-dead-zone-measured-in-gulf-of-mexico (last accessed April 14, 2021).

[511] Ibsen, M., Fernando, D.M., Kumar, A. and Kirkwood, A.E. (2017). Prevalence of antibiotic resistance genes in bacterial communities associated with *Cladophora glomerata* mats along the nearshore of Lake Ontario. Canadian Journal of Microbiology 63(5): 439–449.

[512] "A nutrient budget quantifies the amount of nutrients imported to and exported from a system []. The budget is considered in balance if inputs and outputs are equal. Nutrient budgets can be calculated at any scale, such as a farm, a county, a watershed, a state, or a country." Amy L. Shober, George Hochmuth, and Christine Wiese (2011). "An Overview of nutrient budgets for use in nutrient management planning." University of Florida IFAS Extension SL361. Available at https://edis.ifas.ufl.edu/pdffiles/SS/SS56200.pdf (last accessed April 14, 2021).

[513] Chen, D., Shen, H., Hu, M., Wang, J., Zhang, Y. and Dahlgren, R.A. (2018). Legacy nutrient dynamics at the watershed scale: principles, modeling, and implications. In: Advances in Agronomy. Ed: Donald L. Sparks. 149: 237-313. Academic Press. Cambridge, MA.

[514] Guilherme, S., Gaivão, I., Santos, M.A. and Pacheco, M. (2012). DNA damage in fish (*Anguilla anguilla*) exposed to a glyphosate-based herbicide–elucidation of organ-specificity and the role of oxidative stress. Mutation Research/Genetic Toxicology and Environmental Mutagenesis, 743(1-2): 1–9.

[515] Modesto, K.A. and Martinez, C.B. (2010). Roundup® causes oxidative stress in liver and inhibits acetylcholinesterase in muscle and brain of the fish *Prochilodus lineatus.* Chemosphere, 78(3): 294–299.

[516] Hove-Jensen B, Zechel DL, and Jochlmsen B. (2014). Utilization of glyphosate as phosphate source: biochemistry and genetics of bacterial carbon–phosphorus lyase. Microbiol Mol Biol R 78: 176–97.

[517] Harris TD and Smith VH. 2016. Do persistent organic pollutants stimulate cyanobacterial blooms? Inland Waters 6: 124–30.

[518] Qiu, H., Geng, J., Ren, H., Xia, X., Wang, X. and Yu, Y. (2013). Physiological and biochemical responses of *Microcystis aeruginosa* to glyphosate and its Roundup® formulation. Journal of hazardous materials, 248:172-176.

[519] Hébert, M.P., Fugère, V. and Gonzalez, A. (2019). The overlooked impact of rising glyphosate use on phosphorus loading in agricultural watersheds. Frontiers in Ecology and the Environment. doi: 10.1002/fee.1985.

phosphorus indicator of EPA's National Rivers and Streams Assessment.[520] While both corn and soybean production use glyphosate, corn production can also use atrazine (Table 4.4.2.1-1). In 2012, EPA detected atrazine in 30% of lakes, but concentrations rarely reached the EPA level of concern for plants in freshwaters (<1% of lakes).[521] In 2016, EPA concluded that in areas where atrazine use is heaviest (mainly in the Temperate Plains ecoregion, Figure 4.4.2.3-1), there are impacts on aquatic plants and potential chronic risk to fish, amphibians, and aquatic invertebrates; there is a high probability of changes to aquatic plant assemblage structure, function, and primary production at a 60-day average concentration of 3.4 ug L^{-1} and reproductive effects to fish exposed for several weeks to 5 ug L^{-1} atrazine.[522] When there are changes to aquatic plant assemblage structure, function, or productivity, other parts of the food web become at risk because there is reduced food and altered habitat for fish, invertebrates, and birds. Additional information on the affects to aquatic life will become available as EPA finalizes their evaluation of the affects the RFS program has on endangered species.

4.4.3 Comparison with Petroleum

Biofuel feedstocks are not the only input to energy production affecting soil and water quality. For comparison, petroleum used to produce gasoline and diesel fuel also impacts soil and water quality, but at different spatial and temporal scales than corn and soy. When comparing the two, it is necessary to consider both the spatial extent of the effects (e.g., the acreage of soil or volume of water impacted) and the time or effort to recover from any effects. While petroleum production may have required less land than agriculture in the U.S. between 2007 and 2011, when considering recovery time or effort, a recent study suggested the effects of petroleum production can be longer lasting and harder to mitigate (e.g., brine or oil contamination in soil or groundwater) than those of biofuel feedstocks on soil and water quality.[523] A full comparison between the effects of the two fuel types of energy feedstocks would need to consider both factors (spatial extent and recovery time or effort), but such an assessment would be expansive and could not be performed on the timeline of this rulemaking.

4.4.4 Water Quality and Underground Storage Tanks

Releases from underground storage tank (UST) systems can threaten human health and the environment, contaminating both soil and groundwater. As of September 2021, more than 564,767 UST releases have been confirmed across the United States, averaging about 5,400 per

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[520] USEPA (2020). National Rivers and Streams Assessment 2013-2014: A collaborative Survey. EPA 841-R-19-001. Washington, DC. Available at https://www.epa.gov/national-aquatic-resource-surveys/nrsa (last accessed April 14, 2021).

[521] USEPA (2016). National Lakes Assessment 2012: A Collaborative Survey of Lakes in the United States. EPA 841-R-16-113. U.S. Environmental Protection Agency, Washington, DC.

[522] USEPA (2016). Refined Ecological Risk Assessment for Atrazine. EPA-HQ-OPP-2013-0266. U.S. Environmental Protection Agency, Washington, DC.

[523] Parish ES, Kline KL, Dale VH, Efroymson RA, McBride AC, Johnson TL, Hilliard MR (2012). Comparing Scales of Environmental Effects from Gasoline and Ethanol Production. Env Management: 10.1007/s00267-012-9983-6.

year between 2016 and 2021.[524,525] One possible cause of an UST releasing fuel to the environment is incompatibility of the UST system with the fuel being stored.

Ensuring UST systems are compatible with the substances they store is essential because USTs contain many components made of different materials. In certain percentages petroleum-biofuel blends are more incompatible with certain materials used in UST system construction than petroleum based fuel without biofuels. The whole UST system—including the tank, piping, pipe dopes, containment sumps, pumping equipment, release detection equipment, spill prevention equipment, and overfill prevention equipment—needs to be compatible with the fuel stored to prevent releases to the environment. Compatibility with the substance stored is required for all UST systems under EPA regulations, and storing certain biofuels requires additional actions of UST owners and operators.

Equipment or components incompatible with the fuel stored could harden, soften, swell, or shrink, and could lead to release of fuel to the environment. Examples of observed incompatibility between fuels stored and UST materials include equipment or components such as tanks, piping, or gaskets and seals on ancillary equipment that have become brittle, elongated, thinner, or swollen when compared with their condition when initially installed.

Many of the tanks, piping and ancillary components being newly introduced into the market today have now been designed to be compatible with up to 15% ethanol or up to 20% biodiesel. However, most currently installed UST systems have at least some components that may not be compatible with fuel blends containing more than 10% ethanol or more than 20% biodiesel. EPA's 2015 UST regulation includes requirements for owners and operators of UST systems storing any regulated substances containing greater than 10% ethanol or greater than 20% biodiesel, or any other substance identified by the implementing agency, to demonstrate their UST system is compatible with those blends of biofuels prior to storing them.[526] In 2021, EPA proposed new regulations intended to strengthen the requirements for the underground storage of fuels to ensure compatibility of new systems with high concentrations of biofuels.[527] Nevertheless, insofar as blends of biofuel with gasoline or diesel are stored in USTs that are either incompatible with those blends or have incompatible components, the increased consumption of biofuels could increase leaks that affect water quality.

4.4.5 Potential Future Impacts of Proposed Volume Requirements

Future soil and water quality impacts associated with biofuel volumes will be driven, in large part, by any associated land use/land cover changes. Directionally, increases in production of biofuels made from crops would likely lead to an increase in land used for agriculture globally and in the U.S. There are inherent uncertainties in estimating the amount and type of crop-based feedstocks needed to fulfill the candidate volumes in this action, but an increase in cropland acreage would generally be expected to lead to more negative soil and water quality impacts. As

[524] USEPA (2021). Frequent questions about underground storage tanks. Available at https://www.epa.gov/ust/frequent-questions-about-underground-storage-tanks (last accessed April 14, 2021).
[525] "UST Confirmed Releases National data 2016-2021," available in the docket.
[526] 40 CFR Part 280.
[527] 86 FR 5094 (January 19, 2021).

outlined previously, the conversion of non-cropland, such as the extensification of corn and soybeans onto grasslands, can be expected to have greater negative effects on soil and water quality relative to the conversion of other existing cropland (intensification).

Although effects may generally be more negative, the cumulative magnitude of such an increase in soil and water quality impacts is uncertain. The magnitude of effects depends on the feedstocks planted, the types of land used, and management practices, all of which are not directly determined by the RFS standards. Additional factors, such as vegetative barriers, and advances in biotechnology and crop yields, can lessen future impacts. Expanded use of soil amendments (e.g., biochar, manure) also could help counterbalance the removal of organic matter and avoid or reduce the potential negative impacts of corn stover harvesting on soil quality.[528] In the case of biogas, there are numerous soil and water quality benefits compared to a baseline of no manure or waste management. Dairy digesters, for example, are an essential piece of proper manure management, as once the biogas has been captured, properly aerated manure can be applied evenly to soil as a fertilizer.[529,530] The additional soil and water quality modeling that would be needed to assess the potential cumulative impacts of future land use changes for the candidate volumes in this action would be expansive and could not be performed on the timeline of this rulemaking.

The volume increases for 2023-2025 described in Chapter 3 due to biofuels produced from agricultural feedstocks (especially corn and soybeans) in comparison to the No RFS baseline would suggest the potential for an associated increase in crop production, which in turn may impact soil and water quality. However, the magnitude of this potential impact cannot be estimated at this time, as more information is needed regarding the other factors and the magnitude of the impacts on land use and management changes. There is substantial uncertainty in projecting changes in land use and management associated with corn, soybean, and other crops due to the other factors driving biofuel demand. Furthermore, if we consider the potential impacts relative to the current situation in 2022 (i.e., the 2022 baseline discussed in Chapter 2.2) there would be little impact, as the overall volume increase for biodiesel and renewable diesel is much smaller and expected to be met with expanded waste fats, oils, and greases supply. Additional information and modeling are needed to fully assess the degree to which the annual volume requirements drive land use and management changes that would impact soil and water quality. Such analysis would be expansive and could not be performed on the timeline of this rulemaking.

4.5 Water Quantity and Availability

This section assesses the impact of the production and use of renewable fuels and their primary feedstocks on the use and availability of water in the U.S. We first review the drivers of impacts on water use and availability of freshwater resources, summarize impacts to date, highlight more recent work focused on groundwater supplies. Finally, we discuss the potential

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[528] Blanco-Canqui H (2013). Crop Residue Removal for Bioenergy Reduces Soil Carbon Pools: How Can We Offset Carbon Losses? Bioenergy Research 6(1): 358-371: 10.1007/s12155-012-9221-3.
[529] 2010 – US Climate Action Report: Fifth National Communication of the United States of America Under the United Nations Framework Convention on Climate Change.
[530] 2011 Annual Report: ENERGY STAR and Other Climate Protection Partnerships.

future effects of the candidate volumes as increases in feedstock production such as soybeans may lead to water impacts.

4.5.1 Drivers of Impacts on Water Use and Availability

Water quantity, in the context of renewable fuels, refers to the volume of water used in the production of biomass feedstocks (i.e., irrigation of corn, soybeans or other crops) and the conversion of those feedstocks to biofuel (i.e., water use in the biofuel production plant itself). The irrigation of corn and soybeans used to produce biofuels is the predominant driver of water quantity impact and is generally orders of magnitude greater than water use in the biofuel production process.[531] The water use for the full biofuels supply chain also has been quantified as significantly higher than the water use for petroleum-based fuels, meaning biofuels are more water intensive on a per gallon of fuel basis. Of concern are the impacts that this water use may have on freshwater supplies and availability. Water intensive corn and soybean production occurs on irrigated acres in states such as Nebraska and Kansas, in particular, the western parts of those states. These states also overlap the High Plains Aquifer (HPA)[532] "where groundwater levels have declined at unsustainable rates."[533]

As noted above, the primary driver of impacts to water quantity is the water used for irrigation of the biofuel feedstocks. To the extent that feedstock production expands into regions where irrigation is required, the demand for water will increase, whether the expansion is a direct consequence of production specifically for biofuel feedstocks or an indirect result of increased production for all feedstock uses. Water demand for biofuel production processes can also drive impacts on water use and availability. Although water demands of biofuel production facilities may be much smaller at a national scale than the water demands of irrigated feedstock production, biofuel facility water use may be locally consequential in areas that are already experiencing stress on water availability.

4.5.2 Life Cycle Water Use of Biofuels

In the Second Triennial Report to Congress on Biofuels, the water quantity impacts of biofuels were assessed.[534] Research investigating the water quantity impacts of biofuels started shortly after the passage of the Energy Policy Act of 2005. Several highly cited and visible articles compared the life cycle water use of biofuels relative to petroleum-based fuels on the basis of "gallons of water per mile" or "gallons of water per gallon of fuel."[535] These early

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[531] Wu M, Zhang Z and Chiu Y-w (2014). Life-cycle Water Quantity and Water Quality Implications of Biofuels. Current Sustainable/Renewable Energy Reports 1(1): 3-10.

[532] The High Plains Aquifer is often referred to as the Ogallala Aquifer, which is the largest formation within the High Plains Aquifer.

[533] Smidt, S. J., Haacker, E. M., Kendall, A. D., Deines, J. M., Pei, L., Cotterman, K. A., ... & Hyndman, D. W. (2016). Complex water management in modern agriculture: Trends in the water-energy-food nexus over the High Plains Aquifer. Science of the Total Environment, 566, 988-1001.

[534] U.S. EPA (2018). Biofuels and the Environment: Second Triennial Report to Congress. U.S. Environmental Protection Agency, EPA/600/R-18/195: 159 pp. Washington, DC, June.

[535] U.S. EPA (2018). Biofuels and the Environment: Second Triennial Report to Congress. U.S. Environmental Protection Agency, EPA/600/R-18/195: 159 pp. Washington, DC, June.

studies characterized this issue as biofuel's water intensity,[536] embodied water,[537] and water footprint.[538] Many studies of the water footprint further divide the consumptive water use into two components: *blue* water (ground and surface water) and *green* water (rainwater).[539] Most of the focus of life cycle analyses (LCAs) has been on blue water or irrigation requirements for crop production, as well as other freshwater use for biofuel conversion processes. When comparing different transportation energy sources, Scown et al. (2011) found ethanol from corn-based feedstocks to be one of the most significant users of freshwater.[540] The same study calculated the gallons of water consumed per mile of travel and found that the full life cycle water footprint of ethanol produced from corn grain and stover (using average irrigation rates) would require almost seven times as much surface water consumption as any other transportation power source and an order of magnitude more groundwater consumption when compared to other transportation energy sources.[541]

4.5.2.1 Feedstock Production

Researchers have continued to refine the LCA-based water footprint of biofuels—with a focus on feedstock production—for both current biofuels crops and future feedstocks. Because more than 90% of corn is grown in rain-fed areas where corn production is non-irrigated, Wu et al. (2014) suggested that, at the highly aggregated level, the "national water footprint of corn is consistently low to modest."[542] However, water quantity demands depend on the crops grown, where they are grown, and how they are grown. In terms of differences among feedstocks, Dominguez-Faus et al. (2009) calculated the irrigation water required for corn-based ethanol at an average of approximately 600 liters (approximately 158.5 gallons) of water per liter of ethanol produced (liter/liter).[543] Much of the focus has been on corn ethanol, due to the higher volumes of corn ethanol produced to date. However, in the same article, Dominguez-Faus et al. estimated that irrigated soybean based biodiesel water requirement averaged nearly 1,300 liters of water

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[536] King, C. W., & Webber, M. E. (2008). Water intensity of transportation. *Environmental Science & Technology*, 42(21), 7866.
[537] Chiu, Y. W., Walseth, B., & Suh, S. W. (2009). Water embodied in bioethanol in the United States. *Environmental Science & Technology*, 43(8), 2688-2692.
[538] Dominguez-Faus, R., Powers, S. E., Burken, J. G., & Alvarez, P. J. (2009). The water footprint of biofuels: A drink or drive issue? Environmental Science & Technology 43(9): 3005-3010: 10.1021/es802162x; Scown, C. D., Horvath, A., & McKone, T. E. (2011). Water footprint of US transportation fuels. *Environmental Science & Technology*. 45(7), 2541-2553.
[539] Another category is the *grey* water footprint, which is the volume of water required to assimilate pollutant loads, such as excess nitrogen. Topics relating to grey water are covered in the water quality section. *See* Hoekstra, A. Y., & Mekonnen, M. M. (2012). The water footprint of humanity. *Proceedings of the national academy of sciences*, 109(9), 3232-3237.
[540] Scown CD, Horvath A and McKone TE (2011). Water Footprint of U.S. Transportation Fuels. Environmental Science & Technology 45(7): 2541-2553: 10.1021/es102633h.
[541] Scown CD, Horvath A and McKone TE (2011). Water Footprint of U.S. Transportation Fuels. Environmental Science & Technology 45(7): 2541-2553: 10.1021/es102633h.
[542] Wu, M., Zhang, Z., & Chiu, Y. W. (2014). Life-cycle water quantity and water quality implications of biofuels. *Current Sustainable/Renewable Energy Reports*, 1(1), 3-10.
[543] Dominguez-Faus R, Powers SE, Burken JG and Alvarez PJ (2009). The Water Footprint of Biofuels: A Drink or Drive Issue? Environmental Science & Technology 43(9): 3005-3010: 10.1021/es802162x.

per liter of ethanol-equivalent biodiesel (based on energy equivalence).[544] These values all represent an upper end estimate of water demands, if fuels are made from irrigated crops.

However, where and how crops are grown also matter because irrigation rates for the same crops can vary enormously based on where they are cultivated: from no irrigation in rain-fed acres in the Midwest to high irrigation rates in more arid regions in the West. Dominguez-Faus et al. (2013) calculated a range of irrigation water use for corn ethanol between 350 and 1400 gal/gal.[545] That study estimated that if 20% of corn production was used to produce 12 billion gallons per year of ethanol in 2011 (irrigated at a weighted average of 800 gal/gal), that would amount to 1.8 trillion gallons of irrigation water withdrawals per year. While not an insignificant amount, it represents only 4.4% of all irrigation withdrawals.[546] Other researchers have similarly focused on the wide range of water intensity estimates between rain-fed and irrigated counties and among a variety of crops (see Figure 4.5.2.1-1). Gerbens-Leenes et al. (2012) estimated Nebraska's blue water (irrigation water) footprint at three times higher than the U.S. weighted average blue water footprint.[547] Many other corn producing states have much smaller irrigation demands relative to Nebraska. Yet, it should be noted that, after Iowa, Nebraska is the second largest producer of corn-based ethanol in the U.S., with 25 active ethanol facilities, many concentrated in southern Nebraska.[548] Additionally, the blue water footprint in areas that have already stressed water sources, like the HPA, could experience more severe water quantity impacts. A report by the National Academy of Sciences (NAS 2011) highlighted the groundwater depletion in the HPA, noting that Nebraska is "among the states with the largest water withdrawals for irrigation, and its usage has continued to increase in recent years, largely driven by the need to irrigate corn for ethanol."[549] This suggests that the majority of groundwater consumption would come from areas like Nebraska that are already impacted by over-pumping due to their high blue water footprint for corn production (Gerbens-Leenes et al. 2012).[550]

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[544] Dominguez-Faus R, Powers SE, Burken JG and Alvarez PJ (2009). The Water Footprint of Biofuels: A Drink or Drive Issue? Environmental Science & Technology 43(9): 3005-3010: 10.1021/es802162x.

[545] Dominguez-Faus, R., Folberth, C., Liu, J., Jaffe, A. M., & Alvarez, P. J. (2013). Climate change would increase the water intensity of irrigated corn ethanol. *Environmental science & technology*, 47(11), 6030-6037.

[546] Dominguez-Faus R, Folberth C, Liu J, Jaffe AM and Alvarez PJJ (2013). Climate Change Would Increase the Water Intensity of Irrigated Corn Ethanol. Environmental Science & Technology 47(11): 6030-6037: 10.1021/es400435n.

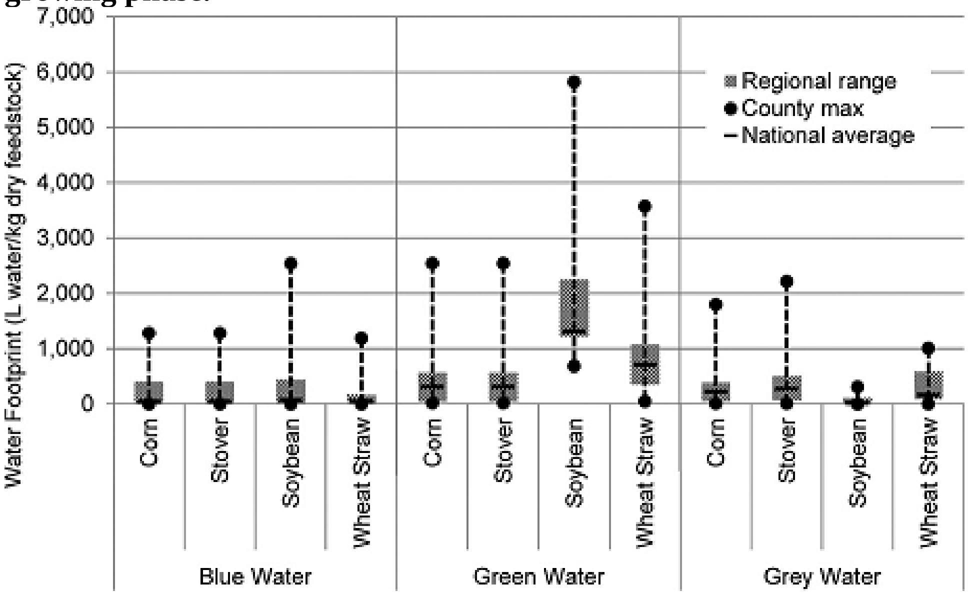
[547] Gerbens-Leenes, W., & Hoekstra, A. Y. (2012). The water footprint of sweeteners and bio-ethanol. *Environment international*, 40, 202-211.

[548] EIA (2018). "Six states account for more than 70% of U.S. fuel ethanol production." Available at https://www.eia.gov/todayinenergy/detail.php?id=36892 (last accessed April 14, 2021). *See also* EIA. (2017, February 16). "Nebraska State Profile and Energy Estimates: Profile Analysis." Retrieved June 2, 2017, from https://www.eia.gov/state/analysis.php?sid=NE.

[549] NAS (2011). Renewable Fuel Standard: Potential Economic and Environmental Effects of U.S. Biofuel Policy. National Academy of Sciences. Washington, DC.

[550] Gerbens-Leenes, W., & Hoekstra, A. Y. (2012). The water footprint of sweeteners and bio-ethanol. *Environment international*, 40, 202-211.

Figure 4.5.2.1-1: Estimate of the blue/irrigation, green/rainwater and grey/pollution water footprint associated with corn grain, stover, wheat straw and soybean during the crop growing phase.



The national production-weighted average is represented by the horizontal bar, while the regional ranges (this includes all USDA regions such as the Corn Belt, Southern Plains, etc.) are represented by the shaded bars. County-level variation in feedstock water footprints, shown in dashed lines, are driven by differences in irrigation and evapotranspiration (ET). The circles show both "County max" as well as "County min." [Source: Chiu and Wu (2012)].

4.5.2.2 Biofuel Processing

Studies of water use at biofuels conversion facilities have generally quantified water consumption as gallons of water per gallon of biofuel produced, mostly concentrating on ethanol, especially dry mill facilities.[551] Process level engineering studies and surveys of ethanol facilities have shown declines in water requirements from 5.8 gallons of water per gallon of ethanol (gal/gal) in 1998 to 2.7 gal/gal in 2012.[552] These values are typical of a dry mill facility. Wet mill facilities require closer to 4 gallons per gallon of ethanol.[553] Some reports also point to reductions in the water intensity of ethanol facilities through more efficient water use and recovery, and reuse of wastewater after treatment for processes such as fermentation or possibly

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[551] U.S. EPA (2018). Biofuels and the Environment: Second Triennial Report to Congress. U.S. Environmental Protection Agency, EPA/600/R-18/195: 159 pp. Washington, DC, June.

[552] Mueller S (2010). 2008 National dry mill corn ethanol survey. Biotechnology Letters 32(9): 1261-1264: 10.1007/s10529-010-0296-7. and Wu Y and Liu S (2012). Impacts of biofuels production alternatives on water quantity and quality in the Iowa River Basin. Biomass and Bioenergy 36: 182-191: 10.1016/j.biombioe.2011.10.030. *See also* Wu Y and Liu S (2012b). Impacts of biofuels production alternatives on water quantity and quality in the Iowa River Basin. Biomass and Bioenergy 36: 182-191: 10.1016/j.biombioe.2011.10.030.

[553] Grubert, E. A., & Sanders, K. T. (2018). Water use in the US energy system: A national assessment and unit process inventory of water consumption and withdrawals. Environmental science & technology.

cooling towers.[554] Some facilities have set goals to both reduce water use and minimize discharges.

Biodiesel conversion from oil crops such as soybeans requires water use for multiple stages of the process (crop to oil, and oil to biodiesel). The soybean processing (crop to oil) stage involves crushing, oil extraction and crude soybean oil refining (degumming). Water consumption includes make-up water for cooling towers and other processes. In the biodiesel production stage (oil to biodiesel), following the crushing and oil extraction steps, water is used to remove residual glycerol, a by-product of the transesterification process, and other impurities, while some water is also for additional make-up water for cooling towers.[555] Tu et al. (2016) estimated that the water footprint of soybean based biodiesel to be under 1 gal/gal biodiesel (0.17 for crop to oil and 0.31 for oil to biodiesel).[556]

Renewable diesel is chemically very similar to petroleum-based diesel despite being made from renewable wastes such as fats and vegetable oils. This means that it is processed in the same manner that petroleum diesel which is hydrotreating. With this knowledge it can be assumed that the same about of water used for processing petroleum diesel is used to process renewable diesel.[557] As renewable diesel is a plant-based feedstock, its additional water usage would be from the irrigation process to grow the plants used to create the oil and not from the process itself.

There are no recently published surveys of water consumption representing all current biofuel and renewable fuel facilities, and no comprehensive data on the type of water sources utilized (e.g., groundwater, surface freshwater, public supply, etc.). Grubert and Sanders estimate that the majority of the water used is freshwater. There is also some evidence that groundwater from aquifers is being extracted for use in ethanol production in states such as Iowa and Nebraska,[558] and likely a source of water for facilities along the HPA (see Figure 4.5.3-3).

4.5.2.3 Summary and Comparison to Petroleum

Improvements in irrigation have brought down the upper range of water use, with recent estimates of irrigation for corn production ranging from 9.7 gal/gal ethanol for USDA Region 5 (Iowa, Indiana, Illinois, Ohio and Missouri) to 220.2 gal/gal ethanol in Region 7 (North Dakota,

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[554] Schill, S. R. (2017) Water: Lifeblood of the Process. *Ethanol Producer Magazine*. January 24, 2017. http://www.ethanolproducer.com/articles/14049/water-lifeblood-of-the-process. See also Jessen, H. (2012) Dropping Water Use. *Ethanol Producer Magazine*. June 12, 2012. Available at http://www.ethanolproducer.com/articles/8860/dropping-water-use (last accessed September 16, 2021).

[555] Tu, Q., Lu, M., Yang, Y. J., and D. Scott (2016) Water consumption estimates of the biodiesel process in the US. *Clean Technologies and Environmental Policy*. 18(2): 507-516.

[556] Tu, Q., Lu, M., Yang, Y. J., and D. Scott (2016) Water consumption estimates of the biodiesel process in the US. *Clean Technologies and Environmental Policy*. 18(2): 507-516.

[557] Sun, Pinping; Estimation of U.S. refinery water consumption and allocation to refinery products; Fuel; Volume 221; June 18, 2018.

[558] Schilling, K. E., Jacobson, P. J., Libra, R. D., Gannon, J. M., Langel, R. J., & Peate, D. W. (2017). Estimating groundwater age in the Cambrian–Ordovician aquifer in Iowa: implications for biofuel production and other water uses. Environmental Earth Sciences, 76(1), 2. *See also* Gerbens-Leenes, W., & Hoekstra, A. Y. (2012). The water footprint of sweeteners and bio-ethanol. *Environment international*, 40, 202-211.

South Dakota, Nebraska and Kansas) for groundwater.[559] The conversion of corn to ethanol requires 2-10 gal/gal for processing, with most dry mill plants requiring roughly 3 gal/gal. When averaging production over all regions, and accounting for co-products of ethanol production (such as distillers dried grain and solubles), the range for full life cycle consumptive water use for U.S. corn ethanol is 8.7 - 160.0 gal/gal ethanol based on the updated analysis by Wu et al (2018). By comparison, the most recent estimates of the net consumptive water use over the petroleum-based fuel life cycle would be in the range of 1.4 - 8.6 gallons of water per gallon of gasoline based on U.S. conventional crude, and diesel fuel would likely be a little less than gasoline's consumption.[560] [561] The Wu et al (2018) analysis does not include biodiesel. The most recent estimate for the full LCA water consumption for biodiesel provides a range of values for each state: Missouri 21-79 gal water/gal biodiesel, Kansas and Oklahoma 80-150 gal/gal, Nebraska and Texas 150-300 gal/gal.[562] The water consumption of a biodiesel plant is well under 1 gallon of water consumed for each gallon of biodiesel produced, therefore, virtually all the water associated with the lifecycle production of biodiesel made from vegetable oils is due to the growing and processing of vegetable oil feedstocks.[563] Assuming that renewable diesel fuel production plants consume the same amount of water as a distillate hydrotreater, then renewable diesel fuel production plants likely consume about 3 gallons of water for each gallon of renewable diesel produced.[564] As with biodiesel, we expect that water consumption associated with renewable diesel made from vegetable oils is primarily associated with the production of the underlying vegetable oil feedstocks. Since biodiesel and renewable diesel made from FOG does not require crop-based inputs, we expect that the water usage for these biofuels is significantly lower.

In summary, while values will vary across states and counties, ethanol, and biodiesel and renewable diesel made from vegetable oils are substantially more water intensive than the petroleum fuels they would displace. It is likely, though, that FOG-based biodiesel and renewable diesel are more similar in water consumption to petroleum diesel fuel which it displaces.

4.5.3 Impacts to Date

Because the majority of the growth in biofuels production has come from corn- and soy-based biofuels, the water consumption impacts to date would have come from additional water use for corn and soybean acreage. To our knowledge, there have been no comprehensive studies of the changes in irrigated acres, rates of irrigation, or changes in surface and groundwater supplies attributed specifically to the increased production of corn grain-based ethanol and

[559] Wu, M., & Xu, H. (2018*). Consumptive Water Use in the Production of Ethanol and Petroleum Gasoline—2018 Update* (No. ANL/ESD/09-1 Rev. 2). Argonne National Lab.(ANL), Argonne, IL (United States). https://publications.anl.gov/anlpubs/2019/01/148043.pdf
[560] Id.
[561] Sun, Pinping; Estimation of U.S. refinery water consumption and allocation to refinery products; Fuel; Volume 221; June 18, 2018.
[562] Tu, Q., Lu, M., Yang, Y. J., and D. Scott (2016). Water consumption estimates of the biodiesel process in the US. *Clean Technologies and Environmental Policy*. 18(2): 507-516.
[563] Haas, M.J, A process model to estimate biodiesel production costs, Bioresource Technology 97 (2006) 671-678.
[564] Sun, Pinping; Estimation of U.S. refinery water consumption and allocation to refinery products; Fuel; Volume 221; June 18, 2018.

soybean-based biodiesel. There are, however, studies that can give some indication of how changes in production of these biofuels may have affected water demand and availability. The Second Triennial Report to Congress on Biofuels highlights analyses in Lark et al. (2015) and Wright et al. (2017) that show changes in land use, including cropland expansion in the western Dakotas and Kansas, related to biofuels.[565] These are areas unlikely to have sufficient precipitation to support corn or soybean cultivation.[566] While difficult to attribute how much additional water use might be required as a result of the candidate volumes in this rule, there are several lines of evidence that suggest increased production of corn-based ethanol and soybean-based biodiesel will increase water demands and, potentially, affect limited water supplies.

The USDA Irrigation and Water Management Surveys (formerly the Farm and Ranch Irrigation Survey or FRIS), a supplement to the Census of Agriculture completed every five years, provide a general indication of the changes in water demands between 2013 and 2018.[567] From 2013 to 2018, there was an increase in total irrigated acres of nearly 0.6 million acres in the U.S.[568] Over the same period, irrigated acres of corn for grain and seed decreased from 13.3 million acres to 11.6 million acres harvested, along with a lower irrigation rate of 0.9 acre-feet applied in 2018 compared to 1.1 acre-feet applied in 2013.[569] Over the same time period, irrigated acres of soybeans increased from 7.4 to 8.2 million acres harvested, while average acre-feet applied declined from 0.9 to 0.6 per acre.[570] Figure 4.5.3-1 shows acres of irrigated land in 2012, the most recent year of data for which this figure is available.

[565] U.S. EPA (2018). Biofuels and the Environment: Second Triennial Report to Congress. U.S. Environmental Protection Agency, EPA/600/R-18/195: 159 pp. Washington, DC, June.

[566] Lark TJ, Salmon JM and Gibbs HK (2015). Cropland expansion outpaces agricultural and biofuel policies in the United States. Environmental Research Letters 10(4): 10.1088/1748-9326/10/4/044003. and Wright, C. K., et al. (2017). "Recent grassland losses are concentrated around US ethanol refineries." Environmental Research Letters 12(4).

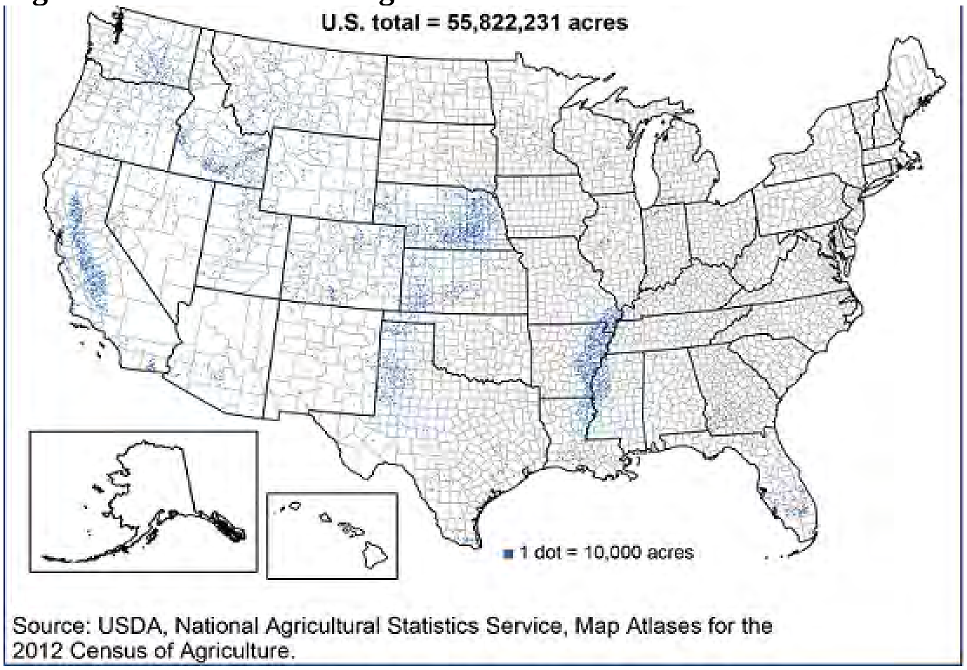
[567] USDA NASS (2018). 2018 Irrigation and Water Management Survey. Available at https://www.nass.usda.gov/Publications/AgCensus/2017/Online_Resources/Farm_and_Ranch_Irrigation_Survey/fris.pdf (last accessed April 14, 2021).

[568] USDA NASS (2018). 2018 Irrigation and Water Management Survey. Available at https://www.nass.usda.gov/Publications/AgCensus/2017/Online_Resources/Farm_and_Ranch_Irrigation_Survey/fris.pdf (last accessed April 14, 2021).

[569] USDA NASS (2018). 2018 Irrigation and Water Management Survey. Available at https://www.nass.usda.gov/Publications/AgCensus/2017/Online_Resources/Farm_and_Ranch_Irrigation_Survey/fris.pdf (last accessed April 14, 2021).

[570] USDA NASS (2018). 2018 Irrigation and Water Management Survey. Available at https://www.nass.usda.gov/Publications/AgCensus/2017/Online_Resources/Farm_and_Ranch_Irrigation_Survey/fris.pdf (last accessed April 14, 2021).

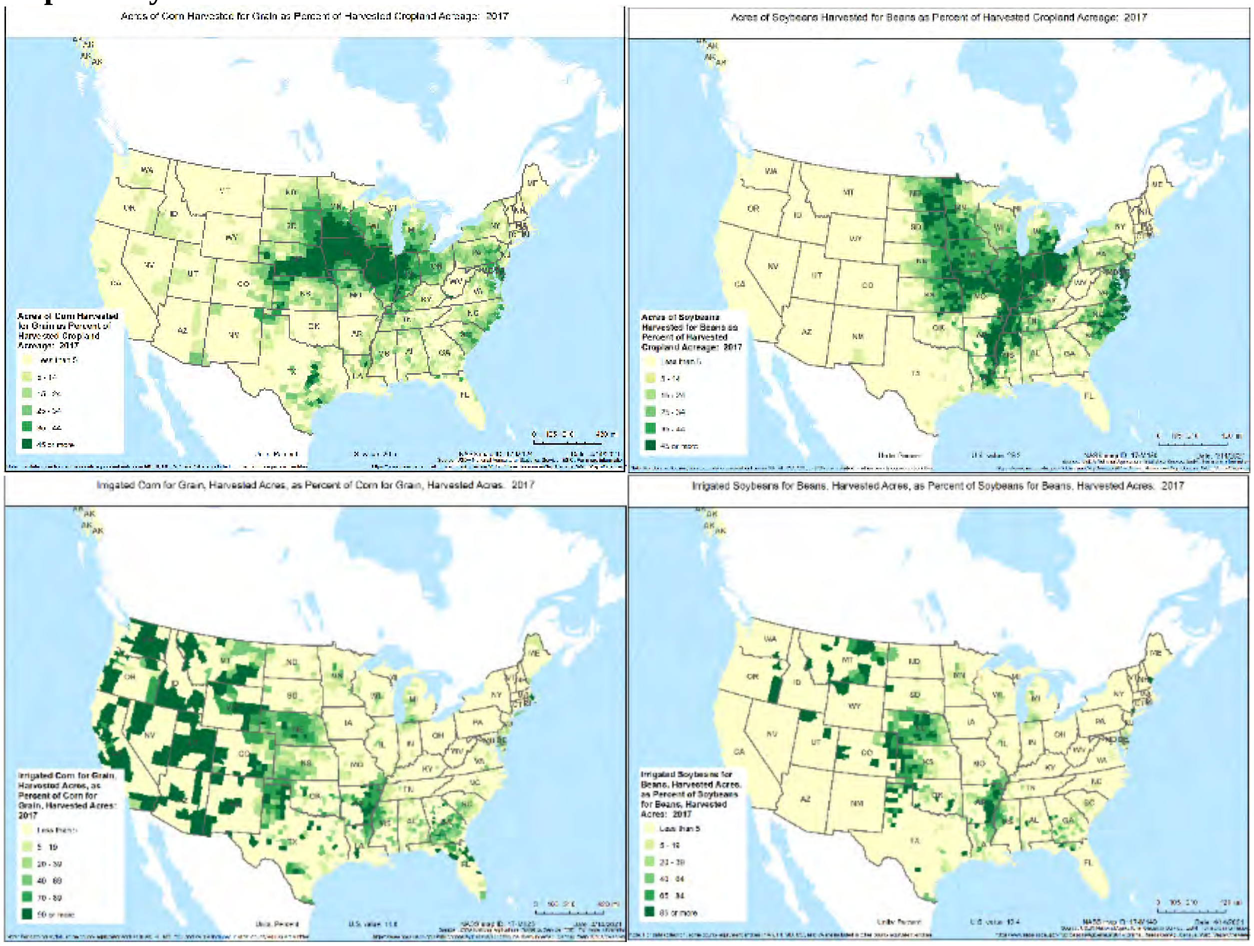
Figure 4.5.3-1: Acres of irrigated land in 2012



Based on the USDA Farm and Ranch Irrigation Survey. Source: https://www.ers.usda.gov/topics/farm-practices-management/irrigation-water-use/background.aspx

Figure 4.5.3-2 shows corn and soybean areas and share of irrigated acres. Irrigated corn grain/seed acres are heavily concentrated in Nebraska (4.5 million acres) followed by Kansas (1.3 million acres). This is a decrease of 0.9 and 0.2 million acres respectively from 2012 to 2018. Irrigated soybean acres are also found in Nebraska, Kansas, particularly the more western part of those states. Overall soybean production is generally more concentrated (as a share of total harvested cropland) in rainfed areas, whereas corn production reaches further west. There is also a high percentage of soybean acres in Arkansas and Mississippi, with a large share of those soybean acres being irrigated. The top rows of Figure 4.5.3-2 show the distribution of corn and soybean acres, as a share of total cropland acres, while the bottom rows of Figure 4.5.3-2 show the percent of irrigated corn and soybean acres relative to total acres for those crops (measures as harvested acres).

Figure 4.5.3-2: Percent of irrigated corn and soybean acres relative to total acres, respectively



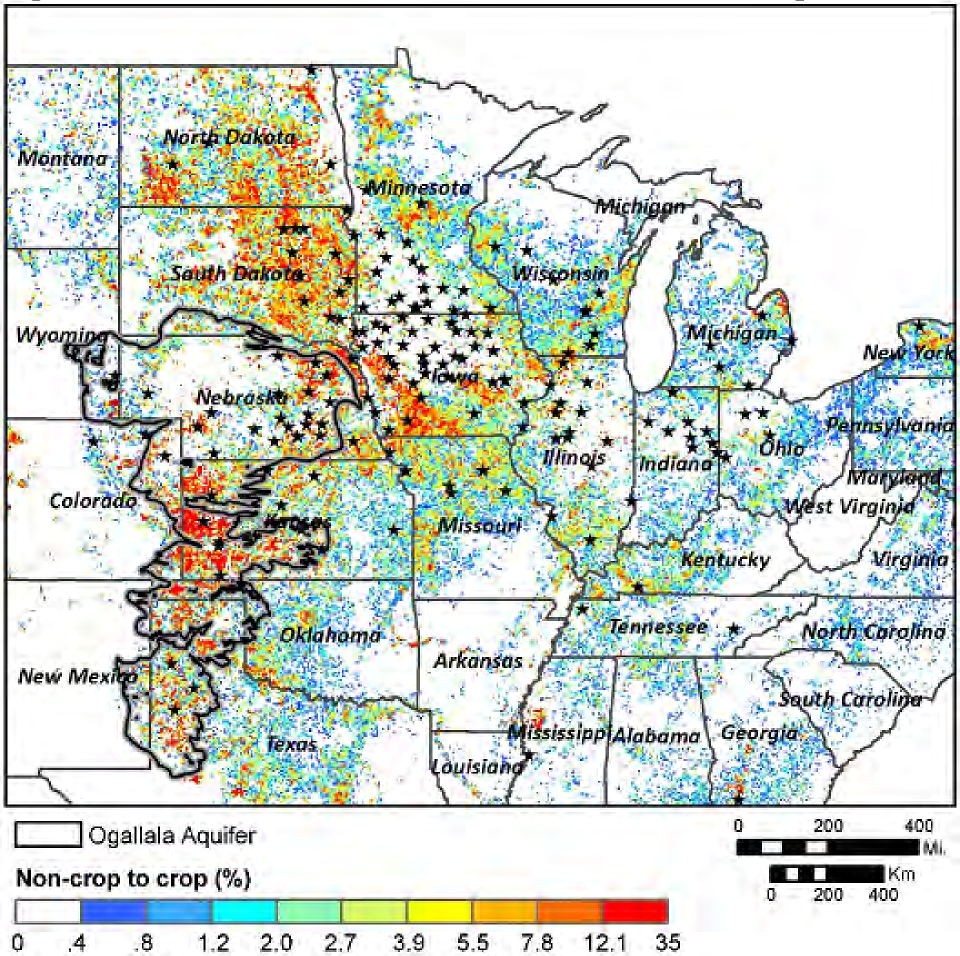
Top left: Acres of Corn Harvested as a Percent of Harvested Cropland Acreage.
Top right: Acres of Soybean Harvested as a Percent of Harvested Cropland Acreage.
Bottom left: Irrigated Corn as a Percent of Total Corn (Harvested Acres).
Bottom right: Irrigated Soybeans as a Percent of Total Soybeans (Harvested Acres).
Source: USDA Agricultural Census Web Maps (Accessed April 14, 2021).
https://www.nass.usda.gov/Publications/AgCensus/2012/Online_Resources/Ag_Census_Web_Maps/index.php

Higher irrigation demands may coincide with areas of already-stressed surface and groundwater resources, such as the HPA (also called the Ogallala Aquifer). A 2011 report by the National Academy of Sciences highlighted the groundwater drawdown in the HPA, noting that Nebraska is "among the states with the largest water withdrawals for irrigation, and its usage has continued to increase in recent years, largely driven by the need to irrigate corn for ethanol."[571] This suggests that the majority of groundwater consumption would come from areas like Nebraska, which are already impacted by over-pumping due to their high blue water footprint for corn production. Changes in irrigation practices are dependent on a number of economic and agronomic factors that affect how land is managed, making it difficult to attribute expanded irrigation to biofuels production and use without more detailed analysis. A study by Wright et al.

[571] NAS (2011). Renewable Fuel Standard: Potential Economic and Environmental Effects of U.S. Biofuel Policy. National Academy of Sciences. Washington, DC.

(2017) of land use change rates noted that "along the Ogallala Aquifer, elevated rates of land use change to corn production in Western Kansas, Oklahoma and Texas coincided with areas experiencing groundwater depletion rates ranging from 5-20% per decade" (see Figure 4.5.3-3). However, this correlation does not necessarily mean there is a direct, causal relationship between biofuel production and groundwater depletion.

Figure 4.5.3-3: Relative conversion rates of arable non-cropland to cropland (2008-2012).



Includes conversion located along the Ogallala aquifer. Stars denote biofuel production facilities. (Source: Wright et al. 2017)

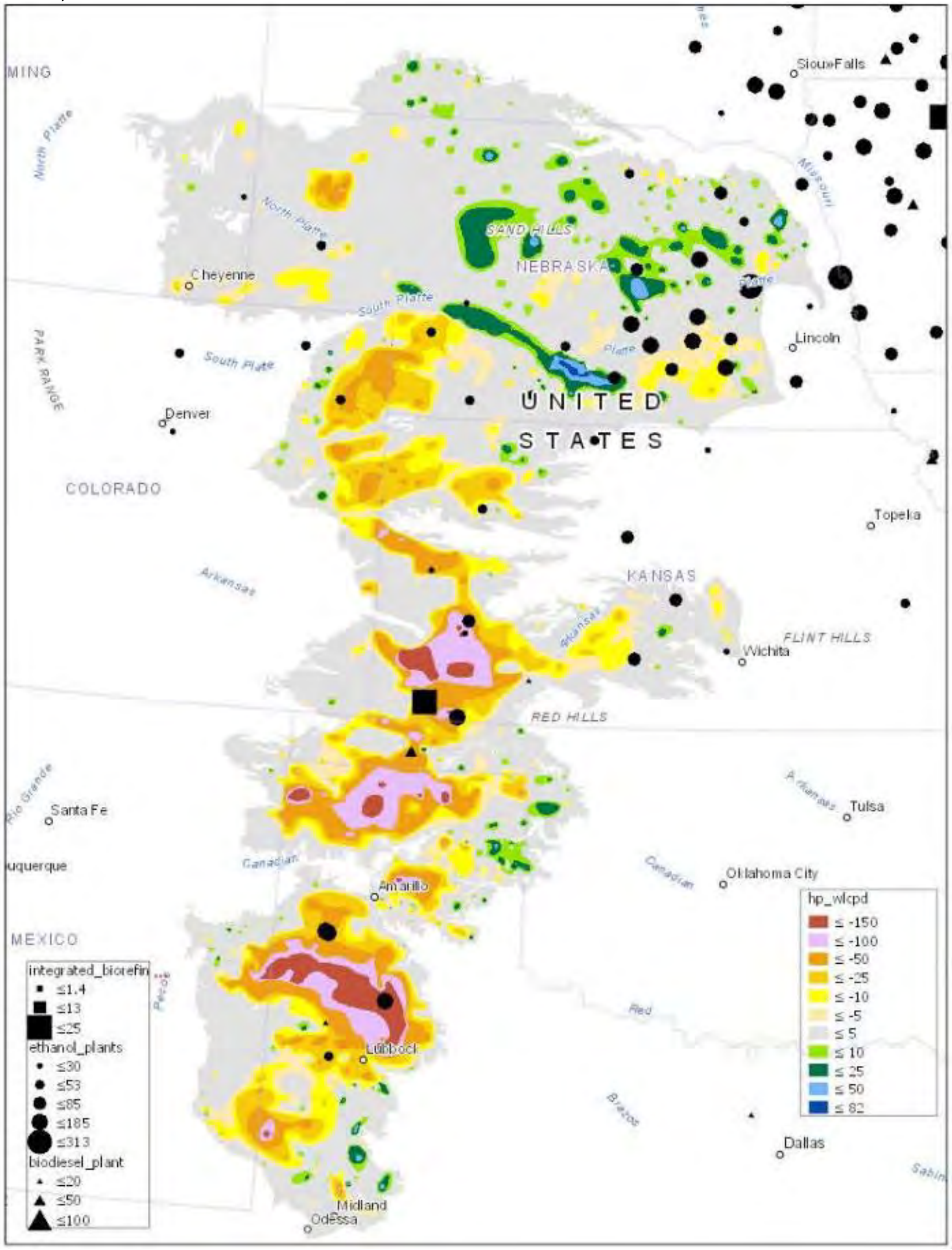
As stated above, there have been no comprehensive studies of the changes in irrigated acres, rates of irrigation, or changes in surface and groundwater supplies attributed specifically to the increased production of corn grain-based ethanol and soybean-based biodiesel. In the absence of analyses that do focus directly on crops for biofuel production, there are studies that look more broadly at the connection between agricultural water use and groundwater levels. For example, Smidt et al. (2016) analyzed the water-energy-food nexus over the HPA to look at the major drivers that have affected and will continue to affect agriculture's water use. That study highlights that, across large portions of the HPA, "groundwater levels have declined at unsustainable rates despite improvements in both the efficiency of water use and water productivity in agricultural practices."[572] Figure 4.5.3-3 shows the relative conversion rates of arable cropland to non-cropland, as well as the location of the HPA and biofuel conversion facilities. Figure 4.5.3-4 also shows the HPA, but shows the absolute changes in groundwater levels, from predevelopment to 2017 based on data from USGS.[573] The HPA can be divided into three geographical regions: the Northern, Central, and Southern High Plains. The Northern HPA groundwater supplies have been relatively stable since predevelopment (with some increases shown in green/blue), whereas the Central and Southern HPAs have seen substantial declines, in some areas over 150 ft of declines (shown in yellow/orange/red). Biofuel facility locations (from the National Renewable Energy Laboratory[574]) are overlaid onto the HPA data from USGS to highlight where biofuel production facilities are co-located with areas of changes in the groundwater levels. Again, while the Central and Southern HPAs have seen substantial declines, the Northern HPA has remained relatively stable and even increased in some areas (as shown in Figure 4.5.3-4). This does not demonstrate that biofuel production causes declines in groundwater levels, but it does show that some biofuel facilities operate in areas that are experiencing water-stressed aquifer resources.

[572] Smidt, S. J., Haacker, E. M., Kendall, A. D., Deines, J. M., Pei, L., Cotterman, K. A., … & Hyndman, D. W. (2016). Complex water management in modern agriculture: Trends in the water-energy-food nexus over the High Plains Aquifer. Science of the Total Environment, 566, 988-1001.

[573] The predevelopment water level is defined as "the water level in the aquifer before extensive groundwater pumping for irrigation, or about 1950. The predevelopment water level was generally estimated by using the earliest water-level measurement in more than 20,000 wells." https://ne.water.usgs.gov/projects/HPA/index.html

[574] https://maps.nrel.gov/biofuels-atlas/

Figure 4.5.3-4: Water-level changes in the High Plains Aquifer, predevelopment (about 1950) to 2015



Water levels changes in feet, yellows and reds represent decreases in groundwater levels while greens and blue represent rises in groundwater levels. Grey indicated no substantial change. Data from U.S. Geological Survey (USGS). Ethanol plants, biodiesel plans, and integrated biorefineries size (based on annual capacity) and location from the Bioenergy Atlas, maintained by NREL. https://maps.nrel.gov/biofuels-atlas/

4.5.3.1 Crop Prices and Value of Irrigation

Recent research has also assessed the linkage between crop prices and irrigation rates to find the irrigation values (\$/ha/mm) which reflect the price incentive to irrigate. Comparing the value of irrigation across commodities, Smidt et al (2017) found that the highest value was for corn. The value of irrigation was lower for soybeans.[575] The high value of irrigation for corn is due to the large yield increases that occur with irrigation for corn, as well as the high water-use efficiency. This indicates that higher corn prices will increase the incentives to irrigation, and, conversely, lower corn prices may lead to decreases in acres and rates of irrigation. The same would hold true for soy– higher prices for soybeans incentivizing more irrigation, lower prices leading to less irrigation. Though the impact would be smaller than it would be from an increase in corn cultivation, since soybeans generally require less irrigation than does corn.

Earlier work also looked at the impact of agricultural commodity prices on irrigation demands by taking an economic-based approach that calculated the price elasticities of irrigation water demands.[576] More recent work by Deines et al (2017) utilized satellite images to produce annual maps of irrigation for 1999-2016 to study changes in irrigation over time.[577] In addition to looking at changes in the area and location of irrigated fields, Deines et al (2017) also did statistical modeling to assess how factors such as precipitation and commodity prices influenced the extent of irrigation. That study confirmed that "farmers expanded irrigation when crop prices were high to increase crop yield and profit."[578]

4.5.3.2 Non-Cropland Biofuels and Non-U.S. Crops

The Second Triennial Report to Congress on Biofuels and the published research on the water quantity impacts of biofuels generally do not report or estimate water used for production of non-cropland biofuels or impacts outside of the U.S. However, some of the changes in volumes are associated with non-cropland biofuels, such as biogas, or with biofuels produced from feedstocks produced in foreign countries, such as palm-based biofuels. We will briefly discuss biogas here. Palm oil water demands are discussed in section 2.6 of the Second Triennial Report. In addition, as noted in Chapter 4.3, there is strong evidence that expanded palm oil production would have adverse impacts on water quality outside of the U.S.

Biogas does not have the irrigation requirements associated with crop-based biofuels. Because their inventory covers all of the U.S. energy system at a high level of detail (including 126 unit processes), Grubert and Sanders (2018) examined whether there were any water consumption and withdrawals for biogas from landfills, wastewater and animal manure digesters.[579] For biogas, they reported no water requirements. Since the biogas is a byproduct of wastes (i.e., landfills, manure, and wastewater), none of the water used for the primary products (e.g., the agricultural operations that produced the manure) is allocated to the produced biogas. In

[575] Smidt, S. J., Haacker, E. M., Kendall, A. D., Deines, J. M., Pei, L., Cotterman, K. A., ... & Hyndman, D. W. (2016). Complex water management in modern agriculture: Trends in the water-energy-food nexus over the High Plains Aquifer. Science of the Total Environment, 566, 988-1001.
[576] See for example, Scheierling, S. M., Loomis, J. B., & Young, R. A. (2006). Irrigation water demand: A meta-analysis of price elasticities. *Water resources research*, 42(1).
[577] Deines, J.M., Kendall, A.D., and Hyndman, D.W. (2017). Annual Irrigation Dynamics in the U.S. Northern High Plains Derives from Landsat Satellite Data. *Geophysical Research Letters 44*, 9350-9360.
[578] Deines, J.M., Kendall, A.D., and Hyndman, D.W. (2017). Annual Irrigation Dynamics in the U.S. Northern High Plains Derives from Landsat Satellite Data. *Geophysical Research Letters 44*, 9350-9360.
[579] Grubert, E., & Sanders, K. (2018). Water Use in the United States Energy System: A National Assessment and Unit Process Inventory of Water Consumption and Withdrawals. *Environmental Science & Technology* 52(11), 6695-6703.

the case of landfill biogas, we therefore assume no significant amounts of water are used. Grubert and Sanders also assume negligible water requirements for the processing and transportation of biogas, although they note that some water may be used for upgrading biogas if water-intensive amine scrubbing is used.

4.5.4 Potential Future Impacts of Annual Volume Requirements

Most of the available research looks at the past and potential future water quantity and availability impacts associated with increased use of corn ethanol, and in some instances, cellulosic biofuels. Because of the high volumes of corn ethanol produced to date, the water quantity and availability concerns have been focused on corn ethanol, with less focus on soy biodiesel. The changes in mandatory volumes under this rule and future rules are different from the scenarios analyzed in the literature published to date. Studies on future water quantity impacts often project larger changes for corn ethanol[580] or focus on future cellulosic feedstocks.[581] Thus, the water quantity impacts due to this rule are difficult to quantify based on the existing literature. That said, there are several ways to assess the impacts of the volume scenarios, based on the studies reviewed above.

We can assess potential water demand changes based on volume changes by biofuel type as summarized in Section 3.3 of the Second Triennial Report to Congress on Biofuels. All else being equal, the life cycle water consumption of ethanol and biodiesel (derived from soybeans and likely palm) is higher, sometimes orders of magnitude higher, than the petroleum-based fuels they are intended to displace (see Chapter 2.2). However, while the life cycle approach estimates the direction of changes in the water demands associated with shifting from petroleum to biomass-based fuels, how much that translates into increased irrigation or changes in water availability is more difficult to assess.

A second approach to estimate changes in water demands due to the volume changes would rely on scenarios projecting land use changes and changes in crop management practices with a high enough level of precision to also assess or estimate the change in irrigation requirements. One study we reviewed attempted to project water requirements of increased biofuels production in the U.S.[582] However, the biofuel volumes modeled by Liu et al. (2017) represented an E20 scenario for 2025 and differed greatly in their modeled expansion of crops compared to the volumes in this rulemaking.

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580 Liu, X. V., Hoekman, S. K., & Broch, A. (2017). Potential water requirements of increased ethanol fuel in the USA. *Energy, Sustainability and Society*, *7*(1), 18.

581 Several studies have estimated water use and availability impacts associated with future scenarios of increased cellulosic biofuel production. These studies often project future land use/management for different scenarios of increased production of cellulosic crops, and then estimate impacts on water use and changes in streamflow for specific watersheds. See for example: Cibin, R., Trybula, E., Chaubey, I., Brouder, S. M., & Volenec, J. J. (2016). Watershed-scale impacts of bioenergy crops on hydrology and water quality using improved SWAT model. Gcb Bioenergy, 8(4), 837-848 or Le, P. V., Kumar, P., & Drewry, D. T. (2011). Implications for the hydrologic cycle under climate change due to the expansion of bioenergy crops in the Midwestern United States. Proceedings of the National Academy of Sciences, 108(37), 15085-15090.

582 Liu, X., Hoekman, S.K., and Broch, A. 2017. Potential water requirements of increased ethanol fuel in the USA. *Energy, Sustainability and Society*, 7: 18.

A third approach to estimate the changes in water demands is based on changes in crop prices and the associated economic value of irrigation. While the attribution of impacts due to land use changes and associated irrigation requirements is difficult, it may be possible to assess at a broad scale, at least in terms of directionality, the changes in irrigation that may result from the impact of the candidate volumes on crop prices. However, we have not yet been able to perform such an analysis and it remains an area where additional analysis and research is needed to better understand the impacts of the promulgated volumes on water demand.

In summary, based on the approaches above, there will likely be some increased irrigation pressure on water resources due to the candidate volumes. Specifically, the volume increases for 2023-2025 compared to the No RFS baseline that is described in Chapter 2 due to biofuels produced from agricultural feedstocks (especially corn and soybeans) would suggest the potential for some associated increase in crop production, which in turn would likely increase irrigation pressure on water resources. The increased volume requirements especially that of renewable diesel could incent greater production of its underlying feedstock (soybeans). There is uncertainty in projecting changes in acreage and irrigation rates associated with corn, soybeans, and other crops. Furthermore, if we consider the potential impacts relative to the current situation in 2022 (i.e., the 2022 baseline discussed in Chapter 2.2) there would be little impact, as the overall volume increase for biodiesel and renewable diesel is much smaller and expected to be met with expanded waste fats, oils, and greases supply. Additional information and modeling are needed to fully assess changes in water demands and effects on water stressed regions, both for crop irrigation as well as impacts of biofuel facility water use. Additionally, and as described in Chapter 4.4, we note that there may be potential effects on water and soil quality. While we could not quantify these effects, as described in Chapter 4.4, the potential for negative effects is an area of ongoing concern and research.

4.6 Ecosystem Services

Ecosystem services broadly consist of the many life-sustaining benefits humans receive from nature, such as clean air and water, fertile soil for crop production, pollination, and flood control.[583] The United Nations Millennium Ecosystem Assessment[584] categorized four different types of ecosystem services, including:

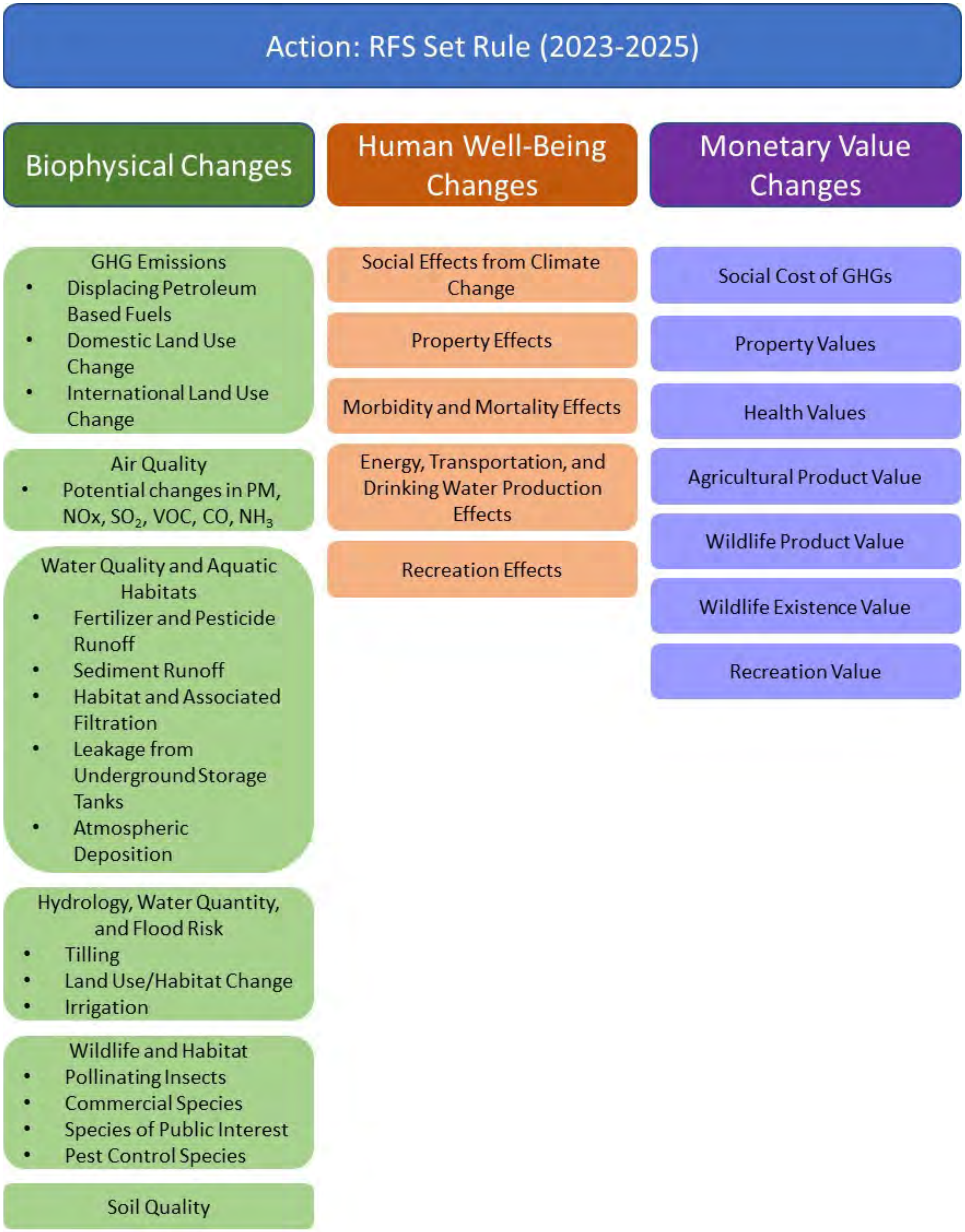
- Provisioning Services; the provision of food, fresh water, fuel, fiber, and other goods
- Regulating Services; climate, water, and disease regulation as well as pollination
- Supporting Services; soil fermentation and nutrient cycling
- Cultural services; education, aesthetic, and cultural heritage values as well as recreation and tourism

Several of the drivers of ecosystems loss identified in the Millennium Ecosystem Assessment, such as climate change, pollution, and land-use change, are expected to be impacted by the production of renewable fuels generally and may be impacted by the candidate volumes in this rule specifically.

[583] US EPA website on Ecosystem Services. Available at: https://www.epa.gov/eco-research/ecosystem-services
[584] Millennium Ecosystem Assessment, 2005. Ecosystems and Human Well-being: Synthesis. Island Press, Washington, DC.

The previous sections in this chapter discussed the projected impacts associated with this rule on a variety of different environmental end points such as air quality, climate change, land-use change, soil and water quality, and water availability as required by the statute. Each of the impacts discussed in these sections would be expected to have an impact on one or more ecosystems services. These impacts could be positive (e.g., result in ecosystem services benefits) or negative. We have focused our analyses in the specific factors identified in the statute and we have not quantified all of the human well-being changes or monetized these effects. We have, however, provided a potential framework for how the impacts on ecosystem services might be considered (see Figure 4.6-1). Note that there are multiple frameworks for categorizing ecosystem services in the literature. Future analyses, such as those presented in the Triennial Biofuels and the Environment reports to Congress, may refine this approach to better capture incremental ecosystem service benefits and costs.

Figure 4.6-1: Framework for Considering the Impact of the RFS Volumes on Ecosystem Services



Chapter 5: Energy Security Impacts

The CAA directs EPA to analyze "the impact of renewable fuels on the energy security of the United States" in using the set authority to establish volumes. U.S. energy security is broadly defined as the continued availability of energy sources at an acceptable price.[585] Most discussions of U.S. energy security revolve around the topic of the economic costs of U.S. dependence on oil imports.[586] In addition to evaluating energy security, we have also considered energy independence, which is the idea of eliminating U.S. dependence on imports of petroleum and other foreign sources of energy. While energy independence is not a statutory factor in the CAA, one goal of the RFS program is to improve the U.S.'s energy independence.[587] Energy independence and energy security are distinct but related concepts, and an analysis of energy independence also helps to inform our analysis of energy security.[588]

Since renewable fuels substitute for petroleum-derived conventional fuels, changes in renewable fuel volumes have an impact on U.S. petroleum consumption and imports. All else being constant, a change in U.S. petroleum consumption and imports would alter both the financial and strategic risks associated with sudden disruptions in global oil supply, thus influencing the U.S.'s energy security position. Renewable fuels also may have some energy security risks, for example, as a result of weather-related events (e.g., droughts). To the extent that renewable fuel price shocks are not strongly correlated with oil price shocks, blending renewable fuels with petroleum fuels can provide energy security benefits. However, the energy security risks of using renewable fuels themselves are not well understood, nor well studied. This chapter reviews the literature on energy security impacts associated with petroleum consumption and imports and summarizes EPA's estimates of the benefits of reduced petroleum consumption and imports that would result from the candidate volumes for 2023–2025.

The U.S.'s oil consumption has been gradually increasing in recent years (2015–2019) before dropping dramatically as a result of the COVID-19 pandemic in 2020 and 2021.[589] U.S. oil consumption is anticipated to return to roughly pre-COVID-19 levels and be relatively steady in 2023–2025.[590] The U.S. has increased its production of oil, particularly "tight" (i.e., shale) oil over the last decade.[591] As a result of the recent increase in U.S. oil production and to a lesser extent renewable fuels, the U.S. is projected to be a net exporter of crude oil and refined

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[585] Greene, D. 2010. Measuring energy security: Can the United States achieve oil independence? *Energy Policy* 38, pp. 1614–1621.

[586] The issue of cyberattacks is another energy security issue that could grow in significance over time. For example, one of the U.S.'s largest pipeline operators, Colonial Pipeline, was forced to shut down after being hit by a ransomware attack. The pipeline carries refined gasoline and jet fuel from Texas to New York. *Cyberattack Forces a Shutdown of a Top U.S. Pipeline*. New York Times. May 8th, 2021.

[587] See *Americans for Clean Energy v. Env't Prot. Agency*, 864 F.3d 691, 696 (D.C. Cir. 2017) ("By mandating the replacement—at least to a certain degree—of fossil fuel with renewable fuel, Congress intended the Renewable Fuel Program to move the United States toward greater energy independence and to reduce greenhouse gas emissions."); id. 697 (citing 121 Stat. at 1492).

[588] Greene, D. 2010. Measuring energy security: Can the United States achieve oil independence? Energy Policy 38, pp. 1614–1621.

[589] EIA. Total Energy. *Monthly Energy Review*. Table 3.1. Petroleum Overview. December 2021.

[590] EIA. AEO 2022. Reference Case. Table A11. Petroleum and Other Liquids Supply and Disposition.

[591] https://www.eia.gov/energyexplained/oil-and-petroleum-products/images/u.s.tight_oil_production.jpg.

petroleum products in 2023–2025.[592] This is a significant reversal of the U.S.'s oil trade balance position since the U.S. has been a substantial net importer of crude oil and refined petroleum products starting in the early 1950s.[593]

Given that the U.S. is projected to be a modest net exporter of crude oil and refined petroleum products for 2023–2025, one could reason that the U.S. no longer has a significant energy security problem. However, U.S. refineries still rely on significant imports of heavy crude oil from potentially unstable regions of the world. Also, oil exporters with a large share of global production have the ability to raise or lower the price of oil by exerting the market power associated with a cartel—the Organization of Petroleum Exporting Countries (OPEC)—to alter oil supply relative to demand. The degree of market power that OPEC has during the three-year time frame of this analysis is difficult to quantify. These factors contribute to the continued vulnerability of the U.S. economy to episodic oil supply shocks and price spikes, even when the U.S. is projected to be a modest net exporter of crude oil and refined petroleum products in 2023–2025.

We recognize that because the U.S. is a participant in the world market for crude oil and refined petroleum products, its economy cannot be shielded from worldwide price shocks.[594] But the potential for petroleum supply disruptions due to supply shocks has been diminished due to the increase in tight oil production, and to a lesser extent renewable fuels (among other factors), which have shifted the U.S. to being a modest net petroleum exporter in the world petroleum market in 2023–2025**.** The potential for supply disruptions has not been eliminated, however, due to the continued need to import petroleum to satisfy the demands of the U.S. petroleum industry and because the U.S. continues to consume substantial quantities of oil.[595]

5.1 Review of Historical Energy Security Literature

Energy security discussions are typically based around the concept of the oil import premium, sometimes also labeled the oil security premium. The oil import premium is the extra cost/impacts of importing oil beyond the price of the oil itself as a result of: (1) potential macroeconomic disruption and increased oil import costs to the economy from oil price spikes or "shocks"; and (2) monopsony impacts. Monopsony impacts stem from changes in the demand for imported oil, which changes the price of all imported oil.

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592 EIA. AEO 2022. Reference Case. Table A11. Petroleum and Other Liquids Supply and Disposition. While the U.S. is a net exporter of the aggregate of crude oil and refined petroleum products, it is still a net importer of crude oil.

593 EIA. "Oil and petroleum products explained – Oil imports and exports." April 21, 2022. https://www.eia.gov/energyexplained/oil-and-petroleum-products/imports-and-exports.php.

594 Bordoff, J. 2019. The Myth of US Energy Independence has Gone Up in Smoke. *Foreign Policy*. September 18. https://foreignpolicy.com/2019/09/18/the-myth-of-u-s-energy-independence-has-gone-up-in-smoke.

595 Foreman, D. 2018. Why the US must Import and Export Oil: American Petroleum Institute. June 14th. https://www.api.org/news-policy-and-issues/blog/2018/06/14/why-the-us-must-import-and-export-oil.

The so-called oil import premium gained attention as a guiding concept for energy policy in the aftermath of the oil shocks of the 1970s (Bohi and Montgomery (1982), EMF (1981)).[596] Plummer (1982) provided valuable discussion of many of the key issues related to the oil import premium as well as the analogous oil stockpiling premium.[597] Bohi and Montgomery (1982) detailed the theoretical foundations of the oil import premium and established many of the critical analytic relationships.[598] Hogan (1981) and Broadman and Hogan (1986, 1988) revised and extended the established analytical framework to estimate optimal oil import premia with a more detailed accounting of macroeconomic effects.[599] Since the original work on energy security was undertaken in the 1980s, there have been several reviews on this topic by Leiby, Jones, Curlee and Lee (1997) and Parry and Darmstadter (2004).[600,601]

The economics literature on whether oil shocks are the same level of threat to economic stability as they once were, is mixed. Some of the literature asserts that the macroeconomic component of the energy security externality is small. For example, the National Research Council (2009) argued that the non-environmental externalities associated with dependence on foreign oil are small, and potentially trivial.[602] Analyses by Nordhaus (2007) and Blanchard and Gali (2010) question the impact of oil price shocks on the economy in the early-2000s time frame.[603] They were motivated by attempts to explain why the economy actually expanded during the oil shock in the early-2000s, and why there was no evidence of higher energy prices being passed on through higher wage inflation. One reason, according to Nordhaus and Blanchard and Gali, is that monetary policy has become more accommodating to the price impacts of oil shocks. Another reason is that consumers have simply decided that such movements are temporary and have noted that price impacts are not passed on as inflation in other parts of the economy.

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[596] Bohi, D. and Montgomery, D. 1982. Social Cost of Imported and U.S. Import Policy, *Annual Review of Energy*, 7:37-60. Energy Modeling Forum, 1981. World Oil, EMF Report 6, Stanford University Press: Stanford 39 CA. https://emf.stanford.edu/publications/emf-6-world-oil (accessed November 30, 2022).

[597] Plummer, J. (Ed.). 1982. Energy Vulnerability, “Basic Concepts, Assumptions and Numerical Results,” pp. 13 - 36, Cambridge MA: Ballinger Publishing Co.

[598] Bohi, D. and Montgomery, D. 1982. Social Cost of Imported and U.S. Import Policy, *Annual Review of Energy*, 7:37-60.

[599] Hogan, W. 1981. “Import Management and Oil Emergencies,” Chapter 9 in Deese, 5 David and Joseph Nye, eds. Energy and Security. Cambridge, MA: Ballinger Publishing Co. Broadman, H. 1986. “The Social Cost of Imported Oil,” *Energy Policy* 14(3):242-252. Broadman H. and Hogan, W. 1988. “Is an Oil Import Tariff Justified? An American Debate: The Numbers Say ‘Yes,’” *The Energy Journal* 9: 7-29.

[600] Leiby, P., Jones, D., Curlee, R. and Lee, R. 1997. Oil Imports: An Assessment of Benefits and Costs, ORNL-6851, Oak Ridge National Laboratory, November.

[601] Parry, I. and Darmstadter, J. 2004. “The Costs of U.S. Oil Dependency,” Resources for the Future, November 17, 2004. Also published as NCEP Technical Appendix Chapter 1: Enhancing Oil Security, the National Commission on Energy Policy 2004 Ending the Energy Stalemate–A Bipartisan Strategy to Meet America’s Energy Challenges.

[602] National Research Council. 2009. Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use. National Academy of Science, Washington, DC.

[603] Nordhaus, W. 2007. “Who’s Afraid of a Big Bad Oil Shock?”. Brookings Papers on Economic Activity, Economic Studies Program, The Brookings Institution, vol. 38(2), pp. 219-240. Blanchard, O. and Gali, J. 2010. The macroeconomic effects of oil price shocks: why are the 2000’s so different from the 1970s. International Dimensions of Monetary Policy. University of Chicago Press.

Hamilton (2012) reviews the empirical literature on oil shocks and suggests that the results are mixed, noting that some work (e.g., Rasmussen and Roitman (2011)) finds less evidence for economic effects of oil shocks or declining effects of shocks (Blanchard and Gali (2010)), while other work continues to find evidence regarding the economic importance of oil shocks.[604] For example, Baumeister and Peersman (2012) find that an "oil price increase of a given size seems to have a decreasing effect over time, but noted that the declining price-elasticity of demand meant that a given physical disruption had a bigger effect on price and turned out to have a similar effect on output as in the earlier data."[605] Hamilton observes that "a negative effect of oil prices on real output has also been reported for a number of other countries, particularly when nonlinear functional forms have been employed" (citing as examples Kim (2012) and Engemann, Kliesen, and Owyang (2011)).[606,607] Alternatively, rather than a declining effect, Ramey and Vine (2010) find "remarkable stability in the response of aggregate real variables to oil shocks once we account for the extra costs imposed on the economy in the 1970s by price controls and a complex system of entitlements that led to some rationing and shortages."[608]

Some of the literature on oil price shocks emphasizes that economic impacts depend on the nature of the oil shock, with differences between price increases caused by a sudden supply loss and those caused by rapidly growing demand. Recent analyses of oil price shocks have confirmed that "demand-driven" oil price shocks have greater effects on oil prices and tend to have positive effects on the economy while "supply-driven" oil shocks still have negative economic impacts (Baumeister, Peersman, and Robays (2010)).[609] A paper by Kilian and Vigfusson (2014), for example, assigns a more prominent role to the effects of price increases that are unusual, in the sense of being beyond the range of recent experience.[610] Kilian and Vigfussen also conclude that the difference in response to oil shocks may well stem from the different effects of demand- and supply-based price increases: "One explanation is that oil price shocks are associated with a range of oil demand and oil supply shocks, some of which stimulate the U.S. economy in the short-run and some of which slow down U.S. growth (see Kilian 2009)."[611]

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604 Rasmussen, T. and Roitman, A. 2011. Oil Shocks in a Global Perspective: Are We Really That Bad. IMF Working Paper Series.

605 Baumeister, C. and Peersman, G. 2012. The Role of Time-Varying Price Elasticities in Accounting for Volatility Changes in the Crude Oil Market. *Journal of Applied Economics*.

606 Kim, D. 2012. What is an oil shock? Panel data evidence. *Empirical Economics*, Volume 43, pp. 121-143.

607 Engemann, K., Kliesen. K. and Owyang, M. 2011. Do Oil Shocks Drive Business Cycles, Some U.S. and International Evidence. Federal Reserve Bank of St. Louis, Working Paper Series. No. 2010-007D.

608 Ramey, V. and Vine, D. 2010. "Oil, Automobiles, and the U.S. Economy: How Much have Things Really Changed?". National Bureau of Economic Research Working Papers, WP 16067 (June).

609 Baumeister C., Peersman, G. and Van Robays, I. 2010. "The Economic Consequences of Oil Shocks: Differences across Countries and Time," RBA Annual Conference Volume in: Renée Fry & Callum Jones & Christopher Kent (ed.), Inflation in an Era of Relative Price Shocks, Reserve Bank of Australia.

610 Kilian, L. and Vigfusson, R. 2014. "The role of oil price shocks in causing U.S. recessions," CFS Working Paper Series 460, Center for Financial Studies.

611 Kilian, L. 2009. "Not All Oil Price Shocks Are Alike: Disentangling Demand and Supply Shocks in the Crude Oil Market." *American Economic Review*, 99 (3): pp. 1053-69.

The general conclusion that oil supply-driven shocks reduce economic output is also reached in a paper by Cashin et al. (2014), which focused on 38 countries from 1979–2011.[612] They state: "The results indicate that the economic consequences of a supply-driven oil-price shock are very different from those of an oil-demand shock driven by global economic activity, and vary for oil-importing countries compared to energy exporters." Cashin et al. continues "…oil importers (including the U.S.) typically face a long-lived fall in economic activity in response to a supply-driven surge in oil prices." But almost all countries see an increase in real output caused by an oil-demand disturbance.

EPA's assessment of the energy security literature finds that there are benefits to the U.S. from reductions in its oil imports. But there is some debate as to the magnitude, and even the existence, of energy security benefits from U.S. oil import reductions. Over the last decade, differences in economic impacts from oil demand and oil supply shocks have been distinguished. The oil import premium calculations in this analysis (described in Chapter 5.4) are based on price shocks from potential future supply events. Oil supply shocks, which reduce economic activity, have been the predominant focus of oil security issues since the oil price shocks/oil embargoes of the 1970s. While we project some increase in imported renewable fuels due to this rule, the rule results in an overall reduction by the U.S. in imported fuels (i.e., combined total of imported oil and imported renewable fuels), moving the U.S. modestly towards the goal of energy independence and enhanced energy security.

5.2 Review of Recent Energy Security Literature

There have also been a handful of recent studies that are relevant for the issue of energy security. We provide a brief review and high-level summary of each of these studies below.

5.2.1 Recent Oil Energy Security Studies

The first studies on the energy security impacts of oil that we review are by Resources for the Future (RFF), a study by Brown and two studies by Oak Ridge National Laboratory (ORNL). The RFF study (2017) attempts to develop updated estimates of the relationship among gross domestic product (GDP), oil supply and oil price shocks, and world oil demand and supply elasticities.[613] In a follow-on study, Brown summarized the RFF study results as well.[614] The RFF work argues that there have been major changes that have occurred in recent years that have reduced the impacts of oil shocks on the U.S. economy. First, the U.S. is less dependent on imported oil than in the early 2000s due in part to the "fracking revolution" (i.e., tight/shale oil), and to a lesser extent, increased production of renewable fuels. In addition, RFF argues that the U.S. economy is more resilient to oil shocks than in the earlier 2000s time frame. Some of the factors that make the U.S. more resilient to oil shocks include increased global financial integration and greater flexibility of the U.S. economy (especially labor and financial markets), many of the same factors that Nordhaus and Blanchard and Gali pointed to as discussed above.

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[612] Cashin, P., Mohaddes, K., and Raissi, M. 2014. The Differential Effects of Oil Demand and Supply Shocks on the Global Economy, *Energy Economics*, 12 (253).
[613] Krupnick, A., Morgenstern, R., Balke, N., Brown, S., Herrara, M. and Mohan, S. 2017. "Oil Supply Shocks, U.S. Gross Domestic Product, and the Oil Security Problem," Resources for the Future Report.
[614] Brown, S. 2018. New estimates of the security costs of U.S. oil consumption", *Energy Policy*, 113 pp. 171-192.

In the RFF effort, a number of comparative modeling scenarios are conducted by several economic modeling teams using three different types of energy-economic models to examine the impacts of oil shocks on U.S. GDP. The first is a dynamic stochastic general equilibrium model developed by Balke and Brown.[615] The second set of modeling frameworks use alternative structural vector autoregressive models of the global crude oil market.[616] The last of the models utilized is the National Energy Modeling System (NEMS).[617]

Two key parameters are focused upon to estimate the impacts of oil shock simulations on U.S. GDP: oil price responsiveness (i.e., the short-run price elasticity of demand for oil) and GDP sensitivity (i.e., the elasticity of GDP to an oil price shock). The more inelastic (i.e., the less responsive) short-run oil demand is to changes in the price of oil, the higher the price impacts of a future oil shock. Higher price impacts from an oil shock result in higher GDP losses. The more inelastic (i.e., less sensitive) GDP is to an oil price change, the less the loss of U.S. GDP with future oil price shocks.

For oil price responsiveness, RFF reports three different values: a short-run price elasticity of oil demand from their assessment of the "new literature," –0.17; a "blended" elasticity estimate; –0.05, and short-run oil price elasticities from the "new models" RFF uses, ranging from –0.20 to –0.35. The "blended" elasticity is characterized by RFF in the following way: "Recognizing that these two sets of literature [old and new] represent an *evolution* in thinking and modeling, but that the older literature has not been wholly overtaken by the new, Benchmark-E [the blended elasticity] allows for a range of estimates to better capture the uncertainty involved in calculating the oil security premiums."

The second parameter that RFF examines is the GDP sensitivity. For this parameter, RFF's assessment of the "new literature" finds a value of –0.018, a "blended elasticity" estimate of –0.028, and a range of GDP elasticities from the "new models" that RFF uses that range from –0.007 to –0.027. One of the limitations of the RFF study is that the large variations in oil price over the last 15 years are believed to be predominantly "demand shocks" (e.g., a rapid growth in global oil demand followed by the Great Recession and then the post-recession recovery).

There have only been two recent situations where events have led to a potential significant supply-side oil shock in the last several years. The first event was the attack on the Saudi Aramco Abqaiq oil processing facility and the Khurais oil field. On September 14, 2019, a drone and cruise missile attack damaged the Saudi Aramco Abqaiq oil processing facility and the Khurais oil field in eastern Saudi Arabia. The Abqaiq oil processing facility is the largest crude

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[615] Balke, N. and Brown, S. 2018. "Oil Supply Shocks and the U.S. Economy: An Estimated DSGE Model." *Energy Policy*, 116, pp. 357-372.

[616] These models include Kilian, L. 2009. Not All Oil Price Shocks are Alike: Disentangling Demand and Supply Shocks in the Crude Oil Market, *American Economic Review*, 99:3, pp., 1053-1069; Kilian, L. and Murphy, D. 2013. "The Role of Inventories and Speculative Trading in the Global Market for Crude Oil," *Journal of Applied Economics*, https://doi.org/10.1002/jae.2322; and Baumeister, C. and Hamilton, J. 2019. "Structural Interpretation of Vector Autoregressions with Incomplete Identification: Revisiting the Role of Oil Supply and Demand Shocks," *American Economic Review*, 109(5), pp.1873-1910.

[617] Mohan, S. 2017. "Oil Price Shocks and the U.S. Economy: An Application of the National Energy Modeling System." Resources for the Future Report Appendix.

oil processing and stabilization plant in the world, with a capacity of roughly 7 MMBD or about 7% of global crude oil production capacity.[618] On September 16, the first full day of commodity trading after the attack, both Brent and WTI crude oil prices surged by $7.17/bbl and $8.34/bbl, respectively, in response to the attack, the largest price increase in roughly a decade.

However, by September 17, Saudi Aramco reported that the Abqaiq plant was producing 2 MMBD, and they expected its entire output capacity to be fully restored by the end of September.[619] Tanker loading estimates from third-party data sources indicated that loadings at two Saudi Arabian export facilities were restored to the pre-attack levels.[620] As a result, both Brent and WTI crude oil prices fell on September 17, but not back to their original levels. The oil price spike from the attack on the Abqaiq plant and Khurais oil field was prominent and unusual, as Kilian and Vigfusson (2014) describe. While pointing to possible risks to world oil supply, the oil shock was short-lived, and generally viewed by market participants as being transitory, so it did not influence oil markets over a sustained time period.

The second situation is the set of events leading to the recent world oil price spike experienced in 2022. World oil prices rose fairly rapidly in the beginning of 2022. For example, on January 3, 2022, the WTI crude oil price was roughly $76/bbl. The WTI oil price increased to roughly $123/bbl on March 8, 2022, a 62% increase.[621] High and volatile oil prices in 2022 are a result of a combination of several factors: supply not rising fast enough to meet rebounding world oil demand from increased economic activity as the COVID-19 pandemic recedes; reduced supply from some leading oil-producing nations; and geopolitical events and concerns (e.g., the Ukraine War). It is not clear to what extent the current oil price volatility will continue, or even increase, or be transitory. Since both significant demand and supply factors are influencing world oil prices in 2022, it is not clear how to evaluate unfolding oil market price trends from an energy security standpoint. Thus, the attack of the Abqaiq oil processing facility in Saudi Arabia and the unfolding events in the world oil market in 2022 do not currently provide enough empirical evidence to provide an updated estimate of the response of the U.S. economy to an oil supply shock of a significant magnitude.[622]

A second set of recent studies related to energy security are from ORNL. In the first study, ORNL (2018) undertakes a quantitative meta-analysis of world oil demand elasticities based upon the recent economics literature.[623] The ORNL study estimates oil demand elasticities for two sectors (transportation and non-transportation) and by world regions (OECD and Non-OECD) by meta-regression. To establish the data set for the meta-analysis, ORNL undertakes a

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[618] EIA. "Saudi Arabia crude oil production outage affects global crude oil and gasoline prices." *Today in Energy*. September 23, 2019. https://www.eia.gov/todayinenergy/detail.php?id=41413.
[619] Ibid.
[620] Ibid.
[621] EIA. *Petroleum and Other Liquids Spot Prices*. https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm.
[622] Hurricanes Katrina and Rita in 2005 primarily caused a disruption in U.S. oil refinery production, with a more limited disruption of some crude supply in the U.S. Gulf Coast area. Thus, the loss of refined petroleum products exceeded the loss of crude oil, and the regional impact varied even within the U.S. Hurricanes Katrina and Rita were a different type of oil disruption event than is quantified in the Stanford EMF risk analysis framework, which provides the oil disruption probabilities than ORNL is using.
[623] Uría-Martínez, R., Leiby, P., Oladosu, G., Bowman, D., Johnson, M. 2018. Using Meta-Analysis to Estimate World Oil Demand Elasticity, ORNL Working Paper.

literature search of peer reviewed journal articles and working papers between 2000–2015 that contain estimates of oil demand elasticities. The data set consisted of 1,983 observations from 75 published studies. The study finds a short-run price elasticity of world oil demand of –0.07 and a long-run price elasticity of world oil demand of –0.26.

The second relevant ORNL (2018) study from the standpoint of energy security is a meta-analysis that examines the impacts of oil price shocks on the U.S. economy as well as many other net oil-importing economies.[624] 19 studies after 2000 were identified that contain quantitative/accessible estimates of the economic impacts of oil price shocks. Almost all studies included in the review were published since 2008. The key result that the study finds is a short-run oil price elasticity of U.S. GDP, roughly one year after an oil shock, of –0.021, with a 68% confidence interval of –0.006 to –0.036.

5.2.2 Recent Studies on Tight/Shale Oil

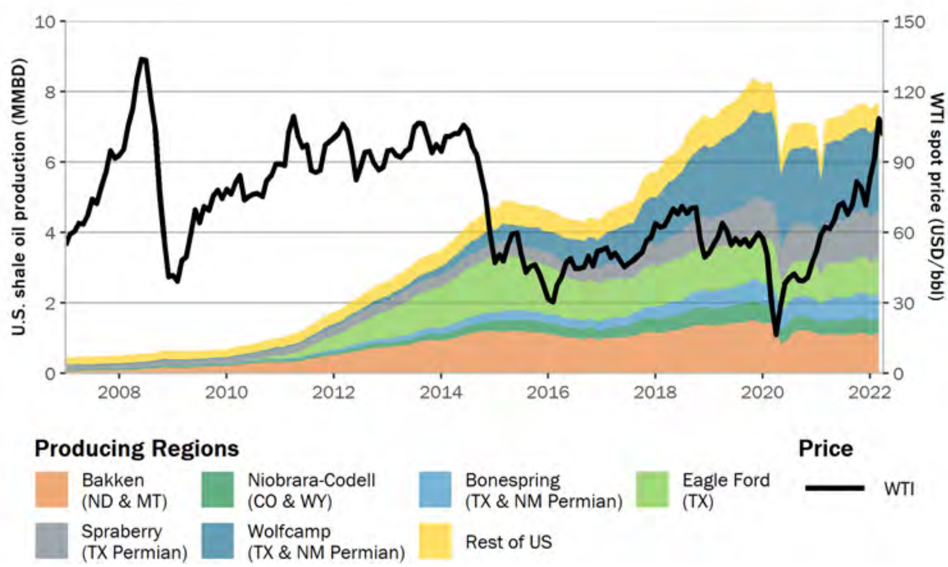
The discovery and development of U.S. tight oil (i.e., shale oil) reserves that started in the mid-2000s could affect U.S. energy security in at least several ways.[625] First, the increased availability of domestic supplies has resulted in a reduction of U.S. oil imports and an increasing role of the U.S. as exporter of crude oil and petroleum-based products. Largely due to increases in tight oil, in December 2015, the U.S. Congress lifted the ban on the U.S.'s ability to export domestically produced crude oil.[626] Second, due to differences in development cycle characteristics and average well productivity, tight oil producers could be more price responsive than most other oil producers. However, the oil price level that triggers a substantial increase in tight oil production appears to be higher in 2021–2022 relative to the 2010s as tight oil producers seek higher profit margins per barrel in order to reduce the debt burden accumulated in previous cycles of production growth.[627]

U.S. crude oil production increased from 5.0 MMBD in 2008 to an all-time peak of 12.3 MMBD in 2019 and tight oil wells have been responsible for most of the increase.[628] Figure 5.2.2-1 shows tight oil production changes from various tight oil producing regions (e.g., Eagle Ford, Bakken, etc.) in the U.S. and the WTI crude oil spot price. Viewing Figure 5.2.2-1, one can see that the annual average U.S. tight oil production grew from 0.6 MMBD in 2008 to 7.8 MMBD in 2019.[629] Growth in U.S. tight oil production during this period was only interrupted in

[624] Oladosu, G., Leiby, P., Bowman, D., Uría-Martínez, R., Johnson, M. 2018. Impacts of oil price shocks on the U.S. economy: a meta-analysis of oil price elasticity of GDP for net oil-importing economies, *Energy Policy* 115. pp. 523–544.
[625] Union of Concerned Scientist, "What is Tight Oil?". 2015. "Tight oil is a type of oil found in impermeable shale and limestone rock deposits. Also known as "shale oil," tight oil is processed into gasoline, diesel, and jet fuels — just like conventional oil — but is extracted using hydraulic fracturing, or "fracking.
[626] GAO, 2020. Crude Oil Markets: Effects of the Repeal of the Crude Oil Export Ban. GAO-21-118. According to the GAO, "Between 1975 and the end of 2015, the Energy Policy and Conservation Act directed a ban on nearly all exports of U.S. crude oil. This ban was not considered a significant policy issue when U.S. oil production was declining and import volumes were increasing. However, U.S. crude oil production roughly doubled from 2009 to 2015, due in part to a boom in shale oil production made possible by advancements in drilling technologies. In December 2015, Congress effectively repealed the ban, allowing the free export of U.S. crude oil worldwide".
[627] Kemp, J. 2021. U.S. shale restraint pushes oil prices to multi-year high. Reuters. June 4, 2021.
[628] EIA (2021). *Crude Oil Production*. https://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_m.htm.
[629] EIA (2021). *Tight oil production estimates by play*. https://www.eia.gov/petroleum/data.php.

2015–2016 following the world oil price downturn that began in mid-2014. The second growth phase started in late 2016 and continued until 2020. The sharp decrease in demand that followed the onset of the COVID-19 pandemic resulted in a 25% decrease in tight oil production in the period from December 2019 to May 2020. U.S. tight oil production in 2020 and 2021 averaged 7.4 MMBD and 7.2 MMBD, respectively, and represents a relatively modest share (less than 10% in 2019) of global liquid fuel supply.[630] Importantly, U.S. tight oil is considered the most price-elastic component of non-OPEC supply due to differences between its development and production cycle and that of conventional oil wells. Unlike conventional wells where oil starts flowing naturally after drilling, shale oil wells require the additional step of fracking to complete the well and release the oil.[631] Shale oil producers keep a stock of drilled but uncompleted wells and can optimize the timing of the completion operation depending on price expectations. Combining this decoupling between drilling and production with the front-loaded production profile of tight oil—the fraction of total output from a well that is extracted in the first year of production is higher for tight oil wells than conventional oil wells—tight oil producers have a clear incentive to be responsive to prices in order to maximize their revenues.[632]

Figure 5.2.2-1: U.S. Tight Oil Production (by Producing Regions) (in MMBD) and WTI Crude Oil Spot Price (in U.S. Dollars per Barrel)



Source: EIA[633,634]

Only in recent years have the implications of the "tight/shale oil revolution" been felt in the international market where U.S. production of oil is rising to be roughly on par with Saudi

[630] The 2019 global crude oil production value used to compute the U.S. tight oil share is from EIA International Energy Statistics. https://www.eia.gov/international/data/world/petroleum-and-other-liquids/annual-petroleum-and-other-liquids-production.

[631] Hydraulic fracturing ("fracking") involves injecting water, chemicals, and sand at high pressure to open fractures in low-permeability rock formations and release the oil that is trapped in them.

[632] Bjørnland, H., Nordvik, F. and Rohrer, M. 2021. "Supply flexibility in the shale patch: Evidence from North Dakota," *Journal of Applied Economics*.

[633] EIA. *Tight oil production estimates by play*. https://www.eia.gov/petroleum/data.php.

[634] EIA. *Petroleum and Other Liquids Spot Prices*. https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm.

Arabia and Russia. Recent economic literature of the tight oil expansion in the U.S. has a bearing on the issue of energy security as well. It could be that the large expansion in tight oil has eroded the ability of OPEC to set world oil prices to some degree, since OPEC cannot directly influence tight oil production decisions. Also, by effecting the percentage of global oil supply controlled by OPEC, the growth in U.S. oil production may be influencing OPEC's degree of market power. But given that the tight oil expansion is a relatively recent trend, it is difficult to know how much of an impact the increase in tight oil is having, or will have, on OPEC behavior.

Three recent studies have examined the characteristics of tight oil supply that have relevance for the topic of energy security. In the context of energy security, the question that arises is: Can tight oil respond to an oil price shock more quickly and substantially than conventional oil?[635] If so, then tight oil could potentially lessen the impacts of future oil shocks on the U.S. economy by moderating the price increases from a future oil supply shock.

Newell and Prest (2019) look at differences in the price responsiveness of conventional versus shale oil wells, using a detailed data set of 150,000 oil wells, during the 2005–2017 time frame in five major oil-producing states: Texas, North Dakota, California, Oklahoma, and Colorado.[636] For both conventional oil wells and shale oil wells (i.e., unconventional oil wells), Newell and Prest estimate the elasticities of drilling operations and well completion operations with respect to expected revenues and the elasticity of supply from wells already in operation with respect to spot prices. Combining the three elasticities and accounting for the increased share of tight oil in total U.S. oil production during the period of analysis, they conclude that U.S. oil supply responsiveness to prices increased more than tenfold from 2006 to 2017. They find that tight/shale oil wells are more price responsive than conventional oil wells, mostly due to their much higher productivity, but the estimated oil supply elasticity is still small. Newell and Prest note that the tight oil supply response still takes more time to arise than is typically considered for a "swing producer," referring to a supplier able to increase production quickly, within 30–90 days. In the past, only Saudi Arabia and possibly one or two other oil producers in the Middle East have been able to ramp up oil production in such a short period of time.

Another study, by Bjornland et al. (2021), uses a well-level monthly production data set covering more than 16,000 crude oil wells in North Dakota to examine differences in supply responses between conventional and tight/shale oil.[637] They find a short-run (i.e., one-month) supply elasticity with respect to oil price for tight oil wells of 0.71, whereas the one-month response of conventional oil supply is not statistically different from zero. It should be noted that the elasticity value estimated by Bjornland et al. combines the supply response to changes in the spot price of oil as well as changes in the spread between the spot price and the 3-month futures price.

[635] Union of Concerned Scientist, "What is Tight Oil?". 2015. "Tight oil is a type of oil found in impermeable shale and limestone rock deposits. Also known as "shale oil," tight oil is processed into gasoline, diesel, and jet fuels—just like conventional oil – but is extracted using hydraulic fracturing, or "fracking."
[636] Newell, R. and Prest, B. 2019. The Unconventional Oil Supply Boom: Aggregate Price Response from Microdata, *The Energy Journal*, Volume 40, Issue Number 3.
[637] Bjørnland, H., Nordvik, F. and Rohrer, M. 2021. "Supply flexibility in the shale patch: Evidence from North Dakota," *Journal of Applied Economics*.

Walls and Zheng (2022) explore the change in U.S. oil supply elasticity that resulted from the tight oil revolution using monthly, state-level data on oil production and crude oil prices from January 1986 to February 2019 for North Dakota, Texas, New Mexico, and Colorado.[638] They conduct statistical tests that reveal an increase in the supply price elasticities starting between 2008–2011, coinciding with the times in which tight oil production increased sharply in each of these states. Walls and Zheng also find that supply responsiveness in the tight oil era is greater with respect to price increases than price decreases. The short-run (one-month) supply elasticity with respect to price increases during the tight oil area ranges from zero in Colorado to 0.076 in New Mexico; pre-tight oil, it ranged from zero to 0.021.

The results from Newell and Prest, Bjornland et al., and Walls and Zheng all suggest that tight oil may have a larger supply response to oil prices in the short-run than conventional oil, although the estimated short-run elasticity is still small. The three studies use data sets that end in 2019 or earlier. The responsiveness of U.S. tight oil production to recent price increases does not appear to be consistent with that observed during the episodes of crude oil price increases in the 2010s captured in these three studies. Despite an 80% increase in the WTI crude oil spot price from October 2020 to the end of 2021, Figure 5.2.2-1 shows that U.S. tight oil production has increased by only 8% in the same period**.** It is a somewhat challenging period in which to examine the supply response of tight oil to its price to some degree, given that the 2020–2021 time period coincided with the COVID-19 pandemic. However, previous shale oil production growth cycles were financed predominantly with debt, at very low interest rates.[639] Most U.S. tight oil producers did not generate positive cashflow.[640] As of 2021, U.S. shale oil producers have pledged to repay their debt and reward shareholders through dividends and stock buybacks.[641] These pledges translate into higher prices that need to be reached (or sustained for a longer period) than in the past decade to trigger large increases in drilling activity.

In its first quarter 2022 energy survey, the Dallas Fed (i.e., the Federal Reserve Bank of Dallas) asked oil exploration and production (E&P) firms about the WTI price levels needed to cover operating expenses for existing wells or to profitably drill a new well. The average breakeven price to continue operating existing wells in the shale oil regions ranged from $23–35/bbl. To profitably drill new wells, the required average WTI prices ranged from $48–69/bbl. For both types of breakeven prices, there was substantial variation across companies, even within the same region. The actual WTI price level observed in the first quarter of 2022 has been roughly $95/bbl, substantially larger than the breakeven price to drill new wells. However, the median production growth expected by the respondents to the Dallas Fed Energy Survey from the fourth quarter of 2021 to the fourth quarter of 2022 is modest (6% among large firms and 15% among small firms). Investor pressure to maintain capital discipline was cited by 59% of respondents as the primary reason why publicly traded oil producers are restraining growth despite high oil prices. The other reasons cited included supply chain constraints, difficulty in hiring workers, environmental, social, and governance concerns, lack of access to financing, and

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[638] Walls, W. D., & Zheng, X. 2022. Fracking and Structural Shifts in Oil Supply. *The Energy Journal*, *43*(3).
[639] McLean, B. *The Next Financial Crisis Lurks Underground*. New York Times, September 1, 2018.
[640] Ibid.
[641] https://www.bloomberg.com/news/articles/2021-08-02/shale-heavyweights-shower-investors-with-dividends-on-oil-rally.

government regulations.[642] Given the recent behavior of tight oil producers, we do not believe that tight oil will provide additional significant energy security benefits in 2023–2025 due to its lack of price responsiveness. The ORNL model still accounts for U.S. tight oil production increases on U.S. oil imports and, in turn, the U.S.'s energy security position.[643]

Finally, despite continuing uncertainty about oil market behavior and outcomes and the sensitivity of the U.S. economy to oil shocks, it is generally agreed that it is beneficial to reduce petroleum fuel consumption from an energy security standpoint. The relative significance of petroleum consumption and import levels for the macroeconomic disturbances that follow from oil price shocks is not fully understood. Recognizing that changing petroleum consumption will change U.S. imports, our quantitative assessment of oil costs of this rule in Chapter 5.4 focuses on those incremental social costs that follow from the resulting changes in net imports, employing the usual oil import premium measure.

5.3 Cost of Existing U.S. Energy Security Policies

An additional often-identified component of the full economic costs of U.S. oil imports is the costs to the U.S. taxpayers of existing U.S. energy security policies. The two primary examples are maintaining the Strategic Petroleum Reserve (SPR) and maintaining a military presence to help secure a stable oil supply from potentially vulnerable regions of the world.

The SPR is the largest stockpile of government-owned emergency crude oil in the world. Established in the aftermath of the 1973/1974 oil embargo, the SPR provides the U.S. with a response option should a disruption in commercial oil supplies threaten the U.S. economy.[644] Emergency SPR drawdowns have taken place in 1991 (Operation Desert Storm), 2005 (Hurricane Katrina), 2011 (Libyan Civil War), and 2022. All of these releases have been in coordination with releases of strategic stocks from other International Energy Agency (IEA) member countries. In the first four months of 2022, using the statutory authority under Section 161 of the Energy Policy and Conservation Act, DOE conducted two emergency SPR drawdowns in response to ongoing oil supply disruptions.[645] The first drawdown resulted in a sale of 30 million barrels in March 2022. The second drawdown, announced in April, authorized a total release of approximately one MMBD from May to October 2022.[646] 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 the effect of the SPR in moderating price shocks is factored into the analysis that EPA is using to estimate the macroeconomic oil security premiums, the cost of maintaining the SPR is excluded.

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642 https://www.dallasfed.org/research/surveys/des/2022/2201.aspx#tab-questions.

643 EPA will monitor data as tight oil production continues to adjust to market conditions in 2022 and will consider differentiating shale oil price responsiveness on the U.S.'s energy security position in this final RFS rulemaking should evidence suggest that is appropriate.

644 Energy Policy and Conservation Act, 42 U.S. Code § 6241(d) (1975).

645 https://www.energy.gov/fecm/articles/doe-announces-emergency-notice-sale-crude-oil-strategic-petroleum-reserve-address-oil.

646 https://www.energy.gov/articles/doe-announces-second-emergency-notice-sale-crude-oil-strategic-petroleum-reserve-address.

We have also considered the possibility of quantifying the military benefits components of energy security but have not done so here for several reasons. The literature on the military components of energy security has described four broad categories of oil-related military and national security costs, all of which are difficult to quantify. These include possible costs of U.S. military programs to secure oil supplies from unstable regions of the world, the energy security costs associated with the U.S. military's reliance on petroleum to fuel its operations, possible national security costs associated with expanded oil revenues to "rogue states," and relatedly the foreign policy costs of oil insecurity.

Of these categories listed above, the one that is most clearly connected to petroleum use and is, in principle, quantifiable is the first: the cost of military programs to secure oil supplies and stabilize oil supplying regions. There is ongoing literature on the measurement of this component of energy security, but methodological and measurement issues—attribution and incremental analysis—pose two significant challenges to providing a robust estimate of this component of energy security. The attribution challenge is to determine which military programs and expenditures can properly be attributed to oil supply protection, rather than some other objective. The incremental analysis challenge is to estimate how much the petroleum supply protection costs might vary if U.S. oil use were to be reduced or eliminated. Methods to address both of these challenges are necessary for estimating the effect on military costs arising from a modest reduction (not elimination) in oil use attributable to this proposed rule.

Since "military forces are, to a great extent, multipurpose and fungible" across theaters and missions (Crane et al. 2009), and because the military budget is presented along regional accounts rather than by mission, the allocation to particular missions is not always clear.[647] Approaches taken usually either allocate "partial" military costs directly associated with operations in a particular region, or allocate a share of total military costs (including some that are indirect in the sense of supporting military activities overall) (Koplow and Martin 1998).[648]

The challenges of attribution and incremental analysis have led some to conclude that the mission of oil supply protection cannot be clearly separated from others, and the military cost component of oil security should be taken as near zero (Moore et al. 1997).[649] Stern (2010), on the other hand, argues that many of the other policy concerns in the Persian Gulf follow from oil, and the reaction to U.S. policies taken to protect oil.[650] Stern presents an estimate of military cost for Persian Gulf force projection, addressing the challenge of cost allocation with an activity-based cost method. He uses information on actual naval force deployments rather than budgets, focusing on the costs of carrier deployment. As a result of this different data set and assumptions regarding allocation, the estimated costs are much higher, roughly 4–10 times, than other estimates. Stern also provides some insight on the analysis of incremental effects, by estimating that Persian Gulf force projection costs are relatively strongly correlated to Persian Gulf

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[647] Crane, K., Goldthau, A., Toman, M., Light, T., Johnson, S., Nader, A., Rabasa, A. and Dogo, H. 2009. Imported oil and US national security. RAND, 2009.

[648] Koplow, D. and Martin, A. 1998. Fueling Global Warming: Federal Subsidies to Oil in the United States. Greenpeace, Washington, D.C.

[649] Moore, J., Behrens, C. and Blodgett, J. 1997. "Oil Imports: An Overview and Update of Economic and Security Effects." CRS Environment and Natural Resources Policy Division report 98, no. 1: pp. 1-14.

[650] Stern, R. 2010. "United States cost of military force projection in the Persian Gulf, 1976–2007." *Energy Policy* 38, no. 6. June: 2816-2825. http://linkinghub.elsevier.com/retrieve/pii/S0301421510000194.

petroleum export values and volumes. Still, the issue remains of the marginality of these costs with respect to Persian Gulf oil supply levels, the level of U.S. oil imports, or U.S. oil consumption levels.

Delucchi and Murphy (2008) seek to deduct from the cost of Persian Gulf military programs the costs associated with defending U.S. interests other than the objective of providing more stable oil supply and price to the U.S. economy.[651] Excluding an estimate of cost for missions unrelated to oil, and for the protection of oil in the interest of other countries, Delucci and Murphy estimated military costs for all U.S. domestic oil interests of between $24–74 billion per year. Delucchi and Murphy assume that military costs from oil import reductions can be scaled proportionally, attempting to address the incremental issue.

Crane et al. considers force reductions and cost savings that could be achieved if oil security were no longer a consideration. Taking two approaches and guided by post-Cold War force draw downs and by a top-down look at the current U.S. allocation of defense resources, they concluded that $75–91 billion, or 12–15% of the current U.S. defense budget, could be reduced.

Finally, an Issue Brief by Securing America's Future Energy (SAFE) (2018) found a conservative estimate of approximately $81 billion per year spent by the U.S. military protecting global oil supplies.[652] This is approximately 16% of the recent U.S. Department of Defense's budget. Spread out over the 19.8 million barrels of oil consumed daily in the U.S. in 2017, SAFE concludes that the implicit subsidy for all petroleum consumers is approximately $11.25/bbl of crude oil, or $0.28/gal. According to SAFE, a more comprehensive estimate suggests the costs could be greater than $30/bbl, or over $0.70/gal.[653]

As in the examples above, an incremental analysis can estimate how military costs would vary if the oil security mission were no longer needed, and many studies stop at this point. It is substantially more difficult to estimate how military costs would vary if U.S. oil use or imports were partially reduced, as is projected to be a consequence of this rule. Partial reduction of U.S. oil use likely diminishes the magnitude of the energy security problem, but there is uncertainty that supply protection forces and their costs could be scaled down in proportion, and there remains the associated goal of protecting supply and transit for U.S. allies and other importing countries, if they do not decrease their petroleum use as well.[654] We are unaware of a robust methodology for assessing the effect on military costs of a partial reduction in U.S. oil use. Therefore, we are unable to quantify this effect resulting from the projected reduction in U.S. oil use attributable to this rule.

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[651] Delucchi, M. and Murphy, J. 2008. "US military expenditures to protect the use of Persian Gulf oil for motor vehicles." *Energy Policy* 36, no. 6. June: 2253-2264.
[652] Securing America's Future Energy. 2018. Issue Brief. The Military Cost of Defending the Global Oil Supply.
[653] Ibid.
[654] Crane, K., Goldthau, A., Toman, M., Light, T., Johnson, S., Nader, A., Rabasa, A. and Dogo, H. 2009. Imported oil and US national security. 2009. RAND.

5.4 Energy Security Impacts

5.4.1 U.S. Oil Import Reductions

From 2023–2025, the AEO 2022 Reference Case projects that the U.S. will be both an exporter and an importer of crude oil.[655] The U.S. produces more light crude oil than its refineries can refine. Thus, the U.S. exports lighter crude oil and imports heavier crude oil to satisfy the needs of U.S. refineries, which are configured to efficiently refine heavy crude oil. U.S. crude oil exports are projected to be stable at 3.3 MMBD from 2023–2025. U.S. crude oil imports, meanwhile, are projected to decrease from 7.8 MMBD in 2023 to 7.2 MMBD in 2025. AEO 2022 also projects that net U.S. exports of refined petroleum products will increase from 4.7 MMBD in 2023 to 5.0 MMBD in 2025. Given the pattern of stable net U.S. crude oil imports, and the projected growth in the U.S.'s net oil product exports, the U.S. is projected to grow its net crude oil and refined petroleum products exports from 0.4 MMBD in 2023 to 1.2 MMBD in 2025.

U.S. oil consumption is estimated to have decreased from 19.8 MMBD in 2019 to 17.5 MMBD in 2020 and 19.1 MMBD in 2021 as a result of social distancing and quarantines that limited personal mobility as a result of the COVID-19 pandemic.[656] U.S. oil consumption is projected to increase in 2023 to 19.4 MMBD, continue to be 19.4 MMBD in 2024, and modestly increase to 19.6 MMBD in 2025.[657] It is not just U.S. crude oil imports alone, but both imports and consumption of petroleum from all sources and their role in economic activity, that exposes the U.S. to risk from price shocks in the world oil price. In 2023–2025, the U.S. is projected to continue to consume significant quantities of oil and to rely on significant quantities of crude oil imports. As a result, U.S. oil markets are expected to remain tightly linked to trends in the world crude oil market.

In Chapter 10.4.2.1, we estimate changes in U.S. petroleum consumption as a result of this rule. For this energy security analysis, we undertake a detailed analysis of differences in U.S. fuel consumption, crude oil imports/exports, and exports of petroleum products in 2023–2025 using the AEO 2022 Reference Case in comparison with an alternative AEO 2022 sensitivity case, Low Economic Growth. The Low Economic Growth Case is used since oil demand decreases in comparison to the Reference Case. We estimate that approximately 99.5% of the change in fuel consumption resulting from this rule is likely to be reflected in reduced U.S. imports of crude oil in 2023–2025.[658] The 99.5% oil import reduction factor is calculated by taking the ratio of the changes in U.S. net crude oil and refined petroleum product imports divided by the change in U.S. oil consumption in the two different AEO cases considered. Thus, on balance, each gallon of petroleum reduced as a result of this rule is anticipated to reduce total U.S. imports of petroleum by 0.995 gallons.

[655] EIA. AEO 2022. Reference Case. Table A11. Petroleum and Other Liquids Supply and Disposition.
[656] EIA. Monthly Energy Review. Calculated using series "Petroleum Consumption (Excluding Biofuels) Annual" (Table 1.3) and "Petroleum Consumption Total Heat Content Annual" (Table A3).
[657] EIA. AEO 2022. Reference Case. Table A11. Petroleum and Other Liquids Supply and Disposition.
[658] We looked at changes in U.S. crude oil imports/exports and net petroleum products in the AEO 2022 Reference Case, Table 11. Petroleum and Other Liquids Supply and Disposition, in comparison to an alternative case, the Low Economic Growth Case, from the AEO 2022. See the spreadsheet in the Docket, "Low vs Reference case impact on imports 2022 AEO".

Based on the changes in oil consumption estimated by EPA and the 99.5% oil import reduction factor, the reductions in U.S. oil imports in 2023–2025 as a result of this rule are estimated in Table 5.4.1-1. Included in this table are estimates of U.S. crude oil exports and imports, net oil refined product exports, net crude oil and refined petroleum product exports, and U.S. oil consumption for 2023–2025 based on the AEO 2022 Reference Case.[659]

Table 5.4.1-1: Projected Trends in U.S. Exports, Imports, and Oil Consumption Resulting From the Candidate Volumes (MMBD)[a]

	2023	2024	2025
U.S. Crude Oil Exports	3.3	3.3	3.3
U.S. Crude Oil Imports	7.7	7.5	7.2
U.S. Net Oil Refined Product Exports[b]	4.7	4.9	5.0
U.S. Net Crude Oil and Refined Petroleum Product Exports	0.4	0.7	1.2
U.S. Oil Consumption[c]	19.4	19.4	19.6
Reduction in U.S. Oil Imports from the Candidate Volumes			
Excluding 2023 Supplemental Standard	0.16	0.17	0.18
Including 2023 Supplemental Standard	0.17	0.17	0.18

[a] AEO 2022 Reference Case, Table A11. Values have been rounded off from AEO 2022, so the totals may not add up to the AEO estimates.
[b] Calculated from AEO 2022 Table A11 as Net Product Exports minus Ethanol, Biodiesel, and Other Biomass-derived Liquid Net Exports.
[c] Calculated from AEO 2022 Table A11 as "Total Primary Supply" minus "Biofuels".

5.4.2 Oil Import Premiums Used for This Rule

In order to understand the energy security implications of reducing U.S. oil imports, EPA has worked with ORNL, which has developed approaches for evaluating the social costs and energy security implications of oil use. The energy security estimates provided below are based upon a methodology developed in a peer-reviewed 2008 ORNL study.[660] This ORNL study is an updated version of the approach used for estimating the energy security benefits of U.S. oil import reductions developed in a 1997 ORNL Report.[661] This same approach was used to estimate energy security benefits for the RFS2 final rule.[662] ORNL has updated this methodology periodically for EPA to account for updated projections of future energy market and economic trends reported in the EIA's AEO.

The ORNL methodology is used to compute the oil import premium per barrel of imported oil.[663] The values of U.S. oil import premium components (macroeconomic

[659] EIA. AEO 2022. Reference Case. Table A11. Petroleum and Other Liquids Supply and Disposition.
[660] Leiby, P. 2008. *Estimating the Energy Security Benefits of Reduced U.S. Oil Imports,* Final Report, ORNL/TM-2007/028, Oak Ridge National Laboratory. March.
[661] Leiby, P., Jones, D., Curlee, R. and Lee, R. 1997. *Oil Imports: An Assessment of Benefits and Costs*, ORNL-6851, Oak Ridge National Laboratory, November.
[662] 75 FR 14839-42 (March 26, 2010).
[663] The oil import premium concept is defined in Chapter 5.1.

disruption/adjustment costs and monopsony components) are numerically estimated with a compact model of the oil market by performing simulations of market outcomes using probabilistic distributions for the occurrence of oil supply shocks, calculating marginal changes in economic welfare with respect to changes in U.S. oil import levels in each of the simulations, and summarizing the results from the individual simulations into a mean and 90% confidence intervals for the import premium. The macroeconomic disruption/adjustment import cost component is the sum of two parts: the marginal change in expected import costs during disruption events and the marginal change in GDP due to the disruption. The monopsony component is the long-run change in U.S. import costs as the level of oil import changes.

For this rule, we are using oil import premiums that incorporate the oil price projections and energy market and economic trends, particularly global regional oil supplies and demands (i.e., the U.S./OPEC/rest of the world), from AEO 2022 into its model.[664] We only consider the avoided macroeconomic disruption/adjustment oil import premiums (i.e., labeled macroeconomic oil security premiums below) as costs, since the monopsony impacts stemming from changes in renewable fuel volumes are considered transfer payments. In previous EPA rules when the U.S. was projected by EIA to be a net importer of crude oil and petroleum-based products, monopsony impacts represented reduced payments by U.S. consumers to oil producers outside of the U.S. There was some debate among economists as to whether the U.S. exercise of its monopsony power in oil markets (e.g., from the implementation of EPA's rules) was a "transfer payment" or a "benefit." Given the redistributive nature of this monopsony impact from a global perspective, and since there are no changes in resource costs when the U.S. exercises it monopsony power, some economists argued that it is a transfer payment. Other economists argued that monopsony impacts were a benefit since they partially address, and partially offset, the market power of OPEC. In previous EPA rules, after weighing both countervailing arguments, EPA concluded that the U.S.'s exercise of its monopsony power was a transfer payment, and not a benefit.[665]

In the context of this rule, the U.S.'s oil trade balance is quite a bit different than in many previous RFS rules. The U.S. is projected to be a net exporter of oil and petroleum-based products in 2023–2025. As a result, reductions in U.S. oil consumption and, in turn, U.S. oil imports, still lower the world oil price modestly. But the net effect of the lower world oil price is now a decrease in revenue for U.S. exporters of crude oil and petroleum-based products, instead of a decrease in payments to foreign oil producers. The argument that monopsony impacts address the market power of OPEC is no longer appropriate. Thus, we continue to consider the

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[664] The oil market projection data used for the calculation of the oil import premiums came from AEO 2022, supplemented by the latest EIA international projections from the *Annual Energy Outlook (AEO)/International Energy Outlook (IEO) 2021*. Global oil prices and all variables describing U.S. supply and disposition of petroleum liquids (domestic supply, tight oil supply fraction, imports, demands) as well as U.S. non-petroleum liquids supply and demand are from AEO 2022. Global and OECD Europe supply/demand projections as well as OPEC oil production share are from IEO 2021. The need to combine AEO 2022 and IEO 2021 data arises due to two reasons: (a) EIA stopped including Table 21 "International Petroleum and Other Liquids Supply, Disposition, and Prices" in the U.S.-focused *Annual Energy Outlook* after 2019, (b) EIA does not publish complete updates of the IEO every year.

[665] We also discuss monopsony oil import premiums in previous EPA GHG vehicle rules. See, e.g., Section 3.2.5, Oil Security Premiums Used for this Rule, RIA, Revised 2023 and Later Model Year Light Duty Vehicle GHG Emissions Standards, December 2021, EPA-420-F-21-077.

U.S. exercise of monopsony power to be transfer payments. We also do not consider the effect of this rule on the costs associated with existing energy security policies (e.g., maintaining the SPR or strategic military deployments), which are discussed in Chapter 5.3.

The macroeconomic oil security premiums arise from the effect of U.S. oil imports on the expected cost of supply disruptions and accompanying price increases. A sudden increase in oil prices triggered by a disruption in world oil supplies has two main effects: (1) it increases the costs of oil imports in the short-run, and (2) it can lead to macroeconomic contraction, dislocation, and GDP losses. Since future disruptions in foreign oil supplies are an uncertain prospect, each of the disruption cost components must be weighted by the probability that the supply of petroleum to the U.S. will actually be disrupted. Thus, the "expected value" of these costs—the product of the probability that a supply disruption will occur and the sum of costs from reduced economic output and the economy's abrupt adjustment to sharply higher petroleum prices—is the relevant measure of their magnitude.

In addition, EPA and ORNL have worked together to revise the oil import premiums based upon recent energy security literature. Based on EPA and ORNL's review of the recent energy security literature, EPA is updating its macroeconomic oil security premiums for this rule. The recent economics literature (discussed in Chapter 5.2) focuses on three factors that can influence the macroeconomic oil security premiums: price elasticity of oil demand, GDP elasticity in response to oil price shocks, and the impacts of the shale oil boom. We discuss each factor below and provide a rationale for how we are updating the first two factors to develop new estimates of the macroeconomic oil security premiums. We are not accounting for how U.S. tight oil is influencing the macroeconomic oil security premiums in this rule, other than how it significantly reduces the need for net U.S. oil imports.

First, we assess the price elasticity of demand for oil. In RFS rules prior to the 2020–2022 annual rule, EPA used a short-run elasticity of demand for oil of –0.045.[666] From the recent RFF study, the "blended" price elasticity of demand for oil is –0.05. The ORNL meta-analysis estimate of this parameter is –0.07. We find the elasticity estimates from what RFF characterizes as the "new literature," –0.175, and from the "new models" that RFF uses, –0.20 to –0.33, somewhat high. Most of the world's oil demand is concentrated in the transportation sector and there are limited alternatives to oil use in this sector. According to IEA, the share of global oil consumption attributed to the transportation sector grew from 60% in 2000 to 66% in 2019.[667] The next largest sector by oil consumption, and an area of recent growth, is petrochemicals. There are limited alternatives to oil use in this sector, particularly in the 2023–2025 time frame. Thus, we believe it would be surprising if short-run oil demand responsiveness has changed in a dramatic fashion.

The ORNL meta-analysis estimate encompasses the full range of the economics literature on this topic and develops a meta-analysis estimate from the results of many different studies in a structured way, while the RFF study's "new models" results represent only a small subset of the economics literature's estimates. Thus, for the analysis of this rule, and consistent with the 2020–

[666] See, e.g., 75 FR 26049 (May 10, 2010).
[667] IEA, Data and Statistics, https://www.iea.org/data-and-statistics?country=WORLD&fuel=Oil&indicator=OilProductsConsBySector.

2022 annual rule, we are increasing the short-run price elasticity of demand for oil from –0.045 to –0.07, a 56% increase.[668] This increase has the effect of lowering the macroeconomic oil security premium estimates undertaken by ORNL for EPA.

Second, we consider the elasticity of GDP to an oil price shock. In RFS rules prior to the 2020-2022 annual rule, a GDP elasticity to an oil shock of –0.032 was used.[669] The RFF "blended" GDP elasticity is –0.028, the RFF's "new literature" GDP elasticity is –0.018, while the RFF "new models" GDP elasticities range from –0.007 to –0.027. The ORNL meta-analysis GDP elasticity is –0.021. We believe that the ORNL meta-analysis value is representative of the recent literature on this topic since it considers a wider range of recent studies and does so in a structured way. Also, the ORNL meta-analysis estimate is within the range of GDP elasticities of RFF's "blended" and "new literature" elasticities. For this rule and consistent with the 2020–2022 annual rule, EPA is using a GDP elasticity of –0.021, a 34% reduction from the GDP elasticity used previously (i.e., the –0.032 value).[670] This GDP elasticity is within the range of RFF's "new literature" elasticity, –0.018, and the elasticity EPA has used in previous rules, –0.032, but lower than RFF's "blended" GDP elasticity, –0.028. This decrease has the effect of lowering the macroeconomic oil security premium estimates. For U.S. tight oil, EPA has not made any adjustments to the ORNL model, given the limited tight oil production response to rising world oil prices in 2020 and 2021.[671] Increased tight oil production still results in energy security benefits though, through its impact of reducing U.S. oil imports in the ORNL model.

Table 5.4.2-1 provides EPA's estimates of the macroeconomic oil security premium for 2023–2025, showing that it is relatively steady over this time period.

Table 5.4.2-1: Estimated Macroeconomic Oil Security Premiums (2021$/bbl)[a]

Year	Avoided Macroeconomic Disruption/Adjustment Costs (Range)
2023	$3.37 ($0.88 - $6.20)
2024	$3.46 ($0.89 - $6.36)
2025	$3.46 ($0.83-$6.40)

[a] Top values in each cell are mean values. Values in parentheses are 90% confidence intervals.

We note that the quantified energy security benefits of this rule, while significant, are dwarfed by the quantified costs discussed in Chapter 10, which are more than an order of magnitude greater. Even if we were to use the lowest or highest end of the range for oil security premiums in Table 5.4.2-1, that would continue to be the case: significant quantified energy

[668] EPA and ORNL worked together to develop an updated estimate of the short-run elasticity of demand for oil for use in the ORNL model.
[669] See, e.g., 75 FR 26049 (May 10, 2010).
[670] EPA and ORNL worked together to develop an updated estimate of the GDP elasticity to an oil shock for use in the ORNL model. This slightly different value also was produced by an earlier draft of the ORNL meta-analysis.
[671] The short-run oil supply elasticity assumed in the ORNL model is 0.06 and is applied to production from both conventional and shale oil wells.

security benefits are far smaller than the quantified costs. In all cases, we would reach the same conclusions as we factor in quantified benefits and costs with regard to the candidate volumes in this rule.

5.4.3 Energy Security Benefits

Estimates of the total annual energy security benefits of the candidate volumes are based on the ORNL oil import premium methodology with updated oil import premium estimates reflecting the recent energy security literature and using AEO 2022. Annual per-gallon benefits are applied to the reductions in U.S. crude oil and refined petroleum product imports shown in Table 5.4.3-1. We do not consider military cost impacts or the monopsony effect of U.S. crude oil and refined petroleum product import changes. The energy security benefits are presented in Table 5.4.3-1.

Table 5.4.3-1: Annual Energy Security Benefits of the Candidate Volumes

Year	Net Crude Import Reductions[a] (millions of gallons)	Benefits (millions of 2021$)
2023		
Excluding Supplemental Standard	2,494	$200.1
Including Supplemental Standard	2,663	$211.2
2024	2,663	$219.4
2025	2,705	$222.8

[a] Oil import reductions used for the energy security analysis in this chapter are a combination of reduced U.S. imports of gasoline, diesel fuel, and crude oil from Tables 10.4.2.1-3 and 4 converted to crude oil-equivalent gallons.

Chapter 6: Rate of Production and Consumption of Renewable Fuel

This chapter discusses the expected annual rate of future commercial production of renewable fuels, including advanced biofuels in each category (cellulosic biofuel and biomass-based diesel). For 2023–2025, we project production based on historic data and other relevant factors. We consider both domestically produced biofuels as well as foreign produced biofuels that are imported into and available for use in the U.S.[672]

We also project the use (i.e., consumption) of qualifying renewable fuels in the United States. While not an explicit factor that we must consider under the statute, consumption is inherent in the requisite consideration of infrastructure which is addressed in Chapter 7, and in the cost to consumers of transportation fuel which is addressed in Chapter 10. For 2023–2025, the projection of consumption is based on our assessment of production, exports and imports, infrastructure constraints on distributing and using biofuels, costs, and other factors explained below and throughout this DRIA. Sometimes, we term this overall resulting use of biofuels as the "supply" of biofuels. In general, we expect that all cellulosic biofuels produced in the U.S. will be used here as they have been historically. By contrast, some quantities of domestically produced advanced and conventional renewable fuels have historically been exported, and we expect exports of such fuels to continue through 2025.

We discuss the production and use of each major type of biofuel in turn: cellulosic biofuel (Chapter 6.1), biomass-based diesel (biodiesel and renewable diesel) (Chapter 6.2), sugarcane ethanol (Chapter 6.3), other advanced biofuels (besides ethanol, biodiesel, and renewable diesel) (Chapter 6.4), total ethanol (Chapter 6.5), corn ethanol (Chapter 6.6), and conventional biodiesel and renewable diesel (Chapter 6.7).

6.1 Cellulosic Biofuel

In the past several years, production of cellulosic biofuel has continued to increase. Cellulosic biofuel production reached record levels in 2021, driven by CNG and LNG derived from biogas.[673] The projected volumes of cellulosic biofuel production in 2022 is even higher than the volume produced in 2021. Production of liquid cellulosic biofuel has remained limited in recent years (see Figure 6.1-1). This section describes our assessment of the rate of production of qualifying cellulosic biofuel in 2023–2025 and some of the uncertainties associated with the projected volume for these years. Significantly, in this rule we are proposing regulations that would allow for the generation of cellulosic biofuel RINs from electricity used as transportation fuel (eRINs) beginning in 2024. This section therefore includes a projection of eRIN generation for 2024 and 2025. These assessments address our obligation to analyze the rate of production of renewable fuel in these years under our reset authority, CAA section 211(o)(2)(B)(ii)(III).

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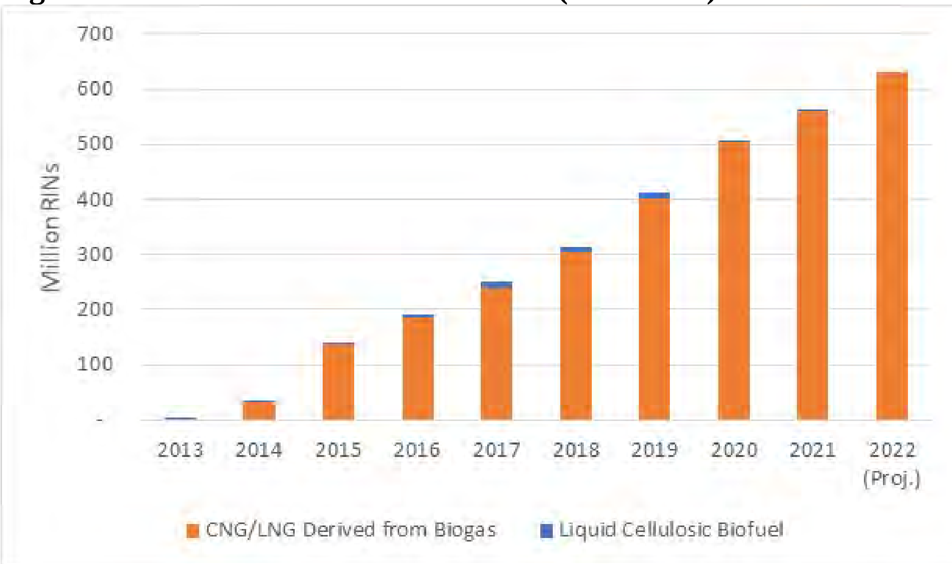
[672] This is what we generally mean when we use the term biofuel "production" in this chapter and do not specify whether we are discussing domestic production or imports.

[673] The majority of the cellulosic RINs generated for CNG/LNG are sourced from biogas from landfills; however, the biogas may come from a variety of sources including municipal wastewater treatment facility digesters, agricultural digesters, separated municipal solid waste (MSW) digesters, and the cellulosic components of biomass processed in other waste digesters.

Figure 6.1-1: Cellulosic RINs Generated (2013-2022)



To project the volume of cellulosic biofuel production in 2023–2025, we considered numerous factors, including the accuracy of the methodologies used to project cellulosic biofuel production in previous years, data reported to EPA through EMTS, available cellulosic feedstocks, projected use of CNG, LNG, and electricity as transportation fuel, and information we collected through meetings with representatives of facilities that have produced qualifying volumes of cellulosic biofuel in recent years or have the potential to produce qualifying volumes of cellulosic biofuel by 2025.

To project potential production volumes of liquid cellulosic biofuel for 2023–2025 we used the same general methodology as the methodology used in the 2018–2022 RFS annual rules. We have adjusted the percentile values used to select a point estimate within a projected production range for each group of companies based on updated information (through 2021) with the objective of improving the accuracy of the projections. To project the production of cellulosic biofuel RINs for CNG/LNG derived from biogas, we used the same general year-over-year growth rate methodology as in the 2018–2022 final rules, with updated RIN generation data through December 2021. This methodology reflects the mature status of this industry, the large number of facilities registered to generate cellulosic biofuel RINs from these fuels, and EPA's continued attempts to refine its methodology to yield estimates that are as accurate as possible. This proposal also contains a newly developed methodology to project the production of eRINs for 2024–2025.

The balance of this section is organized as follows: Chapter 6.1.1 discusses our current cellulosic biofuel industry assessment, including a review of the accuracy of EPA's projections in prior years and the companies EPA assessed in the process of projecting qualifying cellulosic biofuel production in the U.S. Chapters 6.1.2 through 6.1.4 discuss the methodologies used by EPA to project cellulosic biofuel production for liquid cellulosic biofuels, CNG/LNG derived from biogas, and eRINs in 2023–2025. Chapter 6.1.5 summarizes the projected rate of production and import of cellulosic biofuel volume for 2023–2025.

6.1.1 Cellulosic Biofuel Industry Assessment

In this section, we first explain our general approach to assessing facilities or groups of facilities (which we collectively refer to as "facilities") that we believe are likely to generate qualifying RINs for cellulosic biofuel in 2023–2025. We then review the accuracy of EPA's projections in prior years. Next, we discuss the criteria used to determine whether to include potential domestic and foreign sources of cellulosic biofuel in our projection. Finally, we provide a summary table of all facilities that we expect to produce cellulosic biofuel by the end of 2025.

To project the rate of cellulosic biofuel production for 2023–2025, we have tracked the progress of a number of potential cellulosic biofuel production facilities, located both in the U.S. and in foreign countries. We considered a number of factors, including information from EMTS, the registration status of potential biofuel production facilities as cellulosic biofuel producers in the RFS program, publicly available information (including press releases and news reports), information provided by representatives of potential cellulosic biofuel producers, and the comments received on the proposed rule. As discussed in greater detail in Chapter 6.1.2 through 6.1.4, our projection of liquid cellulosic biofuel is based on a facility-by-facility assessment of each of the likely sources of cellulosic biofuel in 2023–2025, while our projections of CNG/LNG derived from biogas and eRINs are based on an industry-wide assessment. To make a determination of which facilities are most likely to produce liquid cellulosic biofuel and generate cellulosic biofuel RINs by the end of 2025, each potential producer of liquid cellulosic biofuel was investigated further to determine the current status of its facilities and its likely cellulosic biofuel production and RIN generation volumes. Both in our discussions with representatives of individual companies and as part of our internal evaluation process, we gathered and analyzed information including, but not limited to, the funding status of these facilities, current status of the production technologies, anticipated construction and production ramp-up periods, facility registration status, and annual fuel production and RIN generation targets.

6.1.1.1 Review of EPA's Projection of Cellulosic Biofuel in Previous Years

As an initial matter, it is useful to review the accuracy of EPA's past cellulosic biofuel projections. The record of actual cellulosic biofuel production, including both cellulosic biofuel (which generate D3 RINs) and cellulosic diesel (which generate D7 RINs), and EPA's projected production volumes from 2015-2021[674] are shown in Table 6.1.1.1-1. These data indicate that EPA's projection was lower than the actual number of cellulosic RINs made available in 2015 and 2018[675] and higher than the actual number of RINs made available in 2016, 2017, 2019, and 2020.[676] The fact that the projections made using this methodology have been somewhat inaccurate, under-estimating the actual number of RINs made available in some years and over-estimating in other years, reflects the inherent difficulty with projecting cellulosic biofuel production. It also emphasizes the importance of continuing to consider refinements to our projection methodology in order to make our projections more accurate.

[674] 2021 is the last year for which complete data is available at the time of this proposed rule.
[675] EPA only projected cellulosic biofuel production for the final three months of 2015, since data on the availability of cellulosic biofuel RINs (D3+D7) for the first nine months of the year were available at the time the analyses were completed for the final rule.
[676] 2021 values were set at the actuals after the fact, see 87 FR 39600 (July 1, 2022).

Table 6.1.1.1-1: Projected and Actual Cellulosic Biofuel Production (2015-2021) (million gallons)

	Projected Volume[a]			Actual Production Volume[b]		
Year	Liquid Cellulosic Biofuel	CNG/LNG Derived from Biogas	Total Cellulosic Biofuel[c]	Liquid Cellulosic Biofuel	CNG/LNG Derived from Biogas	Total Cellulosic Biofuel[c]
2015[d]	2	33	35	0.5	52.8	53.3
2016	23	207	230	4.1	186.2	190.3
2017	13	298	311	11.7	239.4	251.1
2018	14	274	288	10.6	303.9	314.5
2019	20	399	418	11.1	402.8	413.9
2020	16	577	593	2.1	502.5	504.6
2021	N/A	N/A	N/A	0.7	561.8	562.5

[a] Projected volumes for 2015 and 2016 can be found in the 2014-2016 Final Rule (80 FR 77506, 77508, December 14, 2015); projected volumes for 2017 can be found in the 2017 Final Rule (81 FR 89760, December 12, 2016); projected volumes for 2018 can be found in the 2018 Final Rule (82 FR 58503, December 12, 2017); projected volumes for 2019 can be found in the 2019 Final Rule (83 FR 63704, December 11, 2018); projected volumes for 2020 can be found in the 2020 Final Rule (85 FR 7016, February 6, 2020).
[b] Actual production volumes are the total number of RINs generated minus the number of RINs retired for reasons other than compliance with the annual standards, based on EMTS data.
[c] Total cellulosic biofuel may not be precisely equal to the sum of liquid cellulosic biofuel and CNG/LNG derived from biogas due to rounding.
[d] Projected and actual volumes for 2015 represent only the final 3 months of 2015 (October–December) as EPA used actual RIN generation data for the first 9 months of the year.

EPA's projections of liquid cellulosic biofuel were higher than the actual volume of liquid cellulosic biofuel produced each year from 2015 to 2020. In an effort to take into account the most recent data available and make the liquid cellulosic biofuel projections more accurate, EPA adjusted our methodology in the 2018 final rule following the over-projections in 2015-2016 (and anticipated over-projection in 2017).[677] Despite these adjustments, EPA continued to over-project the volume of liquid cellulosic biofuel in each year from 2018 through 2020. 2020, however, was a challenging year for the entire industry due to the impacts of COVID-19, which was an unforeseen event that EPA could not have accounted for in projecting the volume. Given this and the fact the liquid cellulosic biofuel volume is a small fraction of the total cellulosic biofuel volume, we are again applying the same general approach we first used in the 2018 final rule: using percentile values based on actual production in previous years, relative to the projected volume of liquid cellulosic biofuel in these years. We believe that the use of the methodology (described in more detail in Chapter 6.1.2), results in a projection that reflects a neutral aim at accuracy since it accounts for expected growth in the near future by using historical data.

We next turn to the projection of CNG/LNG derived from biogas. For 2018 - 2022, EPA used an industry-wide approach, rather than an approach that projects volumes for individual companies or facilities, to project the production of CNG/LNG derived from biogas. EPA used a facility-by-facility approach to project the production of CNG/LNG derived from biogas from

[677] 82 FR 58486 (December 12, 2017).

2015-2017. Notably the facility-by-facility methodology resulted in significant over-estimates of CNG/LNG production in 2016 and 2017, leading EPA to develop the alternative industry wide projection methodology first used in 2018. This updated approach reflects the fact that this industry is far more mature than the liquid cellulosic biofuel industry, with a far greater number of potential producers of CNG/LNG derived from biogas. In such cases, industry-wide projection methods can be more accurate than a facility-by-facility approach, especially as macro market and economic factors become more influential on total production than the success or challenges at any single facility. The industry-wide projection methodology slightly under-projected the production of CNG/LNG derived from biogas in 2018 and 2019 but over-projected the production of these fuels in 2020. The accuracy of the 2020 projection, however, may have been influenced by the unforeseen and significant impacts of COVID-19.

As further described in Chapter 6.1.3, EPA is again projecting production of CNG/LNG derived from biogas using the industry-wide approach in this final rule. We calculate a year-over-year rate of growth in the renewable CNG/LNG industry and apply this year-over-year growth rate to the total number of cellulosic RINs generated and available to be used for compliance with the annual standards in 2021 to estimate the production of CNG/LNG derived from biogas in 2023–2025.[678] In comments on the 2020–2022 RFS rule, some parties claimed that the production of CNG/LNG derived from biogas was negatively impacted by the COVID-19 pandemic in 2020 and 2021, and that using a growth rate based on data from these years underestimates the potential production of this fuel in future years. During this time period the production of CNG/LNG continued to grow, but at lower rate of growth than in previous years. At this time, we do not have sufficient information to determine whether the lower growth rate observed from data in the last 24 months is the result of the COVID-19 pandemic or the maturation of the market for CNG/LNG derived from biogas. We will continue to monitor the rate of growth of these fuels in future years, and may consider using RIN generation data from a longer time period and/or other types of data in addition to RIN generation data to calculate a rate of growth to project the production of CNG/LNG derived from biogas in future years.

We applied the growth rate to the number of available 2021 RINs generated for CNG/LNG derived from biogas as data from this year allows us to adequately account for not only RIN generation, but also for RINs retired for reasons other than compliance with the annual standards. While more recent RIN generation data is available, the retirement of RINs for reasons other than compliance with the annual standards generally lags RIN generation.

The production volumes of cellulosic biofuel in previous years also highlight that the production of CNG/LNG derived from biogas has been significantly higher than the production of liquid cellulosic biofuel. This is likely the result of a combination of factors, including the mature state of the technology used to produce CNG/LNG derived from biogas relative to the technologies used to produce liquid cellulosic biofuel, the relatively low production cost of CNG/LNG derived from biogas (see Chapter 9), and the comparatively high value of the

[678] To project the volume of CNG/LNG derived from biogas in 2023 – 2025, we multiply (1) the number of 2021 RINs generated for these fuels and available to be used for compliance with the annual standards by (2) the calculated growth rate to project production of these fuels in 2022. We then multiply the projected volume of CNG/LNG derived from biogas for 2022 by the growth rate again to project the volume of these fuels for 2023, and repeat this process for 2024 and 2025.

cellulosic RIN. These factors are unlikely to change in 2023–2025. While we project production volumes of liquid cellulosic biofuel, CNG/LNG derived from biogas, and eRINs separately, ultimately it is overall accuracy of the combined cellulosic biofuel volume projection that is relevant to obligated parties.

6.1.1.2 Potential Domestic Producers

There are several companies and facilities located in the U.S. that have either already begun producing cellulosic biofuel for use as transportation fuel, heating oil, or jet fuel at a commercial scale,[679] or are anticipated to be in a position to do so in 2023–2025. The RFS program provides a strong financial incentive for domestic cellulosic biofuel producers to sell any fuel they produce for domestic consumption.[680] To date nearly all cellulosic biofuel produced in the U.S. has been used domestically. This, along with the significant incentives provided by the high cellulosic RIN prices, gives us a high degree of confidence that cellulosic biofuel RINs will be generated for all cellulosic biofuel produced by such domestic commercial scale facilities. To generate RINs, each of these facilities must be registered with EPA under the RFS program and comply with all the regulatory requirements. This includes using an approved RIN-generating pathway and verifying that their feedstocks meet the definition of renewable biomass. Most of the domestic companies and facilities considered in our assessment of potential cellulosic biofuel producers through 2023–2025 have already successfully completed facility registration, and have successfully generated RINs.[681] The remainder of this section presents a brief description of each of the domestic companies (or group of companies for cellulosic CNG/LNG producers, new producers of ethanol from corn kernel fiber, and renewable electricity) that EPA considered and/or believes may produce commercial-scale volumes of RIN generating cellulosic biofuel by the end of 2025. General information on each of these companies or group of companies considered in our projection of the potentially available volume of cellulosic biofuel in 2023–2025 is summarized in Table 6.1.1.4-1. We intend to update this list of potential cellulosic biofuel producers considered in our projection of cellulosic biofuel production using the most recent data available in the final rule.

Compressed Natural Gas (CNG) and Liquefied Natural Gas (LNG) Producers

In July 2014 EPA approved, as part of the "Pathways II" rule,[682] a new cellulosic biofuel pathway for CNG and LNG derived from biogas produced at landfills, separated MSW digesters, municipal wastewater treatment facilities, agricultural digesters, and from the cellulosic components of biomass processed in other waste digesters. The production potential for this type

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[679] For a further discussion of EPA's decision to focus on commercial scale facilities, rather than research and development and pilot scale facilities, see the 2019 proposed rule (83 FR 32031, July 10, 2018).
[680] According to data from EMTS, the average price for a 2021 cellulosic biofuel RINs sold in 2021 was $2.75. Alternatively, obligated parties can satisfy their cellulosic biofuel obligations by purchasing an advanced (or biomass-based diesel) RIN and a cellulosic waiver credit. The average price for a 2021 advanced biofuel RINs sold in 2021 was $1.61 while the price for a 2021 cellulosic waiver credit is $2.23 (EPA-420-B-22-033).
[681] Most of the facilities listed in Table 5.1.1.4-1 are registered to produce cellulosic (D3 or D7) RINs with the exception of several of the producers of CNG/LNG derived from biogas and Red Rock Biofuels. EPA is unaware of any outstanding issues that would reasonably be expected to prevent these facilities from registering as cellulosic biofuel producers and producing qualifying cellulosic biofuel in 2023–2025.
[682] 79 FR 42128, July 18, 2014.

of cellulosic biofuel is large and has increased at a rapid pace since 2014 due to the fact that many U.S.-based entities currently capture or produce biogas. This means that in many cases both historically and in some cases in future years the construction of new facilities capable of capturing and/or producing biogas will not be required for facilities to begin generating cellulosic biofuel (D3) RINs. In many cases, however, new equipment is necessary to upgrade the biogas that is currently captured or produced to meet pipeline specifications, to compress the gas for injection into a pipeline, and to build a stub line to connect to the natural gas pipeline system. Given the required investment associated with these steps, we anticipate that many facilities in the future may instead opt to generate renewable electricity from the biogas instead.

Corn Kernel Fiber to Ethanol Technologies

EPA is aware of several companies that have developed or are developing technologies to enable existing corn ethanol plants to convert the cellulosic components present in the corn kernel to ethanol. These technologies generally seek to use some combination of pretreatment and enzymatic hydrolysis to convert the cellulose and hemicellulose present in the corn kernel to simple sugars, and to then ferment these sugars to produce ethanol. Some of these technologies are designed to convert the cellulosic components of the corn kernel to sugars and eventually to ethanol simultaneously with the conversion of the corn kernel starch to ethanol. Other technologies first convert the starch to ethanol and then separately convert the cellulosic components remaining in the wet cake co-product of the corn starch ethanol process to sugars and eventually to ethanol. EPA regulations currently contain a pathway (Pathway K in Table 1 to 40 CFR 80.1426(f)) that would allow ethanol produced in either manner to qualify for cellulosic biofuel RINs, if all other regulatory requirements are satisfied.

A significant issue that must be resolved to register a facility to generate cellulosic biofuel RINs for ethanol when both corn starch and corn kernel fiber are processed together is the accurate quantification of the volume of ethanol produced from cellulosic feedstocks rather than non-cellulosic feedstocks such as starch. In September 2022 EPA published updated guidance on how to demonstrate that an analytical method for determining the cellulosic converted fraction of corn kernel fiber co-processed with starch at a traditional ethanol facility. Prior to publishing this guidance EPA registered a small number of facilities to generate cellulosic RINs for ethanol produced from corn kernel fiber. These facilities are eligible to generate cellulosic RINs for ethanol produced from CKF, provided they meet the requirements of their registration. At this point it is unclear how many additional facilities will address the technical issues necessary to produce ethanol from CKF by 2025.

Renewable Electricity Producers

With the regulatory provisions proposed for eRINs, it is expected that renewable electricity produced from biogas will begin to be produced under the RFS program beginning in 2024. There are a large number of existing biogas to electricity producers that have been operating for a number of years primarily at landfills and wastewater treatment plants, but also increasingly in recent years at large animal feedlots with installed manure digesters. The quantity of existing biogas to electricity production from such facilities already exceeds the projected use of the light-duty vehicle fleet in 2024 and 2025. For 2024 and 2025 the potential renewable electricity volume under the program will therefore be limited not by the generation of electricity from these facilities, but rather by the potential consumption in the light-duty vehicle fleet. While we anticipate that the existing generation facilities will register under the RFS program we do not anticipate the need for additional facilities to be constructed and registered under the program until after 2025.

Fulcrum BioEnergy

Fulcrum BioEnergy has developed a technology to convert separated MSW into a synthetic crude oil using a gasification and Fischer-Tropsch process.[683] Fulcrum intends to transport this synthetic crude oil, which EPA would consider to be a biointermediate, to an existing petroleum refinery where it would be further processed into transportation fuel. Fulcrum is currently constructing a facility designed to produce 11 million gallons of synthetic crude oil in Storey County, Nevada. Construction of this facility started in May 2018.[684] In May 2022 Fulcrum announced that this facility had begun producing syngas from a prepared waste feedstock, and that their focus was now on producing liquid fuels from the syngas.[685]

6.1.1.3 Potential Foreign Sources of Cellulosic Biofuel

EPA's projection of cellulosic biofuel production through 2025 also considered cellulosic biofuel that could be imported into the U.S.—specifically from all currently registered foreign facilities under the RFS program. Currently, there are several foreign cellulosic biofuel companies registered with EPA and with the potential to generate RINs for qualifying cellulosic biofuel in 2025. These include facilities owned and operated by Enerkem, GranBio, and Raizen. All of these facilities use fuel production pathways that have been approved by EPA for cellulosic RIN generation provided eligible sources of renewable feedstock are used, the fuel is used as transportation fuel in the U.S., and other regulatory requirements are satisfied. Given this, we consider imports from these companies as potential sources of cellulosic biofuel. Nonetheless, we also note that demand for the cellulosic biofuels they produce is expected to be high in their own local markets.

By contrast, we believe that cellulosic biofuel imports from foreign facilities not currently registered to generate cellulosic biofuel RINs are generally highly unlikely through 2025. This is due to the strong demand for cellulosic biofuel in local markets (often driven by mandates or incentive programs in other countries, such as Canada's recently finalized Clean Fuels Regulations[686]) and the time necessary for potential foreign cellulosic biofuel producers to register under the RFS program and arrange for the importation of cellulosic biofuel to the U.S. For purposes of our 2023–2025 projection of the rate of production of cellulosic biofuel we have excluded potential volumes from foreign cellulosic biofuel production facilities that are not currently registered under the RFS program.

[683] Unless otherwise noted, all information in this paragraph from Fulcrum BioEnergy website: Sierra Biofuels Plant: https://fulcrum-bioenergy.com/facilities
[684] Fulcrum BioEnergy Completes Construction of the Sierra Biofuels Plant: https://fulcrum-bioenergy.com/wp-content/uploads/2021/07/2021-07-06-Sierra-Construction-Completion-Press-Release-FINAL.pdf
[685] Fulcrum BioEnergy Successfully Starts Operations of its Sierra BioFuels Plant. News Release. May 24, 2022.
[686] Tuttle, Robert. *Canada Releases California-Style Fuel Rules to Cut Emissions*. Bloomberg, June 29, 2022.

Cellulosic biofuel produced at two foreign facilities (GranBio's and Raizen's Brazilian facilities) have generated cellulosic biofuel RINs for fuel exported to the U.S. in previous years. Another foreign facility (Enerkem's Canadian facility) has completed the registration process as a cellulosic biofuel producer. Each of these facilities is described briefly below. However, based on data available through EMTS no foreign facilities have generated cellulosic (D3) RINs for imported liquid cellulosic biofuel since March 2019. Therefore, while we have considered these facilities as potential sources of cellulosic biofuel we are not projecting any imports of cellulosic biofuel through 2025. All of the potential cellulosic biofuel producers through 2025 are listed in Table 6.1.1.4-1.

Enerkem

Enerkem has developed a commercial-scale technology capable of converting non-recyclable waste to a variety of renewable chemicals and fuels, including both methanol and ethanol.[687] After feedstock preparation, Enerkem's feedstocks are gasified to produce a synthetic gas (or syngas). Enerkem next purifies the syngas and processes it through a catalytic reactor to convert the syngas into the desired products. Enerkem has developed their proprietary technology over a period of 10 years before deploying it at commercial scale in Edmonton, Canada.[688] Enerkem's facility in Edmonton is designed to produce up to 13 million gallons of cellulosic ethanol per year.[689] This facility began production of methanol in 2015, with production switching from methanol to ethanol in 2017.

Ensyn

Ensyn has developed a technology known as Rapid Thermal Processing (RTP) that involves the non-catalytic thermal conversion of carbon-based solid feedstocks to liquid products. This technology is currently being used to produce specialty chemicals and heating fuels. The renewable fuel oil (RFO) produced using Ensysn's technology can be used for heating and cooling applications, and Ensyn is currently exploring opportunities to sell biocrude to petroleum refiners for co-processing with petroleum feedstocks. Ensyn is currently developing projects in Canada,[690] Brazil,[691] and the United States[692] with the intention of selling heating oil and/or biocrude into the U.S. market.

GranBio

GranBio uses a hydro-thermal pretreatment and enzymatic hydrolysis process to convert cellulosic biomass into ethanol.[693] Construction of their first cellulosic ethanol production

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687 "Technology," Enerkem Website. Accessed 5/15/2018. https://enerkem.com/about-us/technology/
688 Ibid
689 "Enerkem Alberta Biofuels," Enerkem Website. Accessed 5/15/2018. https://enerkem.com/facilities/enerkem-alberta-biofuels/
690 "Cote Nord," Ensyn Website. Accessed 7/11/22. Available at: http://www.ensyn.com/quebec.html.
691 "Aracruz Project," Ensyn Website. Accessed 7/11/22. Available at: http://www.ensyn.com/brazil.html.
692 "Georgia Project,: Ensyn Website. Accessed 7/11/22. Available at: http://www.ensyn.com/georgia.html.
693 "Who We Are," GranBio Website. Accessed May 15, 2018. http://www.granbio.com.br/en/conteudos/who-we-are/

facility was announced in mid-2012, and financing was completed in May 2013.[694] In September 2014, GranBio announced that its first cellulosic ethanol facility became operational.[695] The facility uses sugarcane straw or bagasse as a feedstock and produces both ethanol and electricity, depending on market conditions. The facility is located in Sao Miguel dos Campos, Alagoas, Brazil and originally had a production capacity of approximately 21.5 million gallons (82 million liters) of ethanol per year.[696] Since 2016, GranBio has been implementing several equipment and technology modifications at the plant, which will result in a production capacity of approximately 15.8 million gallons (60 million liters) of ethanol per year.

Raizen

Raizen, a joint venture between Shell and Cosan, uses a technology developed by Iogen Energy to convert sugarcane bagasse into ethanol. Raizen has constructed a facility co-located with a first generation ethanol production facility in Piracicaba/SP Brazil designed to be capable of producing approximately 10.5 million gallons of ethanol a year from biomass residues from first generation sugarcane ethanol production.[697] Construction of this facility began in November 2013, and the first phase, allowing for the conversion of C6 sugars into ethanol, was completed in July 2015.[698] Further construction allowing for the conversion of both C5 and C6 sugars into ethanol was completed in May 2016. Raizen began exporting cellulosic ethanol produced at this facility to the United States in 2017, and has exported a total of 32 million liters of cellulosic ethanol to the U.S. through the end of 2019.

6.1.1.4 Summary of Potential Sources of Cellulosic Biofuel in 2023–2025

General information on each of the cellulosic biofuel producers (or group of producers, for producers of CNG/LNG derived from biogas, renewable electricity producers, and producers ethanol from CKF) that factored into our projection of cellulosic biofuel production through 2025 is shown in Table 6.1.1.4-1. This table includes both facilities that have already generated cellulosic RINs, as well as those that have not yet generated cellulosic RINs, but may do so by the end of 2025. Since we are proposing regulations that would allow for the production of qualifying cellulosic biofuel from eRINs, we have considered facilities intending to produce cellulosic biofuel from eRINs in this table, and in our projections of liquid cellulosic biofuel production for 2024 and 2025. Note that while we believe all these facilities have the potential to produce or import cellulosic biofuel by the end of 2025, our projections of cellulosic biofuel production do not include volumes from all of the listed facilities in all years, as we believe the most likely volume of cellulosic biofuel produced or imported from some of these facilities is zero.

694 Schill, Susanne R. "Financing Complete on Brazil's first commercial 2G Ethanol Plant," Ethanol Producer Magazine. May 17, 2013.
695 "Who We Are," GranBio Website. Accessed May 15, 2018. http://www.granbio.com.br/en/conteudos/who-we-are/
696 Ibid
697 "A track record of innovation." Iogen website. Accessed May 1, 2018.
698 Ibid

Table 6.1.1.4-1: Potential Producers of Cellulosic Biofuel for U.S. Consumption in 2023–2025

Company Name	Location	Feedstock	Fuel	Facility Capacity (Million Gallons per Year)[699]	Construction Start Date	First Production[700]
CNG/LNG Producers	Various	Biogas	CNG/ LNG	Various	Various	Various
Enerkem	Edmonton, AL, Canada	Separated MSW	Ethanol	10[701]	2012	September 2017[702]
Ethanol from CKF (registered)	Various	Corn Kernel Fiber	Ethanol	Various	Various	Various
Ethanol from CKF (new)	Various	Corn Kernel Fiber	Ethanol	Various	Various	Various
Ensyn	Various	Woody Biomass	Heating Oil, Diesel, Jet	Various	Various	Various
Renewable Electricity Producers	Various	Biogas	Electricity	Various	Various	Various
Fulcrum/ Marathon	Storey County, NV	Separated MSW	Diesel, Jet Fuel	11	May 2018	2022
GranBio	São Miguel dos Campos, Brazil	Sugarcane bagasse	Ethanol	21	Mid 2012	September 2014
QCCP/ Syngenta	Galva, IA	Corn Kernel Fiber	Ethanol	4	Late 2013	October 2014
Raizen	Piracicaba City, Brazil	Sugarcane bagasse	Ethanol	11	January 2014	July 2015

[699] The Facility Capacity is generally equal to the nameplate capacity provided to EPA by company representatives or found in publicly available information. Capacities are listed in physical gallons (rather than ethanol-equivalent gallons). If the facility has completed registration and the total permitted capacity is lower than the nameplate capacity, then this lower volume is used as the facility capacity.

[700] Where a quarter is listed for the first production date EPA has assumed production begins in the middle month of the quarter (i.e., August for the 3rd quarter) for the purposes of projecting volumes.

[701] The nameplate capacity of Enerkem's facility is 10 million gallons per year. However, we anticipate that a portion of their feedstock will be non-biogenic municipal solid waste (MSW). RINs cannot be generated for the portion of the fuel produced from non-biogenic feedstocks. We have taken this into account in our production projection for this facility (See "November 2022 Liquid Cellulosic Biofuel Projections for 2023 – 2025 CBI").

[702] This date reflects the first production of ethanol from this facility. The facility began production of methanol in 2015.

6.1.2 Projected Liquid Cellulosic Biofuel Production

For our 2023–2025 liquid cellulosic biofuel projections, we use the same general approach as we have in projecting these volumes in previous years. We begin by first categorizing potential liquid cellulosic biofuel producers according to whether or not they have achieved consistent commercial scale production of cellulosic biofuel to date. We refer to these facilities as consistent producers and new producers, respectively. Next, we define a range of likely production volumes for each year from 2023–2025 for each group of companies. Finally, we use a percentile value to project from the established range a single projected production volume for each group of companies for each year. As in the 2018–2022 final rules, we then calculated percentile values for each group of companies based on the past performance of each group relative to our projected production ranges.

We first separate the list of potential producers (listed in Table 6.1.1.4-1) into two groups according to whether the facilities have achieved consistent commercial-scale production and cellulosic biofuel RIN generation. As in the 2020–2022 RFS annual rule, we have not listed the names of the companies that fall into each group due to the small number of companies in some of the categories and the fact that some of the data used to calculate the ends of the range is considered confidential business information by these companies.[703] We next defined a range of likely production volumes for each group of potential producers. The low end of the range for each group of producers reflects actual RIN generation data over the last 12 months for which data were available at the time our technical assessment was completed (June 2021 – May 2022).[704] For potential producers that have not yet generated any cellulosic RINs, the low end of the range is zero. For the high end of the range, we considered a variety of factors, including the expected start-up date and ramp-up period, facility capacity, and the number of RINs the producer expects to generate each year from 2023–2025.[705] The projected range for each group of companies is shown in Table 6.1.2-1.[706]

[703] More information on the companies included in each group is contained in the memos "November 2022 Liquid Cellulosic Biofuel Projections for 2023 – 2025 CBI".

[704] We recognize that in some years cellulosic biofuel production from facilities that have achieved consistent commercial scale production may be lower than the volume achieved in the previous 12 months. This has happened several times since 2016. In these cases the methodology would suggest that using a negative percentile value (indicating production in the coming year that is lower than the volume produced in the previous 12 months). By considering the use of negative percentile values for facilities that have achieved consistent commercial scale production we believe this methodology adequately accounts for this possibility.

[705] As in our 2015-2022 projections, EPA calculated a high end of the range for each facility (or group of facilities) based on the expected start-up date and a six-month straight-line ramp-up period. The high end of the range for each facility (or group of facilities) is equal to the value calculated by EPA using this methodology, or the number of RINs the producer expects to generate in 2023 – 2025, whichever is lower.

[706] More information on the data and methods EPA used to calculate each of the ranges in these tables in contained in "November 2022 Liquid Cellulosic Biofuel Projections for 2023 – 2025 CBI" memorandum from Dallas Burkholder to EPA Docket EPA-HQ-OAR-2021-0324. We have not shown the projected ranges for each individual company. This is because the high end of the range for some of these companies are based on the company's production projections, which they consider confidential business information (CBI). Additionally, the low end of the range for facilities that have achieved consistent commercial scale production is based on actual RIN generation data in the most recent 12 months, which is also claimed as CBI.

Table 6.1.2-1: Liquid Cellulosic Biofuel Projected Production Ranges (million ethanol-equivalent gallons)[a]

Category	Low End of the Range	High End of the Range
2023		
New Producers	0	0
Consistent Producers	1	7
2024		
New Producers	0	24
Consistent Producers	1	7
2025		
New Producers	0	60
Consistent Producers	1	7

[a] Rounded to the nearest million gallons.

After defining likely production ranges for each group of companies, we next determined the percentile values to use in projecting a production volume for each group of companies. We calculate the percentile values by comparing actual production data from 2016 through 2020 with the production ranges projected in the annual rules for those years. We chose the 2016-20 time period because the first full year in which EPA used the current methodology for developing the range of potential production volumes for each company was 2016, while 2020 is the most recent year for which we have both cellulosic RIN generation data and a prospective projection of liquid cellulosic biofuel production.[707]

As in previous years, to calculate the percentiles within the projected ranges used to project liquid cellulosic biofuel production for 2023–2025 we used the average percentile values for each group of companies from 2016–2020. We considered weighting recent years more heavily than previous years, but we have not done so. The disruptions in the cellulosic biofuel industry caused by the COVID pandemic in 2020 suggest that we should not more heavily weigh 2020, even though this is the most recent year for which we have data. Alternatively, we considered only considering the percentile values from 2016-2019 and excluding 2020 due to the unforeseen impacts of the COVID pandemic. Excluding the percentiles from 2020 results in slightly higher percentile values than those we calculate when including the 2020 data (the 9th percentile for new producers and the 6th percentile for consistent producers). However, using the slightly higher percentile values for consistent producers that results from excluding consideration of 2020 has a very small impact on our projection of liquid cellulosic biofuel production and no impact on the cellulosic biofuel volume for 2022 (which is rounded to the nearest 10 million gallons).

For each group of companies and for each year from 2016-2020, Table 6.1.2-2 shows the projected ranges for liquid cellulosic biofuel production (from relevant annual rules), actual

[707] While we did project liquid cellulosic biofuel production for 2021 in the proposed rule, we did not finalize our projection of cellulosic biofuel production for 2021 with the benefit of updated data and public comment. We have therefore not included 2021 in our consideration of the percentile values used to project cellulosic biofuel production in 2022.

production, the percentile values that would have resulted in a projection equal to the actual production volume, and the weighting factor used in each year.

Table 6.1.2-2: Projected and Actual Liquid Cellulosic Biofuel Production in 2016-2020 (million gallons)

	Low End of the Range	High End of the Range	Actual Production[708]	Actual Percentile
New Producers[709]				
2016	0	76	1.06	1st
2017	0	33	8.79	27th
2018	0	47	2.87	6th
2019	0	10	0.00	0th
2020	0	30	1.53	5th
Average[a]	N/A	N/A	N/A	8th
Consistent Producers[710]				
2016	2	5	3.28	43rd
2017	3.5	7	3.02	–14th
2018	7	24	7.74	4th
2019	14	44	11.13	–10th
2020	10	36	0.52	–36th
Average[a]	N/A	N/A	N/A	–3rd

[a] We have not averaged the low and high ends of the ranges, or actual production, as we believe it is more appropriate to consider the averages of the actual percentiles from 2016 - 2020 rather than calculating a percentile value for 2016–2020 in aggregate.

Based upon this analysis, EPA has projected cellulosic biofuel production from new producers at the 8th percentile of the calculated range and from consistent producers at the –3rd percentile.[711] These percentiles are calculated by averaging the percentiles that would have produced cellulosic biofuel projections equal to the volumes produced by each group of companies in 2016 - 2020. Prior to 2016, EPA used different methodologies to project available

[708] Actual production is calculated by subtracting RINs retired for any reason other than compliance with the RFS standards from the total number of cellulosic RINs generated.

[709] Companies characterized as new producers in the 2014-2016, 2017, 2018, 2019, and 2020 final rules were as follows: Abengoa (2016), CoolPlanet (2016), DuPont (2016, 2017), Edeniq (2016, 2017), Enerkem (2018, 2019, 2020), Ensyn Port Cartier (2018, 2019, 2020), GranBio (2016, 2017), IneosBio (2016), and Poet (2016, 2017) Red Rock Biofuels (2020).

[710] Companies characterized as consistent producers in the 2014-2016, 2017, 2018, and 2019 final rules were as follows: Edeniq Active Facilities (2018, 2019, 2020), Ensyn Renfrew (2016 -2020), GranBio (2018-2020), Poet (2018, 2019), Quad County Corn Processors/Syngenta (2016 - 2020), and Raizen (2019-2020).

[711] The negative percentile we are using to project cellulosic biofuel production from consistent producers in 2022 means that we are projecting less cellulosic biofuel will be produced from these facilities than they produced over the last 12 months for which data is available. We observed a similar pattern in 2017 and 2020, where liquid cellulosic biofuel production from consistent producers fell from the prior year. This is generally because producing liquid cellulosic biofuel at a commercial scale remains challenging, and many producers have gone out of business not long after they began production.

volumes of cellulosic biofuel and thus believes it inappropriate to calculate percentile values based on projections from those years.[712]

We then used these percentile values, together with the ranges determined for each group of companies discussed above, to project a volume for each group of companies in 2022. These calculations are summarized in Table 6.1.2-3.

Table 6.1.2-3: Projected Volume of Liquid Cellulosic Biofuel in 2023–2025 (million ethanol-equivalent gallons)

	Low End of the Range[a]	High End of the Range[a]	Percentile	Projected Volume[a]
2023				
Liquid Cellulosic Biofuel Producers; New Producers	0	0	8th	0
Liquid Cellulosic Biofuel Producers; Consistent Producers	1	7	–3rd	0
Total	N/A	N/A	N/A	0
2024				
Liquid Cellulosic Biofuel Producers; New Producers	0	24	8th	2
Liquid Cellulosic Biofuel Producers; Consistent Producers	1	7	–3rd	0
Total	N/A	N/A	N/A	3
2025				
Liquid Cellulosic Biofuel Producers; New Producers	0	60	8th	5
Liquid Cellulosic Biofuel Producers; Consistent Producers	1	7	–3rd	0
Total	N/A	N/A	N/A	5

[a] Volumes rounded to the nearest million gallons.

6.1.3 Projected Production of CNG/LNG Derived from Biogas

For 2023–2025, EPA is using the same industry wide projection approach as used for 2018–2022 based on a year-over-year growth rate to project production of CNG/LNG derived from biogas used as transportation fuel.[713] EPA calculated the year-over-year growth rate in CNG/LNG derived from biogas by comparing RIN generation from June 2021 to May 2022 (the most recent 12 months for which data are available) to RIN generation in the 12 months that

[712] EPA used a similar projection methodology for 2015 as in 2016-2018, however we only projected cellulosic biofuel production volume for the final 3 months of the year, as actual production data were available for the first 9 months. We do not believe it is appropriate to consider data from a year for which 9 months of the data were known at the time the projection was made in determining the percentile values used to project volume over a full year.
[713] Historically RIN generation for CNG/LNG derived from biogas has increased each year. It is possible, however, that RIN generation for these fuels in the most recent 12 months for which data are available could be lower than the preceding 12 months. Our methodology accounts for this possibility. In such a case, the calculated rate of growth would be negative.

immediately precede this time period (June 2020 to May 2021). The growth rate calculated using this data is 13.1%. These RIN generation volumes are shown in Table 6.1.3-1.

Table 6.1.3-1: Generation of Cellulosic Biofuel RINs for CNG/LNG Derived from Biogas (ethanol-equivalent gallons)

RIN Generation (June 2020 – May 2021)	RIN Generation (June 2021 – May 2022)	Year-Over-Year Increase
526,129,526	595,311,069	13.1%

EPA then applied this 13.1% year-over-year growth rate to the total number of 2021 cellulosic RINs generated and available for compliance for CNG/LNG. That is, in this rule, as in the 2018–2022 final rules, we are multiplying the calculated year-over-year rate of growth by the volume of CNG/LNG actually supplied in the most recent year for which data is available (in this case 2021), taking into account actual RIN generation as well as RINs retired for reasons other than compliance with the annual volume obligations. This provides a projection of the production of CNG/LNG derived from biogas in 2022. This results in a projection of 636 million ethanol-equivalent gallons of CNG/LNG derived from biogas in 2022. Since we are proposing volumes for three future years, we do not have data which would allow for separate rates of growth to project volumes for 2023–2025. Consequently, we applied the same rate of growth to project the production of CNG/LNG derived from biogas in 2023–2025.

Table 6.1.3-2: 2022–2025 Projection of CNG/LNG Derived from Biogas (ethanol-equivalent gallons)

D3 RINs generated for CNG/LGN derived from biogas in 2021	567,086,813
RINs retired for reasons other than compliance with annual obligations	5,241,195
Net RINs generated in 2021	561,845,618
Growth rate	13.15%
Projected production of CNG/LNG derived from biogas in 2022	635,723,522
Projected production of CNG/LNG derived from biogas in 2023	719,315,741
Projected production of CNG/LNG derived from biogas in 2024	813,899,622
Projected production of CNG/LNG derived from biogas in 2025	920,920,477

In discussions with EPA a number of cellulosic biogas producers have argued that the rate of growth observed in 2020 and 2021 was negatively impacted by relatively low cellulosic RIN prices in 2019 and 2020 and challenges developing new cellulosic biogas production facilities in 2020 and 2020 related to the COVID pandemic. These parties argued that the higher growth rates observed in previous years were more reflective of the potential growth in cellulosic biogas production in 2023–2025. Generation of cellulosic RINs for CNG/LNG derived from biogas from 2015 (the first full year in which CNG/LNG derived from biogas was approved to generate cellulosic RINs) and 2021 (the last year for which complete data are available), and the annual rate of growth for each year is shown in Table 6.1.3-3.

Table 6.1.3-3: Cellulosic RIN Generation (Million RINs) and Annual Growth Rate for CNG/LNG Derived from Biogas

	2015	2016	2017	2018	2019	2020	2021
D3 RIN Generation	139.9	188.6	240.6	304.2	404.3	503.8	567.1
Annual Growth Rate	N/A	34.8%	27.6%	26.4%	32.9%	24.6%	12.6%

It is apparent in looking at this data that the observed rate of growth in RIN generation for CNG/LNG derived from biogas was notably lower from 2019 to 2020 and from 2020 to 2021 than in previous years. While it is likely that lower RIN prices and the COVID pandemic were factors in the lower observed growth rates, we would also expect that as this industry matures and approaches the quantity of CNG and LNG used as transportation fuel the rate of growth would decrease even in the absence of other external factors. At this time we are unable to determine how much of the decrease in the rate of growth of CNG/LNG derived from biogas was due to the low cellulosic RIN prices in 2019 and 2020 and the COVID pandemic vs. the maturation of the industry and limitations on the quantity of these fuels used as transportation fuel (discussed further below). Because of this, and because using data from the most recent 24 months as the basis for the rate of growth when projecting the production of CNG/LNG derived from biogas for future years has produced reasonably accurate projections since 2018, we are using data from the most recent 24 months to project the production of CNG/LNG derived from biogas in 2023–2025. However, we have also calculated alternative projections of CNG/LNG production in 2023–2025 using the average annual growth rate from 2015–2021 (all years for which complete data are available) and 2015–2019 (all non-COVID years for which data are available) in Table 6.1.3-4.

Table 6.1.3-4: Alternative Projections of CNG/LNG Derived from Biogas (million ethanol-equivalent gallons)

Time Period	Average Growth Rate	Projected Production of CNG/LNG Derived from Biogas		
		2023	2024	2025
2015–2019	30.4%	955.4	1,245.8	1,624.5
2015–2021	26.3%	896.2	1,131.9	1,429.7

We then compared these projected volumes with the total volume of CNG/LNG expected to be used as transportation fuel in 2023–2025. We are aware of several estimates for the quantity of CNG/LNG that will be used as transportation fuel in 2022 that cover a wide range of projected volume. EIA's 2022 AEO projects that 0.12 trillion cubic feet of natural gas will be used in the transportation sector in 2023 and 2024 (approximately 1.62 billion ethanol-equivalent gallons), increasing to 0.13 trillion cubic feet of natural gas in 2025 (approximately 1.75 billion ethanol-equivalent gallons).[714] A paper prepared by Bates White for the Coalition for Renewable

[714] These values are from the projections for Motor Vehicles, Trains, and Ships in Table 13: Natural Gas Supply, Distribution, and Prices in the 2022 AEO.

Natural Gas presented an independent assessment of 1.53, 1.55, and 1.58 billion ethanol-equivalent gallons used in 2023–2025.[715]

Separately, EPA projects that approximately 1.36 ethanol-equivalent gallons of CNG/LNG will be used as transportation fuel in 2022. This estimate is based on the average throughput at CNG/LNG refueling stations in California and the number of CNG/LNG stations in operation according to the Alternative Fuels Data Center. The data used to make this projection is summarized in Table 6.1.3-5. Due to significant variation in the annual increase in the number of CNG/LNG refueling stations historically we have not used this information to project the use of CNG/LNG in 2023–2025, however consumption would be expected to increase as the number of operational refueling stations increases.

Table 6.1.3-5: Projected Consumption of CNG/LNG Used as Transportation Fuel in 2022

CNG/LNG used as transportation fuel in California in 2021	303.2 million ethanol-equivalent gallons
CNG/LNG refueling stations in California in 2021	358 stations
Average annual throughput per station in California in 2021	0.85 million ethanol-equivalent gallons
CNG/LNG refueling stations in the U.S. in 2022	1611 stations
Projected CNG/LNG used as transportation fuel in the U.S. in 2022	1.36 billion ethanol-equivalent gallons

These estimates of the consumption of CNG/LNG used as transportation fuel are all fairly similar, and all are greater than the volume of qualifying CNG/LNG derived from biogas projected to be used in 2023–2025. Thus, the volume of CNG/LNG used as transportation fuel would not appear to constrain the number of RINs generated for this fuel in these years. We note, however, that using a higher rate of growth such as those used in our alternative projections of the production of CNG/LNG derived from biogas are much closer to the estimates of the quantity of CNG/LNG used as transportation fuel, and in some cases exceed these estimates. Thus, even if the production of CNG/LNG in 2023–2025 can grow at a rate consistent with the higher observed growth rate observed prior to 2020, RIN generation in these years may still be limited to the quantity of CNG/LNG used as transportation fuel. In any case, the use of CNG/LNG derived from biogas appears to be increasing at a greater rate than the use of CNG/LNG as transportation fuel and is likely approaching the total volume of CNG/LNG used as transportation fuel during the 2023–2025 time period. As the volume of CNG/LNG derived from biogas approaches the total volume of CNG/LNG used as transportation fuel it may become increasingly difficult to demonstrate the use of CNG/LNG derived from biogas as transportation fuel. This factor could slow or ultimately limit the generation of cellulosic RINs from this fuel in future years.

We believe that projecting the production of CNG/LNG derived from biogas using the same methodology as in recent years appropriately takes into consideration the actual recent rate of growth of this industry, and that this growth rate accounts for both the potential for future growth and the challenges associated with increasing RIN generation from these fuels for 2023-

[715] *Renewable Natural Gas: Transportation Demand*. Bates White Economic Consulting. February 2, 2022; Updated April 29, 2022.

2025. This methodology may not be appropriate to use as the projected volume of CNG/LNG derived from biogas approaches the total volume of CNG/LNG that is used as transportation fuel, as RINs can be generated only for CNG/LNG used as transportation fuel. We do not believe that this is yet a constraint as our projection through 2025 as the volume of CNG/LNG derived from biogas is still below the total volume of CNG/LNG that is currently used as transportation fuel.

6.1.4 Projected Supply of Electricity Derived from Biogas

With this proposal we are seeking to put into place regulations to enable the renewable electricity pathway to be used to generate RINs for the first time since approval. As with CNG/LNG from biogas, the potential supply of qualifying renewable electricity from biogas is bounded by both the production and use. Unlike biogas used in CNG/LNG, we anticipate the ultimate constraint on volumes for renewable electricity to be electricity use in the light-duty EV fleet for the timeframe of this action; with a proximate constraint of renewable electricity generators registering for the program. The following sections describe the analysis and data which support our assessment that the use of electricity by the light-duty fleet will be the limiting factor for volumes in 2024 and 2025. Additionally, we describe the methods utilized for projecting eRIN volumes, electrified vehicle activity, and renewable electricity generation. Lastly, we present the analysis which forms the basis for the proposed revised equivalence value for electricity in the RFS program.

6.1.4.1 Projecting eRIN Volumes

The incorporation of renewable electricity into the RFS program as part of this proposal necessitated the development of a novel means of calculating eRIN generation and forecasting volumes for renewable electricity in the program. In this section we describe the data and methodology for projecting RIN volumes from renewable electricity in the RFS program. Included in this discussion is the establishment of the initial parameters used in the RIN generation equations for OEMs, acting as RIN generators, participating in the eRIN program. Additionally, we provide our assessment of renewable electricity volumes for the 2024 and 2025 RFS years and discuss the potential economic value of the RINs associated with those volumes for program participants.

6.1.4.1.1 Method for Calculating Electricity Used as Transportation Fuel

As described in Preamble Section VIII.F we are proposing to use a top-down methodology for calculating the quantity of renewable electricity used as transportation fuel that is eligible for RIN generation. Each participating OEM will perform the following calculations described for their individual fleet[716], but we have laid out the following derivation of proposed volumes to describe the aggregate, national-level calculation for the use of renewable electricity as a transportation fuel. Consequently, the following serves as an illustrative walk-through of the process by which we determined the maximum volume of renewable electricity eligible for RIN generation for each of the years for which RFS volumes have been established. At the highest level the methodology can be expressed by the following equation:

[716] "Examples of RIN generation under the proposed RFS eRIN provisions," available in the docket for this action.

$$Population * Activity * Efficiency = Consumption$$

Where:

- *Population* is the fleet size and disposition of all electric vehicles in the U.S. fleet
- *Activity* is the average miles traveled on electricity by electric vehicles as discussed in 6.1.4.3
- *Efficiency* is the average per mile energy consumption of electric vehicles
- *Consumption* is the quantity of electricity consumed by the fleet

This is a simplified mathematical representation, but it serves as a useful foundation upon which to add further detail and complexity to each of the equation terms. We next discuss each of the terms in the simplified equation above in greater detail and present the data used for each in calculating the national volume of renewable electricity eligible for RIN generation.

Population

In order to determine the total population of electrified vehicles in the U.S. fleet we leveraged vehicle sales data that went back to model year 2011[717] and then utilized projections for electrified vehicle sales from EPA's recent light-duty vehicle rulemaking[718] for the years where sales data was not yet available. Once the eRIN program is up and running, the OEMs will be submitting current electrified vehicle populations on a quarterly basis as a condition of RIN generation; negating the need to rely on historical sales data and scrappage rates in the future. The historical electrified vehicle sales and the projected sales are presented in Table 6.1.4.1-1.

[717] https://www.anl.gov/esia/light-duty-electric-drive-vehicles-monthly-sales-updates for sales of 2011-2019 and then https://www.energy.gov/energysaver/articles/new-plug-electric-vehicle-sales-united-states-nearly-doubled-2020-2021 for sales years 2020-2021.

[718] 86 FR 74434 (December 30, 2021).

Table 6.1.4.1.1-1: Electrified Vehicle Sales Data

Model Year	BEV Sales	PHEV Sales
2011	10,060	7,671
2012	14,650	38,584
2013	47,694	49,008
2014	63,416	55,357
2015	71,044	42,879
2016	86,731	72,837
2017	104,471	90,774
2018	238,816	122,491
2019	244,569	84,959
2020	230,612	65,737
2021	443,840	164,160
2022	831,296	109,396
2023	1,150,866	124,243
2024	1,621,250	121,880
2025	2,140,707	110,676

The next step in determining the relevant population for the years for which we projected volumes was to adjust the sales numbers to reflect vehicle attrition and to aggregate the sales data in a cumulative fashion to arrive at a projected total population for each year. Attrition rates for electrified vehicles have not yet been well established or verified, so we took a conservative approach and ascribed an assumed attrition rate of five percent per annum. Literature shows that the average electric vehicle is 3.9 years old, and that 4-year-old vehicles in the U.S. fleet[719] have an attrition rate of 1.3%.[720,721] Accounting for this attrition, the cumulative PHEV and BEV fleet sizes are presented by year in Table 6.1.4.1.1-2.

[719] In this case, the best available research only focuses on the U.S. fleet inclusive of EVs and ICEVs.
[720] IHS Markit, https://news.ihsmarkit.com/prviewer/release_only/id/4759502
[721] Antonio Bento, Kevin Roth, Yiou Zuo, "Vehicle Lifetime Trends and Scrappage Behavior in the U.S. Used Car Market" (Jan. 18, 2016).

Table 6.1.4.1.1-2: Cumulative EV Fleet with Attrition

Model Year	BEV	PHEV
2011	10,060	7,671
2012	24,207	45,871
2013	70,691	92,586
2014	130,572	143,314
2015	195,088	179,027
2016	272,064	242,913
2017	362,932	321,541
2018	583,601	427,955
2019	798,990	491,516
2020	989,653	532,677
2021	1,384,010	670,203
2022	2,146,106	746,089
2023	3,189,666	833,028
2024	4,651,433	913,256
2025	6,559,568	978,270

One additional adjustment to the population values must be performed in order to translate the cumulative PHEV and BEV fleet numbers into the appropriate form for calculating volumes for renewable electricity used as transportation fuel. Sales numbers are reported for the entire calendar year of any given year i.e., the total sales of that vehicle type that occur sometime prior to December 31st of the year in question. The issue for our purpose is that a vehicle sold in the last quarter of the RFS year would not have been in the fleet, eligible for RIN generation, in the first quarter of the RFS year. Consequently, absent better information regarding the distribution of future vehicle sales, we have elected to assume that half of the current year sales volume will be eligible to generate RINs for the entirety of the current year. The resulting cumulative PHEV and BEV fleet sizes adjusted for ability to be eligible for RIN generation are presented in Table 6.1.4.1.1-3.

Table 6.1.4.1.1-3: Effective Electrified Vehicle Fleet for RFS Program Years

RFS Year	BEV	PHEV
2021	1,211,573	614,757
2022	1,799,658	724,901
2023	2,721,539	808,211
2024	4,000,291	893,968
2025	5,721,787	968,594

Throughout this description of the population term we have kept BEVs separate from PHEVs. This separation is required because of the unique powertrain and operational characteristics possessed by each classification of electrified vehicles. The next section on activity goes into further detail on these characteristics, but the result is that now we have arrived at a more detailed expression for population in our simplified equation:

$$Population = BEV\_CFleet_{RFSyearX} + PHEV\_CFleet_{RFSyearX}$$

Where:

- $BEV\_CFleet_{RFSyearX}$ is the cumulative fleet of BEVs is any given RFS year
- $PHEV\_CFleet_{RFSyearX}$ is the cumulative fleet of PHEVs is any given RFS year

Activity

Having determined the quantity and type of vehicles which makeup the population of our consumption equation we next turn to determining the frequency at which those vehicle types are used. In this proposal we have elected to use electric vehicle miles travelled (eVMT) as the metric for evaluating the frequency of which each vehicle type is used. Chapter 6.1.4.3 presents the derivations for eVMT for both BEV and PHEV vehicles based upon the all-electric range. For the purposes of calculating aggregate, national-level use of renewable electricity as a transportation fuel an eVMT value of 7,200 mi/yr was used for BEVs and 3,000 mi/yr was used for PHEVs.

$$Activity: BEV_{Activity} = 7{,}200 \, {}^{mi}/_{yr} \mid PHEV_{Activity} = 3{,}000 \, {}^{mi}/_{yr}$$

As discussed in Preamble Section XIII.F. we are proposing to have OEMs submit either eVMT or aggregated charging information as a condition of program participation and RIN generation. This data will aid the EPA in validating the appropriateness of the values for activity we have established in addition to allowing for future refinements and improvements to the eRIN program. If the data collection process functions as intended, the intention will be for the agency to update these activity values in a future action to reflect the real-world data collected on electric vehicle usage.

Efficiency

The last term necessary to be defined in the consumption equation is the efficiency for the two vehicle types we have specified for population and activity. We are proposing an efficiency value (η) of 0.32 kWh/mi for both PHEV and BEV vehicles. This value was chosen based on an evaluation of the certification data[722] for BEVs and PHEVs as being a representative average value for all electrified vehicles. Given the rapid increase in new BEV and PHEV models being introduced it is apparent that there is a significant variation among vehicles and that this average value may change over time. As discussed in Preamble Section VIII.F, we are proposing to have the OEMs submit vehicle efficiency data by model as part of eRIN program participation. This real world efficiency information will allow us to verify the 0.32 kWh/mi value and update it as necessary in a future action.

$$Efficiency = \eta_{BEV} = \eta_{PHEV} = 0.32 \, {}^{kWh}/_{mi}$$

Consumption

[722] The 2021 Automotive Trends Report, EPA-420-R-21-023, November 2021

The simplified consumption equation originally laid out can now be rewritten with the more detailed parameter names in the following fashion:

$$Consumption = (BEV\_CFleet_{RFSyearX} * \; BEV_{Activity} * \; \eta_{BEV}) \\ + (PHEV\_CFleet_{RFSyearX} * \; PHEV_{Activity} * \; \eta_{PHEV})$$

Or, with the known numerical values inserted:

$$Consumption = (BEV\_CFleet_{RFSyearX} * \; 7200 * \; 0.32) \\ + (PHEV\_CFleet_{RFSyearX} * \; 3000 * \; 0.32)$$

Using the above equation along with the electrified vehicle populations yields values for the gigawatt hours of electricity used as transportation fuel which will be eligible for RIN generation for each corresponding RFS year.

Table 6.1.4.1.1-4: Electricity Eligible as Transportation Fuel [GWh]

RFS Year	BEV	PHEV	Total
2021	2,791	590	3,382
2022	4,146	696	4,842
2023	6,270	776	7,046
2024	9,217	858	10,075
2025	13,183	930	14,113

With the methodology to determine the volume of renewable electricity used as transportation fuel eligible for RIN generation for each of the years for which RFS volumes established, the values in Table 6.1.4.1.1-4 under the "Total" column for 2024 and 2025 represent the maximum amount of electricity used as transportation fuel which would be eligible for RIN generation in this proposal.

6.1.4.1.2 Method for Setting Volumes for eRINs

The process for setting volumes for RINs from renewable electricity (eRINs) involves comparing the calculated quantity of renewable electricity used as transportation fuel (calculated in 6.1.4.1.1), the supply of qualifying renewable electricity, and the rate at which companies can complete engineering reviews (ERs) for facilities producing qualifying renewable electricity. At the most basic level, we are contrasting available supplies with calculated demand and setting the volume at the lesser of the three. However, there are some additional considerations which serve to slightly complicate the process. As laid out in the preamble, the statute requires that both the "from qualifying renewable biomass" and "used as transportation fuel" aspects be met in order for valid RIN generation to occur. We interpret this to mean that the quantity of qualifying renewable fuel delivered to the vehicle must match the quantity of renewable fuel used as transportation fuel by that vehicle.

In Preamble Section XIII.F we outlined the need to account for losses in the transmission and charging process in order to ensure that an adequate quantity of renewable electricity is procured by an OEM to meet the electricity demand of their fleet. Unlike with liquid renewable fuels, where very little volume is lost between production and dispensation into a vehicle's fuel tank, there are appreciable and quantifiable losses in the process of getting electricity from the point of generation to altering an electric vehicle's state of charge. The two sources of loss included in this proposal are line losses, which account for resistive losses in the electricity distribution system, and vehicle charging losses, which represent the collective losses associated with AC to DC conversion, resistive losses, and battery hysteresis losses which occur during the charging process. We have set the line loss rate at 5.3% in accordance with the reported national average value for this parameter by the EPA eGRID Model[723] for the year 2020. Further discussion of the energy losses during electrical transmission is presented in Chapter 6.1.4.4. For charging efficiency, we have set a value of 85%. The derivation of 85% as the charging efficiency is also presented in Chapter 6.1.4.4.

These two sources of loss occur in series, which means that the inefficiencies compound as the electricity moves from source to sink. Consequently, the transmission efficiency of 94.7% (1-line loss rate of 5.3%) and the charging efficiency of 85% must be multiplied together, yielding a total loss rate of approximately 19.5%. The implication of these losses is that 24.2% more renewable electricity (kWh) will have to be generated than what is actually consumed in the vehicles. Thus, the OEMs must procure 24.2% more renewable electricity than the amount of electricity used as transportation fuel calculated for their fleet. For determining the proposed eRIN volumes for 2024 and 2025, the consequence is that the amount of electricity used as transportation fuel calculated for 2024 and 2025 in Table 6.1.4.1.1-4 must be multiplied by 24.2% to account for systemic inefficiencies when we compare renewable electricity supply to demand as transportation fuel.

Table 6.1.4.1.2-1: Effect of Inefficiencies for Renewable Electricity

RFS Year	Electricity Eligible as Transportation Fuel (GWh)	Procured Electricity Required (GWh)
2021	3,382	4,201
2022	4,842	6,016
2023	7,046	8,754
2024	10,075	12,516
2025	14,113	17,533

As stated previously, in order to determine the potential volumes of eRINs in 2024 and 2025, a comparison of the required renewable electricity to be procured from Table 6.1.4.1.2-1 must be made with the projected supply of renewable electricity production, as well as the rate at which these facilities can be properly registered in order to start generating RINs, as discussed in Section 6.1.4.2.3. Table 6.1.4.2-3 presents the projected renewable electricity supply for the years 2024 and 2025. Combining this table with the "Procured Electricity Required" column from Table 6.1.4.1.2-1 yields the desired comparison between supply and demand presented in Table 6.1.4.1.2-2.

[723] eGRID 2019 Technical Guide, prepared by Abt Associates for US EPA Clean Air Markets Division, February 2021. See Section 3.5.

Table 6.1.4.1.2-2: Comparison of Supply and Demand for Setting Volumes

Year	Qualifying Electricity Supply (GWh)	Procured Electricity Required (GWh)	Limiting Electricity Quantity (GWh)
2024	22,314	12,516	12,516
2025	25,270	17,533	17,533

For these two years the demand side of the equation (i.e., the electricity consumed by the electrified vehicle fleet) is a limiting factor on the quantity of eRINs which can be generated. (However, as discussed in Chapter 6.1.4.2.3, the anticipated rate of engineering reviews to enable the qualifying electricity supply to be brought into the program is projected to have it actually be the limiting factor in eRIN generation in 2024 and 2025. In future years as the EV fleet grows rapidly it is likely that qualifying renewable electricity generation will become the limiting factor on eRIN generation. Assuming adequate revenue sharing agreements are established between OEMs, renewable electricity generators and biogas producers we would anticipate both the supply and demand for qualifying renewable electricity would grow in concert in future years.

6.1.4.2 Biogas Electricity Generation Capacity

Another potential constraint on eRIN generation in 2024-5 is the biogas electricity generation capacity. Existing production capacity is estimated to already exceed or meet the EV fleet consumption capacity discussed in 6.1.4.1.

To develop estimates of current domestic biogas electricity generation capacity and potential, we used six well-vetted and publicly available databases. The databases are discussed further below. The total number of domestic facilities characterized by the six databases that may produce biogas, which can be combusted to produce electricity after purification, is approximately 1,700. By way of comparison, an estimate of the current total number of domestic facilities producing and capturing biogas and converting the biogas to electricity in the U.S. is 2,200, according to the Environmental and Energy Study Institute (EESI). EESI also suggests that 13,500 new facilities could be added to the 2,200.[724]

The databases used to develop estimates of the current and potential are:

1. *U.S. EPA Livestock Anaerobic Digester Database (AgSTAR) Database*
    - Contains key information about anaerobic digester (AD) facilities situated on livestock farms in the United States. Information in the AgSTAR Database is compiled from a variety of sources. Data received for inclusion in the AgSTAR Database are reviewed for reasonableness and are corroborated via other data sources when possible. The program attempts to update information in the database, but it is not exhaustive. The AgSTAR Database does not include data for every AD facility situated on livestock farms in the United States.

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[724] Fact Sheet, Biogas: Converting Waste to Energy, *Environmental and Energy Study Institute*, https://www.eesi.org/files/FactSheet_Biogas_2017.09.pdf

2. *U.S. EPA Landfill Methane Outreach Program (LMOP) Database*
    - Contains key information about municipal solid waste (MSW) facilities and landfill gas (LFG) energy projects in the United States. Information in the LMOP Database is compiled from a variety of sources. Data received for inclusion in the LMOP Database are reviewed for reasonableness and are corroborated via other data sources when possible. The program attempts to update information in the database, but it is not exhaustive. The LMOP Database does not include data for every MSW landfill in the United States.
3. *U.S. EPA Landfill Methane Outreach Program (LMOP) Candidates Database*
    - Contains key information about potential municipal solid waste (MSW) candidate facilities in the United States. Candidate facilities are MSW facilities that:
        - Currently accept waste or have been closed for five years or less,
        - Have at least one million tons of waste, and
        - Are not considered to be operational, under-construction, or planned project.
4. *Argonne National Laboratory (ANL) 2020 U.S. Renewable Natural Gas (RNG) Project Database*
    - Contains a comprehensive list of biogas projects that upgrade LFG for pipeline injection or for use as vehicle fuel.
5. *U.S. EPA Clean Air Markets Division Electric Generation and Resource Database (eGRID) 2020*
    - Contains facility locations, generation capacity, and emissions information for various stationary sources
6. *Energy Information Administration*

6.1.4.2.1 Current Sources of Domestic Production

Estimates of the current domestic biogas-derived electric power generation capacity are shown in Table 6.1.4.2.1-1, by specific database and discussed below.

Table 6.1.4.2.1-1: Domestic Biogas-Derived Electric Power Generation Capacity Resources

Database	Facilities Listed	Facility Type(s)	Reported Generation (GWh)	Data Characterization
AgSTAR Database	316	-Agricultural Digesters	805	Existing and Potential Agricultural Anaerobic Digestion
LMOP Database	550	-Landfill -MSW	10468	Existing MSW and Landfills generating biogas electricity or LFG
LMOP Candidate Database	481	-Landfill -MSW	n/a	MSW and Landfill sites without generation or LFG gas collection capabilities
ANL 2020 U.S. RNG Database	233	-Agricultural Digesters -Wastewater Treatment Plants -Landfills -MSW	n/a	Compiled source by Argonne National Labs of different projects collecting RNG from biogas in the U.S.
EIA Electric Power Annual 2020	n/a	-Other Waste Biomass	1402	Records landfill gas, biogenic municipal solid waste, and other waste biomass in terms of net generation, but does not include a facility count
		Biogenic MSW	6093	
U.S. EPA CAMD Electric Generation and Resources Database (eGRID)	378	-Agricultural Digesters	252	A modelled database using the U.S. Greenhouse Gases Sources and Sinks database that records facility locations, nameplate capacity, and net generation.
		Wastewater Treatment	887	
		Landfills	11,196	

There is no central authority or compilation of biogas to electricity resources in the U.S., but several databases, shown in Table 6.1.4.2.1-1, can be used in tandem to create an estimate of biogas resources currently available. Viewed together, as in Table 6.1.4.2-2, it is clear that the domestic generation capacity during the years 2024-2025 can provide more than the 17,533 GWh of renewable electricity required to be procured by OEMs to satisfy the needs of the EV fleet in 2025. Likewise, EIA, LMOP, and AgSTAR data, combined with projections of how the private sector will respond to the eRINs rulemaking, show that electricity generated from biogas will not struggle to meet this power requirement.

Table 6.1.4.2.1-2: Estimated Current Baseline Biogas and Biomass Resources

Source Sector	Current Utilized Capacity (GWh)	Data Source
Agricultural Digestion	805	AgSTAR
Wastewater Treatment	887	eGRID
Landfill	11,196	eGRID
Biogenic MSW	6,093	EIA
Other Waste Biomass	1,402	EIA
Woody Biomass	38,543	EIA
Currently Allowable Total	20,383	-
Potential Total	58,926	-

Given the differences between these data sources, in order to estimate the current utilized biogas electricity generation capacity we selected those sources for the various components that provided the greatest specificity and perceived accuracy. We primarily use EIA and eGRID, though we are using AgSTAR data for the agricultural anaerobic digestion source sector, as the program maintains a detailed, frequently updated database on sites generating electricity from swine, cattle, poultry, and dairy. Wastewater treatment plants and landfills capacity is taken from Clean Air Market Divisions Electricity Generation and Resources Database (eGRID). It should be noted that they only count net exporters to the grid in their database, and many wastewater treatment plants are listed as net consumers despite having on-site electricity generation capacity. They are most likely to currently be using their generated power for CHP or other on-site uses. EIA is our best and most accurate data source for other source categories, namely biomass products and biogenic municipal solid waste source sectors that, while they will contribute during the span of this rule, are likely to play a more outsized role in the future of the program after 2025. In sum, these resources are estimated to currently have a capacity of 20,383 GWh of renewable electricity from biogas.

While this 20,383 GWh may be a good representation of the current generation capacity, it does not necessarily reflect the generation capacity that can be expected to be available in 2024 and 2025. We use a conservative current year (2023) estimate of 50% participation in the eRINs program for biogenic MSW,[725] and assume that current year utilization of wastewater treatment plant and landfill capacity will not exceed the capacity listed in eGRID, meaning that unlisted capacity in the database from net electricity consumers will not be used in the program until later years. This leaves us with a utilization shown in Table 6.1.4.2.1-3. We expect that utilization will begin to include net importers and that generation capacity that remains unused for various reasons will also be employed. Agricultural digesters will also begin to ramp up installed capacity as the program matures due to the fact that many dairy and other farm biogas projects are currently being built or planned.[726] Biogenic MSW and other waste biomass are assumed to increase participation linearly in the eRINs program up to 100% of their current capacity utilization by 2025. We project increases in 2025 for wastewater treatment, agricultural digesters, and landfills based on an assumption of linear growth to a hypothetical 2030 maximum

[725] EIA records this category in their Electricity Power Annual but we cannot be certain that it all qualifies under existing RFS pathways, thus a 50% estimate of qualifying biogas electricity power generation.
[726] American Biogas Council Project Database, https://americanbiogascouncil.org/resources/biogas-projects

potential capacity,[727] which is based on potential capacity numbers from the Schatz Energy Research Center 2021 report on biogas electricity growth.

Table 6.1.4.2.1-3: Participating Biogas Capacity During Program Implementation Years

Source Sector	2024	2025	Total Potential Capacity[728]
Agricultural Digester	805	1,166	16,938
WWTP	887	1,248	4,550
Landfill	15,000	15,361	33,710
Biogenic MSW	4,570	6,093	29,220
Total	22,314	25,270	84,418[729]

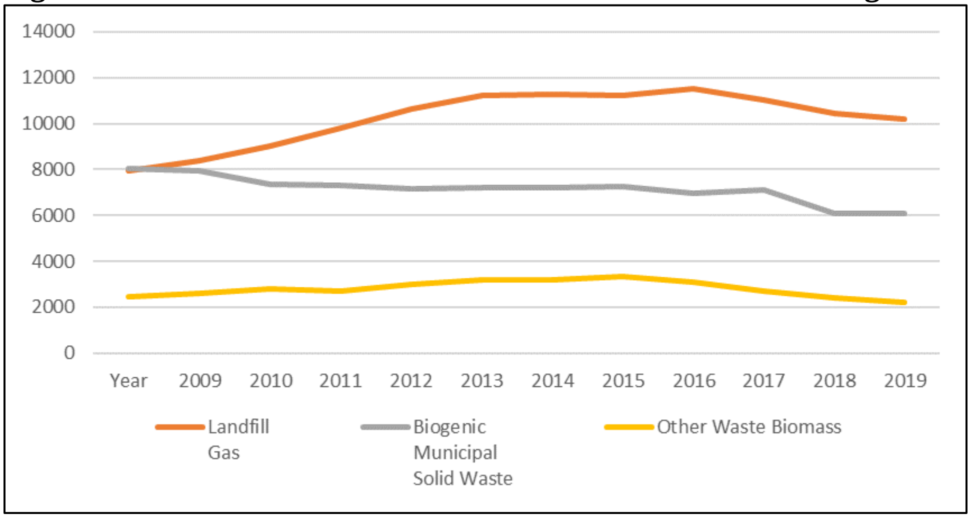
6.1.4.2.2 Assessment of Potential and Underreported Generation Capacity

Chapter 6.1.4.2.1 provides our assessment of the currently available qualifying electricity production from biogas and provided a projection for what we believe the industry may be capable of producing over the time horizon of this action. This section discusses two relatively large additional sources where we believe relatively little effort would be required to provide growth in the available supply of qualifying renewable electricity: utilization of installed capacity and accounting for existing electricity production capacity occurring at facilities which are net-consumers of electricity (e.g., wastewater treatment facilities). This is not intended to serve as an economic or technical assessment of which facilities may be able to alter operational behavior in response to the codification of the eRIN program, but rather to provide context based on our work for where initial increases in renewable electricity production beyond the current generating capacity may be expected.

The first topic to consider is the utilization of installed capacity. In several of the databases on biogas sources of electricity we evaluated for this proposal, it was noted that substantially higher quantities of electricity could be produced if the facilities were to operate at a higher capacity factor. Take for example Figure 6.1.4.2.2-1, which provides a decade worth of electrical production data from three of the EIA source categories for electricity generation which may qualify under the eRIN program.

[727] Younes, A., Barrientos C., Carman J., Johnson, K., Wallach, E., and Fingerman, K. (2021). Incorporating Bioelectricity Under the Renewable Fuel Standard as A Pathway to Widespread Deployment of Electric Vehicles. Humboldt, CA: Schatz Energy Research Center.
[728] These are aggressive estimates from AgSTAR (Agricultural Digester) and SERC (all categories other than Agricultural Digesters or Other Waste Biomass). No source estimates future growth of other waste biomass, an EIA subcategory.
[729] 122,961 GWh with the addition of the upper estimate of woody biomass total potential capacity and the other waste biomass category, rated at 38,543 GWh by EIA.

Figure 6.1.4.2.2-1: Electrical Production from EIA Source Categories



Each of the source categories for electricity production reported by EIA have been in decline the past 3-5 years. Although there may be additional factors which explain this reduction, our interactions with stakeholders have highlighted that the economic pressures in the electrical generation space brought on by the relatively low-cost availability of fossil natural gas have led to a reduction in electrical production from biogas-sourced electricity. If their assessment of the reduction in electricity production from biogas-sourced capacity is correct, it seems likely that the financial incentive provided by participation in the eRIN program would enable biogas-source electricity to, at a minimum, return to the levels seen only a few years ago.

Looking more closely at a particular dataset we evaluated, the Landfill Methane Outreach Program Project Database, the aggregated actual production capacity of the facilities listed is approximately 1,520 MW. However, the aggregated rated capacity of this same set of facilities is approximately 1,930 MW. If it is the case that the primary reason why these facilities have not been operating at or near their rated capacity is due to poor economic conditions, then participation in the eRIN program may quickly result in a change in operations and consequently result in a nearly 30% increase in electrical production from these facilities. Assuming a capacity factor of 90% along with the reported rated capacity of these facilities suggests annual electricity production of over 15,000 GWh is feasible.

The second issue relates to accounting for existing electricity production capacity occurring at facilities which are net-consumers of electricity. We refer to this as underreporting due to the fact that renewable electricity generators which produce electricity inside a larger facility which is a net consumer of electricity, like a wastewater treatment plant, do not get reported as production in the databases[730] we utilized to assess biogas production capacity. Information on the quantity of potentially RFS-qualifying electricity currently being generated and consumed onsite at facilities which are net consumers of electricity has proven exceedingly difficult to find and evaluate, unfortunately. However, we have had conversations with stakeholders and have physically visited facilities where this dynamic is currently occurring. As renewable electricity generators inside net electricity consuming facilities register for the eRIN

[730] eGRID 2019 database maintained by US EPA Clean Air Markets Division.

program we will begin to be able to assess the quantity and scope of this generation capacity, but we proceed knowing that we may not have fully accounted for this capacity as part of our baseline production assessment.

Finally, the estimates presented are only for onsite or direct use of biogas to electricity facilities and therefore represent a conservative assessment of the available supply of qualifying renewable electricity. There may also be additional supply available domestically and from foreign producers of renewable electricity. For example, not included in our assessment is the quantity of electricity which may be generated by merchant electricity generators who purchase renewable natural gas (RNG) from the commercial pipeline system to cofire with fossil natural gas. Absent the financial incentive that eRINs will provide for this new market behavior there did not exist sufficient evidence on which to project the prevalence of this behavior once the program is operational and the incentive is in place. Consequently, we did not include any projection of merchant RNG-based generation capacity in our baseline assessment of available biogas electricity supply despite the strong belief that it will come online as dictated by market demand.

6.1.4.2.3 - Industry Registration Capacity

As discussed above in Chapters 6.1.4.2.1 and 6.1.4.2.2, the existing biogas electricity generation capacity is projected to exceed the electricity demand from the EV fleet discussed in Chapter 6.1.4.1 by a considerable margin in 2024 and 2025 such that the limiting factor on RIN generation would be expected to be the demand from the EV fleet. However, this assumes that there are no constraints associated with bringing that biogas electricity generation capacity into the RFS program in 2024 and 2025. In reality, there will be a various marketplace constraints, including, and perhaps most importantly, the ability for the biogas electricity generators to complete the necessary independent 3rd party engineering reviews in order to register their facilities under the RFS program. Based on stakeholder engagement and industry study, we believe that engineering firm capacity to complete engineering reviews, which require an engineer with a professional engineer license, will limit the rate at which biogas electricity generation capacity can be used to generate RINs in 2024 and 2025. The result is that we believe that the resulting biogas electricity generation will be less than the maximum growth rate possible to keep up with electricity demand from the EV fleet, and be the limiting factor for 2024 and 2025.

To assess the rate at which the engineering reviews could be carried out, we evaluated the current industry engineering review capacity, evaluated the additional capacity that would be needed, projected how quickly this could occur, and then evaluated what impact that might have on biogas electricity generation capacity in 2024 and 2025. We estimate that, under the current RFS, 300 engineering reviews (ERs) are completed annually, mostly occuring in the second half of the year due to the nature and timing of the current registration requirements. Assuming the eRIN program is finalized in June of 2023, then the additional ERs will fall on top of the existing cyclical swell in ERs. Given the very large number of biogas electricity generation facilities this is expected to require nearly twice the current number of PEs to keep pace with the number of facilities that would have to be registered to fully meet EV charging demand. Given that there will be very little time in 2023 between the final rule being signed, its publication in the Federal

Register, it becoming effective 60 days later, and the beginning of the eRIN program on January 1, 2024, we estimate that just 10 biogas electricity facilities will be able to be registered by the end of 2023. As additional PEs enter the workforce, they gain efficiency in completing ERs, and as they become more familiar with the new regulatory requirements for biogas electricity facilities we assume that additional ERs will be possible on an ongoing basis in addition to the already existing ER workload. Given the wide range in facility generation capacity, the largest facilities have a disproportionate impact on biogas electricity generation. For the purposes of our projections, we assume that the largest facilities eligible for electricity production will be the first registered, as shown in Figure 6.1.4.2.3-1. Consequently, despite a low RIN volume projected at the start of the program, even a modest increase in ERs would bring in a large eRIN volume. We further enumerate our assumptions in Table 6.1.4.2.3-1 below, and the capacity values corresponding to the ER rates are calculated by adding facilities to the total capacity number in rank order.

Figure 6.1.4.2.3-1: Cumulative Capacity, By Addition of Rank Order

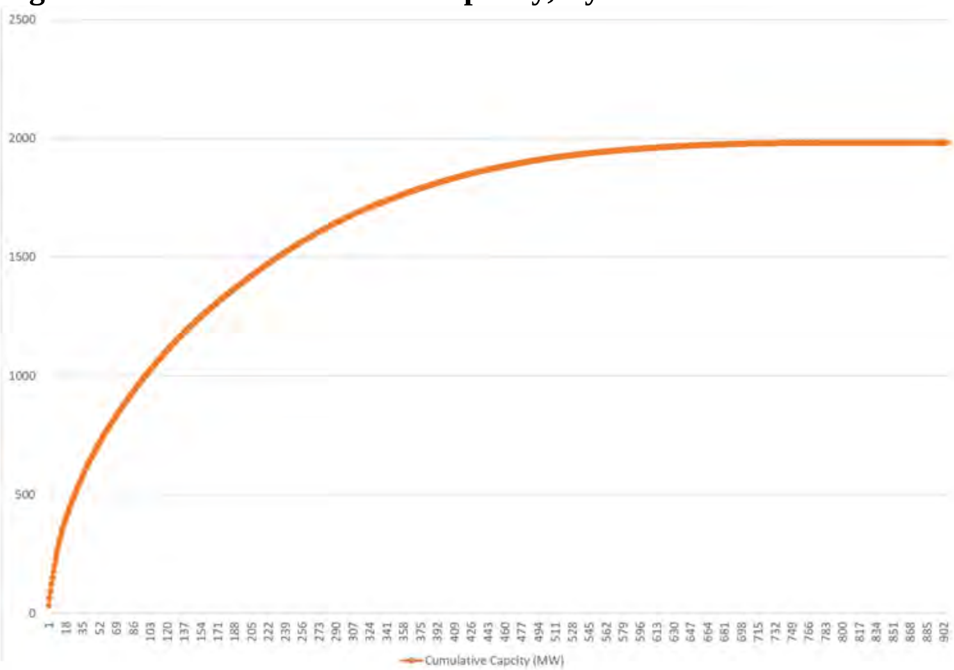


Table 6.1.4.2.3-1: Engineering Review Rates and Biogas Electricity Capacity

Year	Additional ER Rate, per month	Total Facilities Registered	Capacity [MW]	RIN Volumes
2023	2	10	268	
2024	6	76	874.4	604,678,289
2025	10	196	1392.8	1,155,874,099

6.1.4.2.4 Interplay Between Electricity Generation Capacity, Demand, and Industry Registration Capacity

Throughout the preamble we have alluded to the current and potentially future interplay between the capacity of qualifying renewable biogas electricity and the demand for electricity as a transportation fuel by OEM electrified vehicle fleets, as well as the rate at which companies can register eligible facilities Table 6.1.4.2.4-1 provides a summary of these figures based on our analyses above.

Table 6.1.4.2.4-1: Comparison of Supply and Demand Facets for Setting Volumes

Year	Qualifying Electricity Supply (GWh)	Procured Electricity Required (GWh)	Projected Registered Electricity Available (GWh)
2024	22,314	12,516	8,023
2025	25,270	17,533	9,768

For these two years the demand side of the equation (i.e., the electricity consumed by the electrified vehicle fleet) is a limiting factor on the quantity of eRINs which can be generated. (However, as discussed in Chapter 6.1.4.2.3, the anticipated rate of engineering reviews to enable the qualifying electricity supply to be brought into the program is projected to have it actually be the limiting factor in eRIN generation in 2024 and 2025.). In future years as the EV fleet grows rapidly it is likely that qualifying renewable electricity generation will become the limiting factor on eRIN generation. Assuming adequate revenue sharing agreements are established between OEMs, renewable electricity generators and biogas producers we would anticipate both the supply and demand for qualifying renewable electricity would grow in concert in future years.

RFS volumes are expressed in terms of "ethanol equivalent gallons" or RINs, and not gigawatt hours of electricity. Consequently, the electricity values in Table 6.1.4.2.4-1 must be translated into RINs in order to properly establish the cellulosic volume requirement from eRINs for years 2024 and 2025. This translation is performed through the use of the equivalence value (EqV) for electricity in the RFS program. In Chapter 6.1.4.4 we discuss the derivation of the proposed revision of the EqV from the previous EqV of 22.6 kWh/RIN for electricity to what we believe is a more representative EqV of 6.5 kWh/RIN. In Table 6.1.4.2.4-2, we have translated the electricity quantities from Table 6.1.4.2.2-2 into RINs using the proposed, revised EqV of 6.5 kWh/RIN.

Table 6.1.4.2.4-2: Renewable Electricity Translated to RINs

RFS Year	Limiting Quantity of Electricity (GWh)	RINs (EqV = 6.5 kWh/RIN)
2024	8023	1,155,874,099
2025	9768	1,533,750,277

The final steps to setting the eRIN volume standards require translating the limiting quantity of electricity back to the quantity of electricity used as transportation fuel and an adjustment for initial practical program participation rates. In the comparison of qualifying renewable electricity supply and procurement requirements in Table 6.1.4.1.2-2, the procurement requirement values were the limiting factor on the ultimate quantity of renewable electricity for years 2024 and 2025. However, the procurement requirement values had been adjusted upward to account for the systemic losses in the distribution system for renewable electricity and do not directly represent the quantity of renewable electricity used as transportation fuel.

In Table 6.1.4.1.2-3, we present a summary of calculations and adjustments made in establishing the proposed volumes for renewable electricity in the RFS program. The bottom line numbers of 1.15 billion RINs for 2024 and 1.53 billion RINs for 2025 account for the vast majority of the overall cellulosic volumes proposed in this action

Table 6.1.4.1.2-3: Summary of Maximum eRIN Volumes

	2024	**2025**
EV Electricity Use (GWh)	10,075	14,113
RE Procurement Required “Demand” (GWh)	12,516	17,533
RE Production “Supply” (GWh)	15,973	18,138
Registration Rate Limited “Supply” (GWh)	8,023	9,768
Limiting Electricity Value (GWh)	8023	9768
Proposed eRIN Volume	600 million RINs	1.2 billion RINs
RIN Cost @ $3 per D3 RIN	$1.8 billion	$3.6 billion

The projected bottom line cost numbers for the program assuming $3 cellulosic RIN valuations require some context in order to appreciate the potential magnitude of this program for participants. For example, using the parameters for EVs we have established in this proposal, along with a $3/D3 RIN value, the annual value of the RINs generated by a single EV is $838. If the value of the eRIN were shared equally via contracts between the three parties: biogas producer, renewable electricity generator, and OEM it would yield $279/party per year. The OEM would receive $279/EV in their fleet. The renewable electricity generator would receive $279 for the 2.3 MWh of electricity to power that EV throughout the year, a value of $121/MWh just for the RIN generating environmental attributes, which would be in addition to their power purchase agreement and any REC value they may secure. This is a substantial revenue compared to typical wholesale electricity rates which are regularly between $30-50/MWh depending on the location. Lastly, the biogas producer would receive $279 for supplying 5.14 MMBTU of biogas for a unit value of $54/MMBTU. By comparison, spot prices for natural gas (which is not a truly equitable comparison because biogas is not pipeline fungible) are up dramatically over the past few months and currently are still only in the area of $6/MMBTU.

6.1.4.3 EV Fleet Electricity Consumption Capacity

The light-duty EV fleet electricity consumption capacity is growing rapidly, with many more models of both battery electric vehicles (BEVs) and plug-in hybrid electric vehicle (PHEVs) being offered for sale every year and sales projected to increase. Consequently, the electricity consumption capacity of the EV fleet is projected to grow rapidly over time. However, at the same time, the electricity consumption capacity of the existing fleet is still rather limited, being dominated by the more limited EV sales in years past. The electricity consumption capacity itself can be estimated using just a few basic pieces of information, the vehicle miles travelled (VMT) of the EVs, the fraction of VMT operating on electricity (the electricity utility factor), the efficiency of the vehicles (kWh/mi) and the population of each category of electrified vehicle. In order to convert this electricity consumption capacity into the ethanol equivalent volumes needed for the RFS program, another factor needed is then the equivalence value for electricity. Each of these factors is discussed below.

VMT is a measure of total miles driven over a given timespan. It is a useful metric to determine vehicle utilization, especially when compared to their theoretical range. VMT can be compared against Electric Vehicle Miles Traveled (eVMT) to see how BEVs and PHEVs utilize their electric range. This can also be described by a vehicle's utility factor, which is equivalent to the fraction of time a vehicle spends driving using its electric battery. The average annual VMT in the U.S. is 11500 miles,[731] while average annual eVMT for BEVs and PHEVs is currently 7200 miles and 3,000 miles, respectively. Table 6.1.4.3-1 shows these averages by year. We collected cumulative fleet VMT each year from 2014 to 2020, and then compared the cumulative VMT of internal combustion engine vehicles (ICEV) against electric vehicles.[732] This data represents a large fleet of vehicles monitored by the EPA OTAQ Light Duty Vehicle Center using onboard diagnostic data, inclusive of various models of ICEV, BEV, and PHEV.

Table 6.1.4.3-1: Light Duty Vehicle Fleet Annual Cumulative VMT and eVMT

Year	Gas (PHEV) VMT[a] (miles)	BEV eVMT (miles)[a]
2014	82,596	51,027
2015	70,280	41,886
2016	55,239	32,987
2017	41,200	28,577
2018	28,988	19,117
2019	16,269	10,107
2020	7,823	4,674
Average Annual	11,500	7,200

[a] Rounded to the nearest whole number

$$UF = \frac{eVMT}{VMT}$$

Where:

UF = utility factor
eVMT= vehicle miles travelled while operating on electric power
VMT = vehicle miles travelled, either on electric power or ICE-driven

6.1.4.3.1 eVMT for BEVs

All BEVs have a utility factor of 1, as they are always running on battery power. Different models of BEVs have different all-electric range, and thus while their utility factor is

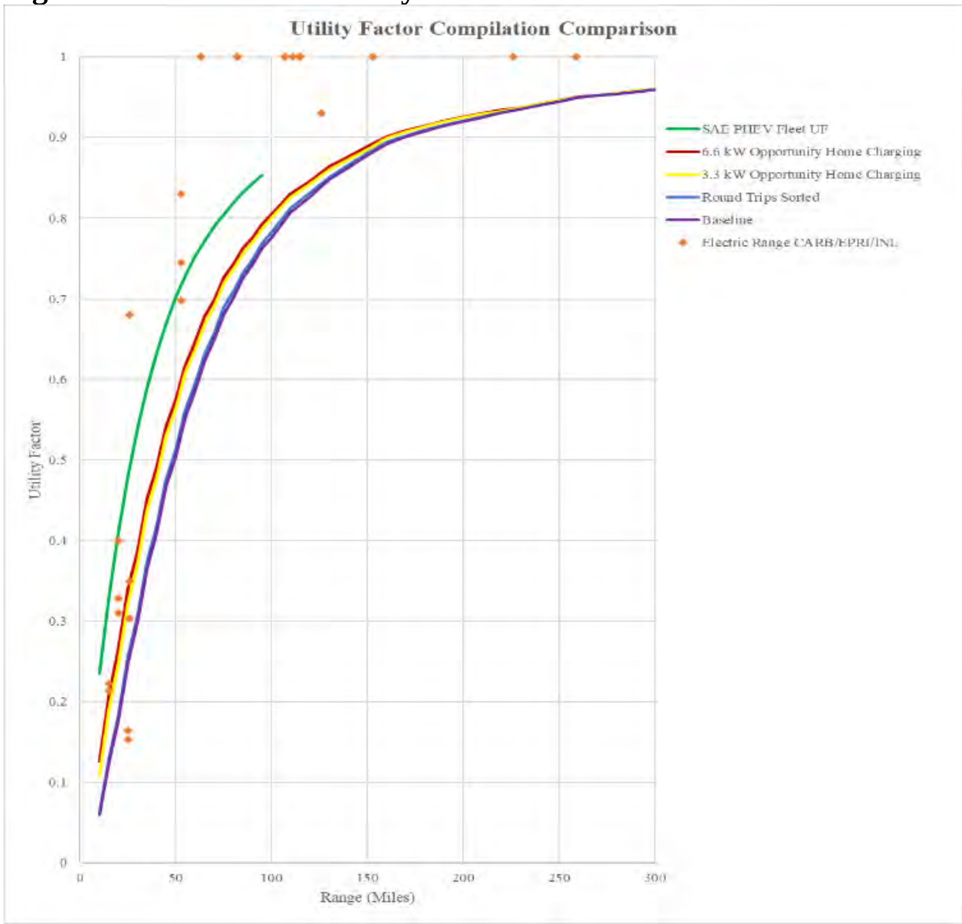
[731] Federal Highway Administration, Highway Statistics 2020, Table VM-1
[732] IHS VMT from Light Duty Vehicle Center Dataset.

shared across models, VMT differs greatly. The average eVMT observed for BEVs is 7,200 miles per year, as reported in Table 6.1.4.3-1.

6.1.4.3.2 eVMT for PHEVs

Utility Factor (UF) refers to the fraction of time spent in a charge depleting mode for a BEV or PHEV in relation to vehicle range. SAE in 2009 developed a set of UF curves and methods for calculating these metrics based on the electric range of EVs.[733]As a comparison, SAE calculated generic UF curves for 5 different scenarios- 4 regarding different charging behavior for BEVs and 1 for PHEVs that was generated from the Department of Transportation National Highway Transportation Survey in 2009. Figure 6.1.4.3.2-1 shows how these generic utility factor curves compare against recorded data.[734]

Figure 6.1.4.3.2-1: SAE Utility Factor Curves



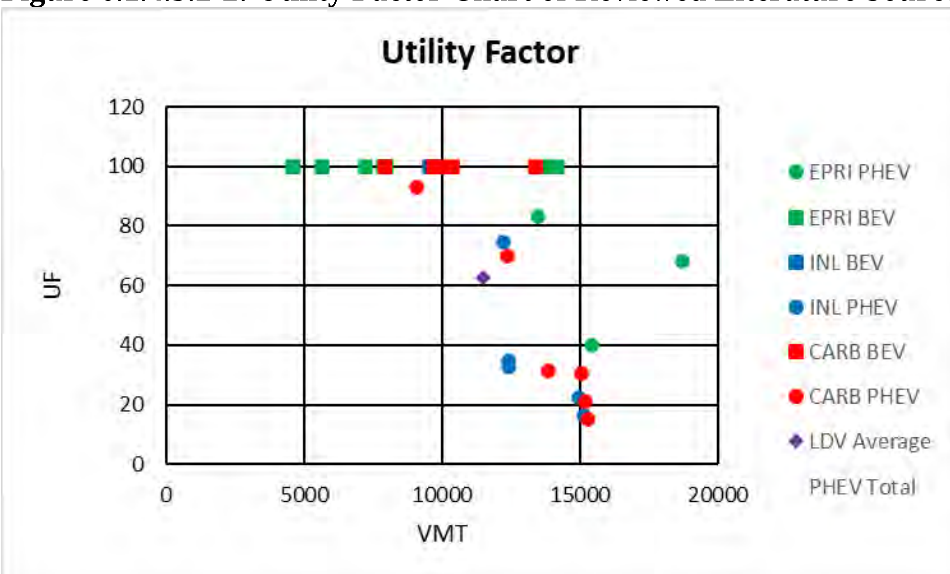
Idaho National Laboratory and the Electronic Power Research Institute have also conducted small scale studies using onboard diagnostics to track when vehicles are operating on their battery and when they are operating using their ICE. Similarly, the California Air Resources

[733] R) Utility Factor Definitions for Plug-In Hybrid Electric Vehicles Using Travel Survey Data, J2841 SEP2010.

[734] The proposal would allow these utility factors to be updated on an ongoing basis in the future based on data proposed to be required to be provided by the vehicle manufacturers.

Board published data submitted to them by OEMs in the 2017 Clean Cars Midterm Review that showed what percentage of total driving time was spent on electric power. Figure 6.1.4.3.2-2 is a compilation of all these studies, and shows that theoretically, while PHEV UF can scale up to over 90% in ideal scenarios,[735] most real world PHEVs utilize their electric range much less, especially as annual VMT increases.

Figure 6.1.4.3.2-2: Utility Factor Chart of Reviewed Literature Sources



For the purposes of this proposal we have omitted the EPRI study data, as all data was obtained from a single geographic area and several samples sizes numbered fewer than five vehicles, making it unlikely to represent national vehicle travel behavior. Figure 6.1.4.3.2-3 and Table 6.1.4.3.2-3 show a predictive curve (shown as a dotted line), compared against the SAE calculated curve, that PHEVs operating during 2024 and 2025 under the eRINs program will likely mirror, using vehicle electric range to project the national PHEV utility factor.[736] The California Air Resources Board (CARB) and Idaho National Lab data follows a curve with the equation:

$$UF = 0.379 \ln(R_{EV}) - 0.878$$

Where R_{EV} is the all-electric, or charge-depleting, range of a vehicle, in miles.

This equation is similar to one put forth by CARB in SB 498 on zero-emission vehicle fleets.[737]

$$UF = 0.305 \ln(R_{EV}) - 0.537$$

[735] Seshadri Srinivasa Raghavan & Gil Tal (2022) Plug-in hybrid electric vehicle observed utility factor: Why the observed electrification performance differ from expectations, International Journal of Sustainable Transportation, 16:2, 105-136, DOI: 10.1080/15568318.2020.1849469.
[736] As discussed in Preamble Section VIII.F, we would intend to update this value in the future based on data collected as part of this proposed program.
[737] CA SB 498, Appendix C, https://ww2.arb.ca.gov/sites/default/files/2019-12/SB%20498%20Appendix%20C%20-%20quantification%20120919.pdf

Figure 6.1.4.3.2-3: PHEV Utility Factor as a Function of All-Electric Range

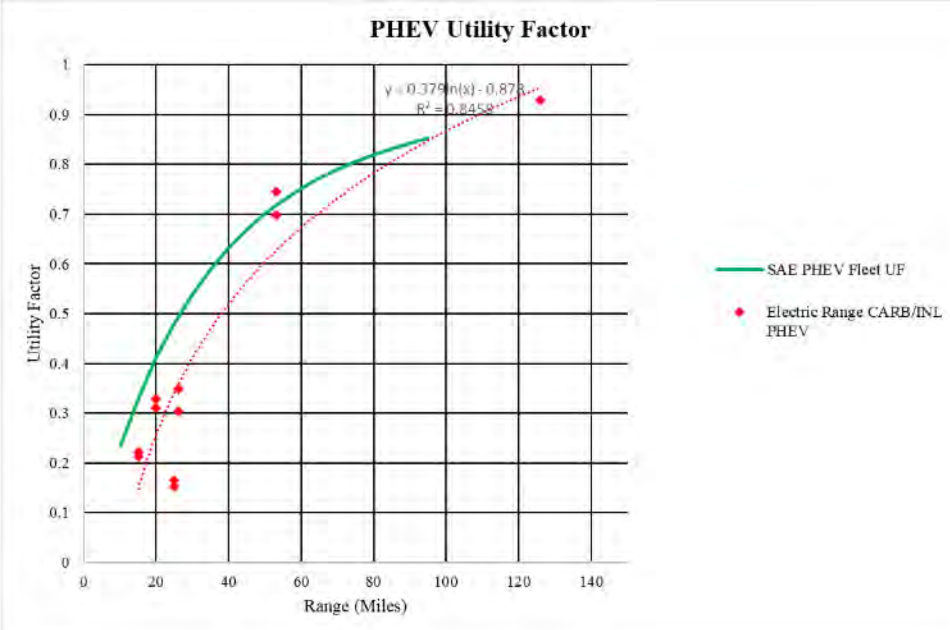


Table 6.1.4.3.2-1: PHEV Model Utility Factor and All-Electric Range

Study	PHEV Model	Electric Range	Utility Factor
INL	Chevrolet Volt	53	0.74
INL	Ford C-Max Energi	20	0.33
INL	Ford Fusion Energi	26	0.35
INL	Honda Accord	15	0.22
INL	Toyota Prius	25	0.16
CARB	BMW i3 Rex	126	0.93
CARB	Chevrolet Volt	53	0.70
CARB	Ford Fusion Energi	26	0.30
CARB	Ford C-Max Energi	20	0.31
CARB	Honda Accord	15	0.21
CARB	Toyota Prius	25	0.15

When deciding on a representative value utility factor for PHEV eVMT to use for projecting volumes of renewable electricity, we chose to take a conservative approach. Our eVMT value for PHEVs is 3,000 electric miles traveled per year and corresponds to a utility factor of approximately 0.25. We received CBI data from a few OEMs which served to validate our chosen eVMT of 3,000 electric miles travelled per year and feel confident that it is representative of the use patterns of legacy PHEVs in the fleet. As the use data collection process proposed as a requirement for RIN generation begins to generate data to inform this estimate, we will affirm or revise this value in future rules.

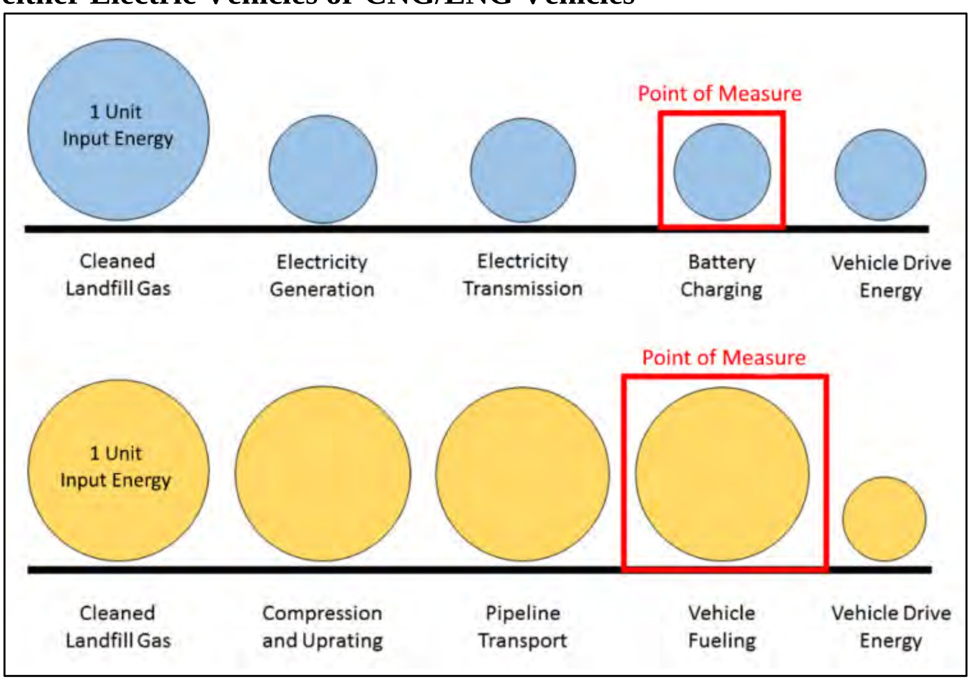
6.1.4.4 Equivalence Value for Renewable Electricity

This section presents data and analysis supporting our proposed revision to the RIN equivalence value (EQV) for electricity used as transportation fuel. This electricity must be produced from qualifying biomass sources, which currently includes biogas from landfills or waste digesters. This biogas may also earn RINs through use as RNG in CNG/LNG vehicles. As described in Preamble Section VIII.I, to determine the revised EQV we estimated the energy losses that occur through both the RNG and electricity supply chains and used this information to compute the number of kWh of EV battery charge that corresponds to 1 RIN (77,000 Btu) of RNG onboard a CNG vehicle. This assessment required consideration of electricity generation, transmission, and EV battery charging as well as biogas cleanup, compression, and transport processes. Both the point of measure (POM) for determining RINs and the losses along the energy supply chains are important elements in our approach to determining the revised EQV.

6.1.4.4.1 Point of Measure

Point of measure (POM) refers to the point in the energy supply chain where metering occurs for the purpose of generating RINs. Figure 6.1.4.4.1-1 considers how one unit of biogas energy is diminished by various types of losses as it moves through the pathways for EV charging (blue) or direct use in CNG/LNG vehicles (yellow).

Figure 6.1.4.4.1-1: Illustration of the Impact of Point-Of-Measure for Landfill Gas Used for either Electric Vehicles or CNG/LNG Vehicles



In both paths, the POM (identified by the red box) identifies the point in the distribution chain where the fuel is transferred to the vehicle. Metering fuel consumption at this POM is convenient since it takes advantage of the data collection infrastructure that is already in place in the form of fuel dispensers and electric meters. However, this POM produces a very different measure of available energy for electricity than it does for RNG. In the case of electricity, the conversion from biogas chemical energy to electricity occurs upstream of POM in the electric generator, and this step results in a significant loss of available energy. In the case of RNG, there is no upstream conversion and thus only minor losses of available energy before the POM. The result is that the apparent energy use in the electrical pathway is heavily discounted relative to the RNG pathway. In effect, this arrangement POM gives credit to RNG for energy that will become waste heat in the vehicle without providing a similar credit for renewable electricity. In an effort to put them on more equitable footing, we summed up the energy losses between the two POMs and incorporated those into the proposed EQV. The following two subsections assess these losses in more detail.

6.1.4.4.2 Energy Losses in Biogas-to-CNG-Vehicle Pathway

We considered losses in three aspects of the CNG vehicle pathway: source biogas cleanup, pipeline distribution, and compression. We assumed landfill gas as the input for our review of the initial cleanup steps, as this currently represents the majority of RNG production. According to an Argonne National Labs (ANL) report on landfill gas facilities, [738] pre-purification steps such as adsorption and chemical oxidation are used remove corrosive hydrogen compounds and non-methane organics like ketones and siloxanes, as well as water vapor. At this stage, the gas stream may be used for on-site power generation but will typically contain a significant fraction of CO_2 that must be removed before natural gas pipeline injection or CNG vehicle refueling. Removal of CO_2 is typically accomplished by some combination of pressure-swing adsorption, aqueous amine absorption, cryogenic distillation, and membrane separation. All of these processes require additional energy inputs in the form of compression, heating, and/or cooling.

ANL provides an overall estimate of 94.4% for efficiency for gas processing operations based on information from eight project sites. They report a range of 91% to 97%, with larger facilities tending to be at the higher end of the range. Facilities that use all their gas to produce electricity may incur fewer processing losses, since less cleanup is required. However, from this dataset, it is not possible to break out more detailed estimates for sites that export generated electricity to the grid versus those that solely produce RNG for vehicles.

Pipeline Distribution

After gas cleanup to meet pipeline specifications, the gas undergoes additional compression and then is injected to a natural gas distribution system. In this system, the gas may travel through hundreds of miles of pipes and several re-compression stations before being pulled off for use at a vehicle refueling station. Since it would be very difficult to account for myriad sources and destinations, we took a high-level approach to estimating losses in the natural gas distribution system by using data from EIA's U.S. Natural Gas Consumption by End

[738] M. Mintz, J. Han, M. Wang, and C. Saricks, "Well-to-Wheels Analysis of Landfill Gas-Based Pathways and Their Addition to the GREET Model," Center for Transportation Research, Energy Systems Division, Argonne National Laboratory. 2010. Report ANL/ESD/10-3.

Use table.[739] Specifically, we used five-year averages over 2016-2020 for the total gas delivered to end users and the total gas consumed for all uses. The ratio of these two figures shows an overall distribution system efficiency of 91.4% in delivering produced gas to end users. The losses include leaks as well as internal usage for gas-powered compressors and other equipment.

Some RNG producers may dispense part or all of their fuel through an on-site refueling station, or another nearby facility (e.g., a school bus depot) that receives the fuel via truck instead of pipeline. We do not have data on energy use or losses from these types of storage and shipment processes, but expect they could be higher or lower than pipelining on a per-Btu basis, depending on specific details of the processes.

Gas Compression

At various points during the processes of cleanup, distribution, and vehicle fueling, gas compression is required. For the purposes our analysis, we simplified this into two compression steps. The first step boosts the gas from atmospheric pressure, representing the starting point of landfill or digester collection, to 200 psi, a typical operating pressure of local distribution systems.[740] This operation would be performed by relatively large volume compressors with an efficiency estimate of 80%, doing work amounting to 2,290 Btu per ethanol-gallon equivalent (EGE). The second step is compression from 200 psi to 4000 psi, the typical refueling pressure of CNG vehicles. Since this occurs at the refueling station with smaller and intermittently-operated equipment, ANL uses an efficiency of 65% for this process. The work total in this step is estimated at 3,270 Btu per EGE. In making the compression energy estimate, we assumed single-stage ideal isothermal compression, adjusted with the efficiency figures above. Note that the compression energy charge in the first step is also applied to fuel that represents the downstream distribution losses in an effort to come up with a comprehensive energy estimate. The ANL efficiency estimate for biogas cleanup does include some compression within those processes, however, additional compression is expected before pipeline injection. Variations in this input represent a source of uncertainty in the compression energy computations.

After considering biogas cleanup, compression, and distribution processes, our analysis indicates a range of 93,500 to 99,700 Btu of energy is required to deliver 1 RIN (77,000 Btu) to the vehicle. The next three subsections assess energy transfer through the electricity delivery pathway.

6.1.4.4.3 Energy Losses in Biogas-to-Electricity Pathway

A major component in the supply of energy to electric vehicles is conversion of chemical energy, in this case from biogas or landfill gas, to electricity. This occurs by combusting the fuel in a piston or turbine engine that turns an electric generator. These devices typically have energy conversion efficiencies in the range of 20 to 30 percent. A significant number of these are part of combined-heat-and-power (CHP) installations that recover engine exhaust heat to make steam for secondary generation systems, which can in some cases double the overall conversion

[739] U.S. Natural Gas Consumption by End Use, U.S. Department of Energy, Energy Information Administration. June 2021.
[740] See Section 3.7.1 of Mintz, *et al*. cited above.

efficiency. To estimate an overall efficiency value, we used nameplate generation and heat rate data for gas-fired electrical generators contained in the EPA's eGRID2019 database.[741] From this data, we computed an average facility heat rate of 11,850 Btu of fuel energy consumed per kWh generated. Dividing 3,412 Btu, the heat energy equivalent of one kWh of electrical energy, by 11,850 Btu fuel per kWh, gives an overall biogas electrical generation efficiency of 28.8%.

Electricity Transmission and Distribution

For liquid and gaseous fuels in the RFS program, we have historically assumed that negligible energy loss occurs between the points of production and use. This assumption is based on industry practices for leak tracking and repair, the fact that vapor losses from liquids like gasoline and ethanol represent a very small amount of overall fuel energy content. In contrast, the distribution of electricity has significant measurable losses which occur between the points of generation and use. The electrical distribution system consists of transformers, lines, and switchgear that move electrical power from generators to end users, over hundreds or thousands of miles. Transmission of electricity through lines creates resistive losses, akin to friction in a mechanical system, that increase with the square of the magnitude of electric current flow. Transformers at power generation facilities step up voltage for long-distance transmission to reduce the current required and the related line losses. At the receiving end, voltages are reduced by step-down transformers for local distribution circuits and again for delivery to end users. In addition to the line losses, there are resistive and inductive losses in transformers and corona losses at points of high electric field density.

For this analysis, we used the Grid Gross Loss (GGL) figures from EPA's eGRID2019 database. To compute GGL, eGRID starts from *Total Disposition*, *Direct Use, Exports*, and *Estimated Losses* data reported by the US Energy Information Administration at the state level, and aggregates those to the regional grid interconnect level. The following equation is applied to compute the GGL as a fraction of total distributed power:

Grid Gross Loss = Estimated Losses / [(Total Disposition without Exports) – Direct Use]

In this data, *Total Disposition* is equal to total generation, *Exports* is power sent over state lines, and *Direct Use* represents power used by the utilities themselves and thus doesn't enter the distribution system. Using this methodology, the GGL for the U.S. overall is 5.3%. More detail is available in the eGRID Technical Guide.[742]

Electric Vehicle Battery Charging

For liquid and gaseous fuels in the RFS program we have historically assumed that essentially no losses occur in the vehicle fueling process. Unlike simply transferring a liquid from on tank to another there are potentially substantial losses associated with getting electricity from the gird into a vehicle. One of the largest components affecting energy losses in powering electric vehicles in battery charging. During the charging process, electrical energy is converted

[741] eGRID 2019 database maintained by US EPA Clean Air Markets Division.
[742] eGRID 2019 Technical Guide, prepared by Abt Associates for US EPA Clean Air Markets Division, February 2021. See Section 3.5.

from the standard supply at 240 volts AC to a DC voltage that matches the charging requirements of the vehicle battery pack, typically between 300-500 volts DC. The vehicle's charge controller has battery monitoring algorithms that adjust the voltage and current being applied to the battery pack to optimize the charging rate for pack temperature and other parameters. These conversion and control systems are high-power electronic devices that have resistive and inductive losses in their wiring, transformers, and semiconductor components that are of sufficient consequence to warrant their inclusion in the calculation of a revised equivalence value for renewable electricity. In addition, the battery pack has internal resistance at component junctions (e.g., cells and buses) and due to ion migration and charge transfer processes that result in some of the charging energy being lost as heat.

We reviewed the literature in an effort to make a quantitative estimate of charging efficiency. Work published by Idaho National Labs in 2017 made detailed measurements of charging efficiency and other parameters from eight EVs and PHEVs and found efficiencies ranging from about 82% for Level 1 charging up to about 92% for Level 2.[743] Sears, *et al.*, collected data over a six-month period in 2013 from four vehicles (two Nissan Leafs and two Chevrolet Volts) owned and operated by volunteer participants in Vermont, USA. The study found efficiencies varying from 74% to 91% across 114 charging events, depending on ambient temperature, state-of-charge at start and end of charging, and whether Level 1 or Level 2 charging equipment was used.[744] In a 2020 study by Kostopoulos, *et al.*, analysis of charging events for a BMW i3 showed a range of efficiencies between 80% and 88% depending on the state of charge.[745] Kieldsen, *et al.*, published work in 2016 that attempted to compare different measurement methods using three vehicles (Nissan Leaf, Peugeot iOn, Renault Zoe), including CAN bus data reports and direct probes into the vehicle wiring.[746] Results showed a wide range of 70 to 90%, depending on the measurement method and the charging rate. Taken together, we interpret these sources to indicate a range of 80-90% charging efficiency for a fleet average.

Combining the efficiencies for electricity generation and transmission with battery charging we get a range of 21.8–24.5% of input biogas energy making its way into the EV battery.

6.1.4.4.4 Computation of Revised Equivalence Value

As outlined above, our determination of a revised equivalence value for biogas-derived electricity retains the current regulatory approach for the CNG/LNG vehicle pathway, wherein 77,000 Btu of RNG corresponds to 1.0 RIN, and then applies energy loss data for the supply

[743] Scoffield, D., Smart, J., Carlson, B. (2017). Overview of INL Vehicle/Grid Integration Research. Presentation to Idaho National Lab Advanced Vehicles Group, document # INL/MIS-17-41441.
[744] J. Sears, D. Roberts and K. Glitman, "A comparison of electric vehicle Level 1 and Level 2 charging efficiency," 2014 IEEE Conference on Technologies for Sustainability (SusTech), 2014, pp. 255-258, doi: 10.1109/SusTech.2014.7046253.
[745] Kostopoulos, ED; Spyropoulos, GC; Kaldellis, JK, "Real-world study for the optimal charging of electric vehicles," Energy Reports, Volume 6, 2020, pp 418-426, doi: 10.1016/j.egyr.2019.12.008.
[746] Kieldsen, A., Thingvad, A., Martinenas, S., & Sørensen, T. M. (2016). "Efficiency Test Method for Electric Vehicle Chargers," In Proceedings of EVS29 - International Battery, Hybrid and Fuel Cell Electric Vehicle Symposium

chains of electricity and RNG. This approach is summarized in Figure 6.1.4.4.4-1. The equations below describe our upper and lower estimates based on available data.

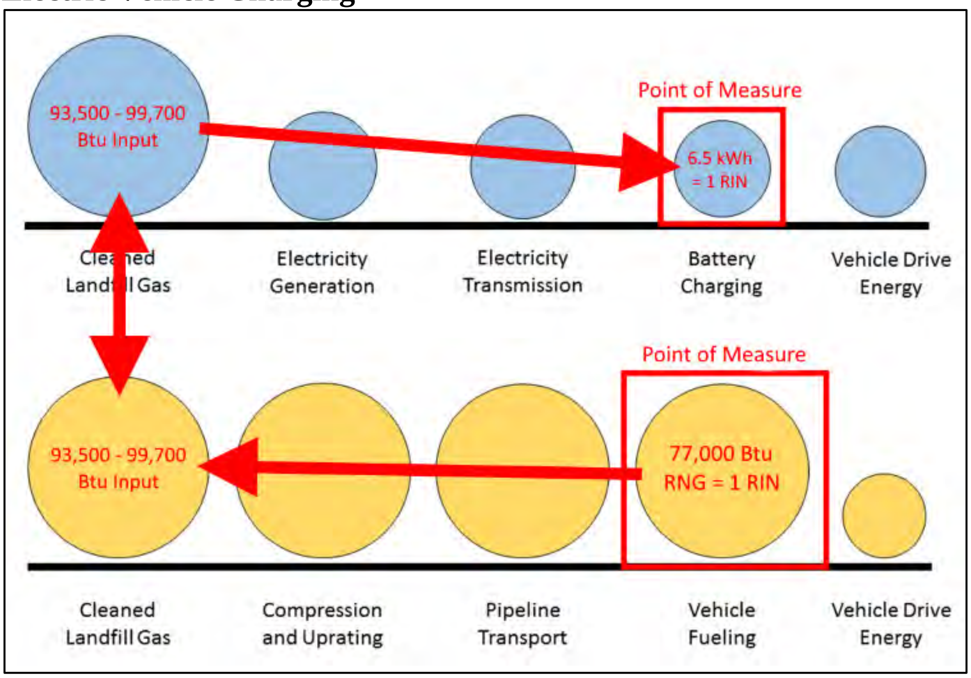
$$99{,}700 \text{ Btu} \times 0.288 \times (1 - 0.053) \times 0.90 / 3{,}412 \text{ Btu per kWh} = 7.2 \text{ kWh per RIN}$$

$$93{,}500 \text{ Btu} \times 0.288 \times (1 - 0.053) \times 0.80 / 3{,}412 \text{ Btu per kWh} = 6.0 \text{ kWh per RIN}$$

Using ANL's overall estimate for biogas cleanup efficiency of 94.4% indicates that 96,100 BTU of input energy is required to deliver 1 RIN (77,000 Btu) of RNG to the vehicle. Combining this value with a central estimate of charging efficiency of 85% gives our proposed value of 6.5 kWh per RIN. This value would ensure that biogas used to make electricity is appropriately credited relative to biogas used to make RNG for CNG/LNG vehicles.

$$96{,}100 \text{ Btu} \times 0.288 \times (1 - 0.053) \times 0.85 / 3{,}412 \text{ Btu per kWh} = 6.5 \text{ kWh per RIN}$$

Figure 6.1.4.4.4-1: Assessment of Losses Across Pathways for CNG Vehicle Fueling and Electric Vehicle Charging



6.1.5 Projected Rate of Cellulosic Biofuel Production for 2023–2025

After projecting production of cellulosic biofuel from liquid cellulosic biofuels, CNG/LNG derived from biogas, and eRINs EPA combined these projections to project total cellulosic biofuel production for 2023–2025. These projections are shown in Table 6.1.4-1. Using the methodologies described in this section, we project that 0.72 billion ethanol-equivalent gallons of qualifying cellulosic biofuel will be produced in 2023, 2.06 billion ethanol-equivalent gallons will be produced in 2024, and 2.88 billion ethanol-equivalent gallons will be produced in 2025.

Table 6.1.5-1: Projected Volume of Cellulosic Biofuel in 2023–2025

Projected Volume in 2023 (million ethanol-equivalent gallons)	Projected Volume
Liquid Cellulosic Biofuel	0
CNG/LNG Derived from Biogas	719.3
eRINs	0
Total[a]	720
Projected Volume in 2024 (million ethanol-equivalent gallons)	**Projected Volume[a]**
Liquid Cellulosic Biofuel	3
CNG/LNG Derived from Biogas	813.9
eRINs	600
Total[a]	1,420
Projected Volume in 2025 (million ethanol-equivalent gallons)	**Projected Volume[a]**
Liquid Cellulosic Biofuel	5
CNG/LNG Derived from Biogas	920.9
eRINs	1,200
Total[a]	2,130

[a] Rounded to the nearest 10 million gallons.

As discussed in Chapter 6.1.4, this projection does not include any volume of cellulosic ethanol produced from corn kernel fiber from facilities that are not currently registered as cellulosic biofuel producers.

6.2 Biomass-Based Diesel

Since 2010 when the biomass-based diesel (BBD) volume requirement was added to the RFS program, production of BBD has generally increased. The volume of BBD supplied in any given year is influenced by a number of factors including production capacity, feedstock availability and cost, available incentives, the availability of imported BBD, the demand for BBD in foreign markets, and other economic factors. From 2010 through 2015 the vast majority of BBD supplied to the U.S. was biodiesel. While biodiesel is still the largest source of BBD supplied to the U.S. since 2015, increasing volumes of renewable diesel have also been supplied. Production and import of renewable diesel are expected to continue to increase in future years. There are also very small volumes of renewable jet fuel and heating oil that qualify as BBD, however as the vast majority of BBD is biodiesel and renewable diesel we have focused on these fuels in this section. This section presents available data on biodiesel and renewable diesel production, import, and use in previous years, describes our assessment of the rate of production and use of qualifying biomass-based diesel biofuel in 2023–2025, and describes some of the uncertainties associated with those volumes.

6.2.1 Production and Use of Biomass-Based Diesel in Previous Years

As a first step in considering the rates of production and use of BBD in future years we review the volumes of BBD produced domestically, imported, and exported in previous years. Reviewing the historic volumes is useful since there are a number of complex and inter-related factors beyond simple total production capacity that could affect the supply of advanced biodiesel and renewable diesel. These factors include, but are not limited to, the RFS volume requirements (including the BBD, advanced biofuel, and total renewable fuel requirements), the availability of advanced biodiesel and renewable diesel feedstocks,[747] the extension of the biodiesel tax credit, tariffs on imported biodiesel, import and distribution infrastructure, and other market-based factors. While historic data and trends alone are insufficient to project the volumes of biodiesel and renewable diesel that could be provided in future years, historic data can serve as a useful reference in considering future volumes. Production, import, export, and total volumes of BBD are shown in Table 6.2.1-1.

[747] Throughout this chapter we refer to advanced biodiesel and renewable diesel as well as advanced biodiesel and renewable diesel feedstocks. In this context, advanced biodiesel and renewable diesel refer to any biodiesel or renewable diesel for which RINs can be generated that satisfy an obligated party's advanced biofuel obligation (i.e., D4 or D5 RINs). While cellulosic diesel (D7) can also contribute towards an obligated party's advanced biofuel obligation, these fuels are included instead in the projection of cellulosic biofuel presented in Chapter 6.1. An advanced biodiesel or renewable feedstock refers to any of the biodiesel, renewable diesel, jet fuel, and heating oil feedstocks listed in Table 1 to 40 CFR 80.1426 or in petition approvals issued pursuant to 40 CFR 80.1416, that can be used to produce fuel that qualifies for D4 or D5 RINs. These feedstocks include, for example, soybean oil; oil from annual cover crops; oil from algae grown photosynthetically; biogenic waste oils/fats/greases; non-food grade corn oil; camelina sativa oil; and canola/rapeseed oil (See pathways F, G, and H of Table 1 to 80.1426).

Table 6.2.1-1: BBD (D4) Production, Imports, and Exports from 2012 to 2021[748] (million gallons)[a]

	2014[b]	2015[b]	2016	2017	2018	2019	2020	2021
Domestic Biodiesel (Annual Change)	1,297 (–67)	1,245 (–52)	1,581 (+336)	1,552 (–29)	1,841 (+289)	1,706 (–135)	1,802 (+96)	1,699 (-103)
Imported Biodiesel (Annual Change)	130 (–23)	261 (+131)	562 (+301)	462 (–100)	175 (–287)	185 (+10)	209 (+24)	208 (-1)
Exported Biodiesel (Annual Change)	72 (–5)	73 (+1)	89 (+16)	129 (+40)	74 (–55)	76 (+2)	88 (+12)	90 (+2)
Total Biodiesel (Annual Change)[c]	1,355 (–85)	1,433 (+78)	2,054 (+621)	1,885 (–169)	1,942 (+57)	1,815 (–127)	1,924 (+109)	1,817 (-107)
Domestic Renewable Diesel (Annual Change)	149 (+79)	169 (+20)	231 (+62)	252 (+21)	282 (+30)	454 (+172)	472 (+18)	780 (+308)
Imported Renewable Diesel (Annual Change)	130 (–15)	120 (–10)	165 (+45)	191 (+26)	176 (–15)	267 (+91)	280 (+13)	362 (+82)
Exported Renewable Diesel (Annual Change)	15 (+10)	21 (+6)	40 (+19)	37 (–3)	80 (+43)	145 (+65)	223 (+78)	241 (+18)
Total Renewable Diesel (Annual Change)[c]	264 (+154)	268 (+4)	356 (+88)	406 (+50)	378 (–28)	576 (+198)	529 (–47)	900 (+371)
Total BBD[d] (Annual Change)	1,619 (–31)	1,701 (+82)	2,412 (+711)	2,293 (–119)	2,322 (+29)	2,393 (+71)	2,457 (+64)	2,721 (+264)

[a] All data from EMTS. EPA reviewed all advanced biodiesel and renewable diesel RINs retired for reasons other than demonstrating compliance with the RFS standards and subtracted these RINs from the RIN generation totals for each category to calculate the volume in each year. This table does not include D5 or D6 biodiesel and renewable diesel. These fuels are discussed in Chapters 6.4 and 6.7, respectively.
[b] RFS required volumes for these years were not established until December 2015.
[c] Total is equal to domestic production plus imports minus exports.
[d] Total BBD includes some small volumes (<10 million gallons per year) of D4 jet fuel.

Since 2014, the year-over-year changes in the volume of advanced biodiesel and renewable diesel used in the U.S. have varied greatly, from a low of 119 million fewer gallons from 2016 to 2017 to a high of 711 million additional gallons from 2015 to 2016. As discussed previously, these changes were likely influenced by multiple factors. This historical information does not by itself demonstrate that the maximum previously observed annual increase of 709 million gallons of advanced biodiesel and renewable diesel would be reasonable to expect in a future year, nor does it indicate that greater increases are not possible. Significant changes have occurred in both the fuel and feedstock markets (discussed further below) that will impact the rates of growth of biodiesel and renewable diesel production and use in future years. Rather,

[748] Similar tables of biodiesel and renewable diesel production, imports, and exports presented in previous annual rules included advanced (D5) biodiesel and renewable diesel. This table only contains volumes of biodiesel and renewable diesel that qualifies as BBD (D4). Advanced (D5) biodiesel and renewable diesel are covered in Chapter 6.4.

these data illustrate both the magnitude of the changes in biomass-based diesel in previous years and the significant variability in these changes.

This data also shows the increasing importance of renewable diesel in the BBD pool. In 2014 approximately 16% of all BBD was renewable diesel, and the remaining 84% was biodiesel. However, in the last 5 years all of the net growth has been in renewable diesel volume. By 2021 production and imports of renewable diesel had increased not only in absolute terms (from 264 million gallons in 2014 to 927 million gallons in 2021), but also as a percentage of the BBD pool. In 2021 approximately 34% of all BBD was renewable diesel, while the remaining 66% was biodiesel. As discussed further in the following sections, we expect that renewable diesel will represent an increasing percentage of total BBD in future years.

The historic data indicates that the biodiesel tax policy in the U.S. can have a significant impact on the volume of biodiesel and renewable diesel used in the U.S. in any given year. The availability of this tax credit also provides biodiesel and renewable diesel with a competitive advantage relative to other biofuels that do not qualify for the tax credit.

While the biodiesel blenders tax credit has applied in each year since 2010, it has historically only been prospectively in effect during the calendar year in 2011, 2013, 2016, and 2020–2022, while other years it has been applied retroactively. Years in which the biodiesel blenders tax credit was in effect during the calendar year (2013, 2016, 2020, and 2021) generally resulted in significant increases in the volume of BBD used in the U.S. over the previous year (629 million gallons, 711 million gallons, 63 million gallons,[749] and 291 million gallons respectively). However, following the large increases in 2013 and 2016, there was little to no growth in the use of advanced biodiesel and renewable diesel in the following years. Data from 2018 and 2019 suggests that while the availability of the tax credit certainly incentivizes an increasing supply of biodiesel and renewable diesel, supply increases can also occur in the absence of the tax credit, likely as the result of the incentives provided by the RFS program, state LCFS programs, and other economic factors.

Another important factor highlighted by the historic data is the tariffs imposed by the U.S. on biodiesel imported from Argentina and Indonesia. In December 2017 the U.S. International Trade Commission adopted tariffs on biodiesel imported from Argentina and Indonesia.[750] According to data from EIA,[751] no biodiesel has been imported from Argentina or Indonesia since September 2017, after a preliminary decision to impose tariffs on biodiesel imported from these countries was announced in August 2017. As a result of these tariffs, total imports of biodiesel into the U.S. were significantly lower in 2018 than they had been in 2016 and 2017. The decrease in imported biodiesel did not, however, result in a decrease in the volume of advanced biodiesel and renewable diesel supplied to the U.S. in 2018. Instead, higher domestic production of advanced biodiesel and renewable diesel, in combination with lower exported volumes of domestically produced biodiesel, resulted in an overall increase in the volume of advanced biodiesel and renewable diesel supplied in 2018 and subsequent years.

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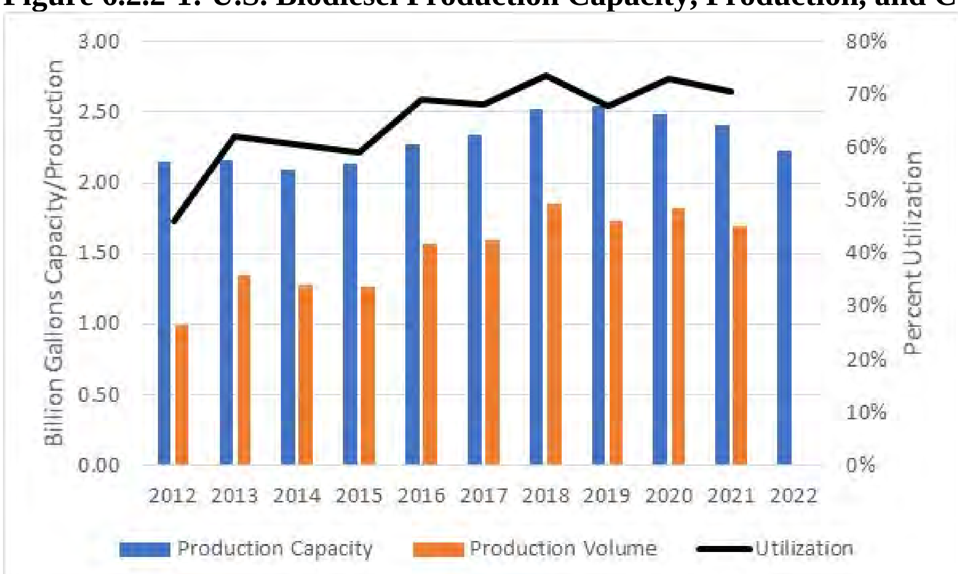
[749] This is the volume increase in 2020, which was impacted by the COVID pandemic.
[750] "Biodiesel from Argentina and Indonesia Injures U.S. Industry, says USITC," Available at: https://www.usitc.gov/press_room/news_release/2017/er1205ll876.htm
[751] See "EIA Biodiesel Imports" available in docket EPA-HQ-OAR-2021-0324.

6.2.2 Biomass-Based Diesel Production Capacity and Utilization

One of the factors considered when projecting the rate of production of BBD in future years is the production capacity. Domestic biodiesel production capacity, domestic biodiesel production, and the utilization rate of the existing biodiesel production capacity each year is shown in Figure 6.2.2-1. Active biodiesel production capacity in the U.S. as reported by EIA has experienced modest growth in recent years, from approximately 2.1 billion gallons in 2012 to just over 2.5 billion gallons in 2019.[752] As of June 2022, active biodiesel production capacity has decreased slightly since then, to approximately 2.2 billion gallons in 2022.[753] While production of biodiesel has generally increased during this time period, significant excess production capacity remains, with facility utilization remaining below 75% through 2021. EPA data on total registered biodiesel production capacity in the U.S., which includes both facilities that are producing biodiesel and idled facilities, is much higher, approximately 3.9 billion gallons. Active biodiesel capacity as reported by EIA is the aggregate production capacity of biodiesel facilities that produced biodiesel in any given month, while the total registered capacity based on EPA data includes all registered facilities, regardless of whether they are currently producing biodiesel or not. These data suggest that domestic biodiesel production capacity is unlikely to limit biodiesel production in future years, and that factors other than production capacity are currently limiting domestic biodiesel production.

Figure 6.2.2-1: U.S. Biodiesel Production Capacity, Production, and Capacity Utilization

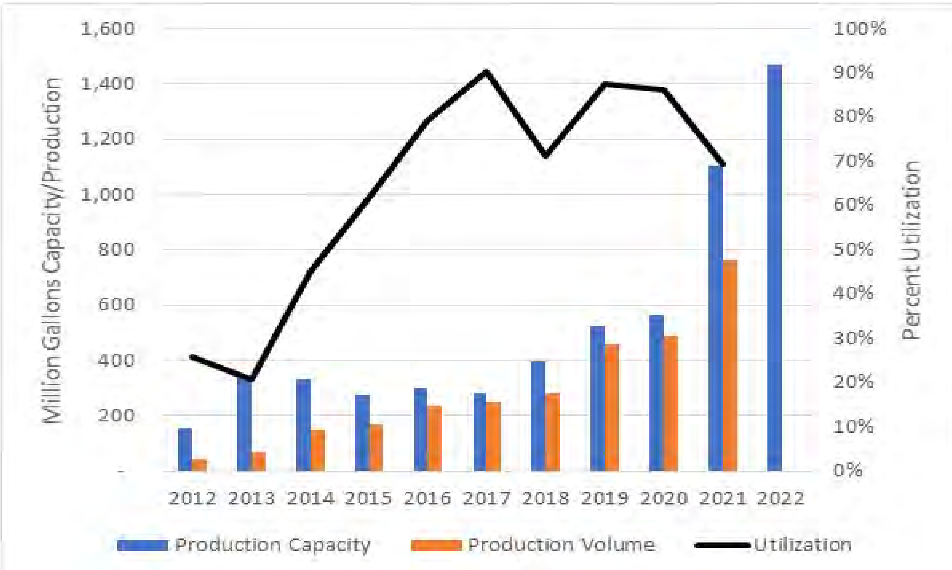


Unlike domestic biodiesel production capacity, domestic renewable diesel production capacity has increased significantly in recent years, from approximately 280 million gallons in 2017 to approximately 1.95 billion gallons in June 2022 (Figure 6.2.2-2).[754] Domestic renewable

[752] Biodiesel production capacity from EIA Monthly Biodiesel Production reports and the EIA Monthly Biofuels Capacity and Feedstock Update.
[753] See EIA Monthly Biofuels Capacity and Feedstock Update.
[754] Renewable diesel capacity is based on RFS facility registration data and EIA Monthly Biofuels Capacity and Feedstock Update.

diesel production has increased along with production capacity in recent years, and capacity utilization at domestic renewable diesel production facilities has been high, approximately 84% from 2017-2021. Further, much of the unused capacity was likely the result of facilities ramping up new capacity to full production rates. Unlike the biodiesel industry, in which unused production capacity has persisted for many years, since 2017 production of renewable diesel neared or exceeded the production capacity from the previous year.

Figure 6.2.2-2: U.S. Renewable Diesel Production Capacity, Production, and Capacity Utilization



Renewable diesel production capacity and actual production values are from EMTS data and EIA Monthly Biofuels Capacity and Feedstock Update. Capacity utilization is calculated by dividing actual production by the total production capacity.

A number of parties have announced their intentions to build new renewable diesel production capacity with the potential to begin production of renewable diesel by the end of 2025. These new facilities include new renewable diesel production facilities, expansions of existing renewable diesel production facilities, and the conversion of units at petroleum refineries to produce renewable diesel. A list of the facilities expected to begin producing renewable diesel by 2025, as well as existing facilities expected to complete expansions by 2025, based on publicly available data is shown in Table 6.2.2-1.

Table 6.2.2-1: New Renewable Diesel Production Capacity in the U.S. Through 2022

Facility Name	Location	Capacity (MGY)	Start Date (Actual or Expected)
HollyFrontier Artesia[755]	Artesia, NM	110	2022
Bakersfield Renewables[756]	Bakersfield, CA	230	2022
New Rise Renewables[757]	Reno, NV	43	2022
Diamond Green Diesel[758]	Port Arthur, TX	470	2022
Marathon Martinez[759]	Martinez, CA	260	2022
Marathon Martinez Expansion[760]	Martinez, CA	470	End 2023
Phillips 66 Rodeo Phase 2[761]	Rodeo, CA	680	Q1 2024
Next Renewable Fuels[762]	Port Westward, OR	575	2024
REG Geismar Expansion[763]	Geismar, LA	250	2024
World Energy[764]	Paramount, CA	340	2025

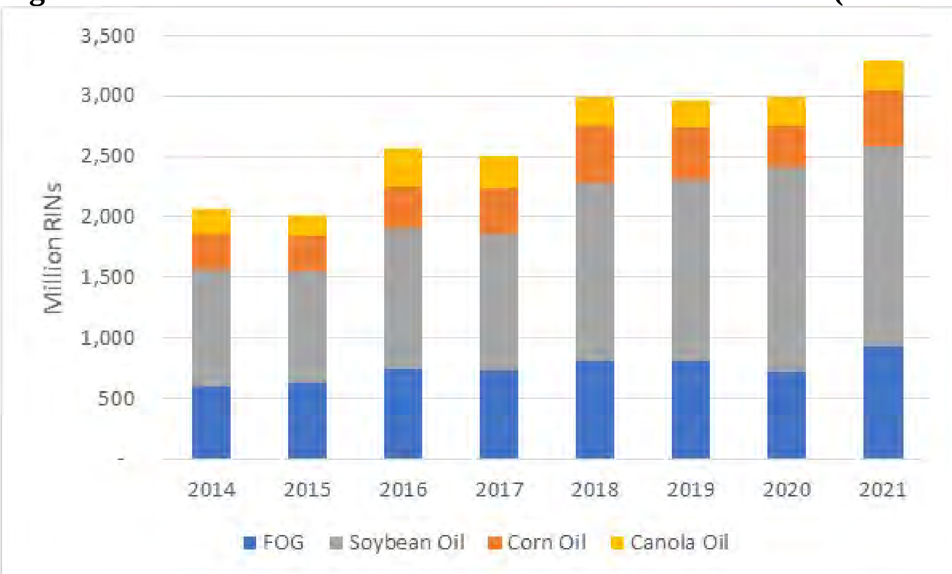
If all these facilities were completed according to their current schedules these facilities would increase domestic renewable diesel production capacity by nearly 3.5 billion gallons per year by 2025. However, feedstock limitations (discussed in Chapter 6.2.3) may not support all of these facilities. As several of these projects are still in the planning stages and have not yet begun construction, it is possible that some of these projects may be delayed or cancelled. Thus, it is unlikely that the domestic renewable diesel production will reach the nearly 5 billion gallons implied by the sum current production capacity and the new renewable diesel projects with the intention to begin production by 2025. Nevertheless, it appears unlikely that domestic production capacity will limit renewable diesel production through 2025. Rather it is more likely that the feedstock limitations discussed in Chapter 6.2.3 may limit production.

[755] Kotrba, Ron. *Cheyenne renewable diesel unit fully operational, but HollyFrintier takes start-up slow*. Biobased Diesel Daily. February 24, 2022.
[756] Cox, John. *Owner of renewable fuels refinery settles injection well violations*. Bakerfield.com. June 17, 2022.
[757] Kotrba, Ron. *Reno renewable diesel project works out deal with Twain to complete construction*. Biobased Diesel Daily. April 5, 2022.
[758] Diamond Green Diesel Website. Accessed June 27, 2022. Available at: https://www.diamondgreendiesel.com/
[759] Voegele, Erin. *Marathon provides update on Martinez conversion project*. Biodiesel Magazine. May 3, 2022.
[760] Voegele, Erin. *Marathon provides update on Martinez conversion project*. Biodiesel Magazine. May 3, 2022.
[761] *Phillips 66 Makes Final Investment Decision to Convert San Francisco Refinery to a Renewable Fuels Facility*. Phillips 66 News Release. May 11, 2022.
[762] Kotrba, Ron. *Oregon approves key permit for $2 billion renewable diesel project*. Biobased Diesel Daily. March 25, 2022.
[763] *Renewable Energy Group Breaks Ground on Geismar, Louisiana Renewable Diesel Expansion and Improvement Project*. Renewable Energy Group Website. Accessed June 27, 2022. Available at: https://www.regi.com/resources/press-releases/renewable-energy-group-breaks-ground-on-geismar-louisiana-renewable-diesel-expansion-and-improvement-project.
[764] *Air Products Teaming Up with World Energy to Build $2 Billion Conversion of Sustainable Aviation Fuel (SAF) Production Facility in Southern California*. Air Products Website. Accessed June 27, 2022. Available at: https://www.airproducts.com/news-center/2022/04/0422-air-products-and-world-energy-sustainable-aviation-fuel-facility-in-california.

6.2.3 Availability of Biomass-Based Diesel Feedstocks

Another key factor in considering the rate of production of BBD through 2025 is the availability of qualifying feedstocks. To assess the availability of feedstocks for producing BBD through 2025 we first reviewed the feedstocks used in previous years. This review of feedstocks used in previous years can provide information about the feedstocks most likely to be used in future years, as well as the likely increase in the availability of these feedstocks in future years. A summary of the feedstocks used to produce BBD from 2012 through 2021 is shown in Figure 6.2.3-1.

Figure 6.2.3-1: Feedstocks Used To Produce BBD in the U.S. (2014-2021)[765]



Domestic BBD production from fats, oils, and greases (FOG) in the U.S. has generally increased from 2014 through 2021 at an average annual rate of approximately 20 million gallons (35 million RINs) per year. These feedstocks are generally by-products of other industries. Assessments submitted by commenters on the 2020–2022 RFS annual rule generally agree that the domestic supply of these feedstocks will increase only slightly in future years.[766] We expect that in future years production of BBD from FOG will continue to increase at approximately the historical rate as the availability of FOG increases with population. It is possible that greater demand for feedstocks for BBD production could result in the diversion of greater quantities of FOG to BBD production at the expense of other markets that currently use FOG feedstocks. Alternatively, it could also result in greater collection of FOG that is currently sent to landfills or wastewater treatment systems, but we do not expect significant increases in the collection rates of FOG for BBD production through 2025.

Production of BBD from distillers corn oil has also generally increased through 2021. The most significant increases in the volume of BBD produced from distillers corn occurred

[765] Based on EMTS data

[766] See comments from the Advanced Biofuels Association (EPA-HQ-OAR-2021-0324-0476) and the Clean Fuels Alliance America (EPA-HQ-OAR-2021-0324-0458) on the 2020–2022 RFS annual rule.

through 2018 as more corn ethanol plants installed equipment to produce distillers corn oil and corn ethanol production expanded. However, production of BBD from this feedstock has been fairly consistent at about 250 – 300 million gallons (400–500 million RINs) per year since 2017. Total production of distillers corn oil in the U.S. in 2020 was approximately 2 million tons,[767] or enough corn oil to produce about 530 million gallons (approximately 800 million RINs) of BBD. This suggests that distillers corn oil could be used to produce over 200 million gallons of additional BBD, but that would require shifting distillers corn oil from other existing uses, which would then have to be backfilled with other new sources.[768] It is also possible that domestic production of distillers corn oil could increase in future years for a variety of reasons, including new varieties of corn with higher oil content, greater extraction rates, or increased ethanol production for domestic or international markets. As with increased FOG collection, however, we do not expect these changes to significantly increase the domestic supply of corn oil in 2025.

The remaining volume of BBD has been produced from canola oil and soybean oil. Production of BBD from canola oil has fluctuated in recent years from a high of approximately 180 million gallons (300 million RINs) in 2016 to a low of approximately 120 million gallons (170 million RINs) in 2015. Production of BBD from canola oil averaged approximately 160 million gallons (240 million RINs) each year from 2018 to 2021. Total production of canola oil reached a high of approximately 1.8 billion pounds in the 2019/2020 agricultural marketing year, or enough canola oil to produce approximately 240 million gallons of BBD.[769] Canola oil production has ranged between 1.5 and 2.0 billion pounds from 2013/2014 and 2021/2022.[770] Significant increases in canola oil production in the U.S. through 2025 are unlikely due to both the relatively poor economic return on canola in many parts of the U.S. and the lack of additional crush capacity for soft seed vegetable oil crops like canola. An additional 4 billion pounds of canola oil, or enough to produce approximately 500 million gallons of BBD, were imported in 2020/2021. It is unclear how much of this imported canola oil would be able to qualify as renewable biomass under the statutory definition, and thus available to be used to produce qualifying BBD under the RFS program.[771] A recently proposed pathway that would allow for the generation of RINs for renewable diesel produced from canola oil could increase demand for canola oil for biofuel production if this pathway were finalized. Conversely, increasing biofuel demand in Canada is likely to impact the quantity of canola oil available to U.S. biofuel producers. Consistent with the relatively small and stable domestic production of canola oil and relatively consistent use of canola oil for biofuel production in the U.S., we are not projecting any growth in the domestic availability of canola oil for biofuel production through 2025, though imported canola oil (or imported biofuels produced from canola oil) may be a potential source of increased biofuel supply in these years.

The largest source of BBD production in the U.S. historically has been soybean oil. Use of soybean oil to produce biodiesel increased from approximately 5.1 billion pounds in the

[767] USDA Grain Crushings and Co-Products Production 2021 Summary. March 2022. Available at: https://www.nass.usda.gov/Publications/Todays_Reports/reports/cagcan22.pdf
[768] For a discussion of backfilling when oil is removed from dried distillers grains, see 83 FR 37735 (August 2, 2018).
[769] U.S. Canola oil production data sourced from USDA's Oil Crops Yearbook (https://www.ers.usda.gov/data-products/oil-crops-yearbook/).
[770] Ibid.
[771] CAA section 211(o)(1)(I).

2013/2014 agricultural marketing year to approximately 8.85 billion pounds in the 2020/2021 agricultural marketing year.[772] During this time period the percentage of all soybean oil produced in the U.S. used to produce biodiesel increased from approximately 25% in 2013/2014 to approximately 35% in 2020/2021. As a point of reference, if all the soybean oil produced in the U.S. in 2020/2021 (25 billion pounds) were used to produce BBD, this quantity of feedstock could be used to produce approximately 3.3 billion gallons of BBD. Thus, BBD production from soybean oil could more than double if it were all shifted from its other existing uses, including food, and backfilled with other new sources such as palm oil, potentially impacting the GHG benefits.

Additional soybean oil production in future years could come from several sources. The first potential source of additional soybean oil is increased crushing of soybeans in the U.S. Soybean crushing is the process by which whole soybeans are converted into soybean oil and soybean meal. The percentage of U.S. soybean production that has been crushed has varied from a low of 44% in the 2016/2017 agricultural year to a high of 61% in the 2019/2020 marketing year.[773] Higher soybean crushing rates produce greater quantities of soybean oil from the same soybean crop.

Strong demand for vegetable oil has already resulted in increasing domestic crushing of soybeans. Recent data from USDA indicates that soybean crushing reached record levels in December 2021.[774] USDA estimates of soybean crush capacity, after accounting for necessary down time at crush facilities, range from 2.45–2.6 billion bushels per year.[775] The high end of this range represents an increase of about 0.4 billion bushels of soybean crush relative to the estimated quantity of soybeans crushed in the 2020/2021 agricultural marketing year.[776] Increasing soybean crushing by 0.4 billion bushels per year would increase soybean oil production by approximately 4.6 billion pounds, assuming an oil yield of 11.6 pounds per bushel, consistent with the soybean oil yield per bushel of soybeans crushed in recent years.[777] This increase in soybean oil production could be used to produce approximately 600 million gallons of biodiesel and renewable diesel if this entire quantity of soybean oil was used solely for production of these fuels. In addition, a number of companies have recently announced plans to build new soybean crushing facilities, or expand existing facilities.[778] In comments on the 2020–2022 RFS annual rule the American Soybean Association noted at least 13 announcements for the expansion of soybean crush facilities or new facilities.[779] They estimated that these projects

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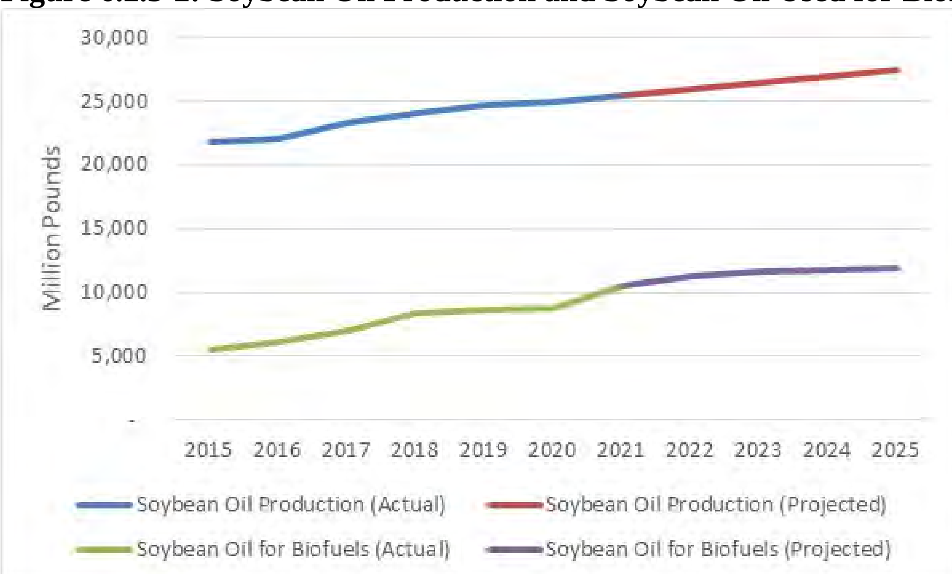
[772] U.S. Soybean oil production and use data sourced from USDA's March 2022 Oil Crops Yearbook (https://www.ers.usda.gov/data-products/oil-crops-yearbook/). The agricultural marketing year for soybeans runs from September to August.
[773] U.S. Soybean crushing data sourced from USDA's Oil Crops Yearbook (https://www.ers.usda.gov/data-products/oil-crops-yearbook/).
[774] Ates, Aron M. and Bukowski, Maria. *Oil Crops Outlook: February 2022*. USDA Economic Research Service. February 11, 2022.
[775] Ibid
[776] USDA Economic Research Service. *Oil Crops Data: Yearbook Tables*. March 25, 2022.
[777] Ibid.
[778] Demarre-Saddler, Holly. *Cargill Plans US Soy Processing Operations Expansion*. World-Grain.com. March 4, 2021.
[779] See comments from the American Soybean Association on the RFS Annual Rule (EPA-HQ-OAR-2021-0324-0471).

could increase soybean crushing by 15%.[780] Any soybean oil production from these facilities if they come online by 2025 would further increase the quantity of soybean oil available for biofuel production or other uses. Increasing the domestic crush of soybeans would likely result in a decrease in the quantity of soybeans exported to other countries and could also result in increased soybean cultivation in the U.S.

The USDA Agricultural Projections to 2031 project increasing domestic soybean oil production through 2025, largely as a result of an increased crushing of soybeans. USDA projects that domestic soybean oil production will increase by approximately 1.4 billion pounds from 2022 (26.0 billion pounds) to 2025 (27.4 billion pounds).[781] If this entire increase in soybean oil production were used to produce biodiesel or renewable diesel, it would result in an increase of approximately 180 million gallons of biofuel from 2022 to 2025, or an increase of approximately 60 million gallons per year.

Figure 6.2.3-2: Soybean Oil Production and Soybean Oil Used for Biofuel Production



Actual data from USDA Oil Crops Yearbook; Projected data from USDA Agricultural Projections to 2031

In addition to increased soybean crushing, additional quantities of soybean oil could be made available for biofuel production from decreased exports and/or increased imports of soybean oil. From the 2011/2012 agricultural marketing year through the 2020/2021 agricultural marketing year approximately 10% of the soybean oil produced in the U.S. was exported.[782] Soybean oil exports in 2020/2021 are estimated at approximately 1.7 billion pounds, or enough soybean oil to produce approximately 225 million gallons of biodiesel or renewable diesel.[783]

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[780] Ibid.
[781] USDA Agricultural Projections to 2031. February 2022. For each year EPA converted soybean oil production projections to calendar year prices by weighting production in the first agricultural marketing year (e.g., 2022/2023 for the 2023 price) by 0.25 and production in the second agricultural marketing year (e.g., 2023/2024 for the 2023 price) by 0.75.
[782] USDA Economic Research Service. *Oil Crops Data: Yearbook Tables*. March 25, 2022.
[783] Ibid.

Soybean oil imports have been relatively small (300–400 million pounds)[784] in recent years, likely due to the tariff on soybean oil imports.[785] As with other potential sources of BBD feedstock with existing markets, increasing BBD production by decreasing exports and/or increasing imports of soybean oil would require shifting these feedstocks from existing markets including food supply in the U.S. and abroad and then backfilling with other new supplies such as palm oil or other vegetable oils produced in foreign countries, potentially impacting the GHG benefits.

Finally, additional vegetable oil feedstocks in future years could come from international sources. The most recent WASDE report from USDA project that global production of vegetable oils will be approximately 212 million metric tons in the 2021/2022 agricultural marketing year.[786] This quantity of vegetable oil, if converted to fuel, would result in approximately 61 billion gallons of biodiesel and/or renewable diesel. The vast majority of this is used for food and other purposes and could not be readily used to supply advanced biodiesel and renewable diesel to the U.S.[787] Furthermore, much of this vegetable oil is also likely to be from palm oil that does not currently have an approved pathway under the RFS program except for the portion that could be produced under the program's grandfathering provisions. However, the large global production of vegetable oil suggests that increased imports of vegetable oil, or biodiesel and renewable diesel produced from vegetable oil (discussed in Chapter 6.2.4), may be made available to markets in the U.S. in future years.

While the global production of vegetable oils far exceeds the quantity of vegetable oil used for biofuel production there is significant demand for vegetable oils in other markets such as for food, animal feed, and oleochemical production. Recent prices for vegetable oils suggest that the market for vegetable oils has tightened in recent years, with demand for vegetable oils increasing relative to supply. From 2013/2014 through 2019/2020 the price for soybean oil generally ranged from $0.30 - $0.40 per pound.[788] In 2020/2021 soybean oil prices increased to $0.57 per pound. Soybean oil prices reached a high of approximately $0.87 per pound in April 2022, before falling to approximately $0.56 per pound in July 2022.[789] Soybean oil prices are decreasing slightly from 2022/2023 ($0.51 per pound) through 2025/2026 ($0.48 per pound).[790]

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[784] Ibid

[785] Harmonized Tariff Schedule of the United States (2020) Revision 19.

[786] United States Department of Agriculture World Agricultural Supply and Demand Estimates. June 10, 2022.

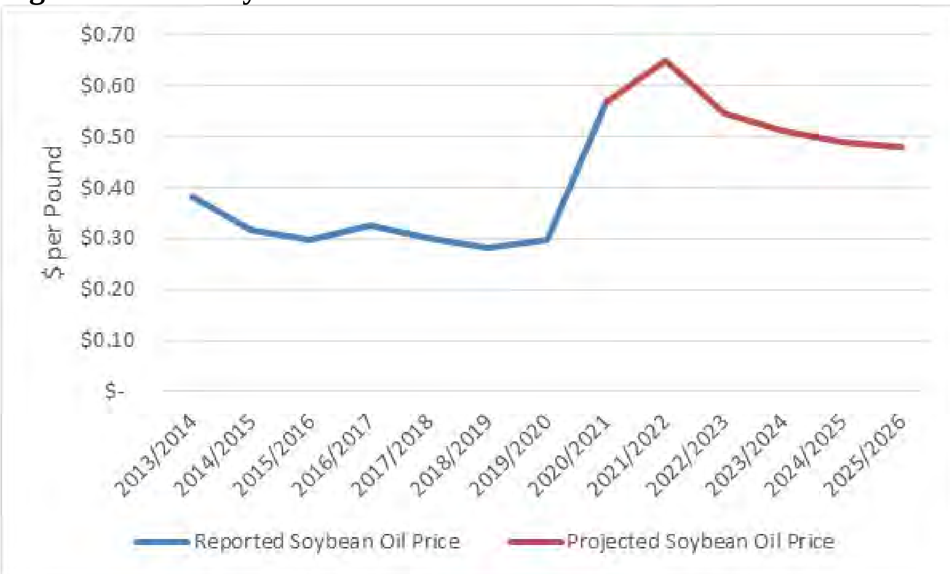
[787] These reasons include the demand for vegetable oil in the food, feed, and industrial markets both domestically and globally; constraints related to the production, import, distribution, and use of significantly higher volumes of biodiesel and renewable diesel; and the fact that biodiesel and renewable diesel produced from much of the vegetable oil available globally may not qualify as an advanced biofuel under the RFS program.

[788] USDA Economic Research Service. *Oil Crops Data: Yearbook Tables*. March 25, 2022.

[789] Nasdaq Soybean Oil Price. Accessed 7/14/2022. Available Online: https://www.nasdaq.com/market-activity/commodities/zl

[790] USDA Agricultural Projections to 2031. February 2022.

Figure 6.3.2-3: Soybean Oil Price



Actual data from USDA Oil Crops Yearbook; Projected data from USDA Agricultural Projections to 2031

While increased soybean oil demand for biofuel production is likely a contributing factor to the higher soybean oil prices observed in recent years it is not the only, or even the primary factor. The current high prices have also been affected by poor weather conditions in South America and Malaysia over the past year, which has negatively impacted global vegetable oil production. In 2021 there was drought in Argentina and Brazil (two of the largest exporters of soybeans and soybean oil).[791] At the same time, palm oil production in Malaysia was impacted by flooding caused by a typhoon.[792]

Despite these current high prices for vegetable oil, the data discussed above indicate that there will be some additional supply of vegetable oil to enable increasing production of biofuels from vegetable oils in future years. We project small increases in the availability of FOG and distillers corn oil, consistent with historical trends. Increasing crushing of soybeans domestically together with better harvest conditions in South America and Southeast Asia are projected to result in an increased supply of vegetable oil. These projected vegetable oil production increases are limited, however, and suggest that the availability of feedstocks, particularly qualifying feedstocks under the RFS program, could be a limiting factor for biodiesel and renewable diesel production through 2025.

6.2.4 Imports and Exports of Biomass-Based Diesel

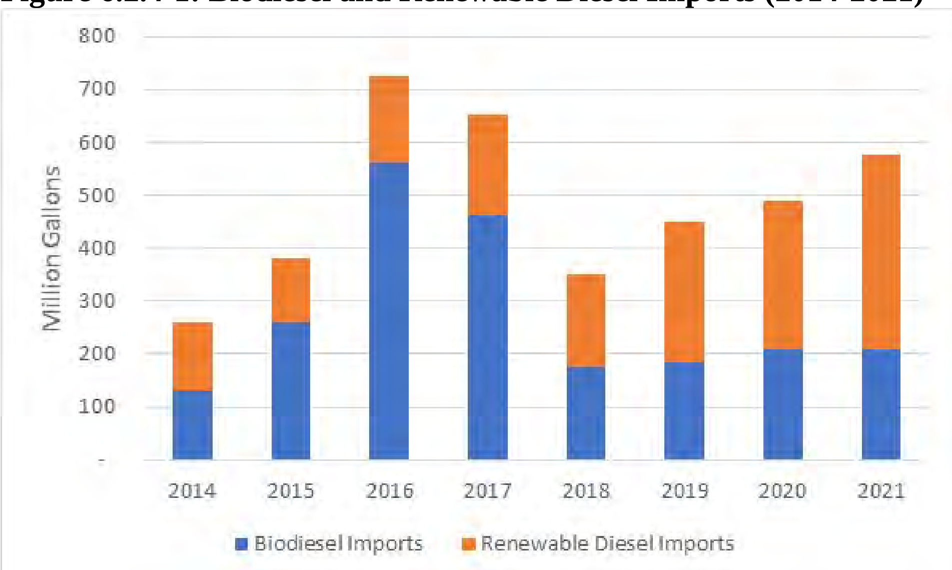
In evaluating the likely rate of production of BBD through 2025 we also examined BBD imports and exports in previous years. While imports and exports of BBD may not directly impact the rate of production of BBD in the U.S., they do impact the volume of these fuels available to obligated parties. We therefore think that the volume of these fuels that may be

[791] Wilson, Nick. *Oil Prices Surge – Vegetable Oil That Is*. Marketplace.org. February 17, 2022.
[792] Ibid.

imported and exported in future years is a relevant consideration as we require volumes through 2025 under the RFS program.

Since 2014 biodiesel imports have generally averaged about 200 million gallons per year, with the exception of 2015-2017. During this time (2015-2017) biodiesel imports from Argentina surged, with biodiesel imported from Argentina responsible for 64% of all biodiesel imports in these three years. In August 2017, the U.S. announced preliminary tariffs on biodiesel imported from Argentina and Indonesia.[793] These tariffs were subsequently confirmed in April 2018.[794] Since the time the preliminary tariffs were announced, EIA has not reported any biodiesel imported from these countries.[795] After the imposition of these tariffs, imports of biodiesel from other countries has increased marginally; however, the biggest effect of these tariffs has been a decrease in the total volume of imported biodiesel to approximately 200 million gallons during 2018-2021.

Figure 6.2.4-1: Biodiesel and Renewable Diesel Imports (2014-2021)



Biodiesel and renewable diesel imports based on data from EMTS

Renewable diesel imports have generally increased since 2014, with larger increases observed in recent years. A significant factor in the increasing imports of renewable diesel appears to be the California Low Carbon Fuel Standard (LCFS), as the vast majority of the renewable diesel consumed in the U.S. (including both domestically produced and imported renewable diesel) has been consumed in California.[796] We expect that, as the carbon intensity

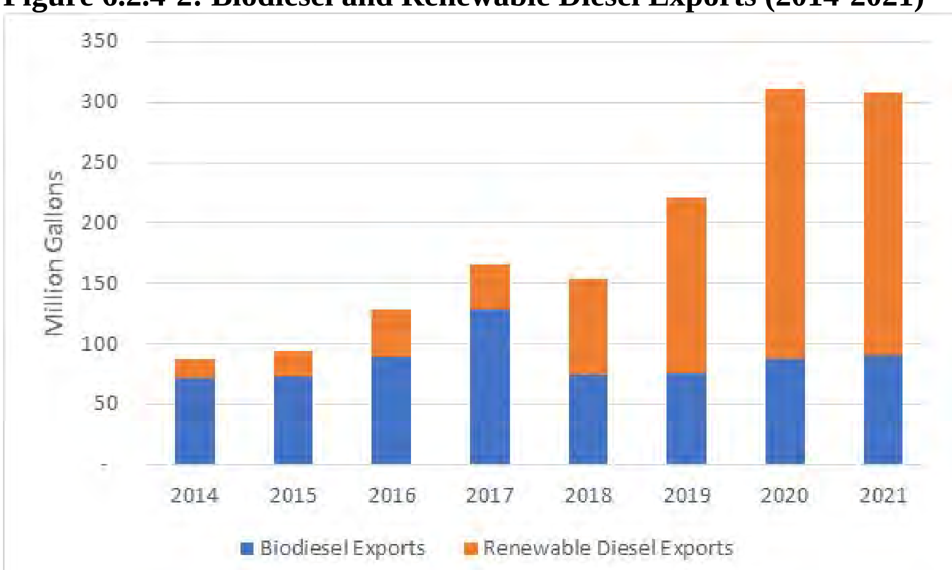
[793] 82 FR 40748 (August 28, 2017).
[794] 83 FR 18278 (April 26, 2018).
[795] See EIA data on biodiesel imports by country, available at: https://www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_EPOORDB_im0_mbbl_a.htm
[796] Data from California's LCFS program indicates that approximately 940 million gallons of renewable diesel were consumed in California in 2021, the most recent year for which data are available (https://ww3.arb.ca.gov/fuels/lcfs/dashboard/dashboard.htm). Data from EMTS indicates that 960 million gallons of renewable diesel were consumed in the U.S. in 2021, including both renewable diesel that generated BBD RINs and advanced RINs.

requirements in California's LCFS program continue to decrease, and as similar LCFS programs are taken up in other states (e.g., Oregon and Washington), these programs, in conjunction with the RFS program and the federal tax credit, will continue to provide an attractive market for domestically produced and imported renewable diesel.

Exports of RIN generating biodiesel, based on EMTS data, have been fairly consistent since 2014, generally ranging between 70 and 100 million gallons per year. According to EMTS data, renewable diesel exports increased with domestic renewable diesel production, reaching over 200 million gallons in 2020 and 2021. Increasing exports of renewable diesel reflect the existence of biofuel mandates and significant financial incentives creating high demand in other countries that the U.S. must compete with. As one example, Canada recently finalized new Clean Fuel Regulations that require increasing volumes of low-carbon fuels in future years.[797] At this time, it is difficult to project whether renewable diesel exports will continue to increase in future years or alternatively return to the low levels observed through 2017.

The fact that there are both imports and exports of BBD simultaneously also suggests that there are efficiencies associated with importing into and exporting from certain parts of the country as well as economic advantages associated with the use of BBD from different feedstocks in different foreign and domestic markets. One factor likely supporting simultaneous imports and exports of biodiesel and renewable diesel is the structure of the biodiesel tax credit. Since the U.S. tax credit for biodiesel and renewable diesel applies to fuel either used or produced in the U.S. it applies equally to fuel whether it is used in the U.S. or exported. Furthermore, by importing foreign produced biodiesel and renewable diesel for domestic use and then exporting domestically produced biodiesel and renewable diesel to other countries parties are able to claim the biodiesel tax credit on both the imported and the exported volumes.

Figure 6.2.4-2: Biodiesel and Renewable Diesel Exports (2014-2021)



Biodiesel and renewable diesel exports based on data from EMTS

[797] Tuttle, Robert. *Canada Releases California-Style Fuel Rules to Cut Emissions*. Bloomberg, June 29, 2022.

6.2.5 Projected Rate of Production and Use of Biomass-Based Diesel

Based on the factors discussed in the preceding sections, we have projected domestic BBD production and net BBD imports through 2025. Our analyses indicate that production capacity and the ability to distribute and use biodiesel and renewable diesel are unlikely to constrain BBD production through 2025 (see Chapters 6.2.2, 7.3, and 7.4 for further discussion on biodiesel and renewable production capacity and impacts on infrastructure). Further, the significant increase in renewable diesel production capacity projected through 2025, in combination with the decreasing biodiesel operational capacity observed in recent years, suggests that increases in BBD production are more likely to be renewable diesel rather than biodiesel.

The factor that appears most likely to constrain BBD production in 2023–2025 is the availability of feedstock. Our projections of BBD production through 2025 are therefore based on our projections of the availability of feedstocks for BBD production. As discussed in Chapter 6.2.2, we expect small increases in the availability of fats, oils, and greases or distillers corn oil for biofuel production through 2025, consistent with the trends observed in past years. We also project that additional volumes of vegetable oils, including canola oil and soybean oil, may be available in future years. The higher vegetable oil prices observed in recent years (relative to previous years) suggest that demand for vegetable oils is increasing faster than vegetable oil production. We project that vegetable oil production will increase in future years due to a variety of factors, including increased soybean crushing in the U.S. and increased production of oilseed crops in South American and Southeast Asia.

We have projected the domestic production and net imports of BBD separately by fuel type (biodiesel and renewable diesel) and feedstock. To project biodiesel and renewable diesel production from fats, oils and greases, distillers corn oil, and canola oil we have used a linear regression based on the quantities of these fuels supplied from 2016–2021. Domestic production and imports of biodiesel was projected in the same way (using a linear regression of the quantity of biodiesel form soybean oil from 2016–2021). The domestic production and net imports of these fuels from 2016–2021, and the equations used to project the domestic production and net imports from 2023–2025 based on a linear regression of the historical data are shown in Table 6.2.5-1.

Table 6.2.5-1: Domestic Production and Net Imports of BBD (2016–2021; million RINs)

Fuel	Feedstock	2016	2017	2018	2019	2020	2021	Equation
Biodiesel	Canola Oil	447	362	321	334	397	403	-2.86*Year + 6,151
Biodiesel	DCO	259	285	382	315	271	295	1.95*Year – 3,634
Biodiesel	FOG	595	508	349	563	517	553	-7.64*Year + 15,990
Biodiesel	Soybean Oil	1,779	1,673	1,562	1,510	1,700	1,432	-48.88*Year + 100,271
Renewable Diesel	DCO	101	110	100	133	103	195	13.71*Year – 27,540
Renewable Diesel	FOG	480	577	517	752	716	1,029	97.20*Year – 195,527

To project domestic production and imports of renewable diesel produced from soybean oil we used a different methodology. This is because there has been no discernable trend in the use of soybean oil for biofuel production from 2016–2021. Instead, the use of soybean oil for biofuel production has fluctuated significantly. These fluctuations appear to be based on a number of factors, including the availability of the federal tax credit and the incentives for BBD production provided by the RFS program and California's LCFS program. We therefore do not expect that production of renewable diesel in previous years provides a good basis for projecting production and net imports of this fuel in future years.

To project the domestic production and net imports of renewable diesel produced from soybean oil in 2023–2025 we first projected the quantity of this fuel that would be used to meet the 2022 RFS volume obligations. In the RIA for the 2020–2022 RFS annual rule EPA projected that 5,555 million RINs of BBD would be supplied in 2022 to meet the required volumes in that year. We then subtracted the projected supplies of biodiesel (all feedstocks) and renewable diesel from feedstocks other than soybean oil calculated using the methodology described in the preceding paragraph from the 5,555 million RINs of BBD projected to be supplied in 2022 to meet the required volumes to project the quantity of renewable diesel produced from soybean oil in 2022. Projected changes to the production and net imports of renewable diesel produced from soybean oil from the projected volume in 2022 were based on the projected increases in soybean oil production in USDA's Agricultural Projections to 2031. We projected domestic production and net imports of renewable diesel from soybean oil in 2023–2025 by adding the projected increase in soybean oil production relative to 2022 in each year plus the projected decrease in domestic production and net imports of biodiesel produced from soybean oil to the quantity of renewable diesel produced from soybean oil projected for 2022. This calculation assumes that all increases in soybean oil production relative to 2022 are used for biofuel production. The calculations to project the domestic production and net imports of renewable diesel produced from soybean oil are shown in Table 6.2.5-2.

A summary of all of the projected volumes of BBD from 2022–2025 is shown in Table 6.2.5-3. We note that the projected domestic production and net imports of renewable diesel produced from soybean oil presented in Table 6.2.5-2 and 3 are slightly different that the candidate volumes for this fuel presented in Chapter 3. The differences range from approximately 80 million gallons in 2023 to approximately 240 million gallons in 2025. These differences are the result of slightly different methodologies used in these chapters. In Chapter 3 we projected the fuel types that were most likely to be used to meet the candidate volumes. In this chapter we projected that renewable diesel produced from soybean oil would be used to satisfy the total demand for biodiesel and renewable diesel after accounting for the projected volumes of these fuels produced from these feedstocks. In this chapter, as described above, we have projected renewable diesel based on the projected increase in soybean oil production. These numbers suggest that renewable diesel volumes that exceed the candidate volumes may be possible, however we note that these projections, particularly in 2025, are subject to uncertainty and that requiring higher volumes of biodiesel and renewable diesel would likely result in higher vegetable oil prices and increased demand for imported vegetable oils.

Table 6.2.5-2: Projected Domestic Production and Net Imports of Renewable Diesel Produced from Soybean Oil (million gallons)

	2023	2024	2025
RD Production and Imports in 2022	1,008	1,008	1,008
Increase in Soybean Oil Production (relative to 2022)	68	131	184
Change in Soybean Oil Biodiesel (relative to 2022)	-33	-65	-98
Projected RD Production and Imports	1,108	1,205	1,290

Table 6.2.5-3: BBD Production and Net Imports (2022–2025; million gallons)[a]

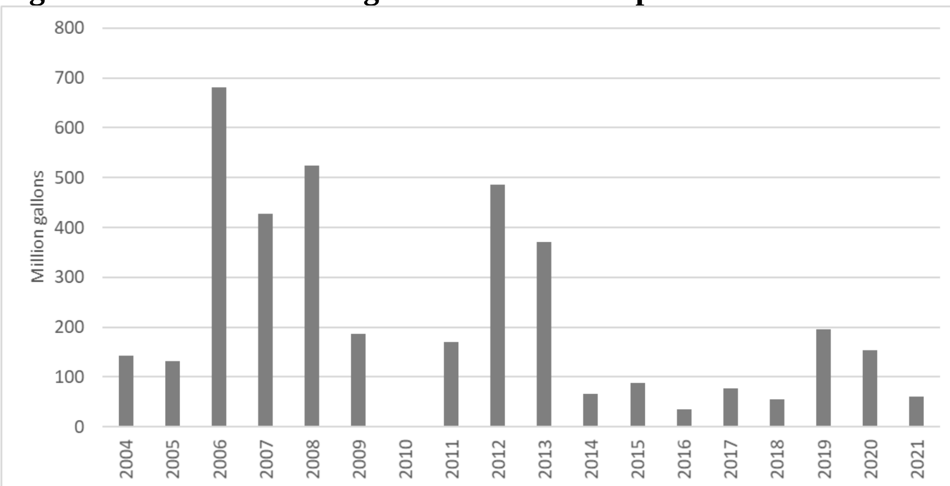
Year	2022	2023	2024	2025
Biodiesel				
Canola Oil	240	240	240	240
DCO	210	210	210	210
FOG	360	350	350	340
Soybean Oil	960	930	890	860
Renewable Diesel				
DCO	100	110	120	120
FOG	600	660	710	770
Soybean Oil	1,010	1,110	1,200	1,290
BBD Total				
All Feedstocks[b]	3,480	3,600	3,730	3,840

[a] Rounded to the nearest 10 million gallons
[b] Numbers may not add due to rounding

6.3 Imported Sugarcane Ethanol

The predominant available source of advanced biofuel other than cellulosic biofuel and BBD has historically been imported sugarcane ethanol. Imported sugarcane ethanol from Brazil is the predominant form of imported ethanol and the only significant source of advanced ethanol. However, data through 2021 demonstrates considerable variability in imports of sugarcane ethanol.

Figure 6.3-1: Historical Sugarcane Ethanol Imports



Source: "US Imports of Brazilian Fuel Ethanol from EIA - February 2022." Includes imports directly from Brazil and those that are transmitted through the Caribbean Basin Initiative and Central America Free Trade Agreement (CAFTA).

Moreover, data from EIA indicates that all 2019 - 2021 ethanol imports entered the U.S. through the West Coast. We believe that these imports were likely used to help refiners meet the requirements of the California Low Carbon Fuel Standard (LCFS), which provide significant additional incentives for the use of advanced ethanol beyond the RFS.

As noted in previous annual standard-setting rulemakings, the high variability in historical ethanol import volumes makes any projection of future imports uncertain.[798] However, import volumes for more recent years are likely to provide a better basis for making future projections than import volumes for earlier years. To address these issues, in the final rulemaking which established the volume requirements for 2022 we used a different methodology for making projections of future ethanol imports than we had used in previous years.[799] Specifically, we used a weighted average of import volumes for all years where the weighting was higher for more recent years and lower for earlier years. The weighting factor for any given year's volume was twice as large as the weighting factor for the previous year's volume. This approach provided a better predictor of future imports of sugarcane ethanol than either simple averages of historical volumes or a trendline based on historical volumes.

We have again used this methodology in this proposed rulemaking to estimate the volumes of imported sugarcane ethanol that could be expected in the future. The volumes and weighting factors we are using are shown in Table 6.3-1. The resulting weighted average is 110 million gallons. As we are projecting volumes for 2023-2025 for this proposal, and this is the latest data available, the same projection would apply for all three years.

[798] See, e.g., 85 FR 7032-33 (February 6, 2020) and 87 FR 39600 (July 1, 2022).

[799] See *FCC v. Fox Television Stations, Inc.*, 556 U.S. 502, 515 (2009).

Table 6.3-1: Annual Advanced Ethanol Imports and Weighting Factors

Year	Imported advanced ethanol[a] (million gallons)	Weighting factor
2014	64	0.0078125
2015	89	0.015625
2016	34	0.03125
2017	74	0.0625
2018	78	0.125
2019	196	0.25
2020	185	0.5
2021	60	1

[a] Based on RINs generated for imported ethanol and assigned a D-code of 5 according to EMTS.

As noted above, the future projection of imports of sugarcane ethanol is inherently imprecise, and actual imports in years 2023 - 2025 could be lower or higher than 110 million gallons. Factors that could affect import volumes include uncertainty in the Brazilian political climate, weather and harvests in Brazil, world ethanol demand and prices, constraints associated with the E10 blendwall in the U.S., world demand for and prices of sugar, the cost of sugarcane ethanol relative to that of corn ethanol, and the impact of the novel virus COVID-19 on transportation fuel prices and demand.

6.4 Other Advanced Biofuel

In addition to cellulosic biofuel, imported sugarcane ethanol, and BBD, there are other advanced biofuels that can be supplied in the years after 2022. These other advanced biofuels include non-cellulosic CNG, naphtha, heating oil, renewable diesel co-processed with petroleum, and domestically produced advanced ethanol. However, the supply of these fuels has been relatively low in the last several years.

Table 6.4-1: Historical Supply of Other Advanced Biofuels (million ethanol-equivalent gallons)

Year	CNG/LNG	Domestic Ethanol	Heating Oil	Naphtha	Renewable Diesel (D5)	Total
2014	20	26	0	12	15	73
2015	0	25	1	24	8	58
2016	0	27	2	27	8	64
2017	2	25	2	32	9	70
2018	2	25	3	31	40	101
2019	5	24	3	37	58	127
2020	5	23	3	33	86	150
2021	6	26	2	32	98	164

We have used the same weighted averaging approach (see Table 6.3-1) for other advanced biofuels as we have used for sugarcane ethanol to project the supply of these other advanced biofuels. Based on this approach, the weighted average of other advanced biofuels is 146 million RINs. This volume of other advanced biofuel is composed of 25 million RINs of domestic advanced ethanol, 81 million RINs of co-processed renewable diesel, and 80 million RINs of other advance biofuels (non-cellulosic RNG, heating oil, and naphtha). We have used these values in our candidate volumes for all three of the years addressed in this proposed rulemaking, 2023 - 2025. We do not believe the available data and the methodology we employed can reasonably be used to project future volumes that change over time for other advanced biofuels.

We recognize that the potential exists for additional volumes of advanced biofuel from sources such as jet fuel, liquefied petroleum gas (LPG), butanol, and liquefied natural gas (as distinct from CNG), as well as non-cellulosic CNG from biogas produced in digesters. However, since they have been produced, if at all, in very small amounts in the past, we do not believe the market will make available substantial volumes from these sources in the timeframe of this rulemaking (2023 - 2025).[800]

6.5 Total Ethanol Consumption

In order to properly analyze possible future volume targets for the different categories of renewable fuel, it was necessary to separately estimate volumes by fuel type and feedstock. For ethanol, the process of making such estimates is complicated by the fact that there are constraints on total ethanol consumption, a topic we discuss further in Chapter 7.5. It was therefore necessary to estimate the total volume of ethanol that is projected to be consumed in the 2023–2025 timeframe.

The total volume of ethanol consumed is the net result of ethanol used in E10, E15, and E85, while accounting for some small volume of ethanol-free gasoline (E0). In previous rulemakings we have estimated volumes of these individual blends for the purpose of projecting total ethanol consumption.[801] However, the projection of E0, E15, and E85 for future years has been hampered by a lack data on nationwide consumption of each individual blend. For the purposes of this rulemaking, we have developed an alternative method that we believe is both more accurate and avoids the need to estimate volumes separately for E0, E15, and E85. This method, presented in Chapter 6.5.1, correlates historical poolwide ethanol concentration derived from EIA data with the number of stations that have offered E15 and E85.

For the purposes of estimating the costs of renewable fuel, however, it is helpful to account for the different distribution practices required for different gasoline-ethanol blends. Thus, for cost purposes only, we have projected volumes of E15 and E85 for 2023–2025 using aggregate consumption data from USDA's Biofuels Infrastructure Partnership (BIP) program. This analysis is presented in Chapter 6.5.2, and yields lower total volumes of ethanol than we believe would actually be consumed in 2023–2025. For this reason, the estimated volumes of E15 and E85 are relevant for cost estimation purposes only and are not used in any other analyses discussed in this DRIA.

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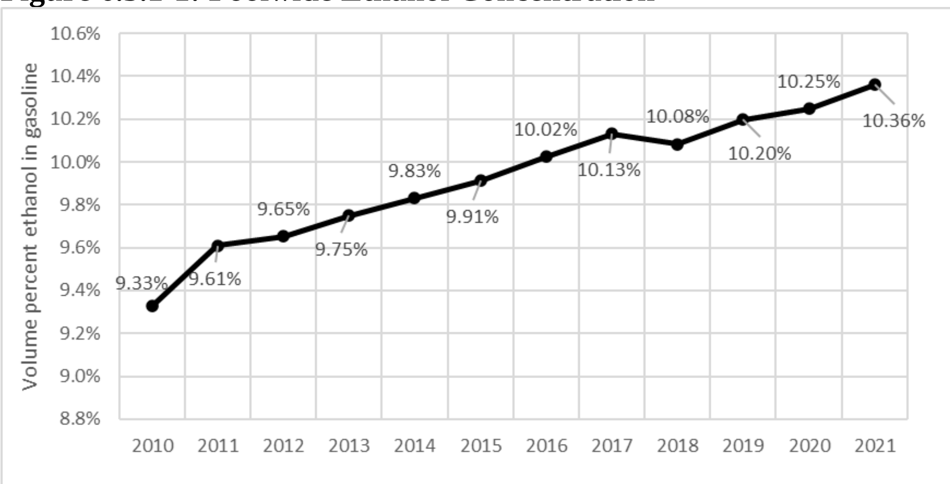
[800] Less than 1 million gallons of these other renewable fuels were produced in the years prior to 2021. In 2021, 8 million gallons of D4 jet fuel was produced, but it is difficult to project volumes of jet fuel for 2022 based on data from this single year.

[801] For instance, see "Estimates of E15 and E85 volumes in 2017," completed for use in the 2017 standards rulemaking (81 FR 89746, December 12, 2016. See relevant discussion on page 89777).

6.5.1 Estimation of Ethanol Consumption for Analysis of Target Volumes

The national average ethanol concentration of gasoline rose above 10.00% in 2016 and has continued to increase since then.

Figure 6.5.1-1: Poolwide Ethanol Concentration



Source: Ethanol consumption from Table 10.3 of EIA's Monthly Energy Review, gasoline consumption from Table 3.5 of EIA's Monthly Energy Review.

As the average ethanol concentration approached and then exceeded 10.00%, the gasoline pool became saturated with E10, with a small, likely stable volume of E0 and small but increasing volumes of E15 and E85. The average ethanol concentration can exceed 10.00% only insofar as the ethanol in E15 and E85 exceeds the ethanol content of E10 and more than offsets the volume of E0. As a result, one would expect a strong correlation between ethanol concentration and the number of retail service stations offering E15 and E85.

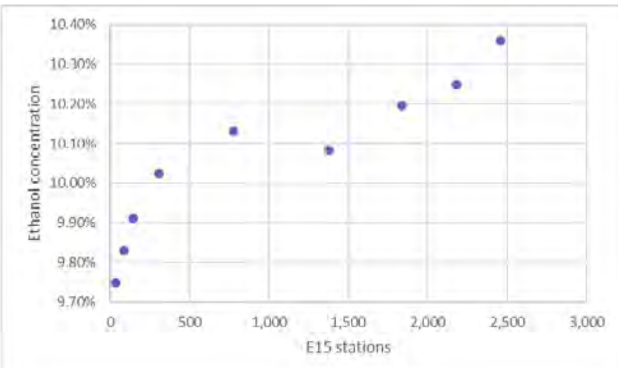
To evaluate this proposition, we calculated the annual average number of stations offering E15 and E85. For E15, annual averages were based on interpolations of the data provided by Prime the Pump (see Figure 7.5.3-2), while for E85 annual averages were calculated from the monthly estimates provided by DOE's Alternative Fuel Data Center (see Figure 7.5.2-2). The results are shown in Table 6.5.1-1.

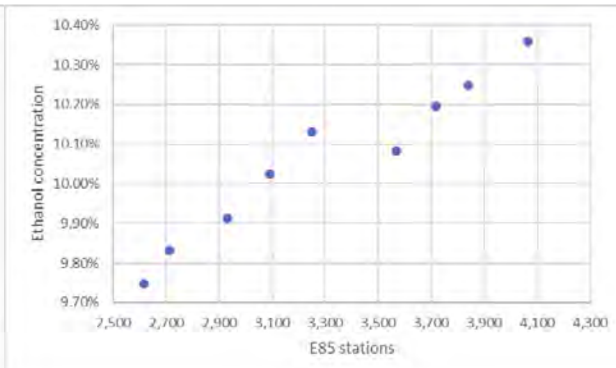
Table 6.5.1-1: Annual Average Number of Stations Offering Higher Level Ethanol Blends

	E15 stations	E85 stations
2013	36	2,616
2014	88	2,713
2015	145	2,932
2016	308	3,091
2017	777	3,251
2018	1,376	3,567
2019	1,838	3,717
2020	2,180	3,841
2021	2,458	4,063

Examination of these sets of data suggested that the E15 station data was nonlinearly correlated with poolwide ethanol concentration, while the E85 station data was roughly linearly correlated.

Figure 6.5.1-2: Correlations Between E15 and E85 Stations and Poolwide Ethanol Concentration





Based on these observations, we applied a least-squares regression to the ethanol concentration using the natural logarithm of the number of E15 stations and a linear term for the number of E85 stations as the independent variables. The result was the following equation:

$$\text{Ethanol concentration (\%)} = (5.328\times10^{-4}) \times \ln(\text{E15 station count}) + (2.224\times10^{-6}) \times (\text{E85 station count}) + 0.08994$$

Given that this regression has an r squared value of 0.95, it represents a strong basis for projecting the poolwide ethanol concentration for 2023–2025.

Using the projected number of E15 and E85 stations discussed in Chapters 7.5.3 and 7.5.2, the regression equation above yields the ethanol concentration projections shown in Table 6.5.1-2.

Table 6.5.1-2: Projected Poolwide Ethanol Concentration

	E15 stations	E85 stations	Ethanol concentration
2023	3,818	4,511	10.44%
2024	4,567	4,689	10.49%
2025	5,146	4,866	10.53%

The projected ethanol concentration can then be combined with total projected gasoline energy demand from EIA's Annual Energy Outlook (AEO) 2022 to estimate total ethanol consumption.

Table 6.5.1-3: Projected Total Ethanol Consumption

	Projected ethanol concentration	Gasoline energy demand (Quad Btu)[a]	Projected ethanol consumption (million gallons)[b]
2023	10.44%	16.8067	14,590
2024	10.49%	16.7825	14,640
2025	10.53%	16.7396	14,669

[a] See AEO2022 Table 2, "Delivered Energy Consumption, All Sectors," "Motor Gasoline"
[b] Based on the energy-to-volume conversion factors for denatured ethanol and BOB (Blendstock for Oxygenate Blending) found in AEO2022 Table 68.

6.5.2 Estimation of Gasoline Blend Volumes for Cost Purposes

For the purposes of estimating costs only, we projected the volumes of E15 and E85 that may be consumed in 2023–2025. These volume projections were based on data collected by USDA through their BIP program and made available to EPA.[802] While this data includes only a subset of all E15 and E85 stations, it is considerably more comprehensive than the alternatives. For instance, the BIP data covers almost 800 retail stations in 19 states. The only other data of which we are aware on E15 sales at retail is from two states (Iowa and Minnesota) [803,804] while the data of which we are aware on E85 sales at retail is from six states (Iowa, Minnesota, California, New York, Kansas, and North Dakota).[805]

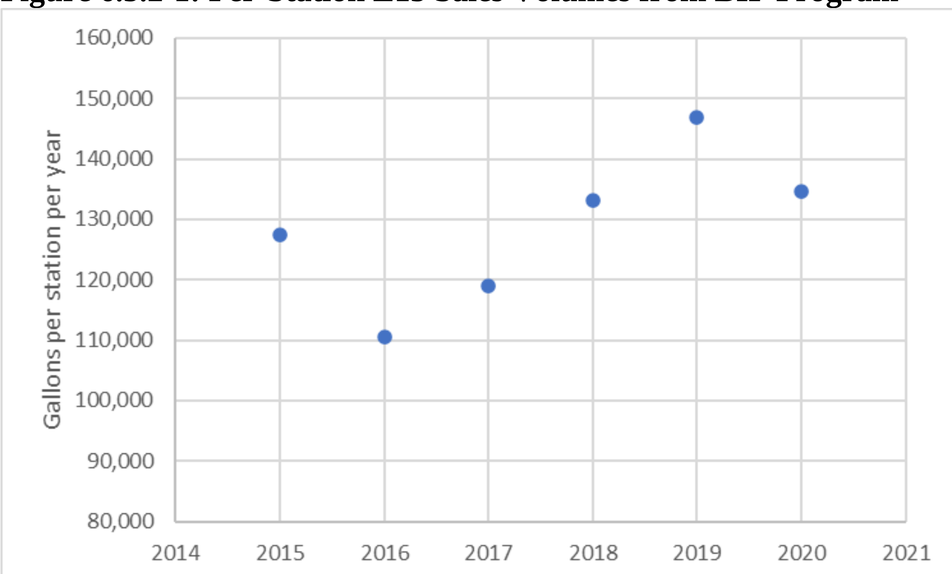
USDA collected data on sales of E15 and E85 over a six-year period ending in 2020. However, the BIP program was not completed until the end of 2018 and the largest number of respondents to the survey occurred in 2019 and 2020. Moreover, there was a noticeable decrease in E15 and E85 consumption in 2020 that was consistent with the decrease in all gasoline consumption brought about by the COVID pandemic, and which may not be representative of future years. As a result, we would expect that the data collected for 2019 and 2020 would be more representative of the country as a whole than the data collected for 2015–2018. Between these two years, we chose to use BIP data from 2019, as opposed to 2020, for our analyses for

[802] "Communication with USDA on the BIP program 1-19-22," available in the docket.
[803] Iowa Department of Revenue. https://tax.iowa.gov/report-category/retailers-annual-gallons. See, for instance "Iowa Department of Revenue - 2021 Retailers Fuel Gallons Annual Report."
[804] Minnesota Commerce Department. https://mn.gov/commerce/consumers/your-vehicle/clean-energy.jsp. See, for instance, "Minnesota Commerce Department - 2022 Minnesota E85 & Mid-Blends Station Report."
[805] See discussion of data sources in "Estimate of E85 consumption in 2020," available in the docket.

2020-2022. The BIP per-station sales volumes for 2019 reflect rising volumes over the prior several years and are somewhat higher than for 2020.

We recognize that in 2019 the 1 psi waiver applied to E15, but that it would not apply in 2023–2025.[806,807] The 1 psi waiver could have resulted in higher sales volumes in 2019 than would have been the case if the 1 psi waiver had not applied. As a result, the use of BIP data on E15 sales volumes in 2019 may overestimate the potential for sales in 2023–2025 when the 1psi waiver does not apply. However, there are reasons to believe that the use of data from 2019 is appropriate for 2023 - 2025. To begin with, E15 sales volumes per station have increased in previous years, and thus could continue to increase in the future as well. The BIP demonstrates an increasing trend that is disrupted only by the results for 2015 when only 8 retail stations reported E15 sales volumes (compared to 767 in 2019), and for 2020 when the pandemic reduced sales volumes of all fuels.

Figure 6.5.2-1: Per-Station E15 Sales Volumes from BIP Program

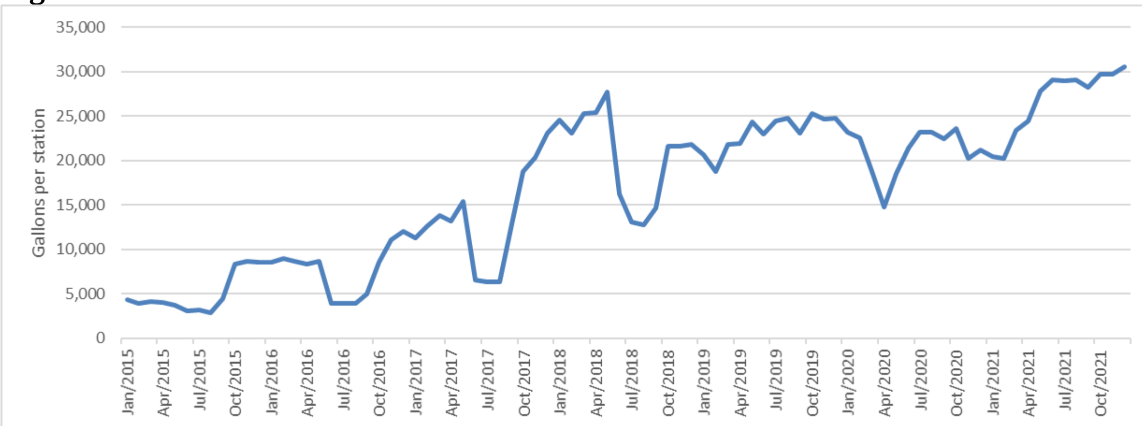


This 2020 decrease in E15 volumes in the BIP data is consistent with the decrease in total gasoline consumption brought about by the COVID pandemic. Given the rebound in gasoline demand in 2021 and 2022, as well as the overall increase in E15 use leading up to 2019, we believe that using the higher 2019 BIP volumes for all three years reflects a reasonable choice. Moreover, a similar upward trend is evident in per-station E15 sales volumes in Minnesota.

806 84 FR 26980, June 10, 2019.

807 "Court decision on 1 psi waiver for E15," available in the docket.

Figure 6.5.2-2: Per-Station E15 Sales Volumes in Minnesota



Source: Minnesota Commerce Department. https://mn.gov/commerce/consumers/your-vehicle/clean-energy.jsp. See for example "2021 Minnesota E85 + Mid-Blends Station Report," available in the docket.

The reasons for such increases over time in per-station E15 sales volumes are not clear. They may be attributable to any or all of the following: the relative price of E15 versus E10, changes in consumer preferences for higher octane fuel, signage and advertising, marketing incentives on the part of the retailers, or the increasing awareness that consumers have developed over time of their choices at retail stations.

The use of BIP data from 2019 as the basis for making a projection for 2023–2025 would also be consistent with recent letters from nine state governors requesting that EPA remove the 1 psi waiver for E10 used in their states.[808] If approved, those requests would result in the gasoline blendstock for E10 and E15 having the same production costs, in contrast to the current situation wherein those production costs are different due to E10 receiving a 1 psi waiver while E15 does not receive the same waiver. The net result could be that summer E15 sales volumes increase in those nine states. In light of this, the use of 2019 data on per-station E15 sales volumes from the BIP program is an appropriate basis for estimating E15 sales volumes in future years.

The BIP data allowed us to estimate per-station annual sales volumes of E15 and E85. In combination with future projections of the number of stations offering these fuel blends (derived and discussed in Chapters 7.5.2 and 7.5.3), we were able to project volumes of E15 and E85 as shown in Tables 6.5.2-1 and 2.

Table 6.5.2-1: Projected Volume of E15

	E15 stations	E15 sales volumes per year per station	Annual E15 sales volumes (mill gal)	Ethanol in Excess of E10 (mill gal)
2023	3,818	146,857	561	28
2024	4,567	146,857	671	34
2025	5,146	146,857	756	38

[808] "Governor letters requesting removal of 1psi waiver for E10," available in the docket.

Table 6.5.2-2: Projected Volume of E85

	E85 stations	E85 sales volumes per year per station	Annual E85 sales volumes (mill gal)	Ethanol in Excess of E10 (mill gal)
2023	4,511	78,342	353	233
2024	4,689	78,342	367	242
2025	4,866	78,342	381	252

These are the volumes used to estimate distribution costs associated with E15 and E85 for 2023–2025 as discussed in Chapter 10.1.4.

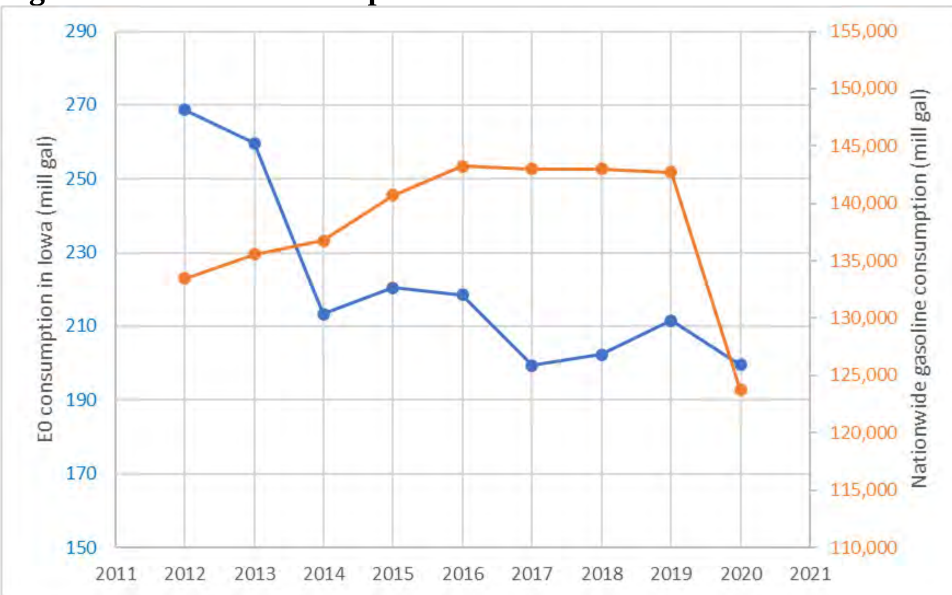
As we noted above, we do not use these E15 and E85 estimates to assess total ethanol volumes or for any purpose other than estimating costs.[809] We note, however, that the E15 and E85 volume projections shown in Tables 6.5.2-1 and 6.5.2-2 correspond to lower total ethanol consumption than the volumes shown in Table 6.5.1-3. Below we explain how we identified this discrepancy, why we chose to use estimates from EIA for total ethanol consumption rather than those derived from the E15 and E85 estimates shown in Tables 6.5.4-1 and 6.5.4-2, and why we nonetheless believe it is reasonable to use these E15 and E85 estimates for purposes of our costs analyses.

Total ethanol consumption can be calculated in a bottom-up fashion by combining the estimates of E15 and E85 with an estimate of E10. An estimate of E10 consumption, in turn, can be back-calculated from an estimate of E0 and total gasoline energy demand derived from the EIA's 2022 Annual Energy Outlook. As noted above, this exercise produces an amount of total ethanol consumption that is somewhat less than our projection of total ethanol consumption shown in Table 6.5.1-3.

As for E15 and E85, there is very little available data on the consumption of E0. Iowa's Department of Revenue has collected data on E0 sales at retail for many years, but it is unclear how representative Iowa E0 sales are of the entire nation. For instance, the pattern of consumption of E0 in Iowa does not appear to have followed the nationwide consumption pattern of total gasoline since 2012.

[809] Our proposed approach to projecting total ethanol consumption as discussed in Chapter 6.5.1 does use a projection of the number of stations offering E15 and E85, but does not involve any projection of separate volumes for E15 or E85.

Figure 6.5.2-3: E0 Consumption in Iowa



E0 data source: See, for instance, “2020 Retailers Fuel Gallons Annual Report,” available in the docket. https://tax.iowa.gov/reports.
Gasoline consumption data source: “MER March 2022 Table 3.5,” available in the docket.

Moreover, E0 sales in Iowa in 2020 represented about 15% of total gasoline sales, a proportion that is much too high to be representative of the nation as a whole. For instance, 15% of total gasoline consumption in 2020 would mean that 18.6 billion gallons of gasoline would have been sold as E0.[810] Given that total ethanol consumption was 12.7 billion gallons in 2020[811], 18.6 billion gallons of E0 would have required that 37.9 billion gallons of E15 be consumed.[812] As there were about 2,180 retail stations offering E15 in 2020 (see Table 6.5.1-1), the sale of 37.9 billion gallons of E15 would have required each station to sell 17 million gallons of E15 in 2020. This is far more than the total volume of gasoline sold by the largest retail stations.

Nevertheless, the Iowa data represents the only available estimate of actual E0 sales volumes. Therefore, we used Iowa data to estimate that the average per-station sales of E0 were 128,642 gal/year.[813] For the total number of retail stations in the U.S. that offer E0, we used the estimate provided by Pure-gas.org on January 7, 2022, which was 16,544 stations. The result was an estimate of 2,128 million gallons of E0.

We were able to confirm that 2,128 million gallons of E0 is consistent with data collected by the RFG Survey Association. That data indicated that 1.44% of sampled gasoline blends sold

[810] According to Table 3.5 of EIA's Monthly Energy Review, total gasoline consumption in 2020 was 123.73 billion gallons.
[811] Table 10.3 of EIA's Monthly Energy Review
[812] Assumes that E85 consumption was 312 million gallons in 2020. See Table 5.5.4-2 of the Regulatory Impacts Analysis associated with the final rule establishing the applicable standards for 2020 - 2022. See 87 FR 39600 (July 1, 2022).
[813] “2020 Retailers Fuel Gallons Annual Report,” available in the docket.

in 2021 was E0.[814] Insofar as this proportion is representative of the nation as a whole, 1.44% corresponds to about 1,940 million gallons of E0, based on EIA's estimate of 134.75 billion gallons of gasoline sold in 2021.[815] Since 1,940 million gallons is very similar to 2,128 million gallons, we had confidence that 2,128 million gallons is a reasonable estimate of E0 consumption.

Estimates of E0, E15, and E85 consumption, combined with total gasoline energy demand from AEO2022, allowed us to calculate the consequent volume of E10 consumed as shown in Table 6.5.2-3.

Table 6.5.2-3: Estimating E10 Consumption

	E0 (mill gal)	E15[a] (mill gal)	E85[b] (mill gal)	Gasoline energy (Quad Btu)	E10[c] (mill gal)
2023	2,128	561	353	16.8067	136,643
2024	2,128	671	367	16.7825	136,323
2025	2,128	756	381	16.7396	135,871

[a] Assumes that the denatured ethanol concentration of E15 is 15%.
[b] Assumes that the denatured ethanol concentration of E85 is 74%, consistent with the assumption made by EIA.
[c] Assumes that the denatured ethanol concentration of E10 is 10.1%, based on data collected by the RFG Survey Association indicating that the average ethanol concentration was 9.9% in 2021, and assuming 2% denaturant.

We could then derive the total volume of ethanol consumed as a function of the projected volumes of E15 and E85.

Table 6.5.2-4: Projected Total Ethanol Consumption Derived From E15 and E85 Volumes

	E15		E85		E10		Total ethanol
	Fuel	Ethanol	Fuel	Ethanol	Fuel	Ethanol	
2023	561	84	353	261	136,643	13,801	14,146
2024	671	101	367	272	136,323	13,769	14,141
2025	756	113	381	282	135,871	13,723	14,118

[a] Assumes that the denatured ethanol concentration of E15 is 15%.
[b] Assumes that the denatured ethanol concentration of E85 is 74%, consistent with the assumption made by EIA.
[c] Assumes that the denatured ethanol concentration of E10 is 10.1%, based on data collected by the RFG Survey Association indicating that the average ethanol concentration was 9.9% in 2021, and assuming 2% denaturant.

The total ethanol consumption calculated as a function of projected E0, E10, E15, and E85 (Table 6.5.2-4) can then be compared to the total ethanol consumption calculated as a function of projected poolwide ethanol concentration (Table 6.5.1-3). The results are shown in Table 6.5.2-5.

[814] "National Fuels Survey Program Ethanol Data for the 2021 Compliance Period," available in the docket.
[815] "STEO Jan 2022 Table 4a," available in the docket.

Table 6.5.2-5: Comparison of Projected Total Ethanol Consumption (million gallons)

	Based on projected ethanol concentration	Based on projected ethanol blend volumes	Difference
2023	14,590	14,146	-444 (3.0%)
2024	14,640	14,141	-499 (3.4%)
2025	14,669	14,118	-551 (3.8%)

We do not know why ethanol consumption based on projected ethanol concentration differs so much from the ethanol consumption based on projected ethanol blend volumes. We hypothesize that these differences may be the result of errors in estimates of E0, the possibility that the data collected through the BIP program may not be representative of the nation as a whole, underestimates of the total gasoline demand, or some combination of the three. Regardless, we believe that the BIP data represents the best available source of information on sales of E15 and E85, and that the estimates of E15 and E85 consumption shown in Tables 6.5.2-1 and 6.5.2-2 are a reasonable basis for estimating distribution costs for these two blends. We are not aware of better sources of data or clearly superior methodologies to estimating E15 and E85 use. As such, we have done the best we can with the limited information available to us. We acknowledge the significant limitations in the data available to us and the uncertainties this creates for our estimates. In any event, as shown in Chapter 10, the costs unique to E15 and E85 relative to E10 (associated with distribution, including blending and retail costs) reflect only a small portion of the costs of ethanol and a miniscule portion of the total costs associated with the candidate volumes. Thus, even were we to estimate significantly different E15 and E85 volumes, that would have very limited impacts on our assessments of costs and no impact on our provisional judgment with respect to the appropriate volumes to propose.

6.6 Corn Ethanol

As described in more detail in Chapter 1.7, total domestic ethanol production capacity increased dramatically between 2005 and 2010, and increased at a slower rate thereafter. In 2020, production capacity had reached 17.4 billion gallons.[816,817] This production capacity was significantly underused in 2020 due to the COVID-19 pandemic, which depressed gasoline demand in comparison to previous years. Actual production of ethanol in the U.S. reached 12.85 billion gallons in 2020, compared to 14.72 billion gallons in 2019.[818]

The expected annual rate of future commercial production of corn ethanol will be driven primarily by gasoline demand as most gasoline is expected to continue to contain 10% ethanol in the foreseeable future. Commercial production of corn ethanol is also a function of exports of ethanol and to a much smaller degree the demand for E0, E15, and E85. While production of corn ethanol may be limited by production capacity in the abstract, it does not appear that production capacity will be a limiting factor in 2023–2025 for meeting the candidate volumes.

As described in Chapter 6.5.1, we estimated total ethanol consumption for 2023–2025 by extrapolating from historical poolwide ethanol concentration and the number of retail stations

[816] "2021 Ethanol Industry Outlook - RFA," available in docket EPA-HQ-OAR-2021-0324.
[817] "Ethanol production capacity - EIA April 2021," available in docket EPA-HQ-OAR-2021-0324.
[818] "RIN supply as of 3-22-21," available in docket EPA-HQ-OAR-2021-0324.

offering E15 and E85. This total volume is a combination of corn ethanol, cellulosic ethanol, and advanced ethanol. Our estimate of corn ethanol consumption for 2023–2025 for the purposes of estimating the mix of biofuels that could be made available is shown in Table 6.6-1.

Table 6.6-1: Calculation of Projected Corn Ethanol Consumption for 2023–2025 (million gallons)

	2023	2024	2025
Total ethanol	14,590	14,640	14,669
Imported sugarcane ethanol	110	110	110
Domestic advanced ethanol	25	25	25
Corn ethanol	14,455	14,505	14,534

Total production of corn ethanol in 2023–2025 is likely to be higher than the consumption levels shown in Table 6.6-1 because the U.S. has exported significant volumes in recent years. For instance, in 2021 ethanol export volumes were 1.25 billion gallons.[819]

6.7 Conventional Biodiesel and Renewable Diesel

While the vast majority of conventional renewable fuel supplied in the RFS program has been corn ethanol, there have been smaller volumes of conventional biodiesel and renewable diesel used in the U.S. in some years. Conventional biodiesel and renewable diesel can only be produced at facilities grandfathered under the provisions of 40 CFR 80.1403 as there currently exist no valid RIN-generating pathways for the production of conventional (D6) biodiesel or renewable diesel. These biofuels are not required to meet the 50% GHG reduction threshold to qualify as BBD under the statutory definition, but the feedstocks used to produce grandfathered biodiesel or renewable diesel must still meet the regulatory definition of renewable biomass, and the biofuel produced must meet all other statutory and regulatory requirements. The quantity of conventional biodiesel and renewable diesel consumed each year from 2014–2021 is shown in Table 6.7-1.

Table 6.7-1: Conventional Biodiesel and Renewable Diesel Used in the U.S. (million gallons)

	2014	2015	2016	2017	2018	2019	2020	2021
Domestic D6 Biodiesel	1	0	0	0	0	0	0	0
Domestic D6 Renewable Diesel	0	0	0	0	0	0	0	0
Imported D6 Biodiesel	52	74	113	0	0	0	0	0
Imported D6 Renewable Diesel	2	86	45	2	0	0	0	0
All D6 Biodiesel and Renewable Diesel	55	160	158	2	0	0	0	0

In 2014-2016 the volume of conventional biodiesel and renewable diesel used in the U.S. was relatively small, but still significant. Use of these fuels in the U.S. dropped to very low levels in 2017 and has been less than 1 million gallons per years from 2018-2021. Nearly all of

[819] "Fuel Ethanol Exports by Destination from EIA 6-27-22," available in the docket.

the conventional biodiesel and renewable diesel used in the U.S. has been imported, with the only exception being one million gallons of domestically produced biodiesel in 2014. However, conventional (D6) RINs have continued to be generated for biodiesel and renewable diesel in recent years. From 2018 through 2021 the volumes of renewable diesel for which conventional biofuel RINs were generated each year (in million gallons) were 107, 116, 76, and 135 respectively. These RINs were retired for reasons other than compliance with the annual volume obligations, suggesting that they were used outside of the U.S. or for purposes other than transportation fuel.

The potential for conventional biodiesel and renewable diesel production and use in the U.S. is far greater than the quantity of these fuels actually supplied in previous years. The total production capacity of registered grandfathered biodiesel and renewable diesel producers is over 3 billion gallons in the U.S., with an additional 0.6 billion gallons internationally. Feedstock availability does also not appear to be a limiting factor, as USDA estimates that approximately 212 million metric tons of vegetable oil will be produced globally in the 2021/2022 agricultural marketing year.[820] This quantity of vegetable oil could be used to produce approximately 61 billion gallons of biodiesel and renewable diesel.[821] While much of this vegetable oil is currently used in non-biofuel markets, any of this vegetable oil that meets the regulatory definition of renewable biomass could be used to produce conventional biodiesel or renewable diesel at a grandfathered facility so long as it meets all other RFS program requirements. The quantity of conventional biodiesel and renewable diesel that could be supplied to the U.S. in 2023–2025 is not without limit, but this data suggests that large quantities of this fuel are being or could be produced,[822] and that the use of these fuels in the U.S. is largely a function of demand for this fuel in the U.S. versus other markets.

[820] USDA World Agricultural Supply and Demand Estimates. June 10, 2022.
[821] This calculation assumes one gallon of biodiesel or renewable diesel can be produced from 7.6 pounds of vegetable oil.
[822] The OECD-FAO Agricultural Outlook 2021-2030 projects global biodiesel consumption to reach approximately 50 billion liters (about 13.2 billion gallons) in 2022.

Chapter 7: Infrastructure

This chapter analyzes the impact of renewable fuels on the distribution infrastructure of the U.S. The CAA indicates that this assessment must address two aspects of infrastructure:

1. Deliverability of materials, goods, and products other than renewable fuel.
2. Sufficiency of infrastructure to deliver and use renewable fuel.

This chapter begins by addressing the sufficiency of infrastructure to deliver and use different types of renewable fuels. We then address how the use of renewable fuels affects the deliverability of materials, goods, and products other than renewable fuel.

Note that while we are projecting higher volumes of renewable fuel consumption relative to the No RFS baseline, in analyzing the impacts of the candidate volumes on infrastructure we have considered whether the candidate volumes would require additional infrastructure relative to the infrastructure that currently exists. We believe that the existing infrastructure is the relevant point of reference for the No RFS baseline since it is unlikely that the infrastructure enabling and supporting consumption of renewable fuel in 2022 would change even if we did not establish volume requirements for future years, at least not in the 2023–2025 timeframe. The number of vehicles that can consume particular renewable fuels, pipelines, storage tanks, fuel delivery vehicles, and retail service stations generally change only on longer timescales, and only insofar as the outlook for renewable fuel demand changes. Therefore, this chapter discusses infrastructure impacts primarily in terms of the changes that might be needed or expected to occur in 2023–2025 in comparison to their recent or current status.

7.1 Biogas

Renewable biogas infrastructure considerations differ from those for other biofuels not only because it is a gas rather than a liquid, but also because renewable biogas can be processed to be physically identical to natural gas, which is used for many purposes including transportation.[823] Natural gas was used in CNG/LNG vehicles for many years prior to the introduction of renewable biogas. The RFS program allows RINs to be generated for renewable biogas that is fungible with the wider natural gas pool, provided that a contract is in place to demonstrate that the same volume of natural gas is used for transportation purposes and all other regulatory requirements are met.[824] As the cost of running spur pipelines for anything beyond short distances becomes prohibitively expensive, only those biogas sources that are in relatively close proximity to the existing natural gas pipeline infrastructure are likely to be developed. Once connected to the natural gas pipeline network, renewable biogas uses the existing natural gas distribution system and CNG/LNG vehicle refueling infrastructure, and is used in the same CNG/LNG vehicle fleet as natural gas. According to data from the DOE Alternative Fuels Data

[823] Growth in biogas may require investment in additional gas cleanup operations prior to pipeline injections, particularly in California where pipeline standards currently preclude the injection of most biogas. The potential for such biogas cleanup costs are discussed in Chapter 10.1.2.5.1.
[824] See 40 CFR 80.1426(f).

Center, there are currently approximately 1,500 public and private CNG fueling stations and approximately 100 public and private LNG refueling stations in the U.S.[825]

Once the processed biogas is in the gas pipeline, it is virtually indistinguishable from natural gas. However, expanding CNG/LNG vehicle infrastructure to support growth in the renewable biogas beyond the current level of CNG/LNG used in the transportation sector—estimated at 1.4–1.75 billion ethanol-equivalent gallons of CNG/LNG per year in 2023–2025—would represent a substantial challenge.[826] The incentives for increasing the use of CNG/LNG in the transportation sector, including incentives from the RFS program and state programs such as the California LCFS program, may be insufficient to cause a substantial increase in the CNG/LNG vehicle fleet and refueling infrastructure. CNG/LNG vehicles are predominately used in fleet applications where there is a unique situational advantage (e.g., a natural gas supplier's utility fleet or landfill's waste hauler fleet). In addition, it would be more challenging to establish the necessary contracts to demonstrate that natural gas was used in CNG/LNG vehicles outside of fleet operations. The cost associated with removing the impurities in renewable biogas to make it suitable for use in CNG/LNG vehicles and to facilitate its fungible transportation in the natural gas distribution system could also be a barrier to its expanded use. Nevertheless, we do not expect infrastructure to constrain the use of CNG/LNG derived from biogas to levels below those projected to be available in Chapter 6.1.3.

7.2 Electricity

Infrastructure considerations for electricity differ from biofuel infrastructure, as generation, transmission, and distribution all have unique requirements. Furthermore, renewable electricity generating units and EV charge stations also have their own considerations, all of which play a role in electricity eligible under the RFS program.

Much of the electricity generation capacity that is eligible under the RFS program is already exporting electricity to the grid. This means that much of the hardware required for a grid connection is already in place, and while capital expenditure for these connections can be expensive, much of the capacity in 2023–2025 will come from existing facilities that have already invested in the necessary equipment, such as grid protection hardware and a step-up transformer in order for electricity to be exported to the commercial transmission grid. There are six interconnects in North America that facilitate electricity reliably to customers within their territory, spanning the U.S., Canada, and Mexico. This interconnect, composed of over 700,000 circuit miles of transmission lines,[827] have delivered power to consumers before and during the life of the RFS program. While transmission losses across long distances may contribute to less electricity delivered to EVs compared to what is generated, it is likely to not affect the candidate volumes for biogas to electricity.

[825] AFDC Alternative Fueling Station Locator. https://afdc.energy.gov/stations/#/analyze?fuel=LNG&fuel=CNG&access=public&access=private&country=US. Data current as of September 20, 2022.
[826] See Chapter 6.1.3 for further discussion of the estimated use of CNG/LNG as transportation fuel in 2023–2025 and Chapter 10.1.4 for discussion of the costs associated with refueling stations.
[827] Assessing HVDC Transmission for Impacts of Non-Dispatchable Generation, https://www.eia.gov/analysis/studies/electricity/hvdctransmission/pdf/transmission.pdf

One of the crucial components of the biogas-to-electricity pathway under the RFS program relies on EV charging, either through public or private charging stations. Over 80% of EV charging occurs in private residences, while 20% occurs at public charging stations. There are currently approximately 50,000 public and private charging station locations and 130,000 public and private electric vehicle supply equipment (EVSE) ports in the U.S.[828] Access to public chargers near highways and other high-volume routes is being expanded to support the growth of EVs and so we do not expect charging infrastructure to constrain the generation or expansion of renewable electricity to the candidate volumes.

7.3 Biodiesel

The RFS2 rule projected that 1.5 billion gallons of biodiesel would be used in 2017 and 1.82 billion gallons would be used in 2022 to meet the statutory biofuel volume requirements.[829] We noted that biodiesel plants tended to be more dispersed than ethanol plants, thereby facilitating delivery to local markets by tank truck and lessening the need to distribute biodiesel to over long distances. Biodiesel imports also helped to serve coastal markets. We projected that as biodiesel volumes grew, there would be more need for long-distance transport of domestically-produced biodiesel. We estimated that such long-distance transport would be accomplished by manifest rail and, to a lesser extent, by barge, since the economy of scale would not justify the use of unit trains. We estimated that biodiesel and biodiesel blends would not be shipped by pipeline to a significant extent due to concerns over potential contamination of jet fuel that is also shipped by pipeline.

In 2010, much of the biodiesel blending was taking place at facilities downstream of terminals, such as storage facilities operated by individual fuel marketers. We projected that this would take place to a lesser extent as volumes grew with most biodiesel being blended at terminals to the 5% (B5) blend level that is approved for use in diesel engines by all manufacturers for distribution to retail and fleet fueling facilities. We acknowledged that the expansion of biodiesel volumes could pose issues for petroleum terminals, but that these issues could be resolved.[830] Since vehicle refueling infrastructure is compatible with biodiesel blends up to 20% (B20), we estimated that there would be no changes needed at retail and fleet facilities to accommodate the projected increase in biodiesel use.

There are significant instances where actual biodiesel production and use have developed differently than we projected in the RFS2 rule. Most importantly, biodiesel consumption reached over 2 billion gallons in 2016 and has remained between 1.8–2 billion gallons per year from 2017–2021, largely exceeding the 1.82 billion gallons that we projected would be used in 2022.[831] Another significant difference is that much biodiesel blending is taking place downstream of terminals at fuel marketer storage facilities and even at fuel retail facilities.

[828] AFDC Alternative Fueling Station Locator. https://afdc.energy.gov/stations/#/analyze?fuel=ELEC&access=public&access=private&country=US. Data current as of September 20, 2022.
[829] See Chapter 1.2.2 of the RFS2 Regulatory Impact Analysis (EPA-420-R-10-006).
[830] There is additional difficulty in storing and blending biodiesel because of the need for insulated and/or heated equipment to prevent cold flow problems in the winter. This issue is typically not present for B5.
[831] Biodiesel consumption numbers based on EMTS data.

One factor that could somewhat ease biodiesel transportation to terminals is the fact that in some limited cases, shipment of low-level biodiesel blends up to 5% is currently taking place on some petroleum product pipelines that do not also carry jet fuel.[832] If the transportation of biodiesel blends via pipeline were expanded more broadly, this change could significantly reduce the cost of biodiesel distribution. However, jet fuel is a significant product on much of the petroleum pipeline system and concern over biodiesel contamination of jet fuel remains a significant limitation on the ability to expand the shipment of biodiesel blends by pipeline. Industry is currently investigating whether jet fuel can tolerate higher levels of biodiesel contamination, which may allow low-level biodiesel blends to be shipped on pipelines that also carry jet fuel.[833] Finally, there appears to be substantial volumes of B10–B20 being used despite the fact that a significant number of vehicle manufacturers only warranty their engines for up to B5.[834] This has resulted in an uneven distribution of biodiesel use across the nation, with some parts using more than 5% while other locales use little or no biodiesel.[835]

While we are projecting that the candidate volumes for 2023–2025 would require substantial biodiesel volumes relative to the No RFS baseline, we are also projecting small decreases in the volume of biodiesel relative to the 2022 baseline. Rather, the expansion of BBD is projected to occur through renewable diesel, as discussed in Chapter 7.4. As such, we do not anticipate any challenges associated with the infrastructure to distribute and use biodiesel through 2025.

However, it is possible that domestic biodiesel production and/or biodiesel imports may increase in 2023–2025. Domestic biodiesel production capacity is significantly higher than current production levels.[836] A review of monthly biodiesel imports suggests that import infrastructure can support significantly higher volumes of imports.[837] For example, over 700 million gallons of biodiesel was imported in 2016.[838] Monthly import data suggests that 1.3 billion gallons per year of imports could be supported using the existing infrastructure if we were to assume that the 112 million gallons of biodiesel imports that took place in December 2016 could be maintained year-round. Some additional expansion in import infrastructure may also occur through 2025. Therefore, we do not believe that domestic production capacity or import infrastructure constraints would be a substantial impediment to an expansion in biodiesel volumes at current levels.[839]

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[832] Ethanol, Biofuels, and Pipeline Transportation. Association of Oil Pipelines and American Petroleum Institute. https://www.api.org/~/media/files/oil-and-natural-gas/pipeline/aopl_api_ethanol_transportation.pdf

[833] An ASTM task group is seeking additional data to address negative comments on a 2018 ballot to increase the limit on biodiesel contamination in jet fuel from 50 mg/kg to 100 mg/kg. The ASTM limit on biodiesel contamination of jet fuel was last revised in 2015. Revised ASTM Standard Expands Limit on Biofuel Contamination in Jet Fuels, ASTM New Release, February 2, 2015.

[834] See Pilot Flying J Fuel Offerings, Memorandum to EPA Docket EPA-HQ-OAR-2021-0427.

[835] See Average Biodiesel Blend Level By State Based on EIA Data, Memorandum to EPA Docket EPA-HQ-OAR-2021-0427.

[836] See Chapter 6.2.

[837] EIA, U.S. Imports of Biodiesel 2009 thorough 2021.

[838] Ibid.

[839] The expansion of biodiesel imports to the extent discussed above is for purposes of the infrastructure analyses only. There would be significant challenges in obtaining foreign produced biodiesel volumes to approach such a substantial increase in imported biodiesel. See Chapter 1.4.2.

We anticipate that if biodiesel production and imports increase significantly, investment in the infrastructure to transport biodiesel from the points of production to locations where it can be consumed would be needed. These investments would primarily be associated with securing sufficient downstream biodiesel storage and the requisite number of rail cars and tank trucks suitable for biodiesel transport.[840]

Expanding biodiesel blending infrastructure to accommodate significantly higher biodiesel volumes may also pose challenges. Many terminals that have yet to distribute biodiesel would likely need to install the infrastructure. All vehicle refueling infrastructure is compatible with B20 blends, thereby easing the expansion to retail of biodiesel blends made at terminals. However, significant infrastructure changes would be needed to biodiesel storage and blending facilities downstream of terminals and at retail facilities if substantial additional volumes of biodiesel blends were to be made downstream of terminals.

Further, the cold flow of petroleum-based diesel dispensed to vehicles must often be improved in the winter through the addition of #1 diesel fuel and/or cold-flow improver additives. Biodiesel blends tend to have poorer cold flow performance than straight petroleum-based diesel fuel. This requires the use of additional cold-flow improvers and sometimes limits the biodiesel blend ratio that can be used under the coldest conditions.[841] Biodiesel cold flow properties are dependent on the source of the feedstock with biodiesel produced from palm oil being subject to wax formation at higher temperatures than soy-based biodiesel.[842] Thus, additional actions are necessary to ensure adequate cold-flow performance of palm-based biodiesel blends compared to soy-based biodiesel. Such additional actions may be uneconomical in some cases.[843] Therefore, a substantial increase in the use of biodiesel, especially biodiesel produced from palm oil, during the winter may be a challenge.

7.4 Renewable Diesel

The RFS2 rule projected that the volume of “drop-in” cellulosic and renewable diesel fuel would range from 0.15–3.4 billion gallons in 2017 and 0.15–9.5 billion gallons in 2022.[844] Such fuels are referred to as drop-in fuels because their physical properties are sufficiently similar to petroleum-based diesel to be fungible in the common diesel fuel distribution system.[845] Thus, little change is needed to the fuels infrastructure system to support the use of drop-in biofuels. The RFS2 rule projected that the distribution infrastructure could expand in a timely fashion to accommodate that projected range of growth in drop-in cellulosic and renewable diesel fuel.[846]

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[840] Biodiesel rail cars and to a lesser extent tank trucks must often be insulated and or heated during the winter to prevent cold flow problems. The use of such insulated/heated vessels is sometimes avoided by shipping pre-heated biodiesel.
[841] B5 blend levels can typically be maintained.
[842] Biodiesel Cold Flow Basics, National Biodiesel Board, 2014.
[843] Evaluation and enhancement of cold flow properties of palm oil and its biodiesel, Puneet Verma, et.al., Biofuel Research Laboratory, Indian Institute of Technology, Elsevier Energy Reports, January 2016.
[844] See Chapter 1.2.2 of the RFS2 Regulatory Impact Analysis (EPA-420-R-10-006).
[845] Such drop-in fuels are typically blended with petroleum-based diesel prior to use.
[846] See Chapter 1.6 of the RFS2 Regulatory Impact Analysis (EPA-420-R-10-006).

In practice, much of the renewable diesel produced in the U.S. has been transported by truck, rail, and ship, rather than by pipelines. This is in part due to the location of the renewable diesel production and demand and the lack of available pipelines to transport renewable diesel from production sites to demand centers. Renewable diesel can generate credits under state LCFS programs, and the magnitude of this incentive, especially in California, has caused most renewable diesel production in the U.S. to be shipped in segregated batches to California rather than being blended into diesel where it is produced. Regulatory challenges have also limited the transportation of renewable diesel via pipeline. Product transfer document (PTD) requirements for fuel shipped by pipeline and fuel pump labeling requirements often require that the blend level be indicated, but the concentration would often be uncertain in a fungible distribution system. Transportation of renewable diesel via common carrier pipelines can make documenting the use and blend levels of renewable diesel difficult, if not impossible.

The projected increase in domestic renewable diesel production through 2025 is significant both relative to the No RFS and 2022 baselines.[847] We expect that much of this new renewable diesel will also be used in California and other states with state incentive programs (e.g., Oregon). Renewable diesel produced in California will likely be distributed locally, and much of the renewable diesel produced on or near the Gulf Coast is likely to be transported via ship. The remaining renewable diesel production facilities are not located near the coast, and we therefore project that the fuel they produce will likely be transported via truck and/or rail to markets where the fuel is used. This may require some expansion to the existing infrastructure, such as additional rail cars to transport renewable diesel. The fact that the new or expanding renewable diesel production facilities are generally located in the western U.S., relatively close to California and Oregon, likely reduces the impact of distributing these fuels on the transportation infrastructure, though this may be somewhat offset by the need to transport feedstocks to the renewable diesel production facilities. While some adjustments will likely be needed to accommodate the expected increase in renewable diesel production, we do not expect that these adjustments will inhibit the growth of renewable diesel production or appreciably impact transportation networks in the U.S. more broadly.

7.5 Ethanol

We are projecting that the candidate volumes for 2023–2025 would require moderate ethanol volume increases relative to the No RFS baseline and smaller increases relative to the 2022 baseline. The increases relative to the No RFS baseline are associated predominately with the use of higher-level ethanol blends such as E15 and E85, as E10 is economical to be blended in the absence of the RFS program. However, since gasoline demand is projected to increase slightly in 2023 relative to 2022, E10 is also expected to increase in 2023–2025 when considered relative to 2022.

The infrastructure needed to deliver ethanol includes that required for distribution of denatured ethanol from production facilities to terminals, storage and blending equipment, and distribution of gasoline-ethanol blends to retail service stations. With regard to infrastructure needed to use ethanol, essentially all retail service stations are certified to offer E10 and all vehicles and equipment are designed to use E10. As a result, any infrastructure-related impacts

[847] See Chapter 6.2.

on the use of ethanol in 2023–2025 are associated with service station storage and dispensing equipment for higher-level ethanol blends such as E15 and E85, and the vehicles capable of using those blends. The majority of the E15 and E85 volume projected to be used in 2023–2025 is already being used in 2022; consequently, the infrastructure is already in place. However, the expanded volume in 2023–2025 would require additional infrastructure, primarily the expansion of retail stations as discussed below.

Based on our analysis below of the sufficiency of infrastructure to deliver and use ethanol, we have determined that there are constraints associated with E15 and E85 that limit the rate of future growth in their consumption. These constraints are appropriately reflected in our projections of total ethanol consumption in Chapter 6.5, since those projections represent only moderate changes in the nationwide average ethanol concentration in comparison to earlier years.[848]

7.5.1 Ethanol Distribution

To support the RFS2 rule, ORNL conducted an analysis of potential distribution constraints that might be associated with attaining the statutory volume targets through 2022.[849] The ORNL analysis analyzed ethanol transport pathways from production to blending facilities at terminals by rail, waterways, and roads, and projected that most ethanol would require long-distance shipment to demand centers. The primary mode of long-distance transport in 2010 was via manifest rail and, to a lesser extent, by barge, although transport by unit train was beginning to spread. ORNL projected that rail would continue to be the predominate means of long-distance ethanol transport through 2022, with a substantial increase in the use of unit trains and continued supplemental transport by barge. ORNL concluded that there would be minimal additional stress on most U.S. transportation networks overall to distribute the increased biofuel volumes.

However, ORNL stated that there would be considerable increased traffic along certain rail corridors due to the shipment of biofuels that would require significant investment to overcome the resulting congestion. We concluded that these investments could be made to increase the capacity of the effected rail corridors without undue difficulty, and that therefore the infrastructure system to the blending terminal could accommodate the projected increased volume of ethanol in a timely fashion.[850]

To update and expand upon the analysis of distribution infrastructure upstream of retail that was conducted for the RFS2 rule, EPA contracted with ICF International Inc. ("ICF") to conduct a literature review, background research, and stakeholder interviews to characterize the impacts of distributing ethanol and other biofuels.[851] The 2018 ICF report determined that the conclusions from the 2009 ORNL analysis have largely turned out to be accurate based on an absence of indicators of distribution constraints up to and including the blending terminal. ICF

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[848] A nationwide average ethanol concentration above 10.00% can only occur insofar as there is consumption of E15 and/or E85.
[849] "Analysis of Fuel Ethanol Transportation Activity and Potential Distribution Constraints," ORNL, March 2009.
[850] See Chapter 1.6 of the RFS2 Regulatory Impact Analysis (EPA-420-R-10-006).
[851] Impact of Biofuels on Infrastructure, Report for EPA by ICF International Inc., January 2018.

noted that there were instances when the ethanol industry went through rapid expansion where the rail industry was not able to fully accommodate the expansion of inter-regional trade in ethanol. However, ICF found no evidence to suggest that rail congestion from shipment of biofuel was a persistent or common problem at the time that the study was completed. Likewise, ICF found no evidence that marine networks, including those used for import and export, were experiencing significant issues in accommodating increased volumes of biofuels. Consistent with the 2010 analysis, ICF stated that the expansion of ethanol and biodiesel volumes could pose issues for petroleum terminals, but that these issues could be resolved. While ICF indicated that there likely had been negative impacts on rural and highway transportation networks surrounding ethanol production facilities, ICF also determined that these impacts could be mitigated with network infrastructure planning and increased funding for road maintenance. ICF noted these increased costs would be small in comparison to broader maintenance costs for roads and that the road network could accommodate substantial growth in the movement of biofuels.

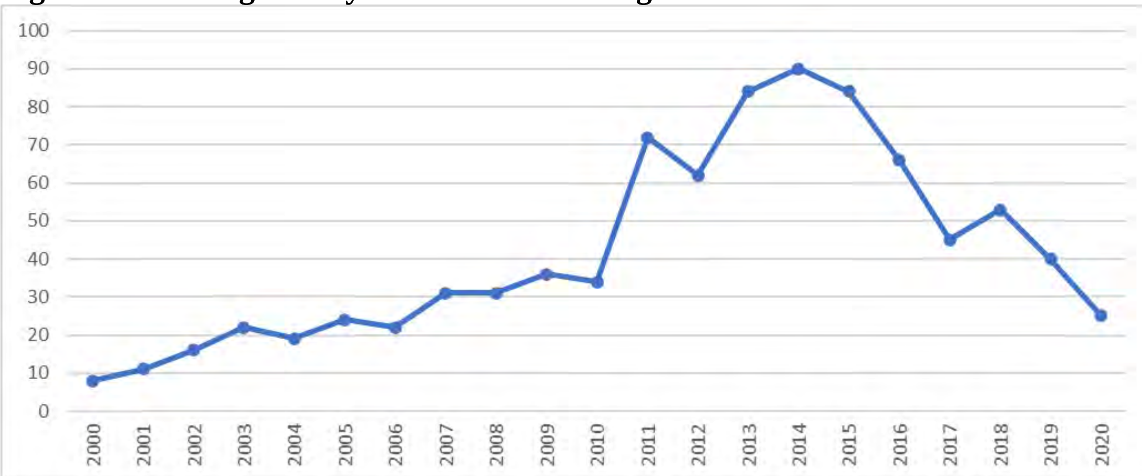
Based on the ICF study and our own assessment of the implementation of the RFS program, we conclude that the response of the ethanol distribution infrastructure system upstream of retail has largely unfolded as we projected in the RFS2 rule. Ethanol imports to coastal demand centers have helped to satisfy local demand. Ethanol transport over long distances is primarily being accomplished by unit train and, to a lesser extent, by manifest rail and barge. Materials compatibility issues continue to prevent ethanol and ethanol blends from being shipped in petroleum product pipelines. Tank trucks are used to distribute ethanol to markets close to the ethanol production facility and from rail receipt facilities to more distant markets. Petroleum terminals have installed the necessary ethanol receipt, storage, and blending infrastructure. Intermodal facilities, such as those that transfer ethanol directly from rail cars to tank trucks, are also being used to ease the burden on terminals.

7.5.2 Infrastructure for E85

E85 is permitted to be used only in designated FFVs. As of 2020, there were about 28 million registered light-duty FFVs in the U.S., representing about 10% of all spark-ignition vehicles.[852] However, the number of registered FFVs is expected to decline in the coming years. For instance, the total number of FFV model offerings has been declining in comparison to its historical maximum in 2014.

[852] "FFV registrations from AFDC December 2021" and "DOT National Transportation Statistics Table 1-11," available in the docket.

Figure 7.5.2-1: Light-Duty FFV Model Offerings



Source: Alternative Fuels Data Center. See "Light-Duty AFV HEV and Diesel Model Offerings by Technology-Fuel March 2022," available in the docket.

The number of registered FFVs in the in-use fleet is changing consistent with the reduced offerings. While the registered FFV count continued to increase during 2016–2020, the rate of increase has slowed, as shown in Table 7.5.2-1. If FFV offerings remain at their 2020 levels or continue to decrease, we would expect the number of FFVs in the in-use fleet to begin decreasing after 2020.

Table 7.5.2-1: Change in Light-Duty FFV Registration Counts

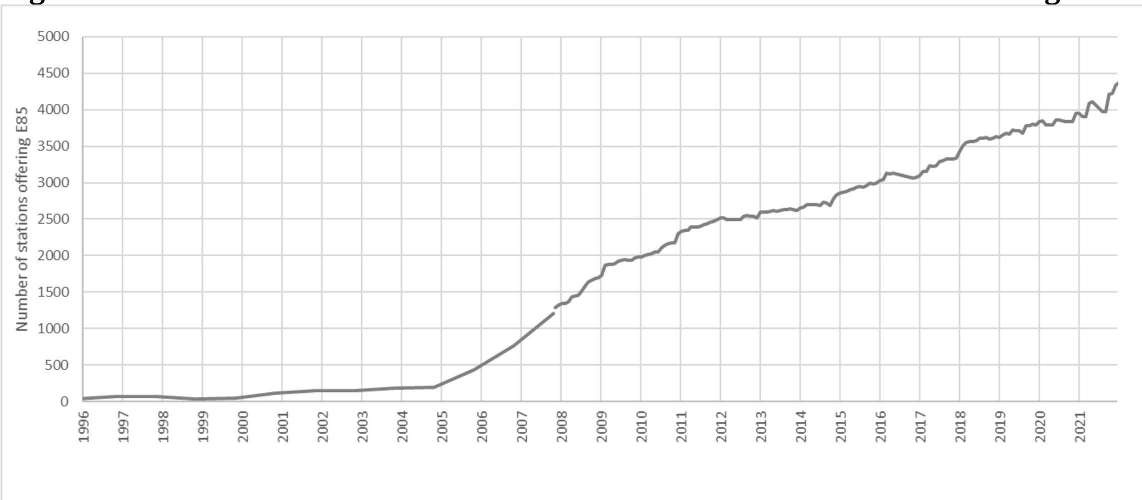
Year	% change in FFV counts compared to previous year
2017	10.0%
2018	6.4%
2019	4.5%
2020	1.6%

Source: Alternative Fuels Data Center. See "Change in Light-Duty Vehicle Registration Counts March 2022," available in the docket.

E85 is sold at retail stations where the pumps, underground storage tanks, and associated equipment has been certified to operate safely with the high ethanol concentrations.[853] As shown in Figure 7.5.2-2, stations offering E85 have increased steadily since about 2005. By June 2022, the total number of stations offering E85 had reached 4,476.

[853] "UST System Compatibility with Biofuels," EPA 510-K-20-001, July 2020.

Figure 7.5.2-2: Number of Public and Private Retail Service Stations Offering E85[a]

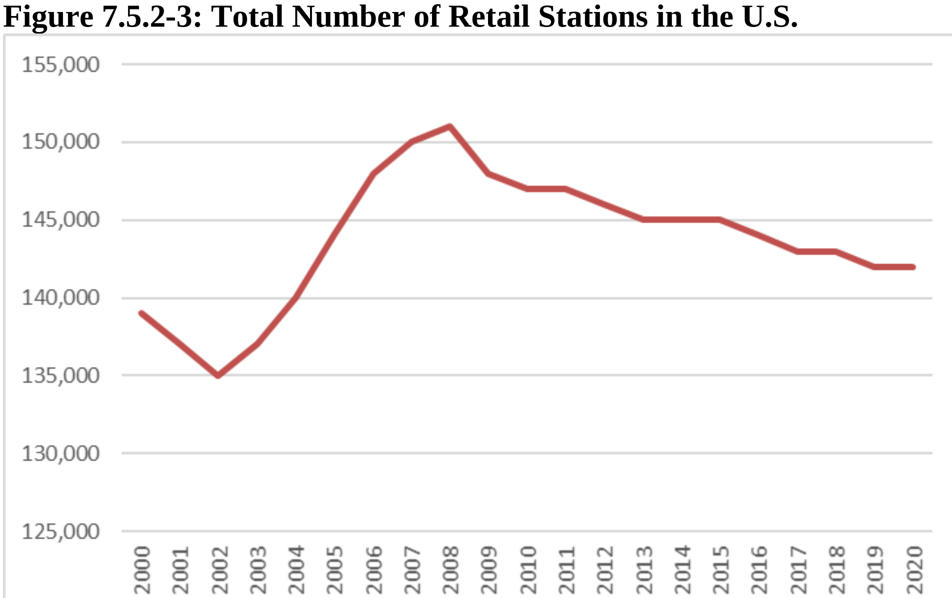


[a] Data through 2007 is annual, whereas data for 2008 and later is monthly.
Source: Department of Energy's Alternative Fuels Data Center (AFDC). https://afdc.energy.gov/stations/states. See, e.g., "AFDC - Alternative Fueling Station Counts by State 10-13-22," available in the docket.

Grant programs such as the USDA Biofuels Infrastructure Partnership (BIP) and the ethanol industry's Prime the Pump program, in addition to individual company efforts, have helped to fund the expansion of E85 offerings at retail stations. The combined effect of these efforts ensured ongoing growth in the number of stations offering E85.

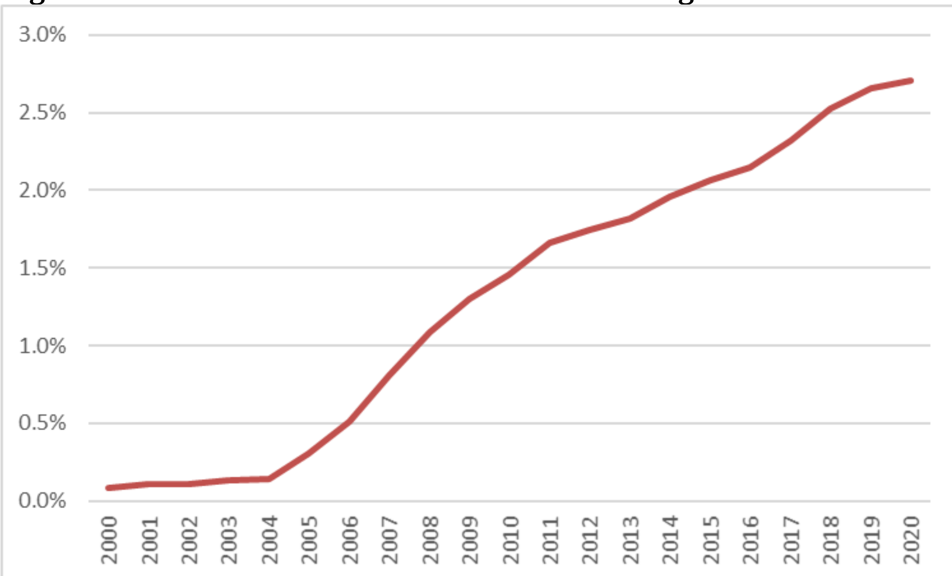
Although the total number of retail stations in the U.S. has varied, as shown in Figure 7.5.2-3, the fraction of those stations offering E85 has steadily increased. By the end of 2020, the fraction of retail stations offering E85 had reached 2.7%, as seen in Figure 7.5.2-4.

Figure 7.5.2-3: Total Number of Retail Stations in the U.S.



Source: Table 4.24, Transportation Energy Data Book, Edition 40.

Figure 7.5.2-4: Fraction of Retail Stations Offering E85



The above two factors—the small and declining fraction of vehicles capable of consuming E85 and the low, albeit modestly growing, number of retail stations that offer E85—represent significant infrastructure constraints on the market's ability to deliver and use E85 in the near future. While the applicable standards under the RFS program could theoretically provide some incentive for retail station owners to upgrade their equipment to offer E85, there is little direct evidence that the RFS program has operated in this capacity in the past.

The BIP program was in effect from 2016–2018, while its successor program—the Higher Blends Infrastructure Incentive Program (HBIIP)—effectively began at the beginning of 2021. While a higher growth rate in the number of E85 stations is not readily apparent in these years compared to previous years in Figure 7.5.2-2, an analysis of growth rates on shorter timescales suggests that these programs did have a moderate impact on growth rates. Therefore, for purposes of making projections of future growth in E85 stations, we applied a least-squares regression to a weighted data set wherein each successive year was given greater weight than the previous year: 2021 data was given a weighting of 12, 2020 data was given a weighting of 11, and so on back to 2010. This approach led to an average growth rate of 178 E85 stations per year. Using this growth rate, we estimated the total number of retail stations offering E85 in 2023–2025, as shown in Table 7.5.2-2.

Table 7.5.2-2: Projected Average Number of Stations Offering E85[a]

Year	Stations
2023	4,511
2024	4,689
2025	4,866

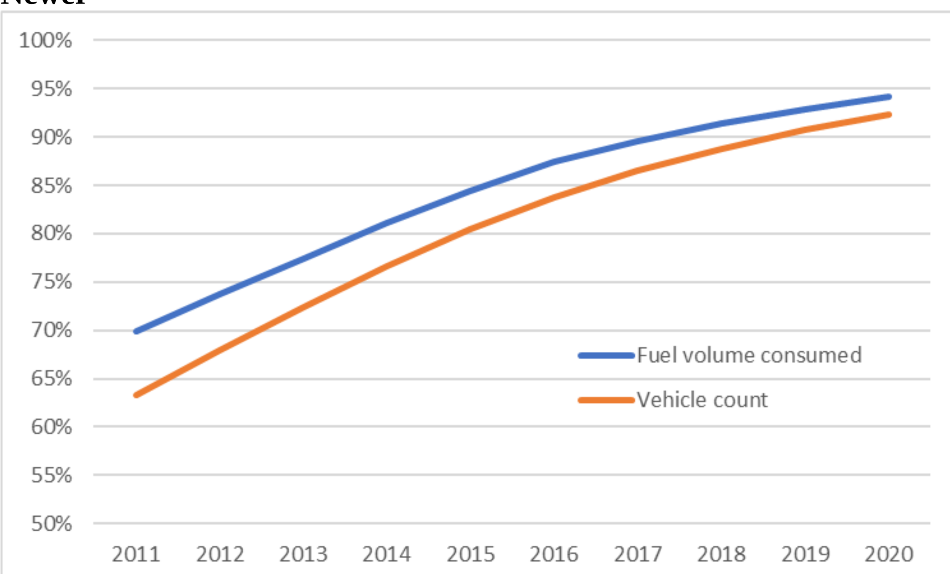
[a] Annual average, not year-end.

7.5.3 Infrastructure for E15

E15 is permitted to be used only in MY2001 and newer light-duty motor vehicles.[854] The infrastructure needed to support the use of E15 includes blending and storage equipment at terminals, certified storage and dispensing equipment at retail service stations, and the vehicles that are permitted to use E15. While the majority of service stations currently offering E15 do so through blender pumps—which can produce E15 on demand for consumers through the combination of E10 (or E0) and E85[855]—the number of terminals offering preblended E15 directly to service stations has been increasing.[856] The first terminals started to offer preblended E15 in 2016, and as of June 2022 E15 is offered at 99 terminals, accounting for about 7% for all U.S. terminals.[857,858]

As shown in Figure 7.5.3-1, the fraction of the in-use fleet that is MY2001 and newer has increased steadily since E15 was approved in 2011, and with it the fraction of all gasoline consumed by highway vehicles that is consumed by MY2001 and newer vehicles.

Figure 7.5.3-1: Fraction of In-Use Fleet and In-Use Gasoline Consumption for MY2001 and Newer



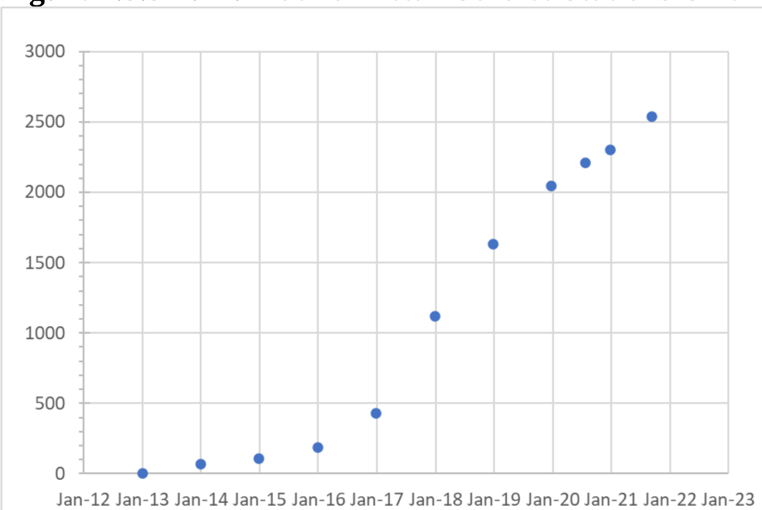
Source: Values calculated using annual retail vehicle sales of cars and trucks (Tables 4.6 and 4.7), survival rates (Table 3.15), miles per year per vehicle by age (Table 9.11), and fuel economy by model year (Table 4.12) from the Transportation Energy Data Book, Edition 40, ORNL, February 2022.

Based on the two modes of E15 production (terminals and blender pumps at retail stations), and the fact that the majority of in-use vehicles are legally permitted to use E15, it

[854] 76 FR 4662 (January 26, 2011).
[855] According to Prime the Pump, 1,771 out of 2,302 stations offering E15 at the end of 2020 used blender pumps.
[856] "Terminal Availability of E15 Grows as EPA Prepares to Remove RVP Barrier," available in the docket.
[857] https://growthenergy.org/resources/retailer-hub. See also "Retailer Hub Growth Energy 92421," available in the docket.
[858] Total number of active fuel terminals was 1,330 as of 3/31/22 per the Internal Revenue Service. https://www.irs.gov/businesses/small-businesses-self-employed/terminal-control-number-tcn-terminal-locations-directory. See "Actual Fuel Terminals as of 3-31-22," available in the docket.

appears that the primary constraint on the consumption of E15 in the near term is likely the number of retail stations that offer it. Since E15 was not approved for use until 2011, there were no retail stations offering it before 2011. Since the vast majority of the existing retail infrastructure (including the entire system of tanks, pipes, pumps, dispensers, vent lines, and pipe dope) is not confirmed to be entirely compatible with E15, growth in the number of retail stations offering E15 is dependent on investments in retail outlets to convert them to E15 compatibility or make them compatible when newly constructed. In cases wherein a retail station already offers E85 through a blender pump, there may be little or no investments needed for new equipment, and the decision to offer E15 may depend largely on the perceived economic benefit of doing so. For other station owners, the costs can be substantial. Growth in the number of stations offering E15 was slow until the BIP and Prime the Pump programs began providing funding for station conversions in 2016.

Figure 7.5.3-2: Number of Retail Service Stations Offering E15



Source: "Prime the Pump Infrastructure Update - Sept 2021," available in the docket.

USDA followed up its BIP program with the HBIIP program, which also provides funds to help retail service station owners to upgrade or replace their equipment to offer biofuels. This program effectively began in 2021 and is estimated to take three years to complete.

There may also be resistance to expanded offerings of E15 due to concerns about liability.[859] These liability concerns fall into two areas: the use of retail storage and dispensing equipment that is not compatible and/or not approved for E15, and consumers that refuel vehicles and engines not designed and/or approved for its use. With regard to equipment compatibility, even if much of the existing equipment at retail is compatible with E15 as argued in studies from the National Renewable Energy Laboratory (NREL)[860] and Stillwater Associates,[861] compatibility with E15 is not the same as being approved for E15 use. Under EPA regulations, parties storing ethanol in underground tanks in concentrations greater than 10% are

[859] See, e.g., "PMMA comments on the proposed 2014 – 2016 standards rule 7-27-15," available in the docket.

[860] K. Moriarty and J. Yanowitz, "E15 and Infrastructure," National Renewable Energy Laboratory, May 2015. Attachment 3 of comments submitted by the Renewable Fuels Association.

[861] Stillwater Associates, "Infrastructure Changes and Cost to Increase RFS Ethanol Volumes through Increased E15 and E85 Sales in 2016," July 27, 2015. Submitted with comments provided by Growth Energy.

required to demonstrate compatibility of their tanks with the fuel through one of the following methods:[862]

- A certification or listing of underground storage tank system equipment or components by a nationally recognized, independent testing laboratory such as Underwriter's Laboratory.
- Written approval by the equipment or component manufacturer.
- Some other method that is determined by the agency implementing the new requirements to be no less protective of human health and the environment.

The use of any equipment to offer E15 that does not satisfy these requirements, even if that equipment is technically compatible with E15, would pose potential liability for the retailer. This issue is of particular concern for underground storage tanks and associated hardware, as the documentation for their design and the types of materials used, and even their installation dates, is often unavailable. As existing underground storage tank systems reach the end of their warranties or are otherwise in need of repair or upgrade, there is an opportunity for retail station owners to install new systems that are compatible with E15. For instance, tanks installed earlier than 1990 have reached the end of their warranties and should be replaced to safely store fuel.

With regard to retailer concerns about litigation liability for E15 misfueling related to vehicles not designed and/or approved for use with E15, we note that EPA regulations are designed to address potential misfueling. These regulations require pump labeling, a misfueling mitigation plan, surveys, PTDs, and approval of equipment configurations, providing consumers with the information needed to avoid misfueling.[863] In addition, the portion of vehicles not designed and/or approved for E15 use continues to decline. MY2000 and earlier light-duty vehicles represent less than 10% of the in-use fleet, and just slightly over 5% of miles traveled. Vehicles designed and warranted by manufacturers to be fueled on E15 are likewise representing an ever-increasing portion of the in-use fleet.

In sum, the relatively small, albeit growing, number of stations offering E15 represents a significant constraint on the expansion of E15 through 2025. While the applicable standards under the RFS program could theoretically provide some incentive for retail station owners to upgrade their equipment to offer E15, there is little direct evidence that the RFS program has operated in this capacity in the past.

In order to project the number of retail stations that may offer E15 through 2025, we first separated the effects of USDA's BIP and HBIIP programs from all other efforts, including both private efforts and those funded by the ethanol industry's Prime the Pump program. The BIP program was responsible for the conversion of 841 retail stations from 2016–2018.[864] During this time, E15 stations were also increasing as a result of other efforts, bringing the total number of E15 stations to 1,630, as shown in Figure 7.5.3-2. Of this total, 841 are estimated to have been the result of the BIP program, while the remaining 789 E15 stations were the result of other

[862] "UST System Compatibility with Biofuels," available in the docket.
[863] See, e.g., 40 CFR 1090.1420 and 1090.1510.
[864] "Biofuel Infrastructure Partnership - original grants & projections" and "Communication with USDA on the BIP program 11-15-21," available in the docket.

efforts. The HBIIP program effectively began in 2021.[865] Given its similarity to the BIP program, we have assumed that it would likewise take three years to complete and would result in 841 new E15 stations. From these estimated impacts of the BIP and HBIIP programs, we were able to back-calculate the growth in E15 stations that can be attributed to private initiatives, including Prime the Pump.

Table 7.5.3-1: Historical Breakdown of E15 Stations

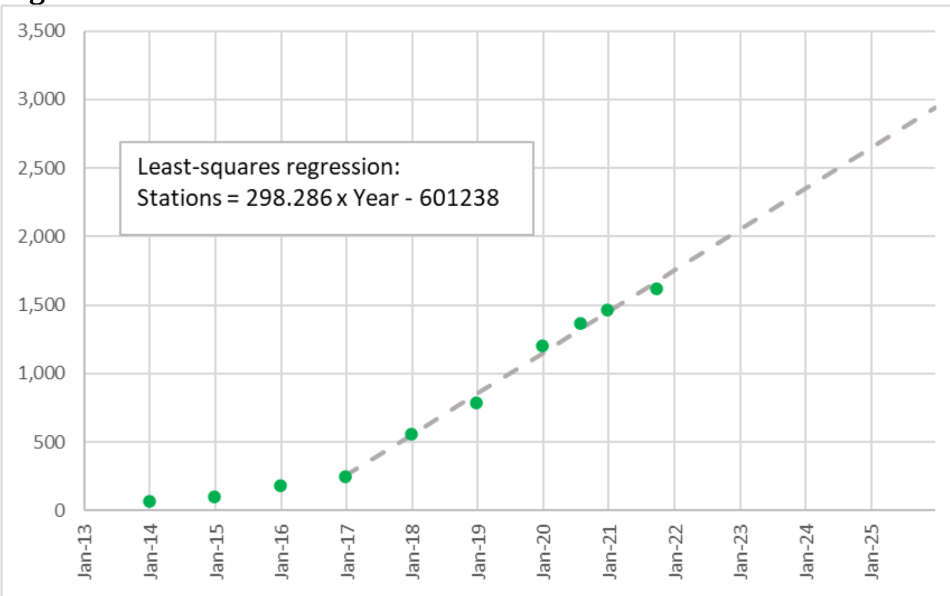
	Total[a]	**BIP[b]**	**HBIIP[c]**	**PTP + private efforts**
December 2012	2	0	0	2
December 2013	70	0	0	70
December 2014	105	0	0	105
December 2015	184	0	0	184
December 2016	431	183	0	248
December 2017	1,122	563	0	559
December 2018	1,630	841	0	789
December 2019	2,045	841	0	1,204
July 2020	2,208	841	0	1,367
December 2020	2,302	841	0	1,461
September 2021	2,536	841	75	1,620

[a] "Prime the Pump Infrastructure Update - Sept 2021".
[b] Assumes linear growth from 2016–2018.
[c] Assumes that 841 new E15 stations will ultimately be created, with linear growth from 2021–2023.

We observed that the growth due to private efforts appears to be linear after December 2016 and therefore used a least-squares regression to estimate this trend through 2025, as shown in Figure 7.5.3-3.

[865] The availability of grants and procedures for applying for them were announced in May 2020. See "USDA Announces $100 Million for American Biofuels Infrastructure," available in the docket.

Figure 7.5.3-3: Growth in E15 Stations Due to Private Initiatives



Using the available information on the BIP and HBIIP programs and the projection shown in Figure 7.5.3-3, we were able to estimate the breakdown of E15 stations for 2023–2025, as shown in Figure 7.5.3-4. The projected total number of E15 stations for 2023–2025 is shown in Table 7.5.3-2.

Figure 7.5.3-4: Projected Breakdown of E15 Stations

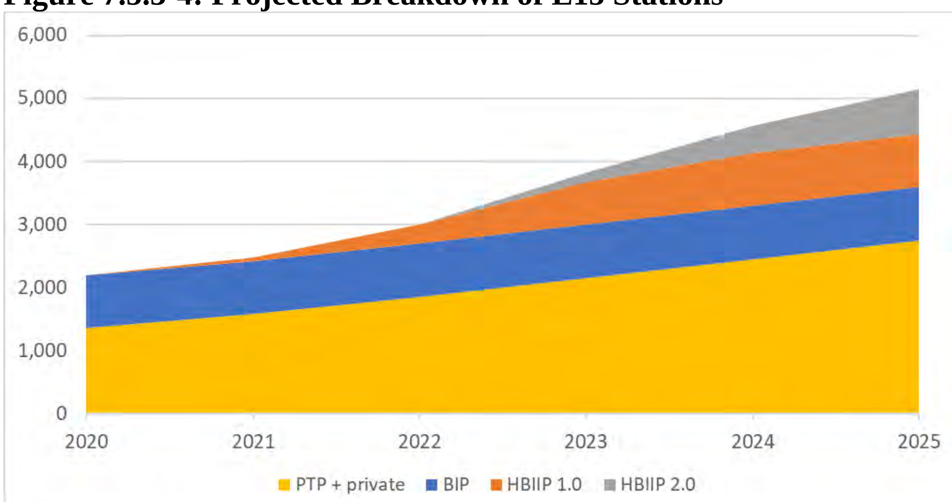


Table 7.5.3-2: Projected Average Number of Stations Offering E15[a]

Year	Stations
2023	3,818
2024	4,567
2025	5,146

[a] Annual average, not year-end.

7.6 Deliverability of Materials, Goods, and Products Other Than Renewable Fuel

The distribution of renewable fuels relies on the same rail, marine, and road infrastructure networks that are used to deliver materials, goods, and products other than renewable fuels. Therefore, we evaluated whether the use of renewable fuels would impact the deliverability of other items that rely on these infrastructure networks.

The 2009 ORNL study of biofuel distribution for the RFS2 rule concluded that there would be minimal additional stress on most U.S. transportation networks overall due to increased biofuel volumes.[866] This indicates that the shipment of the statutory biofuel volumes could be accommodated without impacting the deliverability of other items. However, as discussed in Chapter 7.5.1, ORNL noted that significant investment would be needed to overcome congestion on certain rail corridors. The 2018 ICF study of impacts of distributing ethanol and other biofuels determined that the conclusions from the 2009 ORNL analysis have largely turned out to be accurate based on an absence of indicators of distribution constraints.[867] However, ICF noted that there were instances when the ethanol industry went through rapid expansion where the rail industry was not able to fully accommodate the expansion in inter-regional trade in ethanol. During these periods, the volume of ethanol permitted to be shipped along the sensitive rail corridors was limited to mitigate the congestion. However, ICF found no evidence to suggest that rail congestion from shipment of biofuel was a persistent or common problem at the time of the study's completion in 2018.

Likewise, ICF found no evidence that the shipment of biofuels has had a negative impact on marine networks. While ICF indicated that there likely have been negative impacts on rural and highway transportation networks surrounding ethanol production facilities, it also determined that these impacts can be mitigated with network infrastructure planning and increased funding for road maintenance. ICF noted these increased costs are small in relation to broader maintenance costs for roads and that the road network can accommodate substantial growth in the movement of biofuels.

Based on both the ORNL study and the more recent ICF study, there appears to be minimal overall impact on transportation infrastructure from the distribution of biofuels, and the system appears to have been able to resolve localized instances of increased stress on the system in a timely fashion. As a result, we believe that the candidate volumes would not impact the deliverability of materials and products other than renewable fuel.

As part of considering impacts of biofuels on the deliverability of other items, we also considered constraints on the deliverability of feedstocks used to produce renewable fuel. We do not anticipate constraints that would make the candidate volumes difficult to achieve. For instance, biogas for CNG/LNG vehicles will be delivered through the same pipeline network used to distribute natural gas.[868] Since that biogas will be displacing natural gas used in CNG/LNG vehicles, we do not expect a net increase in total volume of biogas + natural gas

[866] "Analysis of Fuel Ethanol Transportation Activity and Potential Distribution Constraints," ORNL, March 2009.
[867] Impact of Biofuels on Infrastructure, Report for EPA by ICF International Inc., January 2018.
[868] See Chapter 7.1.

delivered. Similarly, we do not anticipate that renewable electricity used as transportation fuel will result from an increase in renewable electricity generation from biogas, but rather from a diversion of existing renewable electricity generation from non-transportation uses to transportation.[869] Consequently, we do not believe that there would be an increase in the production of biogas for use in generating renewable electricity.

As shown in Table 3.1-3, there would be an increase in corn ethanol consumption in 2023–2025 in comparison to 2022. However, the projected corn ethanol volumes are about 14.5 billion gallons, which is the same volume of corn ethanol consumed in 2018.[870] Since the corn collection and distribution network functioned without difficulty in 2018, there is no reason to believe that it would not function similarly in 2023–2025. Moreover, there may in fact be no change in domestic corn ethanol production if the increased consumption results from a reduction in exports.[871]

We estimate that the use of FOG for the production of biofuel will increase by 53 and 59 million gallons, respectively, from 2023 to 2024 and 2024 to 2025 (equivalent to 90 and 100 million RINs as shown in Table 3.1-3). The projected increase in the use of FOG for biofuel production is consistent with the trend observed from 2016–2021. This increase is a very small fraction of the total amount of FOG produced. According to LMC International, the total production volume of all animal fats and used cooking oil was about 2.7 billion gallons in 2020.[872] An annual increase of about 60 million gallons represents only 2% of total 2020 production. FOG is collected and distributed through a diverse network of trucking companies, and this increase would represent a very small portion of their activities. As a result, we do not anticipate any hindrances to the deliverability of FOG for the production of renewable diesel in 2023–2025.

Total soybean oil use for the production of BBD is projected to decrease slightly from 2023–2025 (see Table 3.1-3; soybean oil use in 2023 includes that needed to meet the proposed supplemental standard of 250 million RINs). In light of this projected decrease, we do not anticipate any shortage in the supply of soybeans or other oilseeds. We also expect that the soybean crushing capacity will be sufficient to supply the necessary quantities of soybean oil, and that there will be sufficient infrastructure to distribute biodiesel and renewable diesel to the markets where these fuels are used.

[869] See Chapter 7.2.
[870] "RIN Supply as of 2-17-22," available in the docket.
[871] See Chapter 6.6.
[872] "The Outlook for Increased Availability & Supply of Sustainable Lipid Feedstocks in the U.S. to 2025," attachment to comments submitted by Clean Fuels Alliance America. For 2020, Diagram 10 indicates about 7.55 mill tonnes of total animal fats was produced, while Diagram 11 indicates that about 1.85 mill tonnes of UCO was produced. Conversion factor of 7.66 lb/gal leads to a total of 2.7 billion gallons.

Chapter 8: Other Factors

The CAA directs EPA to consider the impact of the use of renewable fuels on “other” factors, including job creation, the price and supply of agricultural commodities, rural economic development, and food prices. This chapter addresses the enumerated “other” factors.[873] We focus our analysis on the biofuels that are projected to have the largest changes relative to the No RFS baseline: corn ethanol, biodiesel and renewable diesel (from soybean oil, FOG, and corn oil), and biogas.[874]

8.1 Job Creation

This chapter provides greater detail on our evaluation of impacts of renewable fuels on job creation. Attempting to attribute increases or decreases in employment to a single variable such as domestic renewable fuel use is fraught with complexity. Even considering just the biofuel production facilities themselves, there are confounding factors that include biofuel import/export activity, shifts in agricultural commodity prices, and varying demand for coproducts. Assessing the impacts on indirectly affected industries is even more difficult. Recognizing this challenge, we chose to focus the analysis on the economic sectors that have the closest association with biofuel use—biofuel production and agriculture. We acknowledge that changes in indirect employment (e.g., service sectors, transportation, construction, etc.) can also be associated with renewable fuel use, but due to the level of effort and uncertainty involved with indirect effects, they were excluded from the scope of this analysis. We also recognize that this analysis does not estimate the net employment effects, as increases in employment in some sectors may be offset by unemployment in other sectors.

8.1.1 Fuel Production

8.1.1.1 Ethanol Production

We projected the impact of the candidate volumes on employment at ethanol production facilities using an assessment by John Urbanchuk prepared for the Renewable Fuels Association (RFA).[875] Urbanchuk estimates that the total number of direct, full-time-equivalent jobs for domestic corn ethanol production in 2021 was 8,942 across the 208 plants that RFA found to be operating that year. The total nameplate capacity of those plants is reported at 17.7 billion gallons, suggesting an average plant size of 85 million gallons per year and an average employee concentration of 0.51 jobs per million gallons capacity.

The EIA Annual Fuel Ethanol Production Capacity Report provides plant count and total nameplate capacity values for historical calendar years. The data currently available show a total nameplate capacity of 17,380 million gallons of ethanol produced by 192 plants that reported

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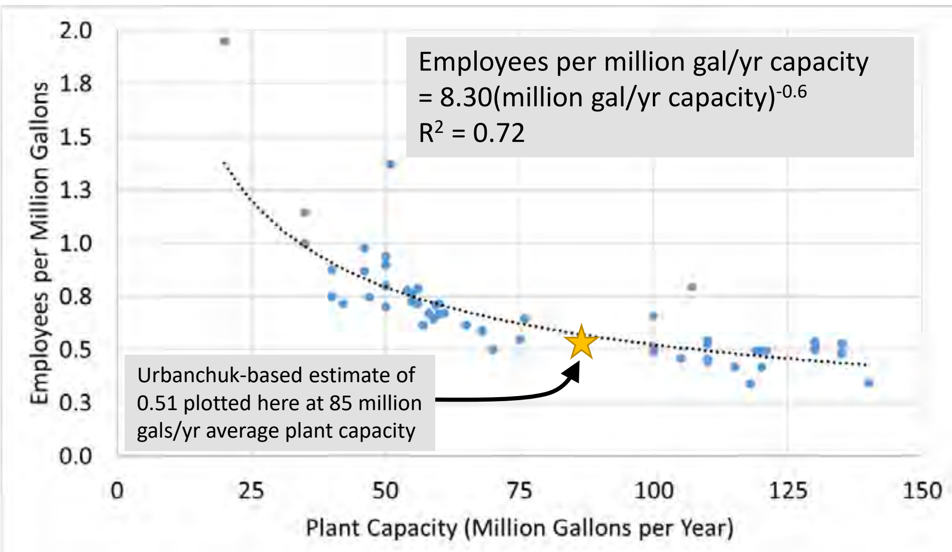
[873] As we explain in Preamble Section II, we also consider several other factors besides those enumerated in the statute.
[874] The impacts evaluated in this chapter are for volume increases for 2023–2025 compared to the No RFS baseline, as shown in Table 3.2.-2.
[875] Urbanchuk, J. ABF Economics. “Contribution of the Ethanol Industry to the Economy of the United States in 2021,” February 3, 2022.

themselves as operational.[876] The average plant size using these figures is 91 million gallons per year, which gives the same average employee concentration of 0.51 jobs per million gallons capacity using Urbanchuk's total direct employment.

In 2018, Ethanol Producer Magazine made available data on the capacity and number of employees at each of 65 corn ethanol facilities.[877] These plant capacities generally compare well with those reported by EIA, deviating by less than 3% when averaged on a state-by-state basis. For these 65 facilities, we examined employee concentration as a function of production capacity. The results show a nonlinear decreasing trend in employee concentration with production capacity, suggesting economies of scale are associated with labor in ethanol plants. Figure 8.1.1.1-1 shows this data fit with an exponential trendline, and includes the Urbanchuk-based estimate of employee concentration of 0.51 plotted at the national average facility size of 85 million gallons per year. The Urbanchuk value shows good agreement with the correlation fit line.

Figure 8.1.1.1-1: Correlation Between Employee Concentration and Facility Size for Corn-Ethanol Facilities



Since the data underlying this analysis is based on nameplate capacity and employment at a particular point in time, we were not able to estimate the sensitivity of employment at a particular facility to changes in production volume at that facility. Regardless, it is unlikely that variations in production volume at a particular plant over in the short term would affect employee headcount. Each of the unit operations (e.g., feedstock unloading, mashing, fermentation, DDGS drying and pelletizing) must remain operational for ethanol production to continue, and each of these areas requires trained operators. Over the longer term, we might anticipate changes consistent with Figure 8.1.1.1-1, and demand that stretches plants above their nameplate capacity for a sustained period could cause construction of new facilities.

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[876] EIA. U.S. Nameplate Fuel Ethanol Production Capacity as of January 1, 2022. https://www.eia.gov/petroleum/ethanolcapacity/archive/2022/index.php.

[877] Ethanol plant employment data obtained via Ethanol Producer Magazine website. Current issue and archives available at http://www.ethanolproducer.com. A table of this information is available in the docket.

The increases in ethanol volume evaluated in this rule generally represent increased consumption of higher-level ethanol blends (e.g., E15 and E85). The connection between greater domestic consumption of ethanol and domestic production of ethanol is unclear, as significant quantities of ethanol have been exported to foreign markets in recent years. The volume of ethanol that would be consumed in 2023–2025 under the No RFS baseline is significantly less than the domestic ethanol production capacity, and less than domestic ethanol production in 2021. Thus, it is possible that a decrease in ethanol consumption in the absence of the RFS program could result in a decrease in domestic ethanol production, or alternatively could simply result in increased ethanol exports.

8.1.1.2 Biodiesel Production

To project the impact of the candidate volumes on employment at biodiesel production facilities, we primarily relied on information from a 2019 study by LMC International on the economic impact of the biodiesel industry prepared for the National Biodiesel Board.[878] In this report, LMC stated that a typical biodiesel production facility in the U.S. has a production capacity of 40–60 million gallons per year and directly employs 40–50 people, though they note that there is considerable variation in the facility capacity and direct employment at domestic biodiesel facilities. This information suggests an employee concentration of approximately 1 job per million gallons of biodiesel production capacity. Relative to the No RFS baseline, we project that the candidate volumes would result in higher employment in biodiesel production facilities by 1,041, 1,008, and 975 jobs in 2023, 2024, and 2025 respectively.

8.1.1.3 Renewable Diesel Production

As described in Chapters 3 and 6, we have seen significant growth in renewable diesel production through 2021 and project that the candidate volumes would result in significantly higher volumes of renewable diesel in 2023–2025 relative to the No RFS baseline. Table 3.2-2 shows increases of 1.2–1.5 billion gallons of renewable diesel annually from 2023–2025 relative to the No RFS baseline. Production of this fuel is expected to come from a mix of expansions at existing facilities, construction of new facilities, and conversions of process trains at existing petroleum refineries. At this time, we do not have employment data specific to renewable diesel. However, we expect that these operations would have comparable employment needs compared to the petroleum refining that they displace. Consequently, we anticipate little net change in employment due to renewable diesel.

8.1.1.4 RNG Production

As described in Chapters 3 and 6, we project continued growth of CNG/LNG derived from biogas as a result of the candidate volumes in 2023–2025. Sources of this fuel are expected to be a mix of landfills and agricultural digesters. While collection of landfill gas has been required by solid waste regulations for many years, increased credit generation under the RFS program is expected to cause additional employment related to upgrading and maintenance of

[878] LMC International. “The Economic Impact of the Biodiesel Industry on the U.S. Economy.” August 2019.

gas cleanup and pipeline interconnect equipment.[879] We also project that the construction and operation of new agricultural digesters and digesters at wastewater treatment facilities would result in additional employment.

An analysis by the Coalition for Renewable Natural Gas (CRNG) using 2021 data showed that an average of 24 jobs were created for every 1 million ethanol-equivalent gallons increase in production of CNG/LNG derived from biogas.[880] The data indicated that 30% of these jobs were related to the operation of these facilities and 70% were related to construction. These factors were applied to the projected volume increases of CNG/LNG derived from biogas in 2022–2025, resulting in the employment impacts shown in Table 8.1.1.4-1. These impacts are based on the average facility producing CNG/LNG derived from biogas in 2021, and the employment estimates therefore implicitly assume that the average employment at facilities in 2023–2025 are equal to the average employment at facilities in 2021. The construction employment figures assume that the construction jobs occur in the year of the volume increase. The actual employment impacts for 2023–2025 may be slightly higher or lower depending on the types of new facilities that produce CNG/LNG derived from biogas (e.g., landfills, wastewater treatment facilities, or agricultural digesters) and the sizes of these facilities.

Table 8.1.1.4-1: Change in Employment in RNG Production Relative to the No RFS Baseline

Year	Construction Jobs	Operations Jobs	Total Jobs
2023	1,462	626	2,088
2024	1,596	1,310	2,906
2025	1,798	2,081	3,879

8.1.2 Agricultural Employment

Job creation in the agricultural sector, beyond the fuel production activities discussed above, is expected primarily in the areas of production and transportation of crops serving as biofuel feedstocks. Because CNG/LNG derived from biogas is produced from waste or byproduct materials (e.g., separated MSW, wastewater, and agricultural residue), we expect the projected increases in the production of CNG/LNG derived from biogas to have very little impact on employment related to feedstock production. As noted above, we are projecting higher volumes of ethanol, biodiesel, and renewable diesel production for 2023–2025 relative to the No RFS baseline. The primary feedstocks projected to be used to produce these fuels are corn and soybean oil.[881]

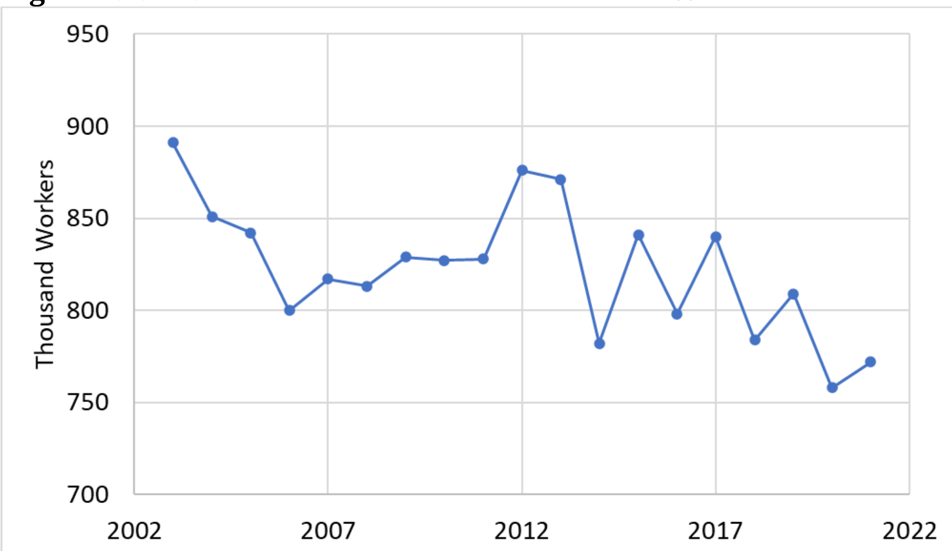
Gauging the impact that increased use of renewable fuels has had on employment in the agricultural sector is challenging for several reasons, including, but not limited to, seasonality, production of a wide array of products, and the broad nature of employment in the sector, which

[879] Jaramillo and Matthews, Environmental Science & Technology 2005 39 (19), 7365-7373.
[880] CRNG. Economic Analysis of the U.S. Renewable Natural Gas Industry. December 2021.
[881] We are also projecting that lesser quantities of FOG and corn oil would be used to produce biodiesel and renewable diesel in 2023–2025, but since these feedstocks are wastes or co-products of other industries, we do not expect their increased use to impact agricultural employment.

stretches from field hands to equipment production. To try to understand this better, we examined available data on agricultural employment over the past several decades, with no pretense of ascribing causation for observed trends to particular volumes of renewable fuels.

Some of the most consistently sourced data available on hired farmworkers is made available by the National Agricultural Statistics Service (NASS).[882] We used a combination of annual and seasonal reports to track the number of harvest season (October) workers hired directly by farm operators over the past two decades. This data is presented in Figure 8.1.2-1.

Figure 8.1.2-1: Number of Harvest Season Farm Workers



The trend in the data is that direct employment of hired farmworkers by farm operators has been relatively stable between 750–850 thousand since 2003/4. There is variation year-over-year, but it is difficult to conclude from this data that there has been any significant increase or decrease in directly hired by farm labor related to increased production of renewable fuels over the past two decades. Given the broad scope of this data, it is not possible to discern whether, for example, an increase of workers harvesting corn in Iowa has been offset by a reduction in employment of workers harvesting pistachios in California. Were more disaggregated employment data available, perhaps it would be possible to discern changes in the employment of farmworkers for the purposes of producing soy and corn.

An additional set of data on agricultural employment is collected by USDA. The methods for categorizing types of employment are slightly different than those found in the NASS data, but the greater breadth of jobs captured by the employment in agriculture and support industries data set provides additional insight. Figure 8.1.2-2 presents the data on employment in agriculture and support activities for 2001–2020.[883]

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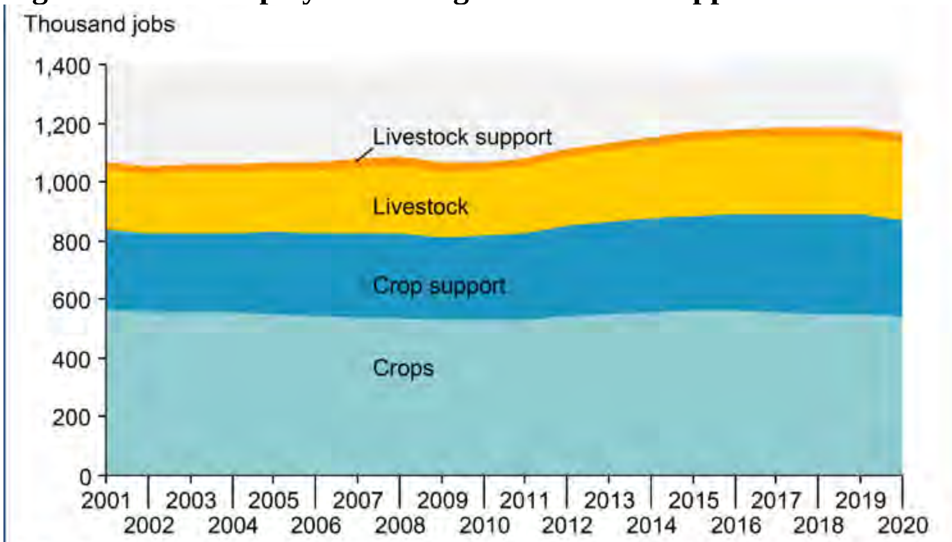
[882] USDA NASS Agricultural Statistics and Farm Labor data, available at https://usda.library.cornell.edu/concern/publications/x920fw89s and https://usda.library.cornell.edu/concern/publications/j3860694x?locale=en.

[883] USDA ERS Farm Labor, March 2022. https://www.ers.usda.gov/topics/farm-economy/farm-labor.

Figure 8.1.2-2: Employment in Agriculture and Support Activities



Note: Employment is measured as the annual average number of full- and part-time jobs. Data do not cover smaller farm employers in those States that exempt them from participation in the unemployment insurance system.
Source: USDA, Economic Research Service using data from U.S. Department of Labor, Quarterly Census of Employment and Wages, as of June 2, 2021.

This data from USDA shows that employment in crop production and crop support activities have increased by about 3% and 20%, respectively, over the past decade. As with the NASS data in Figure 8.1.2-1, the lack of crop-specific data makes drawing associations with biofuel production very difficult. We observe that the lowest employment levels reported in the USDA data for crop production workers coincide with the 2008–2009 recession and that it was not until 2015 that the number of such jobs returned to the pre-recession levels. Looking at this data set, it is difficult to see any clear impact of increased renewable fuel production among broader economy-wide factors.

8.2 Rural Economic Development

Changes in biofuel production can have economic development impacts on rural communities and financial impacts on farmers. We are projecting significantly higher consumption of ethanol, biodiesel, renewable diesel, and CNG/LNG derived from biogas in 2023–2025 relative to the No RFS baseline. As discussed in Chapter 8.1.1.1, the impact of the proposed volumes for 2023–2025 on domestic ethanol production are uncertain. In the absence of the RFS program domestic ethanol production could continue at a level at or near current production volumes with increasing ethanol exports or alternatively domestic ethanol production could decrease. In light of these uncertainties, we are not projecting any significant changes in rural economic development related to the ethanol volumes we are projecting in 2023–2025.

For biodiesel and renewable diesel, we expect that much of the rural economic impacts in 2023–2025 would be related to the production of feedstocks for these fuels. We project that most of the increase in biodiesel and renewable diesel production in 2023–2025 would be produced from soybean oil, with lesser volumes from FOG and corn oil. Some of this soybean oil is expected to come from additional soybean production and crushing, which may bring some revenue increases to rural communities.

The increased production of CNG/LNG derived from biogas is expected to result in additional rural economic activity. Using factors derived from a 2021 analysis by CRNG, we estimated that each additional million RINs of CNG/LNG is associated with $0.88 million in economic activity related to gas upgrading and facility administration activities.[884] This factor suggests that the candidate volumes would result in $77 million, $161 million, and $255 million in economic activity in 2023, 2024, and 2025, respectively, relative to the No RFS baseline. That analysis also indicated that 76% of facilities under construction in 2021 were agricultural waste digesters, which are likely to be located in rural areas. While the total economic impact in rural areas is unknown, the fact that the majority of CNG/LNG facilities under construction in 2021 were agricultural waste digesters suggests that much of this economic activity is likely to be in rural areas.

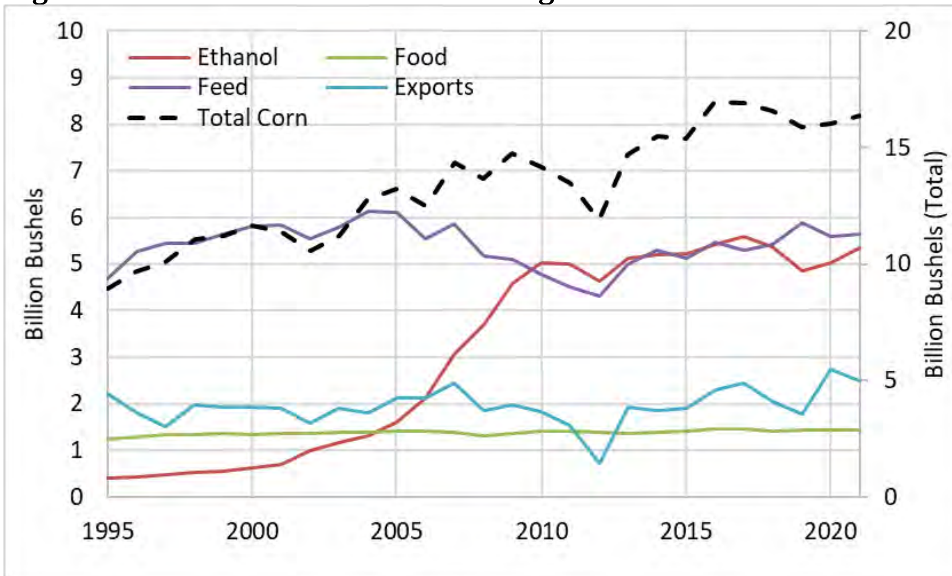
8.3 Supply of Agricultural Commodities

Changes in biofuel production can have an impact on the supply of agricultural commodities. As discussed above, we project an increase in consumption of ethanol, biodiesel, renewable diesel, and CNG/LNG derived from biogas in 2023–2025 relative to the No RFS baseline. These volume increases suggest the potential for associated increases in underlying crop production; however, the magnitude of the potential impact cannot be estimated with any certainty. Biogas is not produced from agricultural commodities and therefore is not expected to affect their supply or price.

For historical context, Figure 8.3-1 shows trends in corn production and uses from 1995–2021.[885] This data suggests domestic corn production has grown steadily at a 25-year average rate of around 2%, or 250 million bushels per year, with no apparent correlation to ethanol production volumes.

[884] CRNG. Economic Analysis of the U.S. Renewable Natural Gas Industry, December 2021.
[885] USDA ERS Feed Grains Data Yearbook, March 2022 (Tables 4 and 31).

Figure 8.3-1: Corn Production and Usage



Between 2005–2010, additional corn required to satisfy increasing ethanol production was sourced primarily by diversion from animal feed until overall production caught up. Supply of corn to food uses continued to grow steadily during this period, despite increased consumption as ethanol feedstock. Exports also remained relatively steady, except for a drop in exports corresponding to weather-related supply disruptions and elevated prices in 2011–2012. Animal feed use began to rebound after 2014 when growth in ethanol production slowed and prices stabilized. Another factor contributing to the longer-term shift of animal feed away from whole corn was the increasing substitution with DDGS, a byproduct of ethanol production. Considering historical trends over the past two decades indicating the ability of production to rise to meet demand, the modest increases in ethanol volumes associated with this rule are likely to have no or only a small short-term impact on the supply of corn to food, exports, or other uses.

Figure 8.3-2 shows that soybean production has risen steadily over time, similar to the trend for corn production.[886] Roughly 80% of this growth since 2005 is associated with rising exports of soybeans, which have nearly doubled over that period. Domestic crushing of beans has grown by 24% since 2005, which mirrors the same relative growth in production of the crush products, soy meal and oil, as shown in Figure 8.3-2. This figure also shows that exports of soy meal nearly doubled during this time, which together with the growth in whole bean exports, presents a picture consistent with expansion of meat production internationally.[887] (Worldwide, over 95% of beans are eventually crushed for meal and oil.)

[886] USDA ERS Oilcrops Data Yearbook, Soy Tables, March 2022.
[887] USDA ERS Oilcrops Data Yearbook, Soy Tables, March 2022.

Figure 8.3-2: Soybean Production and Usage

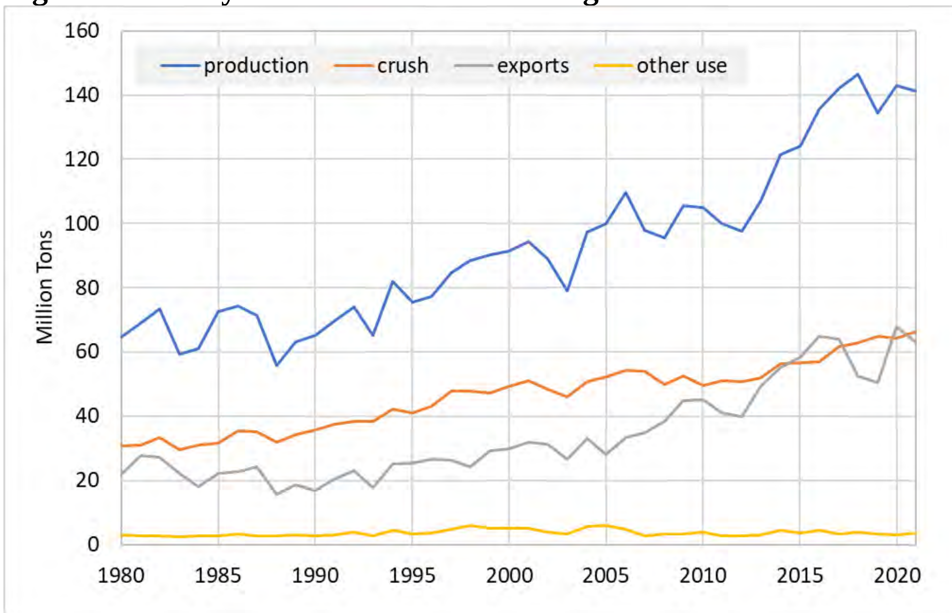
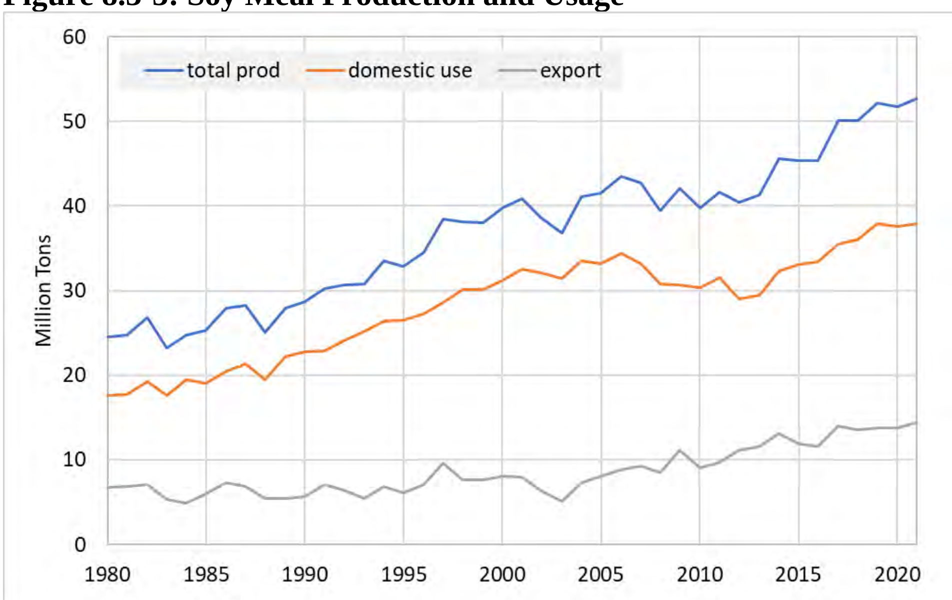


Figure 8.3-3: Soy Meal Production and Usage



As shown in Figure 8.4-2, soybean oil production has generally increased since 2005 with much of this increase being used for biodiesel production. This increase in soybean oil production has been due to both increasing domestic soybean crush and increasing yields of soybean oil per bushel of soybeans crushed. While the use of soybean oil for biofuel production has increased significantly since 2005, the relative value relationship between the oil and meal crush products remained relatively stable through 2020, with meal representing about 70% of the total soybean value. This suggests that demand for meal has historically been the primary driver for increased soybean crushing. Soybean exports have also increased at a much faster rate than the increase in soybean crushing. In terms of overall soybean production, the primary driver for growth in soybean production and planted acres since 2005 has clearly been rising exports, with crushing of beans for meal and oil being a distant second.

8.4 Price of Agricultural Commodities

Agricultural commodities are bought and sold on an international market, where prices are determined by trends and upsets in worldwide production and consumption. Renewable fuels are only one factor among many (e.g., droughts and storm damage) in determining commodity prices. Thus, models that attempt to project prices at specific times in the future, or in reaction to specific demand perturbations, necessarily contain high levels of uncertainty. This chapter reviews historical trends and presents key observations from the literature.

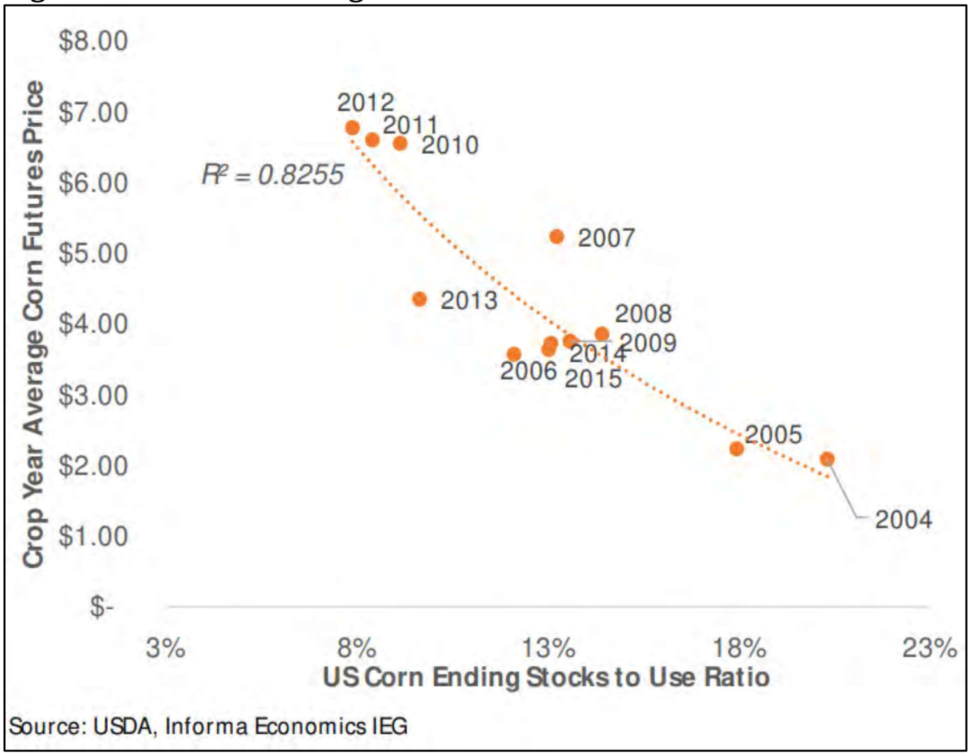
In the U.S., corn and soybeans are generally only harvested once per year, and therefore storage is a critical factor in the supply chain. After harvest, grain stores are replenished and then drawn down throughout the year. In recent years, about 15% of the previous year's overall corn production is typically still in storage at the time of the new harvest.[888] If demand rises after harvest, stocks may be drawn down faster than expected. Conversely, if demand decreases, stocks accumulate into the next season.

Storage also has the effect of dampening price shocks in years when harvests are smaller than expected. In 2012, a drought year, corn stocks fell to the lowest levels since 2000, putting upward pressure on futures prices, which in turn served as a market signal to induce more corn planting in the upcoming season. Work done by Informa Economics for RFA in 2016 examined the historical relationship between corn usage, stocks, and futures prices.[889] Figure 8.4-1 shows the strong correlation between futures prices and the stock-to-usage ratio, illustrating that the latter is a key driver of market signals. More generally, crop prices are influenced by an array of factors from worldwide weather patterns to biofuel policies to international tariffs and trade wars.

[888] USDA ERS Feed Grains Data Yearbook, March 2022 (Table 4).

[889] Informa Economics IEG. "The Impact of Ethanol Industry Expansion on Food Prices: A Retrospective Analysis." November 2016. https://d35t1syewk4d42.cloudfront.net/file/975/Retrospective-of-Impact-of-Ethanol-on-Food-Prices-2016.pdf.

Figure 8.4-1: Corn Ending Stocks / Use Ratio Versus Futures Price



To make more specific quantitative estimates of the impact of increased biofuel production on corn prices, we considered two meta-studies. Condon, *et al.*, reviewed 29 published papers in 2015 and found a central estimate of 3–5% increase in corn prices per billion gallons of ethanol.[890] Focusing only on scenarios where a supply response is included gives a result of 3%. A supply response refers to scenarios where farmers can respond to price signals in subsequent year(s) and plant additional crops to meet a larger demand. This is appropriate, as the scope of the analysis is biofuel policy (rather than something unforeseen like weather shocks). A similar meta-analysis was done in 2016 by FAPRI-Missouri that considered several newer studies.[891] This paper found an increase of $0.19 per bushel per billion gallons, or $0.15 if a supply response is included, a figure that is generally consistent with the 3% impact above if applied to the corn price in 2016.

We are projecting higher corn ethanol consumption in 2023–2025 (an additional 706–840 million gallons per year) as a result of the candidate volumes than would occur under the No RFS baseline. We note, however, that in recent years domestic ethanol production has exceeded consumption, with significant volumes being exported. This trend appears very likely to continue during 2023–2025, as our projected consumption volumes remain below USDA's projected

[890] Condon, Nicole, Klemick, Heather and Wolverton, Ann, (2013), Impacts of Ethanol Policy on Corn Prices: A Review and Meta-Analysis of Recent Evidence, No. 201305, NCEE Working Paper Series, National Center for Environmental Economics, EPA, https://EconPapers.repec.org/RePEc:nev:wpaper:wp201305.

[891] Food and Agricultural Policy Research Institute. Literature Review of Estimated Market Effects of U.S. Corn Starch Ethanol, 2016. FAPRI-MU Report #01-16.

production for these years.[892] This history of significant export volumes makes it difficult to project the impact of the No RFS baseline.

It is possible that a decrease in domestic corn ethanol consumption would result in an increase in exports and minimal change in domestic production volumes. Were this to occur we would expect little to no net change in domestic corn demand, and thus corn prices. Alternatively, it is possible that a decrease in consumption would result in a decrease in domestic corn ethanol production. In this case we would expect a decrease in corn demand and corn prices. To illustrate the potential impact of the candidate volumes on corn prices, we have calculated the projected impact in 2023-2025 assuming that these volumes result in an increase in domestic corn ethanol production relative to the No RFS baseline. The projected price impacts are calculated using a value from the literature of 3% increase per billion gallons of corn ethanol produced, as described above. Because the USDA Agricultural Projections show corn use for ethanol production at quantities that appear similar to the candidate volumes for 2023–2025, we have projected lower corn prices for the No RFS baseline, rather than assuming the corn prices in these projections represent a No RFS case and projecting higher prices for the candidate volumes. The projected impact of the candidate volumes on corn prices relative to the No RFS baseline are shown in Table 8.4-1.

Table 8.4-1: Projected Impact on Corn Prices Relative to the No RFS Baseline

	2023	**2024**	**2025**
Corn Price Percent Increase per Billion Gallons of Ethanol	3%	3%	3%
Corn Price (Candidate Volumes); $/bushel[a]	$4.60	$4.37	$4.13
Corn Price Increase per Billion Gallons of Ethanol; $/bushel	$0.14	$0.13	$0.13
Corn Ethanol Increase; billion gallons	0.706	0.776	0.840
Corn Price Increase; $/bushel	$0.10	$0.10	$0.10
Corn Price (No RFS Baseline); $/bushel	$4.50	$4.27	$4.23

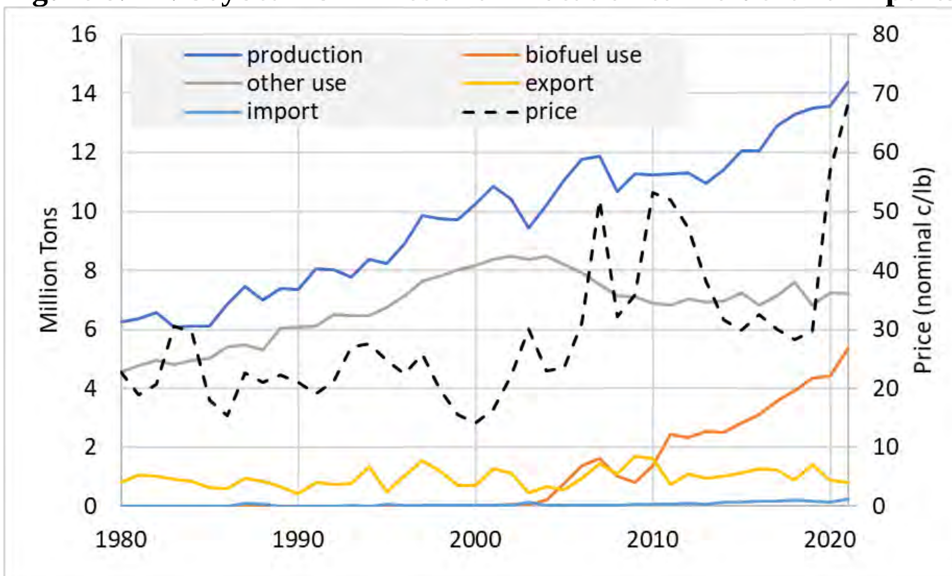
[a] Corn prices are from the June 2022 WASDE. Prices represent the average price for a calendar year. For corn, the price is calculated using 1/3 of the price for the first agricultural marketing year (e.g., 2022/2023 for 2023) and 2/3 of the price for the second agricultural marketing year (e.g., 2023/2024 for 2023).

With biodiesel and renewable diesel production, the commodity input of interest is soybean oil, which has an indirect link to bean production. Oil is produced by crushing, which also creates soy meal, and the supply and prices of these move independently from each other. The crush quantities vary from year to year, depending on the crush margin, which is defined as the sum of oil and meal price minus the bean price. Oversupplying either oil or meal markets can cause prices to fall, decreasing the crush margin. Thus, the degree of passthrough of oil price increases to bean prices, which may then influence acres planted, is not straightforward. Figure 8.4-2 shows historical trends in soybean oil prices alongside allocation to biofuel and other uses, based on data taken from the USDA Oilcrops Yearbook. [893] Use in domestic biofuel rose from 0.8 million tons in 2005 to over 4.4 million tons in 2021. Other domestic uses also increased steadily through 2005, decreased slightly from 2005–2010, and have remained relatively consistent since 2010. Exports of soybean oil play a minor role and have remained fairly consistent over the past decade. Noting the lack of correlation between soybean oil price and its

[892] USDA Agricultural Projections to 2031. February 2022.
[893] USDA ERS Oilcrops Data Yearbook, Soy Tables, March 2022.

use in biofuel production historically, we conclude that the price of soybean oil is influenced by a number of factors occurring in the broader economy, including rising petroleum prices, supply chain disruptions on a range of inputs (e.g., fertilizer), weather-related shortages of vegetable oils internationally, as well as general price inflation. In particular, while increased soybean oil demand for biofuel production was likely a contributing factor to the sharp price increase in soybean oil prices in 2020 and 2021, poor weather conditions in South America and Malaysia were also a significant factor.[894]

Figure 8.4-2: Soybean Oil Price and Allocation to Biofuel and Exports



There are relatively few quantitative studies on the impacts of BBD production on soybean oil and bean prices, and they show a wide range of results. This is in part because these studies have included a variety of different policy combinations, none of which separated out just the impact of the RFS program on BBD demand. Ethanol demand could impact the soybean markets even in the absence of increased demand for BBD from the RFS program due to increased competition for cropland and other inputs. The largest impacts are estimated when the BBD obligations are modeled jointly with the conventional and cellulosic ethanol obligations. Given that actual cellulosic ethanol volumes have been far below those modeled, we focus on the studies that included only a conventional ethanol obligation. The range of soybean price impacts indicated by these studies is 1.8–6.5% per billion gallons of BBD, from which we take a central value of 4.2%.[895,896,897]

To project the impact on crude soybean oil prices, we used a value of 16¢ per pound of oil per billion gallons of BBD produced from soybean oil. This figure was derived from modeling work published by Babcock, *et al.*, and is the same figure used for other cost estimates

[894] Wilson, Nick. "Oil Prices Surge – Vegetable Oil That Is." Marketplace.org. February 17, 2022.
[895] Babcock, B. A. 2012. The impact of US biofuel policies on agricultural price levels and volatility. China Agricultural Economic Review 4:407-426.
[896] J. Huang, J. Yang, S. Msangi, S. Rozelle, and A. Weersink. 2012. Biofuels and the poor: Global impact pathways of biofuels on agricultural markets. Food Policy 37:439-451.
[897] Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis. EPA-420-R-10-006. February 2010.

in this rule.[898] As with corn ethanol, we have assumed that the soybean oil prices in the USDA Agricultural Projections to 2031 represent projected prices of the candidate volumes since they project soybean oil used for biofuel production at quantities that appear similar to the candidate volumes for 2023–2025. We have projected lower soybean oil prices for the No RFS baseline, rather than assuming the soybean oil prices in these projections represent the No RFS baseline and projecting higher prices for the candidate volumes. The projected impacts of the candidate volumes on soybean oil prices are shown in Table 8.4-2.

Table 8.4-2: Projected Impact on Soybean Oil Prices Relative to the No RFS Baseline

	2023	**2024**	**2025**
Soybean Oil Price (Candidate Volumes); $/pound[a]	$0.52	$0.50	$0.48
Soybean Oil Price Increase per Billion Gallons of Biofuel; $/pound	$0.16	$0.16	$0.16
Soybean Oil Biofuel Increase; billion gallons	2,017	1,983	1,955
Soybean Oil Price Increase; $/pound	$0.32	$0.32	$0.31
Soybean Oil Price (No RFS Baseline); $/pound	$0.20	$0.18	$0.17

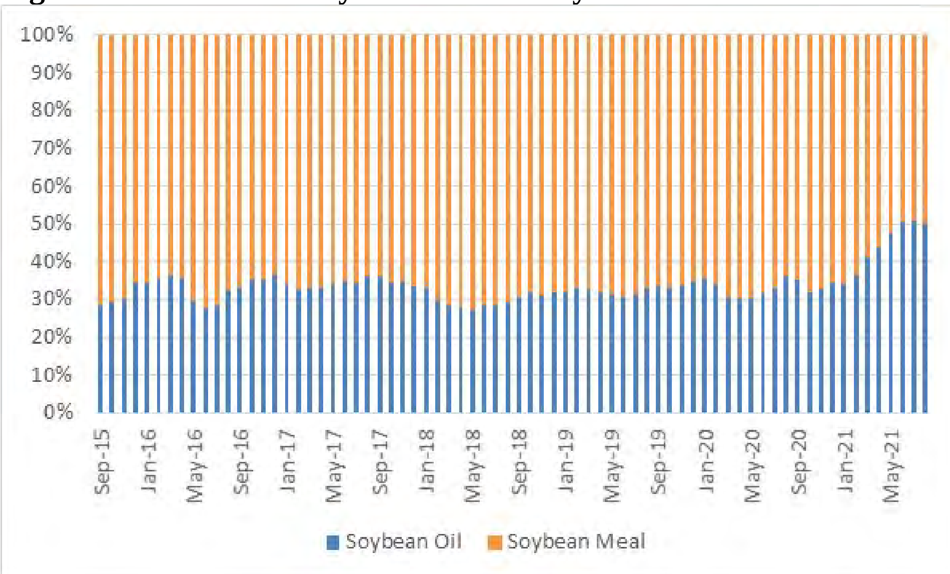
[a] Soybean oil prices are from the June 2022 WASDE. Prices represent the average price for a calendar year. For soybean oil, the price is calculated using 1/4 of the price for the first agricultural marketing year (e.g., 2022/2023 for 2023) and 3/4 of the price for the second agricultural marketing year (e.g., 2023/2024 for 2023).

Analysis published by Irwin at the University of Illinois indicates that soybean oil prices often move separately from meal and bean prices, and that the latter two are closely correlated.[899] In recent years soybean oil prices appear to have increased significantly relative to soybean meal prices, as shown in Figure 8.4-3.

[898] Babcock BA, Moreira M, Peng Y, 2013. Biofuel Taxes, Subsidies, and Mandates: Impacts on US and Brazilian Markets. Staff Report 13-SR 108. Center for Agricultural and Rural Development, Iowa State University.

[899] Irwin, S. “The Value of Soybean Oil in the Soybean Crush: Further Evidence on the Impact of the U.S. Biodiesel Boom.” *Farmdoc Daily* (7):169, Department of Agricultural and Consumer Economics, University of Illinois at Urbana-Champaign, September 14, 2017.

Figure 8.4-3: Relative Soybean Oil and Soybean Meal Value



From 2016 through the end of 2020, the value of soybean oil relative to soybean meal was relatively stable, with soybean oil representing 33% of the value of a soybean on average.[900] Starting in 2021, the relative value of the soybean oil increases significantly, averaging 50% from May to August 2021. This suggests that as demand for soybean oil has increased in recent years, the price for soybean oil has increased more than soybean prices, and that soybean meal prices have increased less than soybean prices. Consistent with this recent trend, and the fact that demand for soybean meal is not directly impacted by increased production of biofuels from soybean oil, we do not expect that the candidate volumes would have any impact on soybean meal in 2023–2025.

In addition to the price impacts on corn, soybean oil, and soybean meal, we also estimated price changes for other feed grains (grain sorghum, barley, and oats) and distillers grains. We adjusted the prices of these commodities, as they historically compete with corn in the feed market, and to a lesser extent for acreage. The price adjustments for grain sorghum, barley, oats, and distillers grains are based on historical price relationships of these commodities with corn. As with corn and soybean oil, we assumed that the prices in the USDA Agricultural Projections to 2031 represent projected prices of the candidate volumes and adjusted the projected prices for these commodities lower in our price projections for the No RFS baseline. The projected impact of the candidate volumes on sorghum, barley, oat, and distillers grain prices are shown in Table 8.4-3.

[900] USDA ERS Oilcrops Data Yearbook, Soy Tables, March 2022.

Table 8.4-3: Projected Impact on Prices of Other Commodities Relative to the No RFS Baseline

	2023	2024	2025
Price Change Factor Relative to Corn Price Change[a]			
Sorghum; $/bushel	0.93	0.93	0.93
Barley; $/bushel	0.88	0.88	0.88
Oats; $/bushel	0.72	0.72	0.72
Distillers Grains; $/ton	0.018	0.018	0.018
Projected Price Impact			
Sorghum; $/bushel	$0.09	$0.09	$0.10
Barley; $/bushel	$0.08	$0.09	$0.09
Oats; $/bushel	$0.07	$0.07	$0.07
Distillers Grains; $/ton	$3.41	$3.55	$3.72

[a] These factors were developed in conjunction with USDA in the 2012 evaluation of the use of the general waiver authority. See “Methodology for Estimating Impacts on Food Expenditures, CPI for Food and CPI for All Items,” available in the docket.

8.5 Food Prices

The above impact on commodity prices may in turn have a ripple impact on food prices and the many other products produced from these commodities. Since the candidate volumes are projected to have a relatively small impact on the overall world commodity markets, and since the cost of these commodities tends to be a relatively small component in the cost of food, the projected impact of this rule on food prices is relatively modest. Further, we note that the projected impact of the candidate volumes on food prices does not represent a cost, but rather a transfer, since higher food prices that result from higher commodity prices represent increased income for feedstock producers (e.g., corn and soybean farmers).[901]

To project the impact of the candidate volumes on food prices, we used a methodology developed in conjunction with USDA in assessing requests from the governors of several states to reduce the 2012 RFS volumes using the general waiver authority.[902] This methodology generally uses estimates of the impact of biofuel volumes on commodity prices (e.g., corn, soybean oil, etc.) to calculate the estimated impacts on total food expenditures. For context, this estimated change in food expenditures is then compared to total food expenditures. Finally, the ratio of the estimated change in food expenditures to the total food expenditures is used to estimate the change in food expenditures for the average consumer unit and the consumer units in the lowest income quintile.

In Chapter 8.4, we presented estimates of the impact of the candidate volumes on commodity prices relative to the No RFS baseline. These estimates are the starting point for our

[901] In other words, food price impacts represent the movement of money within society (from consumers of foods to the producers of foods) as opposed to additional costs that society as a whole incurs. We note that while the CAA specifically directs EPA to calculate the impacts on “food prices,” as opposed to calculating the impact on the cost to consumers of food. We acknowledge that these market interactions are affected by deadweight losses, but we have not estimated the proportion of deadweight losses to transfers in this rule.
[902] 77 FR 70752 (November 27, 2012).

estimate of the impact of the RFS volumes on food prices. From those, we projected the impact of commodity prices on total food expenditures, which are shown in Table 8.5-1. We assumed that changes in commodity prices are fully passed on to consumers at the retail level, and therefore we can project changes in total food expenditures by multiplying the quantity of these commodities used for food and feed. Feed use is included to capture the effects of the change in the price of the commodity on livestock producers' production costs, and ultimately the effects on retail livestock prices.[903]

We recognize that projecting that the price of distillers grains increases proportionally to the price of corn may over-state the impact of this rule on these commodities and ultimately on food prices. It is possible increasing demand for biofuels may result in an over-supply of distillers grains, as it is a co-product of biofuel production. Thus, while biofuel production may increase the prices of corn and food produced from corn, it may not increase the price of distillers grains. This could mitigate the overall impact of this rule on food prices. At this time, we do not have sufficient data to project how increasing demand for corn for biofuel production would impact the price of distillers grains. If the price for distillers grains increases less than the price of corn (or if it decreases) in response to increased demand for biofuels, we would expect a smaller impact on food prices than what we have estimated for the candidate volumes.

This methodology assumes no response by producers or consumers to changes in commodity prices and therefore may overstate the change in food expenditures. However, previous research suggests that demand for food is very inelastic and therefore this methodology should provide a close approximation of the change in food expenditures.[904] Our estimates of the increase of food expenditures only reflect expenditures in the U.S. Because of the integrated nature of agricultural commodity markets, the projected increases in agricultural commodity prices may also impact food prices and expenditures globally. We have not attempted to quantify these global impacts.

[903] This methodology includes the expected price impact on all crops used as animal feed and does not account for the livestock produced for the export market or imported meat or animal products.
[904] Okrent, Abigail M., and Julian M. Alston. The Demand for Disaggregated Food-Away-From-Home and Food-at-Home Products in the United States, ERR-139, USDA, Economic Research Service, August 2012.

Table 8.5-1: Changes in Food Expenditures Relative to the No RFS Baseline

	Commodity Price Change	Quantity Used for Food and Feed[a]	Change in Expenditures
Changes in Food Expenditures in 2023			
Corn	$0.10 per bushel	7,230 million bushels	$690 million
Grain Sorghum	$0.09 per bushel	88 million bushels	$8 million
Barley	$0.08 per bushel	162 million bushels	$14 million
Oats	$0.07 per bushel	143 million bushels	$10 million
Soybean Oil	$0.32 per pound	14.4 billion pounds	$4,631 million
Distillers Grains	$3.41 per short ton	44.6 million short tons	$152 million
Total	N/A	N/A	$5,504 million
Changes in Food Expenditures in 2024			
Corn	$0.10 per bushel	7,335 million bushels	$729 million
Grain Sorghum	$0.09 per bushel	85 million bushels	$8 million
Barley	$0.09 per bushel	165 million bushels	$14 million
Oats	$0.07 per bushel	125 million bushels	$9 million
Soybean Oil	$0.32 per pound	14.5 billion pounds	$4,593 million
Distillers Grains	$3.55 per short ton	44.6 million short tons	$158 million
Total	N/A	N/A	$5,511 million
Changes in Food Expenditures in 2025			
Corn	$0.10 per bushel	7,438 million bushels	$774 million
Grain Sorghum	$0.10 per bushel	82 million bushels	$8 million
Barley	$0.09 per bushel	167 million bushels	$15 million
Oats	$0.07 per bushel	109 million bushels	$8 million
Soybean Oil	$0.31 per pound	14.6 billion pounds	$4,559 million
Distillers Grains	$3.72 per short ton	44.6 million short tons	$166 million
Total	N/A	N/A	$5,530 million

[a] Quantity used for food and feed calculated based on the USDA Agricultural Projections to 2031 (February 2022). Prices represent the average price for a calendar year. Calendar year prices are calculated using a ratio based on the number of months in the calendar year in each agricultural marketing year. In general, the quantity use for food and feed is the sum of the quantities projected for Feed and Residual and Food, Seed & Industrial. For corn, we subtracted the quantity used for Ethanol & by-products from this total. The quantity of distillers grains was calculated based on the production of 17 pounds of distillers grains for every bushel of corn used to produce ethanol. Finally, the quantity of soybean oil is equal to the amount listed for food, feed & other industrial and the quantity of soybean meal is the total quantity of domestic disappearance.

Finally, we compared the estimated change in food expenditures to total food expenditures as reported by the Bureau of Labor and Statistics in their 2020 survey.[905] We used the ratio of the estimated change in food expenditures to the total food expenditures to estimate the change in food expenditures for the average consumer unit (household) and the consumer units in the lowest and second-lowest income quintiles, as shown in Tables 8.5-2 and 3. In this analysis we have assumed the same price effects on all foods when in fact the price impacts on foods consumed by low and high income groups may be affected differently. Additionally, lower

[905] Bureau of Labor and Statistics - Consumer Expenditures in 2020: Table 1, Quintiles of income before taxes: Annual expenditure means, shares, standard errors, and coefficients of variation. 2021.

price elasticities for lower-income consumers mean that the welfare effects of these changes could be aggravated for lower-income groups.

Table 8.5-2: Percent Change in Food Expenditures Relative to the No RFS Baseline

	2023 Estimate	2024 Estimate	2025 Estimate
Number of Consumer Units (thousands)	131,234	131,234	131,234
Food Expenditures per Consumer Unit	$7,316	$7,316	$7,316
Total Food Expenditures	$960 billion	$960 billion	$960 billion
Change in Food Expenditures	$5,504 million	$5,511 million	$5,530 million
Percent Change in Food Expenditures	0.57%	0.57%	0.58%

Table 8.5-3: Change in Food Expenditures per Consumer Unit Relative to the No RFS Baseline

	2023	2024	2025
All Consumer Units			
Food Expenditures	$7,316	$7,316	$7,316
Percent Impact on Food Expenditures	0.57%	0.57%	0.58%
Projected Food Expenditure Increase	$41.94	$41.99	$42.14
Lowest Quintile Income Consumer Units			
Food Expenditures	$4,099	$4,099	$4,099
Percent Impact on Food Expenditures	0.57%	0.57%	0.58%
Projected Food Expenditure Increase	$23.50	$23.53	$23.61
Second-Lowest Quintile Income Consumer Units			
Food Expenditures	$5,380	$5,380	$5,380
Percent Impact on Food Expenditures	0.57%	0.57%	0.58%
Projected Food Expenditure Increase	$30.84	$30.88	$30.99

Chapter 9: Environmental Justice

Executive Order 12898 (59 FR 7629; February 16, 1994) establishes federal executive policy on environmental justice (EJ). Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make EJ 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 U.S. EPA defines EJ as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. Executive Order 14008 (86 FR 7619; February 1, 2021) also calls on federal agencies to make achieving EJ part of their missions "by developing programs, policies, and activities to address the disproportionately high and adverse human health, environmental, climate-related and other cumulative impacts on disadvantaged communities, as well as the accompanying economic challenges of such impacts." It also declares a policy "to secure environmental justice and spur economic opportunity for disadvantaged communities that have been historically marginalized and overburdened by pollution and under-investment in housing, transportation, water and wastewater infrastructure and health care." EPA also released technical guidance[906] (hereinafter "EPA's Technical Guidance") to provide recommendations that encourage analysts to conduct the highest quality analysis feasible, recognizing that data limitations, time and resource constraints, and analytic challenges will vary by media and circumstance.

When assessing the potential for disproportionately high and adverse health or environmental impacts of regulatory actions on minority populations, low-income populations, tribes, and/or indigenous peoples, EPA strives to answer three broad questions:

1. Is there evidence of potential EJ concerns in the baseline (the state of the world absent the regulatory action)? Assessing the baseline will allow EPA to determine whether pre-existing disparities are associated with the pollutant(s) under consideration (e.g., if the effects of the pollutant(s) are more concentrated in some population groups).
2. Is there evidence of potential EJ concerns for the regulatory option(s) under consideration? Specifically, how are the pollutant(s) and its effects distributed for the regulatory options under consideration?
3. Do the regulatory option(s) under consideration exacerbate or mitigate EJ concerns relative to the baseline? It is not always possible to quantitatively assess these questions, though it may still be possible to describe then qualitatively.

EPA's Technical Guidance does not prescribe or recommend a specific approach or methodology for conducting an EJ analysis, though a key consideration is consistency with the assumptions underlying other parts of the regulatory analysis when evaluating the baseline and regulatory options. Where applicable and practicable, EPA endeavors to conduct such an analysis. Going forward, EPA is committed to conducting an EJ analysis for rulemakings based on a framework similar to what is outlined in EPA's Technical Guidance, in addition to investigating ways to further weave EJ into the fabric of the rulemaking process.

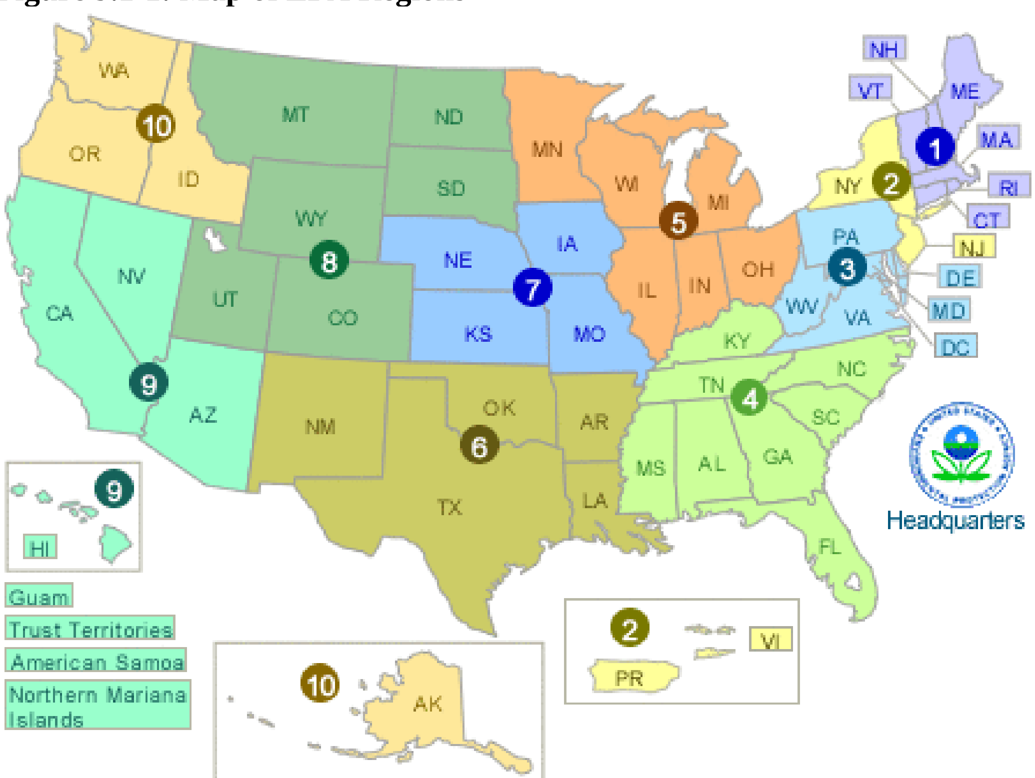
[906] https://www.epa.gov/sites/default/files/2016-06/documents/ejtg_5_6_16_v5.1.pdf

9.1 Proximity Analysis of Facilities Participating in the RFS Program

As of October 2022, there were 342 registered RIN-generating facilities in the U.S. There were also 146 petroleum refineries producing transportation fuel. These facilities are spread out across the U.S., with the addition of 3 petroleum facilities in Hawaii and 5 petroleum facilities in Alaska, Our analysis looks at the demographic composition of communities near these facilities nationally, for the subset of facilities located in rural areas, and by EPA Region (Figure 9.1-1) and major fuel type—in this case, petroleum, renewable diesel, biodiesel, ethanol, and RNG. This proximity-based analysis did not include facilities that generate renewable electricity from biogas, as there were none of these facilities participating in the RFS program as of 2022, and as discussed in Chapter 3, this rule is not expected to result in any additional renewable electricity generated from biogas in 2023–2025 than would occur in the absence of the RFS program.

For data on demographic characteristics near each facility, we use block group level data from the 2016 - 2020 American Community Survey. Areal apportionment is used to attribute these data to uniform buffers of 1-,3-, and 5-mile distances around each RIN-generating facility. Because the demographic composition of urban areas dominates the national average, we also examine facilities located in rural areas separately. We define a rural block group as one whose centroid does not intersect with Census polygons of urban areas/clusters. We then characterize a facility as being located in a rural area if 50% or more of the population within 3 miles live in rural block groups.

Figure 9.1-1: Map of EPA Regions



As the RFS is a national program, it is difficult to track facility-by-facility responses to the candidate volumes, so this demographic analysis focuses on baseline characteristics of communities near RIN-generating production facilities. We examined near-facility demographics in order to bring a quantitative lens to our qualitative observations. As this rule would displace petroleum fuels—primarily gasoline and diesel—with biofuels, it is expected that communities near facilities that produce biofuels may experience an overall increase in criteria pollutant exposure, while those near petroleum refineries could see the opposite if refineries react to the candidate volumes by decreasing production.[3]

Table 9.1-1 shows the demographic composition of communities within 1, 3 and 5 miles of these facilities compared to the national average. As seen below, at the 5 mile buffer radius, approximately 10 percent of the U.S. population lives near one or more RIN-generating facility. These near-facility communities can generally be characterized as having a greater than average percent non-white population, regardless of the distance buffer utilized. The Hispanic population living near these facilities is nearly double the national average. The percent Black population is 1.25 times the national average. In addition, these communities tend to have a higher than average unemployment rate, a lower median income, a higher percent with less than a high school education, and a higher percent living 1x and 2x below the federal poverty line compared to the national average.

Table 9.1-1: Near-Facility Demographics Compared to National Average

Demographic	1 mi	3 mi	5 mi	Nationwide
Total Population (millions)	1.0	12.2	32.8	326.6
% Rural Population	11.0	8.1	7.8	26.6
% White	63.2	60.3	60.0	70.4
% Black	16.1	16.0	16.3	12.6
% American Indian and Alaska Native	0.8	0.7	0.7	0.8
% Asian	4.3	6.1	6.5	5.6
% Native Hawaiian and Other Pacific Islander	0.4	0.4	0.3	0.2
% Other (Including Two or More)	15.2	16.5	16.1	10.3
% Hispanic	31.2	34.7	34.1	18.2
Median Income ($2020)	$58,411	$63,945	$66,529	$73,181
% 1x Poverty Line	18.5	16.7	15.9	12.5
% 2x Poverty Line	40.3	37.3	35.8	29.1
Unemployment Rate	7.0	6.5	6.3	5.4
% Less than High School Education	12.1	12.0	11.4	7.8

Table 9.1-2 presents the demographic characteristics of communities near 236 RIN-generating facilities located in rural areas (or about 48 percent of all RIN-generating facilities). Many biofuel facilities are located in rural areas in order to be close to feedstock crops. They play a role in rural job creation as further discussed in Chapters 8.1 and 8.3. In general, the demographic composition of rural communities that host RIN-generating facilities is similar to the rural national average, with the exception of a substantially higher than average percent Hispanic populations. People of two or more races and those living at or beneath 1x and 2x the

federal poverty line are slightly higher than nationwide rural average, and the median income is slightly lower.

Table 9.1-2: Near-Facility Demographics of Rural Facilities

Demographic	1 mi	3 mi	5 mi	Nationwide
Total Population (millions)	0.1	0.5	1.7	86.9
% Rural Population	85.3	82.3	61.9	100
% White	86.4	84.2	80.9	84.2
% Black	5.8	6.7	6.9	7.0
% American Indian and Alaska Native	0.5	0.6	0.7	1.5
% Asian	1.1	1.5	2.6	1.6
% Native Hawaiian and Other Pacific Islander	0.1	0.2	0.3	0.1
% Other (Including Two or More)	6.2	6.8	8.6	5.6
% Hispanic	12.4	13.9	18.5	9.0
Median Income ($2020)	$63,259	$65,346	$66,886	$68,372
% 1x Poverty Line	11.3	12.0	12.6	11.3
% 2x Poverty Line	30.2	29.7	31.0	27.9
Unemployment Rate	4.6	4.4	4.6	4.8
% Less than High School Education	9.0	8.6	9.0	7.7

Tables 9.1-3.1 through 3.10 show the demographic composition of communities near these biofuel and petroleum facilities by EPA region as shown in Figure 9.1-1. These community demographics are compared to regional averages. We present this information using a 3 mile distance buffer, though trends are similar at the 1 and 5 mile distances.

Table 9.1-3.1: Region 1 Near Facility Demographics Compared to Regional Average

	Within 3 miles	Region
Number of Facilities	7	
Total Population [millions]	0.3	14.8
% Rural Population	7.5	25.0
% White	68.5	79.8
% Black or African American	14.9	6.8
% American Indian and Alaska Native	0.4	0.3
% Asian	4.0	4.9
% Native Hawaiian and Other Pacific Islander	0.1	0.0
% Other (Including Two or More)	12.1	8.1
% Hispanic	19.3	11.3
Median Income [2020$]	$63,395	$85,923
% Low Income (Below 1x Poverty Line)	15.6	9.6
% Low Income (Below 2x Poverty Line)	33.6	21.8
Unemployment Rate	6.5	5.2
% Less than High School Education	7.1	6.0

Table 9.1-3.2: Region 2 Near Facility Demographics Compared to Regional Average

	Within 3 miles	Region
Number of Facilities	16	
Total Population [millions]	0.6	28.4
% Rural Population	4.8	13.2
% White Alone	52.5	63.3
% Black or African American	19.2	14.8
% American Indian and Alaska Native	0.4	0.3
% Asian	3.4	8.9
% Native Hawaiian and Other Pacific Islander	0.0	0.0
% Other (Including Two or More)	24.5	12.6
% Hispanic	43.3	19.5
Median Income [2020$]	$69,340	$83,720
% Low Income (Below 1x Poverty Line)	12.7	12.1
% Low Income (Below 2x Poverty Line)	33.2	26.1
Unemployment Rate	5.9	5.9
% Less than High School Education	11.8	8.3

Table 9.1-3.3: Region 3 Near Facility Demographics Compared to Regional Average

	Within 3 miles	Region
Number of Facilities	21	
Total Population [millions]	0.8	30.8
% Rural Population	7.4	27.7
% White	57.3	70.4
% Black or African American	33.1	17.6
% American Indian and Alaska Native	0.2	0.2
% Asian	3.8	4.8
% Native Hawaiian and Other Pacific Islander	0.0	0.0
% Other (Including Two or More)	5.5	6.9
% Hispanic	5.0	8.4
Median Income [2020$]	$53,629	$80,003
% Low Income (Below 1x Poverty Line)	19.7	10.9
% Low Income (Below 2x Poverty Line)	39.0	25.0
Unemployment Rate	7.8	5.4
% Less than High School Education	7.7	6.6

Table 9.1-3.4: Region 4 Near Facility Demographics Compared to Regional Average

	Within 3 miles	Region
Number of Facilities	42	
Total Population [millions]	1.0	66.3
% Rural Population	8.4	34.9
% White	47.1	68.9
% Black or African American	43.2	21.4
% American Indian and Alaska Native	0.3	0.4
% Asian	1.1	2.6
% Native Hawaiian and Other Pacific Islander	0.0	0.1
% Other (Including Two or More)	8.2	6.6
% Hispanic	26.7	13.0
Median Income [2020$]	$44,532	$61,927
% Low Income (Below 1x Poverty Line)	24.1	14.1
% Low Income (Below 2x Poverty Line)	49.3	33.0
Unemployment Rate	8.5	5.7
% Less than High School Education	13.1	8.3

Table 9.1-3.5: Region 5 Near Facility Demographics Compared to Regional Average

	Within 3 miles	Region
Number of Facilities	99	
Total Population [millions]	1.5	52.5
% Rural Population	14.8	30.1
% White	73.4	78.1
% Black or African American	14.3	11.4
% American Indian and Alaska Native	0.4	0.4
% Asian	2.6	3.6
% Native Hawaiian and Other Pacific Islander	0.1	0.0
% Other (Including Two or More)	9.2	6.5
% Hispanic	11.3	8.3
Median Income [2020$]	$58,621	$69,979
% Low Income (Below 1x Poverty Line)	17.4	12.1
% Low Income (Below 2x Poverty Line)	36.5	27.8
Unemployment Rate	5.9	5.4
% Less than High School Education	8.4	6.2

Table 9.1-3.6: Region 6 Near Facility Demographics Compared to Regional Average

	Within 3 miles	Region
Number of Facilities	105	
Total Population [millions]	2.5	42.4
% Rural Population	10.3	30.4
% White	60.6	69.0
% Black or African American	22.1	13.6
% American Indian and Alaska Native	0.9	1.6
% Asian	2.7	3.9
% Native Hawaiian and Other Pacific Islander	0.1	0.1
% Other (Including Two or More)	13.5	11.8
% Hispanic	44.1	31.2
Median Income [2020$]	$57,184	$65,936
% Low Income (Below 1x Poverty Line)	19.6	14.8
% Low Income (Below 2x Poverty Line)	43.1	33.9
Unemployment Rate	7.0	5.6
% Less than High School Education	14.5	9.6

Table 9.1-3.7: Region 7 Near Facility Demographics Compared to Regional Average

	Within 3 miles	Region
Number of Facilities	77	
Total Population [millions]	0.6	14.1
% Rural Population	18.8	40.6
% White	81.4	83.9
% Black or African American	7.7	7.6
% American Indian and Alaska Native	0.6	0.5
% Asian	2.6	2.4
% Native Hawaiian and Other Pacific Islander	0.1	0.1
% Other (Including Two or More)	7.5	5.4
% Hispanic	10.3	7.3
Median Income [2020$]	$57,183	$66,202
% Low Income (Below 1x Poverty Line)	15.9	11.5
% Low Income (Below 2x Poverty Line)	35.6	28.5
Unemployment Rate	4.8	4.2
% Less than High School Education	7.2	5.8

Table 9.1-3.8: Region 8 Near Facility Demographics Compared to Regional Average

	Within 3 miles	Region
Number of Facilities	39	
Total Population [millions]	1.0	12.1
% Rural Population	8.6	30.7
% White	81.5	83.8
% Black or African American	2.1	2.7
% American Indian and Alaska Native	1.7	2.3
% Asian	2.5	2.4
% Native Hawaiian and Other Pacific Islander	0.7	0.3
% Other (Including Two or More)	11.5	8.4
% Hispanic	21.5	15.2
Median Income [2020$]	$72,331	$77,609
% Low Income (Below 1x Poverty Line)	11.3	10.0
% Low Income (Below 2x Poverty Line)	28.6	25.3
Unemployment Rate	4.2	4.2
% Less than High School Education	6.5	4.9

Table 9.1-3.9: Region 9 Near Facility Demographics Compared to Regional Average

	Within 3 miles	Region
Number of Facilities	55	
Total Population [millions]	3.6	51.0
% Rural Population	2.2	11.3
% White	50.4	58.0
% Black or African American	6.9	5.7
% American Indian and Alaska Native	0.7	1.3
% Asian	13.1	13.5
% Native Hawaiian and Other Pacific Islander	0.6	0.7
% Other (Including Two or More)	28.3	20.9
% Hispanic	56.3	36.6
Median Income [2020$]	$75,139	$82,933
% Low Income (Below 1x Poverty Line)	14.4	12.5
% Low Income (Below 2x Poverty Line)	34.7	29.2
Unemployment Rate	7.0	6.3
% Less than High School Education	15.6	10.2

Table 9.1-3.10: Region 10 Near Facility Demographics Compared to Regional Average

	Within 3 miles	Region
Number of Facilities	27	
Total Population [millions]	0.4	14.2
% Rural Population	9.5	27.7
% White	62.1	77.5
% Black or African American	7.0	2.9
% American Indian and Alaska Native	1.6	1.9
% Asian	12.2	6.5
% Native Hawaiian and Other Pacific Islander	2.4	0.6
% Other (Including Two or More)	14.8	10.7
% Hispanic	13.5	12.7
Median Income [2020$]	$75,937	$78,170
% Low Income (Below 1x Poverty Line)	12.2	10.8
% Low Income (Below 2x Poverty Line)	27.6	26.2
Unemployment Rate	5.3	5.2
% Less than High School Education	6.6	5.8

Overall, we see similar trends at the regional level as compared to the overall national picture. In some regions, there appear to be less stark demographic disparities compared to the regional average, while in other cases, more so. Since biofuel and petroleum facilities are particularly concentrated in Regions 5, 6, and 7 (281 facilities) we use them to illustrate these differences. Regions 5 and 7 have slightly elevated percent Hispanic and Black populations near the biofuel facility compared to their regional averages, while percent Hispanic and Black populations are 1.4 and 1.7 times the regional average in Region 6, respectively. Populations living near these facilities also tend to have lower median incomes, a greater percent living in poverty or with less than a high school education.

The analysis above does not differentiate by type of facility. As stated above, the effects of this rule will not be felt evenly by different demographic groups, but the greatest contributing factor to what communities may experience is what type of facility they are near. While the EPA is unable to ascertain how facilities may respond to changes in required volumes of different RIN categories, the 2023-2025 volumes are greater than those in 2020-2022. Increases in required biofuel volumes will mean, generally, an increase in biofuel production at biofuel facilities and a decrease in petroleum production at refineries that make gasoline or diesel, all else equal. Biofuel directly displaces conventional transportation fuel. Communities near ethanol facilities, biodiesel and renewable diesel facilities, and RNG facilities may see increases in criteria pollutants. Conversely, communities near petroleum refineries may see reductions in air emissions as producers respond to increasing RFS volumes. It is not practicable to assess what facilities may or may not specifically experience any changes directly attributable to the RFS. In spite of these limitations, we examine the demographic composition of communities that may be affected by fuel type in Table 9.1-4. Results are shown for the 3 mile distance buffer.

Regardless of facility type, nearby communities have higher percent Black population than the national average, particularly near biodiesel and petroleum facilities; percent Black populations are 1.7 and 2.3 times the national average, respectively. Percent Hispanic populations near RNG, biodiesel, and petroleum facilities are also almost or more than double than the national average. The median incomes of communities near biodiesel, ethanol, and renewable diesel facilities are nearly $20,000 or more lower than the national median income, while communities near RNG and petroleum facilities have a median income that are lower than the national median by almost $10,000 and $1,000, respectively. Most of the communities near different facility types, other than those producing RNG, have a higher unemployment rate than the national average. All experience higher rates of poverty than the national average. A higher proportion of these populations compared to the national average also do not have at least a high school education.

Table 9.1-4: Facility Demographics Within 3 Miles By Fuel Production Type

	Biodiesel Facilities	Ethanol Facilities	Petroleum Facilities	Renewable Diesel Facilities	RNG Facilities	National Average
Number of Facilities	72	85	146	9	176	
Total Population [millions]	1.9	0.7	6.0	0.2	3.4	326.6
% Rural Population	8.3	20.7	4.3	11.0	11.7	26.6
% White	60.8	68.9	57.8	63.7	62.5	70.4
% Black or African American	21.2	17.9	13.9	28.3	15.9	12.6
% American Indian and Alaska Native	0.5	0.5	0.9	0.6	0.7	0.8
% Asian	2.8	3.3	6.9	1.4	7.3	5.6
% Native Hawaiian and Other Pacific Islander	0.2	0.2	0.5	0.1	0.3	0.2
% Other (Including Two or More)	14.6	9.3	20.1	5.8	13.4	10.3
% Hispanic	34.6	15.0	43.3	17.6	24.8	18.2
Median Income [2020$]	$54,428	$55,725	$63,842	$51,606	$71,935	$73,181
% Low Income (Below 1x Poverty Line)	19.2	17.7	17.3	19.6	13.8	12.5
% Low Income (Below 2x Poverty Line)	42.0	38.2	38.6	42.5	32.0	29.1
Unemployment Rate	6.9	6.7	7.0	8.9	5.4	5.6
% Less than High School Education	12.3	8.4	13.9	10.4	9.2	7.8

9.2 Non-GHG Air Quality Impacts

There is evidence that communities with EJ concerns are impacted by non-GHG emissions. Numerous studies have found that environmental hazards such as air pollution are more prevalent in areas where racial/ethnic minorities and people with low socioeconomic status (SES) represent a higher fraction of the population compared with the general population.[907,908,909,910] Consistent with this evidence, a recent study found that most anthropogenic sources of $PM_{2.5}$, including industrial sources, and light- and heavy-duty vehicle sources, disproportionately affect people of color.[911]

Emissions of non-GHG pollutants such as PM, NOx, CO, SO_2, and air toxics occur during the production, storage, transport, distribution, and combustion of petroleum-based fuels and biofuels. Some communities with EJ concerns are located near petroleum refineries, biorefineries, and on-road sources of pollution. For example, analyses of communities in close proximity to petroleum refineries have found that vulnerable populations near refineries may experience potential disparities in pollution-related health risk from that source.[912] There is also substantial evidence that people who live or attend school near major roadways are more likely to be of a minority race, Hispanic ethnicity, and/or low SES. [913,914,915] For this rule, EPA has not quantitatively assessed the cumulative risks to certain demographics near biorefineries, but is evaluating the extent to which this type of analysis could be done for future rulemakings.

Although proximity to an emissions source is a useful indicator of potential exposure, it is important to note that the impacts of emissions from both upstream and tailpipe sources are not limited to communities in close proximity to them. As a result of regional transport and secondary formation of pollutants in the air, the effects of both potential increases and decreases in emissions from the sources affected by this rule might also be felt many miles away, including in communities with EJ concerns downwind of sources. The spatial extent of these impacts from upstream and tailpipe sources depends on a range of interacting and complex factors, including the amount of pollutant emitted, atmospheric chemistry and meteorology.

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[907] Mohai, P.; Pellow, D.; Roberts Timmons, J. (2009) Environmental justice. Annual Reviews 34: 405-430. https://doi.org/10.1146/annurev-environ-082508-094348

[908] Rowangould, G.M. (2013) A census of the near-roadway population: public health and environmental justice considerations. Trans Res D 25: 59-67. http://dx.doi.org/10.1016/j.trd.2013.08.003

[909] Marshall, J.D., Swor, K.R.; Nguyen, N.P (2014) Prioritizing environmental justice and equality: diesel emissions in Southern California. Environ Sci Technol 48: 4063-4068. https://doi.org/10.1021/es405167f

[910] Marshall, J.D. (2000) Environmental inequality: air pollution exposures in California's South Coast Air Basin. Atmos Environ 21: 5499-5503. https://doi.org/10.1016/j.atmosenv.2008.02.005

[911] C. W. Tessum, D. A. Paolella, S. E. Chambliss, J. S. Apte, J. D. Hill, J. D. Marshall (2021). PM2.5 polluters disproportionately and systemically affect people of color in the United States. Sci. Adv. 7, eabf4491.

[912] U.S. EPA (2014). Risk and Technology Review – Analysis of Socio-Economic Factors for Populations Living Near Petroleum Refineries. Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina. January.

[913] Rowangould, G.M. (2013) A census of the U.S. near-roadway population: public health and environmental justice considerations. Transportation Research Part D; 59-67.

[914] Tian, N.; Xue, J.; Barzyk. T.M. (2013) Evaluating socioeconomic and racial differences in traffic-related metrics in the United States using a GIS approach. J Exposure Sci Environ Epidemiol 23: 215-222.

[915] Boehmer, T.K.; Foster, S.L.; Henry, J.R.; Woghiren-Akinnifesi, E.L.; Yip, F.Y. (2013) Residential proximity to major highways – United States, 2010. Morbidity and Mortality Weekly Report 62(3): 46-50.

The manner in which biofuel producers and markets respond to the candidate volumes in this rule could have non-GHG exposure impacts for communities living near facilities that produce biofuels. Chapter 4.1 summarizes what is known about potential air quality impacts of the candidate volumes assessed for this rule. We expect that small increases in non-GHG emissions from biofuel production and small reductions in petroleum-sector emissions would lead to small changes in exposure to these non-GHG pollutants for people living in the communities near these facilities. This is of some concern, as we noted in Chapter 4.1 that communities living within 10 km of biorefineries were shown to be at a higher risk of adverse respiratory outcomes. However, we do not have the information needed to understand the magnitude and location of facility-specific responses to the candidate volumes, and therefore we are unable to evaluate impacts on air quality in EJ communities near these facilities. We therefore recommend caution when interpreting these broad, qualitative observations.

9.3 Water & Soil Quality Impacts

We conducted an analysis to estimate the impacts associated with the candidate volumes on water and soil quality in Chapter 4.4. Though soil quality is not among the statutory factors required to be analyzed under the set authority in the CAA,[916] it is discussed in conjunction with water quality because it can have direct impacts on water quality. EPA defines water quality as the condition of water to serve human or ecological needs, while USDA defines soil quality as the ability of soil to function, including its capacity to support plant life. The ways in which this rule could potentially impact water and soil is by creating an incentive for land use and management changes, primarily through the encouragement of biofuels produced from corn and soybeans. An increase in demand for corn and soybeans for biofuel production has historically caused the conversion of natural grasslands to cropland.[917] This land use change has negative consequences for soil quality in that it can increase soil erosion, depletion of SOM (soil organic matter), and loss of soil carbon. These negative impacts on soil quality then translate into negative impacts on water quality like increased soil erosion, which causes sedimentation and murky water conditions. Nutrient leaching can result in excessive algae growth and hypoxia (low oxygen levels in the water), which then has negative consequences on aquatic organisms as described in Chapter 4.4.2.3.

As discussed in Chapter 4.4, the candidate volumes have the potential to incentivize increases in crop production, and by extension adverse impacts on soil and water quality. This does not apply to biogas used to generate electricity or produce RNG, as they are making use of waste streams of processes driven by other phenomena.[918,919,920,921] 97% of all RINs generated via biogas-related pathways came from wastewater treatment plants, agricultural digesters, or

[916] CAA section 211(o)(2)(B)(ii).
[917] See Chapter 4.3.2.
[918] Melvin, A.M.; Sarofim, M.C.; Crimmins, A.R., ‘‘Climate benefits of U.S. EPA programs and policies that reduced methane emissions 1993– 2013’’, Environmental Science & Technology, 2016, in press. http://pubs.acs.org/doi/pdf/10.1021/acs.est.6b00367. DOI 10.1021/acs.est.6b00367.
[919] 81 FR 59332 (August 29, 2016).
[920] https://www.epa.gov/agstar/benefits-anaerobic-digestion.
[921] https://www.resourcerecoverydata.org/Potential_Power_of_Renewable_Energy_Generation_From_Wastewater_and_Biosolids_Fact_Sheet.pdf.

landfill methane capture. The RFS program does not affect human, animal, or solid waste production, and in fact incentivizes the collection of these products, improving local soil and water quality. However, the magnitude of both this impact and that of other biofuels is difficult to estimate as it would require more information on the correlation between RFS-driven changes in biofuel volumes and feedstock usage and where any increases in those feedstocks occur (e.g., domestically vs internationally, and on what acres), the cultivation practices applied to those acres (e.g., fertilizer and pesticide use, use of cover crops in the non-growing season, crop rotations, etc.), as well as modeling to evaluate the magnitude of any runoff occurring from those acres. Additionally, we would need additional information on the impacted populations in order to evaluate the EJ concerns: where are the populations that are already being impacted most, who resides in those areas, how are they using the water, and how are the changes in water quality and availability impacting those uses and, thereby, those populations. For these reasons, we are unable to assess the degree of impact the candidate volumes may have. However, going forward, we would like to better understand the relationship between the RFS volume standards and land use/land management decisions.

Any negative impacts on aquatic life have the potential to also negatively impact populations that rely on fish or other aquatic life, like shrimp or crawfish, for sustenance or income. According to a study by Beveridge, et al., fish is a very nutritious food for humans with high quality animal protein, essential fatty acids, and micronutrients.[922] Many American Indian tribes, minority populations, and some low-income populations rely on local food sources—including fish and other aquatic life—to supplement their diets. To better understand these high-risk populations, we conducted a literature review to identify population groups most likely to fall under the high-risk category for mercury exposure based on higher-than-average fish consumption as part of the RIA for the Mercury and Air Toxics Standards rule.[923] These population groups are the same ones that would be most affected by any adverse impact the RFS program has on fisheries and aquatic life due to their heavy reliance on fishing for sustenance. This review included six high-risk population groups, including African-American and white low-income recreational and subsistence fishers in the Southeast, female low-income recreational and subsistence fishers, Hispanic and Laotian subsistence fishers, and Chippewa/Ojibwe Tribe members in the Great Lakes area.[924] American Indian tribes also rely on recreational fisheries for income, as explained by the U.S. Department of the Interior.[925] The fish populations depend on healthy water systems to thrive. If these aquatic ecosystems are negatively impacted by agricultural runoff and nutrient leaching, they could suffer from algae blooms or become hypoxic, making it impossible for fish to survive and endangering the human populations that rely on them. Additionally, any increased use of nitrogen rich fertilizers, as are

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[922] Beveridge, M. C., Thilsted, S. H., Phillips, M. J., Metian, M., Troell, M., & Hall, S. J. (2013). Meeting the food and nutrition needs of the poor: the role of fish and the opportunities and challenges emerging from the rise of aquaculture. Journal of fish biology, 83(4), 1067–1084. https://doi.org/10.1111/jfb.12187

[923] Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards. EPA-452/R-11-011. December 2011.

[924] Id.

[925] U.S. Department of the Interior, Working with Native American Tribes, available at https://www.fws.gov/southeast/our-services/native-american-tribes; see also, U.S. Department of the Interior, Native American Trust Responsibilities, available at https://www.fws.gov/southwest/fisheries/native_american_trust.html, and U.S. Department of the Interior, Indian Affairs, Branch of Fish, Wildlife, and Recreation, available at https://www.bia.gov/bia/ots/division-natural-resources/branch-fish-wildlife-recreation.

applied to approximately 98% of corn acres (see Table 4.4.2.1-1), could result in nitrates leaching into groundwater that may be used for human consumption, particularly in areas with loamy and sandy soil conditions. Nitrate filtration is an expensive process that low-income communities may not have access to. Additionally, where groundwater wells are employed in rural areas, the concern of disproportionate impact on vulnerable populations may increase. In this way, if and to the extent the candidate volumes adversely affect water quality, they could potentially have disproportionately severe negative impacts on EJ communities within American Indian tribes and other low income populations that rely on local fisheries as a source of food or income or that may not be able to afford costly water filtration systems to address nitrate contamination in their drinking water.

9.4 Impacts on Fuel and Food Prices

Costs are also relevant to an EJ analysis when communities are expected to face economic challenges due to impacts of a regulation (E.O. 14008). For instance, if prices for basic commodities such as food and fuel increase as a result of a rulemaking, lower-income households may be differentially affected since these goods and services may make up a relatively larger share of their income, and they are less able to adapt or substitute away from them.

As part of the analyses conducted for this rule, we estimated the impact on food prices. These impacts are attributed to increases in corn and soy prices associated with the candidate volumes. Both the literature[926,927] and our analysis in Chapter 10 indicate corn and soy are a relatively small proportion of most foods purchased and consumed in the U.S., and the overall food price impacts are relatively small as a percentage of total food expenditures. We estimate that the candidate volumes would affect gasoline prices by 0.6¢/gal in 2023, 1.8¢/gal in 2024, and 3.1¢/gal in 2025. Diesel prices would rise by 14.1¢/gal in 2023, 14.4¢/gal in 2024, and 14.9¢/gal in 2025. Food prices would rise from these volumes by 0.57% in 2023 and 2024, and 0.58% in 2025, relative to the No RFS baseline. These impacts are discussed in greater detail in Chapters 8.4 (price of agricultural commodities), 8.5 (food price impacts), and 10 (fuel price impacts).

The projections of the impact associated with the candidate volumes on food and fuel prices are ultimately derived from projections of the impact on widely traded commodities such as corn, soybeans, gasoline, and diesel. We therefore do not expect that the impact on food and fuel prices would vary for different parts of the country. However, changes in food and fuel prices could have a disproportionate impact on populations that spend a larger share of their income on food and fuel. According to data collected via the Consumer Expenditure Survey from the Bureau of Labor and Statistics, consumer units with income in the lowest 20% spend a greater portion of their total expenditures on food and fuel (see Table 9.4-1). Thus, even though

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[926] Hayes, D.J., B.A. Babcock, J.F. Fabiosa, S. Tokgoz, A. Elobeid, T.H. Yu, F. Dong, C.E. Hart, E. Chavez, S. Pan, M. Carriquiry, and J. Dumortier. 2009. "Biofuels: Potential Production Capacity, Effects on Grain and Livestock Sectors, and Implications for Food Prices and Consumers." Working paper 09-WP 487. Center for Agricultural and Rural Development, Iowa State University.

[927] Taheripour, Farzad, et al. “Economic Impacts of the U.S. Renewable Fuel Standard: An Ex-Post Evaluation.” Frontiers in Energy Research, vol. 10, 2022, https://doi.org/10.3389/fenrg.2022.749738.

we expect that the effects on the prices for food and fuel to increase proportionally for all consumers, we also expect that these price impacts, though small, would have a larger impact on lower-income communities where food and fuel expenditures are a greater portion of total expenditures.

Table 9.4-1: Proportion of Total Expenditures on Food and Fuel[26]

	All Consumer Units	Lowest 20% Consumer Unit Income	Second-lowest 20% Consumer Unit Income
Total expenditures	$61,350	$28,782	$39,846
Food expenditures	$7,316	$4,095	$5,380
% of total expenditures on food	11.9%	14.3%	13.5%
Fuel expenditures	$1,568	$814	$1,254
% of total expenditures on fuel	2.6%	2.8%	3.1%
% Women	53%	65%	56%
% Black	13%	19%	15%
% With a High School Degree or Less	30%	49%	41%

Assuming no changes in income available to spend on goods, nor changes to the bundles of goods consumed, the RFS program would cause the lowest quintile of consumer units to spend $4,166, or 14.5% of their income on food (versus 14.3% currently), while the second lowest quintile of consumer units would spend $5,473, or 13.7% of their income on food (versus 13.5% currently), by 2025. This is shown in year by year increments below in Table 9.4-2.

These consumer units would also see increases to their total expenditures on fuel as a result of the RFS program, increasing to $816 for the lowest quintile of consumer units and $1,257 for the second-lowest quintile of consumer units in 2023, $823 and $1,267 in 2024, and $834 and $1,285 in 2025, respectively.[27,28]

Table 9.4-2: Year By Year Change in Food Expenditures per Consumer Unit Relative to the No RFS Baseline

	2023	2024	2025
All Consumer Units			
Food Expenditures	$7,316	$7,316	$7,316
Percent Impact on Food Expenditures	0.57%	0.57%	0.58%
Projected Food Expenditure Increase	$41.94	$41.99	$42.14
Lowest Quintile Income Consumer Units			
Food Expenditures	$4,099	$4,099	$4,099
Percent Impact on Food Expenditures	0.57%	0.57%	0.58%
Projected Food Expenditure Increase	$23.50	$23.53	$23.61
Second-Lowest Quintile Income Consumer Units			
Food Expenditures	$5,380	$5,380	$5,380
Percent Impact on Food Expenditures	0.57%	0.57%	0.58%
Projected Food Expenditure Increase	$30.84	$30.88	$30.99

This would result in a 2.5% increase in fuel expenditures for the lowest and second lowest quintile consumer units, corresponding to 2.9% and 3.2% (versus 2.8% and 3.1% currently), respectively, of each quintile's consumer unit total expenditures. These effects, while minor, will fall disproportionately on low-income consumers, women, people of color, and those without a high school degree.

9.5 Greenhouse Gas Impacts

In 2009, under the "Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act" (hereinafter the "Endangerment Finding"), EPA considered how climate change threatens the health and welfare of the U.S. population. As part of that consideration, we also considered risks to minority and low-income individuals and communities, finding that certain parts of the U.S. population may be especially vulnerable based on their characteristics or circumstances. These groups include economically and socially disadvantaged communities; individuals at vulnerable life stages, such as the elderly, the very young, and pregnant or nursing women; those already in poor health or with comorbidities; the disabled; those experiencing homelessness, mental illness, or substance abuse; and/or Indigenous or minority populations dependent on one or limited resources for subsistence due to factors including but not limited to geography, access, and mobility.

Scientific assessment reports produced over the past decade by the U.S. Global Change Research Program (USGCRP),[928,929] the Intergovernmental Panel on Climate Change

[928] USGCRP, 2018: Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 1515 pp. doi: 10.7930/NCA4.2018.

[929] USGCRP, 2016: The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment. Crimmins, A., J. Balbus, J.L. Gamble, C.B. Beard, J.E. Bell, D. Dodgen, R.J. Eisen, N. Fann, M.D. Hawkins, S.C. Herring, L. Jantarasami, D.M. Mills, S. Saha, M.C. Sarofim, J. Trtanj, and L. Ziska, Eds. U.S. Global Change Research Program, Washington, DC, 312 pp. http://dx.doi.org/10.7930/J0R49NQX.

(IPCC),[930,931,932,933] and the National Academies of Science, Engineering, and Medicine[934,935] add more evidence that the impacts of climate change raise potential EJ concerns. These reports conclude that poorer or predominantly non-white communities can be especially vulnerable to climate change impacts because they tend to have limited adaptive capacities and are more dependent on climate-sensitive resources such as local water and food supplies, or have less access to social and information resources. Some communities of color, specifically populations defined jointly by ethnic/racial characteristics and geographic location, may be uniquely vulnerable to climate change health impacts in the U.S. In particular, USGCRP (2016) found with high confidence that vulnerabilities are place- and time-specific, that particular life stages and ages are linked to immediate and future health impacts, and that social determinants of health are linked to greater extent and severity of climate change-related health impacts.

9.6 Effects on Specific Populations of Concern

EJ populations of concern, such as individuals living in socially and economically disadvantaged communities (e.g., living at or below the poverty line or experiencing homelessness or social isolation) or those who have been historically marginalized or overburdened are at greater risk of health effects from climate change. This is also true with respect to people at vulnerable life stages, specifically women who are pre- and perinatal, or are nursing; *in utero* fetuses; children at all stages of development; and the elderly. Per the Fourth

[930] Oppenheimer, M., M. Campos, R.Warren, J. Birkmann, G. Luber, B. O'Neill, and K. Takahashi, 2014: Emergent risks and key vulnerabilities. In: Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L.White (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 1039-1099.

[931] Porter, J.R., L. Xie, A.J. Challinor, K. Cochrane, S.M. Howden, M.M. Iqbal, D.B. Lobell, and M.I. Travasso, 2014: Food security and food production systems. In: Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L.White (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 485-533.

[932] Smith, K.R., A.Woodward, D. Campbell-Lendrum, D.D. Chadee, Y. Honda, Q. Liu, J.M. Olwoch, B. Revich, and R. Sauerborn, 2014: Human health: impacts, adaptation, and co-benefits. In: Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel,A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L.White (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 709-754.

[933] IPCC, 2018: Global Warming of 1.5°C. An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty [Masson-Delmotte, V., P. Zhai, H.-O. Pörtner, D. Roberts, J. Skea, P.R. Shukla, A. Pirani, W. Moufouma-Okia, C. Péan, R. Pidcock, S. Connors, J.B.R. Matthews, Y. Chen, X. Zhou, M.I. Gomis, E. Lonnoy, T. Maycock, M. Tignor, and T. Waterfield (eds.)]. In Press

[934] National Research Council. 2011. America's Climate Choices. Washington, DC: The National Academies Press. https://doi.org/10.17226/12781.

[935] National Academies of Sciences, Engineering, and Medicine. 2017. Communities in Action: Pathways to Health Equity. Washington, DC: The National Academies Press. https://doi.org/10.17226/24624.

National Climate Assessment (NCA4), "Climate change affects human health by altering exposures to heat waves, floods, droughts, and other extreme events; vector-, food- and waterborne infectious diseases; changes in the quality and safety of air, food, and water; and stresses to mental health and well-being."[936] Many health conditions such as cardiopulmonary or respiratory illness and other health impacts are associated with and exacerbated by an increase in GHGs and climate change outcomes, which is problematic as these diseases occur at higher rates within vulnerable communities. Importantly, negative public health outcomes include those that are physical in nature, as well as mental, emotional, social, and economic.

To this end, the scientific assessment literature, including the aforementioned reports, demonstrates that there are myriad ways in which these populations may be affected at the individual and community levels. Individuals face differential exposure to criteria pollutants, in part due to the proximities of highways, trains, factories, and other major sources of pollutant-emitting sources to less-affluent and traditionally marginalized residential areas. Outdoor workers, such as construction or utility workers and agricultural laborers, who are frequently part of already at-risk groups, are exposed to poor air quality and extreme temperatures without relief. Furthermore, individuals within EJ populations of concern face greater housing and clean water insecurity and bear disproportionate economic impacts and health burdens associated with climate change effects. They tend to have less or limited access to healthcare and affordable, adequate health or homeowner insurance. Finally, resiliency and adaptation are more difficult for economically disadvantaged communities. They have less liquidity, individually and collectively, to move or to make the types of infrastructure or policy changes to limit or reduce the hazards they face. Finally, due to systemic challenges, affected communities may lack the resources necessary to advocate for resources that would otherwise aid in resiliency and hazard reduction and mitigation.

The assessment literature cited in EPA's 2009 and 2016 Endangerment Findings, as well as USGCRP (2016), also concluded that certain populations and people in particular life stages, including children, are most vulnerable to climate-related health effects. The assessment literature produced from 2016 to the present strengthens these conclusions by providing more detailed findings regarding related vulnerabilities and the projected impacts youth may experience. These assessments—including NCA4 and USGCRP (2016)—describe how children's unique physiological and developmental factors contribute to making them particularly vulnerable to climate change. Impacts to children are expected from heat waves, air pollution, infectious and waterborne illnesses, and mental health effects resulting from extreme weather events. In addition, children are among those especially susceptible to allergens, as well as health effects associated with storms, and floods. More generally, these reports note that extreme weather and flooding can cause or exacerbate poor health outcomes by affecting mental health because of stress; contributing to or worsening existing conditions, again due to stress or also as a consequence of exposures to water and air pollutants; or by impacting hospital and

[936] Ebi, K.L., J.M. Balbus, G. Luber, A. Bole, A. Crimmins, G. Glass, S. Saha, M.M. Shimamoto, J. Trtanj, and J.L. White-Newsome, 2018: Human Health. In Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, pp. 539–571. doi: 10.7930/NCA4.2018.CH14

emergency services operations.[937] Further, in urban areas in particular, flooding can have significant economic consequences due to effects on infrastructure, pollutant exposures, and drowning dangers. The ability to withstand and recover from flooding is dependent in part on the social vulnerability of the affected population and individuals experiencing an event.[938] Additional health concerns may arise in low-income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity.

USGCRP (2016) also found that some communities of color, low-income groups, people with limited English proficiency, and certain immigrant groups (especially those who are undocumented) live with many of the factors that contribute to their vulnerability to the health impacts of climate change. While difficult to isolate from related socioeconomic factors, race appears to be an important factor in vulnerability to climate-related stress, with elevated risks for mortality from high temperatures reported for Black or African American individuals compared to white individuals after controlling for factors such as air conditioning use. Moreover, people of color are disproportionately exposed to air pollution based on where they live, and disproportionately vulnerable due to higher baseline prevalence of underlying diseases such as asthma, so climate exacerbations of air pollution are expected to have disproportionate effects on these communities.

Native American Tribal communities possess unique vulnerabilities to climate change, particularly those communities impacted by degradation of natural and cultural resources within established reservation boundaries and threats to traditional subsistence lifestyles. Tribal communities whose health, economic well-being, and cultural traditions depend upon the natural environment will likely be affected by the degradation of ecosystem goods and services associated with climate change. The IPCC's Fifth Assessment Report of the Intergovernmental Panel on Climate Change (AR5) indicates that losses of customs and historical knowledge may cause communities to be less resilient or adaptable.[939] NCA4 noted that while Indigenous peoples are diverse and will be impacted by the climate changes universal to all Americans, there are several ways in which climate change uniquely threatens Indigenous peoples' livelihoods and economies.[940] In addition, there can be institutional barriers (including policy-based limitations and restrictions) to their management of water, land, and other natural resources that could impede adaptive measures. For example, Indigenous agriculture in the Southwest is already being adversely affected by changing patterns of flooding, drought, dust storms, and rising temperatures leading to increased soil erosion, irrigation water demand, and decreased crop quality and herd sizes. The Confederated Tribes of the Umatilla Indian Reservation in the

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[937] USGCRP, 2018: Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 1515 pp. doi: 10.7930/NCA4.2018.
[938] National Academies of Sciences, Engineering, and Medicine. 2019. Framing the Challenge of Urban Flooding in the United States. Washington, DC: The National Academies Press. https://doi.org/10.17226/25381.
[939] Porter et al., 2014: Food security and food production systems.
[940] Jantarasami, L.C., R. Novak, R. Delgado, E. Marino, S. McNeeley, C. Narducci, J. Raymond-Yakoubian, L. Singletary, and K. Powys Whyte, 2018: Tribes and Indigenous Peoples. In Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, pp. 572–603. doi: 10.7930/NCA4.2018.CH15.

Northwest have identified climate risks to salmon, elk, deer, roots, and huckleberry habitat.[941] Housing and sanitary water supply infrastructure are vulnerable to disruption from extreme precipitation events. Confounding the general Indigenous response to natural hazards are limitations imposed by policies such as the Dawes Act of 1887 and the Indian Reorganization Act of 1934, which ultimately restrict Tribal peoples' autonomy regarding land-management decisions through Federal trusteeship of certain Tribal lands and mandated Federal oversight of management decisions.

Additionally, NCA4 noted that Indigenous peoples are subject to institutional racism effects, such as poor infrastructure, diminished access to quality healthcare, and greater risk of exposure to pollutants. Consequently, Indigenous people often have disproportionately higher rates of asthma, cardiovascular disease, Alzheimer's disease, diabetes, and obesity. These health conditions and related effects (e.g., disorientation, heightened exposure to PM2.5, etc.) can all contribute to increased vulnerability to climate-driven extreme heat and air pollution events, which may be exacerbated by stressful situations, such as extreme weather events, wildfires, and other circumstances.

NCA4 and AR5 also highlighted several impacts specific to Alaskan Indigenous Peoples. Coastal erosion and permafrost thaw will lead to more coastal erosion, exacerbated risks of winter travel, and damage to buildings, roads, and other infrastructure. These impacts on archaeological sites, structures, and objects that will lead to a loss of cultural heritage for Alaska's Indigenous people. In terms of food security, NCA4 discussed reductions in suitable ice conditions for hunting, warmer temperatures impairing the use of traditional ice cellars for food storage, and declining shellfish populations due to warming and acidification. While NCA4 also noted that climate change provided more opportunity to hunt from boats later in the fall season or earlier in the spring, the assessment found that the net impact was an overall decrease in food security.

[941] Confederated Tribes of the Umatilla, Indian Reservation, 2015. Climate Change Vulnerability Assessment. Nasser, E., Petersen, S., Mills, P. (eds). Available online: www.ctuir.org.

Chapter 10: Estimated Costs and Fuel Price Impacts

The statute directs EPA to assess the impact of the use of renewable fuels on the cost to consumers of transportation fuel and on the cost to transport goods in using the reset authority. In this chapter, we assess the social costs of renewable fuels, the social costs of the petroleum fuels which the biofuels replace, the fuel economy effect based on each fuel's energy density, and the impacts of this rule on social costs, the costs to consumers of transportation fuel, and the costs to transport goods.

The costs are analyzed for the proposed renewable fuel volumes in 2023 through 2025 relative to a No RFS baseline. Costs are also calculated for the proposed incremental increase in renewable fuel volumes relative to the year 2022 renewable fuel volumes established in the recent 2020-2022 final rule.[942] In both cases, costs are in 2021 dollars. Chapter 2 contains a summary of the baseline volumes, and Chapter 3 contains the candidate volumes analyzed. Chapters 10.4.2.1 and 10.4.3.1 contain the change in candidate volumes relative to the No RFS and 2022 baselines, respectively, as well as the estimated change in fossil fuel volumes displaced by the change in volume of renewable fuels.[943]

10.1 Renewable Fuel Costs

10.1.1 Feedstock Costs

For most renewable fuels, the feedstock costs are a primary contributing factor to the cost to produce and use the renewable fuels. We first estimate the production cost for these feedstocks prior to providing information for the production, distribution and blending costs for the various renewable fuels.

In calculating feedstock costs, we used projections of feedstock prices for 2023 through 2025 from multiple sources, including EIA and USDA.[944] We also made adjustments to account for differences between these projections. Specifically, the projected feedstock prices are adjusted to account for different crude oil prices used by USDA than those projected by EIA, and to adjust the projected nominal prices to constant year 2021 dollars.[945]

In addition, recently geopolitical factors have caused petroleum prices to spike well above their recent price norms, but these recent petroleum price increases are not reflected in the cost analysis since they are not reflected in the underlying price projections from EIA and USDA

[942] 87 FR 39600 (July 1, 2022).
[943] The spreadsheet used to estimate the costs for the candidate volumes relative to the No RFS and 2022 volumes is available in the docket for this action.
[944] USDA Agricultural Projections to 2031; Long Term Projections Report; February 2022
[945] Crude oil prices affect the cost for growing renewable fuels feedstocks, the cost to transport them to the renewable fuels production plants, the cost for transporting the produced renewable fuels from the plant to market, and may impact the cost for producing the renewable fuels. Because USDA agricultural price projections were based on lower crude oil price projections than that by EIA, the USDA agricultural price projections may have underestimated the agricultural prices that would be consistent with the EIA petroleum price projections. Therefore, the USDA price projections for both corn and soybean oil were adjusted in an attempt to remove this potential bias in the cost analysis.

available at this time. We provide a sensitivity analysis at a higher crude oil price to demonstrate the impact of higher crude oil prices. The supply issues related to the aftermath of the COVID-19 pandemic and these other geopolitical factors increases the uncertainty that price projections precisely reflect the cost of producing and using these renewable fuels and ultimately increases the uncertainty in conducting this cost analysis. The final rule cost analysis will rely on the most recent price projections that are available.

10.1.1.1 Corn and Corn Ethanol Plant Byproducts

The price of corn is the most important input to estimating the cost of corn ethanol. Table 10.1.1.1-1 shows the derivation of the corn prices used in this cost analysis, which adjusts the projected prices for crude oil price differences and for inflation. To help to explain the derivation in the discussion below, we refer to the relevant row # in the Table.

As a starting point we used future corn price projections from USDA. We started with the 2023 through 2025 USDA projected corn prices (row #1).[946] However, the USDA corn prices are reported in nominal dollars, reflecting the inflated value of the dollars in those years. The first adjustment we made was to convert those USDA corn prices reported in nominal dollars into the 2021 dollars used across this cost analysis (row #2). [947]

Next, we made an adjustment to account for the different crude oil price projections that USDA used (row #3) compared to those projected by EIA (row #5).[948] Because EIA is the U.S. reference organization for projecting petroleum prices, we adjusted the USDA inflation-adjusted corn prices to put them on the same basis with the petroleum costs which are based on EIA crude oil prices. To do so, we first adjusted the crude oil prices used by USDA (row #3) to 2021 dollars (row #4). Then we used a regression of corn prices and crude oil prices to estimate the corn prices at USDA crude oil prices adjusted to 2021 dollars (row #6) and the corn prices at the EIA crude oil prices (row #6), to enable an adjustment of USDA corn prices to be consistent with the EIA crude oil prices. The regression of corn prices and crude oil prices is based on monthly corn prices between April 2008 and September 2017, which yielded the following equation:[949]

Corn Price ($/bushel) = Crude Oil Price ($/bbl) x 0.0366 + 1.81

The corn prices estimated by this regression was not used directly for the cost analysis because farmers are more efficient at producing corn today than in the past, and corn production is likely to be on a different supply/demand point on the corn price curve as evidenced by today's higher corn prices. Instead, the difference in regressed corn prices (row #8) was added to the USDA corn prices adjusted to 2021 dollars (row #2) to derive the final adjusted corn prices

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[946] USDA Agricultural Projections to 2031; Long Term Projections Report; February 2022.

[947] USDA reports estimated future inflation rates which are used for the nominal dollar to 2021$ adjustment.

[948] There seems to be an association between the renewable fuels feedstock costs and crude oil prices (regression analysis reveals an R-squared of 0.56 for corn and crude oil). Since USDA estimated renewable fuel feedstock prices based on lower crude oil prices, adjusting their renewable fuel feedstock prices higher to be consistent with EIA crude oil prices better syncs the two price projections and leads to a better estimate of costs.

[949] The years from 2008 to 2017 were chosen because of the wide range in crude oil prices which existed over this time period, and a 10 year time period was chosen to provide enough data for a quality regression.

(row #9) subsequently used as an input value for estimating corn ethanol costs as shown in Table 10.1.1.1-1.

Table 10.1.1.1-1: Derivation of Corn Feedstock Production Costs ($/bushel for corn, $/bbl for Crude Oil)

		Row #	2023	2024	2025
Corn Prices	USDA Nominal $	1	4.80	4.50	4.30
	USDA 2021$	2	4.61	4.24	3.97
Crude Oil Prices	USDA Nominal $	3	59.0	58.6	59.3
	USDA 2021$	4	52.8	51.4	51.0
	EIA 2021$	5	57.9	62.9	64.0
Regressed Corn Prices	Based on USDA 2022	6	3.74	3.69	3.68
	Based on EIA 2022 (Jan STEO)	7	3.93	4.11	4.15
Corn Prices	Difference in Regressed Corn Prices EIA - USDA	8	0.19	0.42	0.48
Corn Prices	Adjusted USDA 2021$	9	4.80	4.66	4.45

Both the inflation and crude oil price adjustment are modest, and their effects cause offsetting effects. Also, these adjustments are well within the recent variation in corn prices.

Since corn ethanol plants also produce byproducts which can be sold for additional value, we also estimated the prices for those byproducts, specifically DDGS and corn oil, which is estimated below in Chapter 10.1.1.2. Since USDA does not estimate future prices for DDGS, these were obtained by agricultural price projections made by the University of Missouri, Food and Agricultural Policy Research Institute (FAPRI).[950] The FAPRI DDGS projected prices are reported in nominal dollars, so we adjusted the price projections to 2021 dollars. Table 10.1.1.1-2 summarizes DDGS prices used in the cost analysis.

Table 10.1.1.1-2: DDGS Prices (2021 dollars)

Year	DDGS Prices ($/dry ton)
2023	162.2
2024	159.7
2025	156.6

10.1.1.2 Soybean and Palm Oil Prices

Soybean oil, waste fats, oils, and greases (FOG), corn oil, and palm oil were identified in Chapter 2 as the feedstocks for producing biodiesel and renewable diesel fuel. Soybean oil price projections made by USDA are used as a starting point for this cost analysis.[951]

[950] U.S. Agricultural Market Outlook, Food and Agricultural Policy Research Institute (FAPRI); FAPRI-MU Report #02-22; March 2022.
[951] USDA Agricultural Projections to 2031; Long Term Projections Report; February 2022.

We followed the same methodology we used for corn prices described above, but for soy oil prices this process is summarized in Table 10.1.1.2-1 and the description that follows references the rows in that Table to aid in understanding. The first step required converting USDA projected soy oil prices in nominal dollars (row #1) to 2021 dollars (row #2), and then adjusting for the differences in crude oil prices (row #4 for USDA in 2021 dollars) and EIA (row #5). When adjusting for the differences in crude oil prices, a regression of monthly soy oil and crude oil prices between January 2012 and September 2017 yielded the following equation:[952]

Soy Oil Price ($/lb) = Crude Oil Price ($/bbl) x 0.259 + 19.06

The soy oil prices (row #6) based on USDA crude oil prices and soy oil prices (row #7) based on EIA crude oil prices were not used in the cost analysis directly. Rather the difference in regressed soy oil prices (row #8) was added to the adjusted USDA soy prices (row #2) to derive the adjusted soy oil prices (row #9).

Table 10.1.1.2-1: Derivation of Soy Oil Feedstock Production Costs (cents/pound for soy oil, $/bbl for crude oil)

		Row #	**2023**	**2024**	**2025**
Soy Oil Prices	USDA Nominal $	1	54.5	51.0	49.0
	USDA 2021$	2	52.4	48.0	45.2
Crude Oil Prices	USDA Nominal $	3	59.0	58.6	59.3
	USDA 2021$	4	52.8	51.4	51.0
	EIA 2021$	5	57.9	62.9	64.0
Regressed Soy Oil Prices	Based on USDA 2021	6	32.7	32.4	32.3
	Based on EIA 2021	7	34.1	35.4	35.7
Soy Oil Prices	Difference in Regressed Soy Oil Prices EIA - USDA	8	1.3	3.0	3.4
Soy Oil Prices	Adjusted USDA 2021$	9	53.7	51.0	48.6

Neither USDA nor FAPRI project future corn oil, FOG, or palm oil prices. Instead, future prices for these oils were estimated based on the historical differences between them and soybean oil's spot prices.[953] Corn oil, FOG, and palm oil spot prices were compared to soybean oil spot prices between January 2012 and September 2017. During this time period, vegetable oil prices varied by over a factor of two, so this time period included both low and high vegetable oil prices. Over that time period, soybean oil averaged 38.3 cents per pound (ranged from 33 to 70 cents per pound), and palm oil averaged 30.5 cents per pound (22 to 55 cents per pound), respectively. The palm oil to soybean oil ratio is 0.80, and this ratio was used for establishing palm oil prices relative to USDA projected soybean oil prices. A similar comparison was made for corn oil and FOG, and these were priced at 82 percent and 78 percent of soybean oil, respectively.

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[952] There seems to be an association between the renewable fuels feedstock costs and crude oil prices (regression analysis reveals an r-squared of 0.73 for soybean oil and crude oil). Since USDA estimated renewable fuel feedstock prices based on lower crude oil prices, adjusting their renewable fuel feedstock prices higher to be consistent with EIA crude oil prices better synchronizes the two price projections and leads to a better estimate of costs.

[953] USDA Yearbook Tables by the Economic Research Service, downloaded March 2021.

The additional demand for vegetable oils associated with this rulemaking is expected to increase the price for those oils. A previous review of increased demand for soybean oil on soybean oil prices found that increases of 200 million gallons of soybean oil increased the soybean oil price by 0.032 dollars per pound.[954] This price increase estimate was used to adjust the soybean oil prices for this analysis based on the estimated increase of soybean oil demand under this proposed rulemaking. The baseline soy oil price is based on the soy oil demand prior to the promulgation of the 2020–2022 RFS final rule, so the adjustment to soy oil prices includes accounting for that forecasted increase in soy oil demand in that rule.[955] A similar adjustment was made for the estimated increased demand for palm oil. The volume of the global palm oil market is nearly 6 times greater than the U.S. soybean oil market, so the adjustment to the palm oil prices is assumed to be one sixth that for soy, or 0.005 dollars per pound for each 200 gallon increase in palm oil demand. Similar adjustments are made for FOG and corn oil, the markets of which are one-tenth and one-fifth the size of the soy oil market, respectively. The projected soy and palm oil prices in the baseline and resulting from the increased demand for the candidate volume that are used in this cost analysis are summarized in Table 10.1.1.2-2.

Table 10.1.1.2-2: Projected Vegetable Oil Production Costs (2021 dollars/pound)

	Base Prices	Projected Vegetable Oil Prices			
	Soybean Oil	**Soybean Oil**	**FOG**	**Corn Oil**	**Palm Oil**
2023	53.7	67.3	55.1	45.1	42.8
2024	51.0	63.2	60.4	43.3	40.6
2025	48.6	59.0	66.5	41.7	38.7

10.1.1.3 Biogas

For this analysis we assume that biogas is produced at landfills and collected to prevent the release of methane gas as required by regulation, and then flared, burned to produce electricity, or upgraded for use as natural gas. Since the biogas is a waste gas from existing landfills, we assumed no feedstock cost for biogas. The cost of the necessary steps to collect, purify, and distribute the biogas are all discussed under the sections discussing production and distribution costs.

10.1.2 Renewable Fuels Production Costs

This section assesses the production costs of renewable fuels, including the feedstock costs described above as well as the capital, fixed, and operating costs. We generally express the production costs on a per-gallon basis for the renewable fuels being produced. The one exception is biogas which is reported on a per-million BTU basis and also on a per ethanol-equivalent volume basis.

[954] Shelby, Michael; Cost Impacts of the Final 2019 Annual Renewable Fuel Standards; Memorandum to EPA Air and Radiation Docket EPA-HQ-OAR-2018-0167.
[955] 87 FR 39600 (July 1, 2022).

Detailed cost summaries presented for each renewable fuel in this section are based on 2023 cost inputs.[956] All the costs summarized in this section for all years are calculated in a spreadsheet which is available in the docket for this rulemaking.[957]

10.1.2.1 Cost Factors

10.1.2.1.1 Capital and Fixed Costs

The economic assumptions used to amortize capital costs over the production volume of renewable fuels are summarized in Table 10.1.2.1.1-1. These capital amortization cost factors are used in the following section for converting the one-time, total capital cost to an equivalent per-gallon cost.[958] The resulting 0.11 capital cost amortization factor is the same factor used by EPA in the cost estimation calculations made for other rulemakings and technical papers.[959,960,961,962,963]

Table 10.1.2.1.1-1: Economic Cost Factors Used in Calculating Capital Amortization Factors

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

Capital costs were adjusted to 2021 dollars for this analysis. The cost of installing capital decreased in 2020 due to the pandemic, and then seemed to have increased dramatically in 2021 likely due to production and distribution "bottleneck" issues created by the pandemic. Basing capital cost on either 2020 or 2021 capital cost factors would likely misrepresent the cost of capital moving forward.[964] Instead, a regression of Chemical Engineering Plant Index (CEPI)

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[956] Table 10.1.2.2-1, Table 10.1.2.4-1, Table 10.1.2.5-3, Table 10.1.2.5-4, Table 10.1.2.5.1-1, Table 10.1.2.5.2-2, 10.1.2.5.2-3, and 10.1.2.5.2-4.

[957] RFS Cost Analysis for Set September 2022.xls.

[958] The capital amortization factor is applied to the aggregate capital cost to create an amortized annual capital cost which occurs each and every year for the 15 years of the economic and project life of the unit. The depreciation rate of 10% and economic and project life of 15 years are typical for these types of calculations. The 7% return on investment and the zeroing out of Federal and State taxes is specified by the Office of Management and Budget for these calculations (Office of Management and Budget; Circular A-4; Regulatory Impact Analysis: A primer; https://www.reginfo.gov/public/jsp/Utilities/circular-a-4_regulatory-impact-analysis-a-primer.pdf).

[959] Regulatory Impact Analysis - Control of Air Pollution from New Motor Vehicles: Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements, EPA420-R-99-023, December 1999.

[960] Cost Estimates of Long-Term Options for Addressing Boutique Fuels; Memorandum from Lester Wyborny to the Docket; October 22, 2001.

[961] Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements; EPA420-R-00-028; December 2000.

[962] Final Regulatory Analysis: Control of Emissions from Nonroad Diesel Engines; EPA420-R-04-007; May 2004.

[963] Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis; EPA-420-R-10-006; February 2010.

[964] For newly constructed renewable diesel plants for 2021 and 2022, the ordering of equipment or equipment purchases may have occurred in 2020 when capital costs are low, and other aspects of the capital costs such as its

capital cost factors from 2015 to 2019 was used to estimate a capital cost inflation factor to adjust capital costs to 2021 dollars, and this capital cost factor (640) is consistent with historical increases in capital cost inflation factors—about a 2% per year increase.

Fixed operating costs include the maintenance costs, insurance costs, rent, laboratory charges and miscellaneous chemical supplies.[965] Maintenance costs can range from 1% to 8% for industrial processes.[966] We estimated the aggregated annual fixed operating costs to be 5.5% of the capital costs for all renewable fuels production facilities.

10.1.2.1.2 Utility and Fuel Costs

Variable operating costs are those costs incurred to run the renewable fuel production plants on a day-to-day basis, and are based on the unit throughput. The most obvious of the variable costs are utilities (electricity, natural gas, and water) which are required to operate the renewable fuels plants. Natural gas is consumed for heating process streams, including feedstocks which must be heated prior to being sent to reactors and distillation columns for separating coproducts. Electricity is necessary to run pumps, compressors, plant controls and other plant operations. Water can be necessary as part of the process (reaction medium), or used in heat exchangers and cooling towers.

Projected electricity and natural gas prices are based on national average values from Energy Information Administration's (EIA) 2022 Annual Energy Outlook.[967] The cost of process water is generally quite minimal, but a cost is estimated for it nonetheless since renewable fuels technologies can use fairly large quantities.[968,969]The utility costs used for the cost analysis are summarized in Table 10.1.2.1.2-1.

Table 10.1.2.1.2-1: Summary of Utility Cost Factors (nominal dollars)[a]

Year	Natural Gas ($/1000 cf)	Electricity (c/kWhr)	Water ($/1000 gals)
2023	4.72	7.10	3.0
2024	4.37	6.86	3.0
2025	4.19	6.78	3.0

[a] c/kWh is cents per kilowatt-hour; $/1000 cf is dollars per thousand standard cubic feet; $/1000 gallons is dollars per thousand gallons.

installation could have occurred in 2021, so a highly inflated capital cost inflation factor for 2021 would likely not accurately represent the average of capital installation costs for a new facility being installed for 2021 or 2022. For this reason, a more average cost of capital adjustment is more appropriate.

[965] Peters, Max S., Timmerhaus, Klaus, D.; Plant Design and Economics for Chemical Engineers 3rd Edition; McGraw Hill; 1980.

[966] McNair, Sam Budgeting for Maintenance: A Behavior-Based Approach, Life Cycle Engineering, 2011.

[967] Annual Energy Outlook 2022, Energy Information Administration, March 2022; https://www.eia.gov/outlooks/steo

[968] Haas, M.J, A process model to estimate biodiesel production costs, Bioresource Technology 97 (2006) 671-678.

[969] Water and Wastewater Annual Escalation Rates for Selected Cities across the United States, Office of Energy Efficiency and Renewable Energy, Department of Energy; September 2017.

10.1.2.2 Corn Ethanol Production Costs

Corn ethanol plant input and output information were based on a 2019 survey of corn ethanol plants, although some plant information was sourced from an older analysis.[970,971] Capital costs were based on a review of corn ethanol construction costs for a 100 million gallon per year drymill corn ethanol plant in 2016. For this analysis the capital costs were scaled to the U.S. average sized corn ethanol plant with a nameplate capacity of 85 million gallons per year assumed to operate at 90% of nameplate capacity, therefore producing 76 million gallons of ethanol per year.[972] Since the capital cost is based on the total construction cost of already constructed corn ethanol plants, no contingency cost factors are applied to the capital costs. The survey information estimates the quantity of DDGS produced by corn ethanol plants. Corn prices are farm gate prices and a transportation spreadsheet was used to estimate a cost of 6 cents per bushel to transport the corn to a corn ethanol plant.[973] Of the corn ethanol plants in the 2012 survey, 74% were separating and selling corn oil so selling corn oil was assumed for 70% of the plant capacity. Table 10.1.2.2-1 contains the plant demand and outputs and capital costs for corn ethanol plants.

Table 10.1.2.2-1: Corn Ethanol Plant Demands, Production Levels, and Capital Costs for 2023 (2021 dollars)

Category of Plant Input/Output	Plant Inputs/Outputs	Cost per Input	Cost (MM$)	Cost ($/gal)
Ethanol Yield	2.86 Gal/Bushel	4.86 $/bushel	130	1.70
DDG Yield	11.4 Lbs/Bushel	162 $/ton	–25	–0.32
Corn Oil Yield	0.77 Lbs/Bushel	43 cents/lb	–8.8	–0.12
Thermal Demand	22,480 BTU/Gal	3.49 $/1000 cf	5.8	0.08
Electricity Demand	0.63 kWh/Gal	7.1 c/kwh	3.4	0.04
Water Use	2.7 Gal/Gal	$3/1000 gals	0.6	0.01
Labor Cost	0.07 $/Gal	-	5.3	0.07
Capital Cost (2020 dollars, 76 million Gals/Yr)	2.34 $/Gal Plant Capital cost		25.5	0.33
Annual Fixed Cost	5.5% of Total Capital Cost		12.8	0.17
Denaturant	2 volume percent		0.4	0.01
Total Cost			148	1.94

The projected corn ethanol social production cost for an 85 million gallon capacity ethanol plant is $1.94 per gallon of denatured ethanol for 2023, $1.89 for 2024, and $1.85 for 2025. The downward trend in estimated per-gallon production costs reflect the expected downward trend in corn prices.

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970 Lee, Uisung; Retrospective analysis of the U.S. corn ethanol industry for 2005 – 2019; implications for greenhouse gas emission reductions;: Biofpr; May 4, 2021.
971 Mueller, Steffen; 2012 Corn Ethanol: Emerging Plant Energy and Environmental Technologies; April 29, 2013.
972 Irwin, Scott; Weekly Output: Ethanol Plants Remain Barely Profitable; 3/16/2018.
973 Edwards, William; Grain Truck Transportation Cost Calculator (a3-29graintransportation.xlsx version 1.4_82017); Iowa State University.

10.1.2.3 Biodiesel Production Costs

Biodiesel production costs for this rule were estimated using an ASPEN cost model developed by USDA for a 38 million gallon-per-year transesterification biodiesel plant processing degummed soybean oil as feedstock. Details on the model are given in a 2006 technical publication by Haas.[974,975] Although dated, this model likely still provides representative cost estimates because the process is fairly simple and unlikely to have changed over time, and consequently its cost are likely to be fairly stable over time as well. Furthermore, the biodiesel costs are primarily (>80%) determined by the feedstock prices.

The biodiesel process comprises three separate subprocesses:

1. Transesterification to produce fatty acid methyl esters (biodiesel) and coproduct glycerol (glycerine);
2. Biodiesel purification to meet biodiesel purity specifications; and
3. Glycerol recovery.[976]

For the transesterification process modeled by Haas, soybean oil is continuously fed along with methanol and a catalyst sodium methoxide to a stirred tank reactor heated to 60 ˚C. After a residence time of 1 hour, the contents exit the reactor and the glycerol is separated using a centrifuge and sent to a glycerol recovery unit. The methyl ester stream, which contains unreacted methanol and catalyst, is sent to a second reactor along with additional methanol and catalyst. Again, the reactants reside in the second stirred tank reactor for 1 hour heated to 60 ˚C. The products from of the second reactor are fed to a centrifuge which again separates the glycerol from the other reactants. The reaction efficiency is assumed to be 90% in each reactor, consistent with published reports, resulting in 99% combined conversion in both reactors.

The methyl ester is purified by washing with mildly acidic (4.5 pH) water to neutralize the catalyst and convert any soaps (sodium or potassium carboxylic acids) to free fatty acids. The solution is then centrifuged to separate the biodiesel from the aqueous phase. The remaining water in the biodiesel is removed by a vacuum dryer to a maximum 0.05% of water by volume.

The glycerol can have a high value if it can be purified to U.S. Pharmacopia (USP) grade to enable using this material for food or medicine. However, this purification process is expensive. Most biodiesel plants create a crude glycerol (glycerine) grade, which is 80% glycerol, and sell the crude glycerol for further refining by others. To create the crude glycerol, the various glycerol streams are combined and treated with hydrochloric acid to convert the soaps to free acids, allowing removal by centrifugation and sending to waste. The glycerol stream is then neutralized (pH brought back up to neutral) with caustic soda. Methanol is recovered from this stream by distillation and the methanol is recycled back into the process. The

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[974] Haas, M.J, A process model to estimate biodiesel production costs, Bioresource Technology 97 (2006) 671-678.
[975] Since 2006 when the HAAS biodiesel plant survey was conducted, biodiesel plants may have achieved improved energy efficiency, but also experienced increased costs to improve product quality and expand the quality of feedstocks they can process.
[976] Haas, M.J, A process model to estimate biodiesel production costs, Bioresource Technology 97 (2006) 671-678.

glycerol stream is distilled to remove it from the remaining water, which is recycled back into the process. The glycerol is now at least 80% pure, adequate to sell as crude glycerol.

We made a series of adjustments to the Haas model output. The capital cost is adjusted from 2006 dollars to 2021 dollars using a ratio of the capital cost index from the Chemical Engineering Cost Index. This adjustment increased installed capital cost from $11.9 million to $14.5 million. Fixed operating costs are estimated to comprise 5.5% of the plant cost. Prices were found on the Web for methanol,[977] sodium methoxide,[978] hydrochloric acid,[979] sodium hydroxide,[980] and glycerine.[981] The value of methanol is from a Methanex report plus 15 cents per gallon distribution costs.[982] Prices for sodium methoxide, hydrochloric acid, and sodium hydroxide are all bulk prices from a chemicals supplier.[983]

The value of the glycerin co-product has been volatile due to a large increase in production in biodiesel facilities that has been balanced at times by new uses. Glycerine has traditionally been used for petrochemical-based products, but there is increased demand in personal care and other consumer products as the standard of living increases in many parts of the world. Some facilities are even experimenting with using it as a supplemental fuel.[984] We can expect that new uses for glycerin will continue to be found as long as it is plentiful and cheap. We use recent cost information of about 10 cents per pound for glycerine.[985]

Table 10.1.2.3-1 also shows the production cost allocation for the soybean oil-to-biodiesel facility. Production cost for biodiesel is primarily a function of feedstock price, with other process inputs, facility, labor, and energy comprising much smaller fractions.

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977 Methanex; current North America prices plus 15 c/gal for shipping; https://www.methanex.com/our-business/pricing; August 2018.
978 Alibaba; https://www.alibaba.com/trade/search?fsb=y&IndexArea=product_en&CatId=&SearchText=sodium+methoxide; August 2018.
979 Alibaba; https://www.alibaba.com/trade/search?IndexArea=product_en&CatId=&fsb=y&SearchText=hydrochloric+acid; August 2018.
980 eBioChem; http://www.ebiochem.com/Search/search/cate2/name/cate/0/keywords/sodium%2520hydroxide/; August 2018.
981 Perez, Leela Landress; US crude glycerine prices could dip as spring nears; https://www.icis.com/explore/resources/news/2018/02/14/10193613/us-crude-glycerine-prices-could-dip-as-spring-nears; February 14, 2018.
982 Methanex Methanol Price Sheet; US Gulf Coast; May 31, 2018
983 https://www.alibaba.com.
984 Yang, Fangxia; Value-added uses for crude glycerol – a byproduct of biodiesel production; Biotechnology for Fuels; March 14, 2012.
985 US crude glycerine prices could dip as spring nears; ICIS News; February 14, 2018.

Table 10.1.2.3-1: Biodiesel Production Cost for 2023 (year 2021 dollars)

	Unit Demands	Cost per Unit	Thousand Dollars	$/gal
Soybean Oil Feed	76,875 (1000 lb)	67 cents/lb	51,730	5.17
Methanol	7422 (1000 lb)	1.48 $/gal	1,708	0.17
Sodium Methoxide	927 (1000 lb)	$2000/ton	927	0.09
Hydrochloric Acid	529 (1000 lb)	$200/MT	48.1	0.005
Sodium Hydroxide	369 (1000 lb)	$420/ton	77.5	0.008
Water	2478 (1000 lb)	$3/1000 gals	1.2	0.00
Glycerine	9000 (1000 lb)	10 cents/lb	(900)	(0.09)
Natural Gas	66.9 million cf	$3.49/1000cf	234	0.023
Electricity	1008 kW	7.10 cents/kWh	627	0.063
Labor				0.05
Capital Cost 2006$	11.35 ($million)	-	-	-
Capital Cost 2021$	14.54 ($million)		1,600	0.16
Fixed Cost		5.5%	800	0.08
Total Cost			56,854	5.74

As shown in Table 10.1.2.3-1, biodiesel produced from soybean oil is estimated to cost 5.74 cents per gallon in 2023. The estimated biodiesel production cost for all vegetable oil types and for all three years is summarized in Table 10.1.2.3-2.

Table 10.1.2.3-2: Summary of Estimated Biodiesel Production Costs ($/gal)

Year	Soy Oil	Corn Oil	FOG	Palm
2023	5.74	4.03	4.80	3.85
2024	5.41	3.88	5.20	3.68
2025	5.09	3.76	5.67	3.53

10.1.2.4 Renewable Diesel Production Costs

The renewable diesel process converts plant oils or rendered fats into diesel or jet fuel using hydrotreating. The process reacts hydrogen over a catalyst to remove oxygen from the triglyceride molecules in the feedstocks oils via a decarboxylation (removal of a carbon molecule double-bonded to an oxygen molecule producing carbon dioxide) and hydro-oxygenation reaction, yielding some light petroleum products, carbon dioxide, and water as byproducts. The reactions also saturate the olefin bonds in the feedstock oils, converting them to paraffins, and may also isomerize some paraffins. Depending on process operating conditions, the yield of product which can be blended into diesel fuel is typically between 90-95% by volume, with the rest being naphtha and light fuel gases (primarily propane). In total, the volumetric yield is greater than 100% of the feed due to the cracking that occurs over the hydrotreating catalyst. Besides the renewable diesel product, propane (light gas output), water and carbon dioxide are also produced. The byproducts created from that first reactor are separated from the renewable diesel in a separation unit.

For this cost analysis we chose to focus on stand-alone renewable diesel production. We found a project cost estimate by Diamond Green which was $1,100 million for a standalone 400 million gallon per year facility. This large plant size and its associated capital costs were scaled down to a 220 million gallon per year plant size which is more typical of the renewable diesel fuel plants being built for start-up through 2022.[986] The capital cost for this smaller renewable diesel fuel plant is estimated to be $768 million.

In addition to feedstock and facility costs, another significant cost input is hydrogen. We used an estimate provided by Duke Biofuels for our hydrogen consumption estimate for producing renewable diesel. On average, vegetable and waste oil feedstocks require 2,000 SCF/bbl of feedstock processed.[987] Hydrogen costs are estimated based on hydrogen production by a steam methane reforming hydrogen plant.[988]

Table 10.1.2.4-1: Hydrogen Plant Costs (Based on 32 million cubic feet per day)

			Cost	
	Unit Demands	**Cost per Unit**	**Million Dollars**	**$/thousand FT3**
Feed Natural Gas	0.247 mmBTU	3.49 $/mmBTU	24.8	2.37
Fuel Gas for Heat	0.14 mmBTU	3.49 $/mmBTU	14.0	1.34
Power	0.798 KWh	7.10 c/KWh	5.66	0.54
Catalyst		4.8 cents		0.04
Capital Cost	$50 MM in 2006			
	$80 MM in 2021		13.5	1.29
Fixed Cost		5.5%	5.3	0.51
Total Cost				6.09

Based on our cost analysis, hydrogen is estimated to cost $6.09 per thousand standard cubic feet. The estimate assumes a dedicated hydrogen plant producing for the renewable diesel facility of 220 million gallons per year being modeled for this cost analysis.

Our yield estimates as summarized in Table 10.1.2.4-2 were derived from material presented by UOP and Eni at a 2007 industry conference, which describes producing renewable diesel in a grass roots standalone production process inside a refinery.[989] Despite the age of the reference, the underlying chemistry is unlikely to have changed appreciably.

[986] The typical renewable diesel plant size is based on volume-weighting the renewable diesel capacity data in Table 6.2.2-1. The cost for the smaller sized renewable diesel plant is scaled using a six-tenths factor which captures the higher per gallon cost of a smaller sized plant. The cost scaling is calculated using the following equation: (new plant size/original plant size) raised to the 0.6 power and multiplied by the capital cost of the original plant size.

[987] Conversation with Mike Ackerson, Duke Biofuels, May 2020.

[988] Gary, JH, Handwerk, GE; 2001 Petroleum Refining Technology and Economics, 4th edition, Marcel Dekker.

[989] A New Development in Renewable Fuels: Green Diesel, AM-07-10 Annual Meeting NPRA, March 18-20, 2007.

Table 10.1.2.4-2: Input and Output from Renewable Diesel Plant

Vegetable Oil input	100 gal
Hydrogen	4760 SCF
Renewable diesel output (main product)	93.5 gal
Naphtha output (co-product)	5 gal
Light fuel gas output (co-product)	9 gal

We derived a cost of 6.9 cents/gallon of renewable diesel product to cover other costs: utilities, labor, and other operating costs.[990] Finally, the total cost per gallon was estimated at $6.38. Table 10.1.2.4-3 provides more details for the process assumed in this analysis and summarizes the total and per-gallon costs for the year 2023.

Table 10.1.2.4-3: Renewable Diesel Production Cost Estimate for a Greenfield 220 Million Gallons/Yr Plant Processing Soy Oil in 2023 (2021 Dollars)

Stream		Estimated value	MM$/yr	$/gal
Soy Oil input	235 MMgals/yr	67.0c/lb	1216	5.53
Naphtha output	4.0 MMgals/yr	1.45 c/gal	(17.1)	(0.08)
Light fuel gas output	7.2 MMgals/yr	73 c/gal	(15.5)	(0.07)
Hydrogen input	4760 scf/100 gals	$6.09/thousand standard cubic feet	68.2	0.31
Other Operating Costs			15.2	0.07
Capital Costs (2021 dollars)		$825 million	90.8	0.41
Fixed Costs		5.5%	45.4	0.21
Total Costs			1403	6.38

A number of announced renewable diesel projects projected to start-up in 2023 through 2026 are conversions of petroleum refineries to produce renewable diesel fuel. The existing hydrotreating units, fired heaters, heat exchangers, control and instrumentation equipment, hydrogen plants and tank storage at these refineries is expected to be repurposed for the storage of feedstocks and the production and storage of renewable diesel. There will likely still need to be some additional engineering and construction costs to adapt the existing refinery equipment to produce renewable diesel fuel. Adapting a hydrotreater to process vegetable oil requires modifications for higher heats of reaction, increased depressurization and perhaps some changes in metallurgy.[991] These modifications are estimated to cost about one third the cost of a new renewable diesel hydrotreater, or $270 million, instead of $825 million for a 220 million gallon per year plant. The lower capital cost is due to the avoidance of many investments needed in a greenfield plant, including the hydrotreater itself, the hydrogen plant, a heater and cooling, tankage electrical switchgear, buildings, roads, fencing etc. [992,993]

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[990] Estimated based on the utility cost for an FCC naphtha hydrotreater; Control of Air Pollution from Motor Vehicles: Tier 3 Motor Vehicle Emission and Fuel Standards Final Rule; Regulatory Impact Analysis; US Environmental Protection Agency; March 2014.

[991] Chan, Erin; Converting a petroleum diesel refinery for renewable diesel fuel; Hydrocarbon Processing; April 2021.

[992] Chan, E., Converting a petroleum diesel refinery for renewable diesel; Special Focus: Clean Fuels; April 2021.

[993] Lane, Robert; Renewable Diesel Interest Accelerates; August 26, 2020.

It is very challenging to accurately estimate the portion of the future renewable diesel production which will be produced by these converted refineries as opposed to new greenfield plants because of the large number of announced renewable diesel projects and the significant uncertainty of which of these projects will move forward. Because these converted refineries will require much less capital investment prior to producing renewable diesel fuel, these refinery conversion projects are more likely to move forward than greenfield projects. Despite the relatively large capital cost savings associated with the refinery conversion, the impact on the overall cost to produce renewable diesel fuel is nevertheless modest because most of the cost of producing renewable diesel fuel is the feedstock cost. For example, renewable diesel produced from soybean oil by a converted petroleum refinery is estimated to cost $6.09/gallon versus $6.38/gallon for a greenfield renewable diesel plant. Table 10.1.2.4-4 summarizes the estimated cost information for a refinery converted to produce renewable diesel fuel.

Table 10.1.2.4-4: Renewable Diesel Production Cost Estimate for a Refinery Converted to Produce 220 Million Gallons/Yr Plant Processing Soy Oil in 2023 (2021 Dollars)

Stream		Estimated value	MM$/yr	$/gal
Soy Oil input	235 MMgals/yr	67.0c/lb	1216	5.53
Naphtha output	4.0 MMgals/yr	1.45 c/gal	(17.1)	(0.08)
Light fuel gas output	7.2 MMgals/yr	73 c/gal	(15.5)	(0.07)
Hydrogen input	4760 scf/100 gals	$6.09/thousand standard cubic feet	68.2	0.31
Other Operating Costs			15.2	0.07
Capital Costs (2021 dollars)		$825 million	27.2	0.12
Fixed Costs		5.5%	45.4	0.21
Total Costs			1340	6.09

The difference between the low and high production costs is solely due to the difference in capital costs. For refineries converting their refineries to produce renewable diesel, the amortized capital cost is estimated to be only $0.12 per gallon, while the greenfield plant's estimated capital cost is $0.41 per gallon. As a very rough estimate, half of the future domestic renewable fuel production is estimated to be produced by these converted refineries, and when the refinery conversions are averaged with the greenfield plants, this results in the $6.23 estimated production cost for 2023. The estimated renewable diesel production cost for all vegetable oil types and for all three years is summarized in Table 10.1.2.4-5.

Table 10.1.2.4-5 Summary of Estimated Renewable Diesel Production Costs ($/gal)

Year	Soy Oil	Corn Oil	FOG	Palm
2023	6.23	4.41	5.23	4.22
2024	5.88	4.24	5.65	4.03
2025	5.52	4.10	6.14	3.85

10.1.2.5 Biogas

10.1.2.5.1 Using Biogas as CNG/LNG

Biogas is the result of anaerobic digestion of organic matter, including municipal waste, manure, agricultural waste, and food waste.[994] The primary product of this anaerobic digestion of waste is methane, which is the primary component of natural gas. Thus, once biogas is cleaned up by removing various contaminants, it can be used by processes that normally use natural gas.[995]

The largest source of biogas, which is already being collected to avoid releasing methane into the environment, is from landfills.[996] Since landfill gas is the largest source of biogas available for the motor vehicle fleet, this cost analysis makes the simplifying assumption that the biogas will solely be provided by landfills.

While in some cases biogas can be used in local fleet vehicles which are operated at the landfill site, in most cases, a new pipeline would need to be constructed to transport the cleaned up biogas to a nearby common carrier pipeline. Gas is then pulled off the pipeline at downstream locations and compressed into CNG or liquified into LNG for use in motor vehicles. Tracking the use of the biogas in motor vehicles occurs by proxy through contracts and/or affidavits rather than through a system designed to ensure that the same methane molecules produced at the landfill are used in CNG/LNG vehicles.

One of the costliest aspects of using biogas is its cleanup. Biogas contains large amounts of carbon dioxide, nitrogen, and other contaminants such as siloxanes which cannot be tolerated if it is to be put into a natural gas pipeline or used by fleet vehicles at the landfill site. We estimated a cost for cleaning up landfill biogas using Version 3.5 of the Landfill Gas Energy Cost Model (LFGcost-Web).[997,998] The throughput volume of landfill gas was estimated to be 600 standard cubic feet per minute based on a survey of biogas production facilities.[999] The cost estimates from the Model excluded the gas collection and control system infrastructure at the landfill, as EPA expects that landfills that begin producing high BTU gas in 2021 are very likely to already have this infrastructure in place, and that this infrastructure would be used regardless to control methane emissions. The equations from the LFGcost-Web model for biogas collection and clean-up are summarized in Table 10.1.2.5.1-1. We included a cost for biogas collection at the landfill which amounts to $1.1 per thousand standard cubic feet.[1000] Distribution and retail costs are estimated for biogas in Chapter 10.1.4.3.

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[994] Wikipedia. Accessed April 2021; https://en.wikipedia.org/wiki/Biogas.
[995] LeFevers, Daniel; Landfill Gas to Renewable Energy; Hill Briefing; April 26, 2013.
[996] Biomass Explained, Landfill Gas and Biogas; US Energy Information Administration; February 1, 2019; www.eia.gov/energyexplained/index.php?page=bioimass_biogas
[997] The current version of this model and user's manual dated March 2021 are downloadable from the LMOP website: https://www.epa.gov/lmop
[998] This cost estimate does not include the cost for complying with California's more stringent natural gas pipeline specifications designed to address harmful contaminants in some sources of biogas.
[999] Economic Analysis of the US Renewable Natural Gas Industry; The Coalition of Renewable Natural Gas; December 2021.
[1000] LFG Energy Project Development Handbook – Project Economics and Financing; Chapter 4.

Table 10.1.2.5.1-1: Biogas Cleanup Costs (600 scf/min)

	Cost Factors (2019$)	million dollars (2021$)	$ per thousand cubic feet (2021$)
Interconnection	$400,000	0.42	0.15
Capital Costs	$6{,}000000 * e^{(0.0003*ft3/min)}$	7.57	2.64
Operating and Maintenance	250 * ft3/min +148,000	0.90/yr	2.85
Electricity Costs	0.009 kWh/ft3	0.30/yr	0.96
Total			6.60

10.1.2.5.2 Using Biogas to Produce Electricity

We also estimate the cost for producing electricity from biogas in an electricity generation set (genset) facility co-located at the biogas production site. As discussed in Chapter 6.1.4, the quantity of biogas already being used to produce electricity is sufficient to satisfy the electric vehicle market during the years of this proposed rulemaking, so we do not include any biogas-to-electricity production and distribution costs in our estimated cost to comply with this proposed rulemaking. However, we nevertheless analyze and present the costs of using biogas to produce electricity in order to allow for a comparison to other renewable fuel costs and provide an indication of the costs of production costs in years after this proposed program (i.e., 2026+)

We identified several different scenarios for gen sets installed at biogas source sites for producing renewable electricity. The biogas source sites analyzed here are landfills and agricultural digesters with a range of different size genset units which consume biogas at different rates. Table 10.1.2.5.2-1 summarizes the genset unit scenarios and their associated biogas consumption rates that we analyzed.

Table 10.1.2.5.2-1: Biogas to Renewable Electricity Scenarios Analyzed for Costs

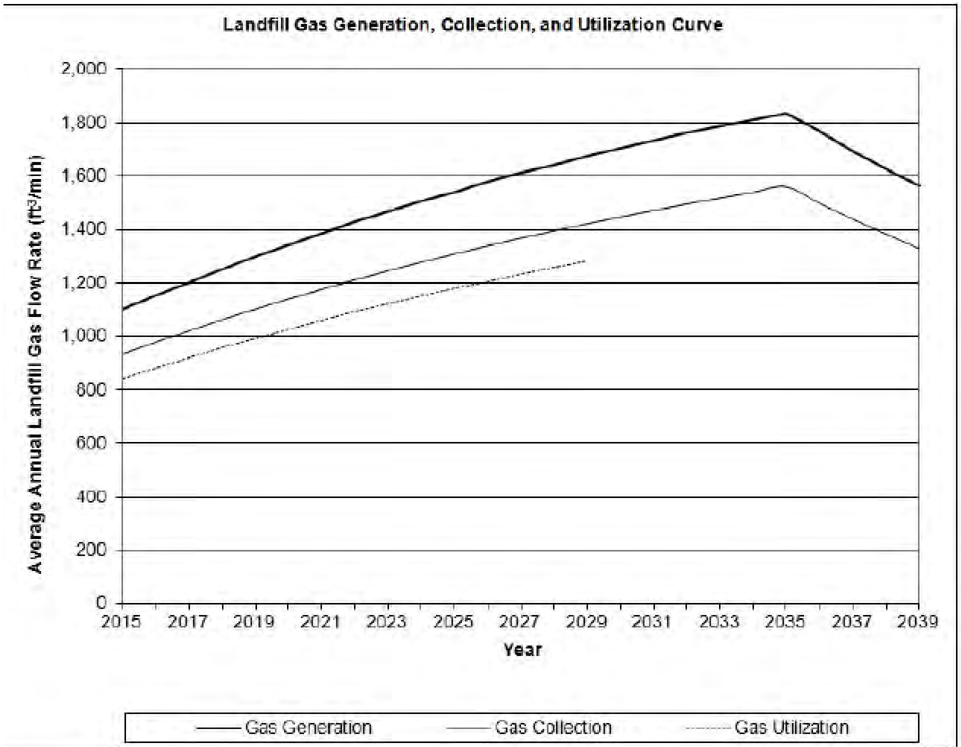
Biogas Source	Small Ag Digester	Large Ag Digester; Small Landfill	Medium Landfill	Large Landfill
Genset Capacity	150 KW	1.6 MW	5 MW	15 MW
Biogas Consumption (SCF/min)	84	216	590	2025
Genset Type	Small Reciprocating Engine Genset	Standard Reciprocating Engine Genset		

We obtained genset cost information which allowed us to estimate the electricity generation cost for each scenario.[1001] This information is presented in Table 10.1.2.5.2-2 for a genset installed at a small agricultural digester, and in Table 10.1.2.5.2-3 for a genset installed at a medium sized landfill. Similar calculations were conducted for two other configurations, a large agricultural digester/small landfill and a large landfill, with the results for all configurations

[1001] Landfill Gas Energy Cost Model (LFCcost-Web) version 3.5 – Users Manual; Environmental Protection Agency; March 2021.

summarized in Table 10.1.2.5.2-4. While each genset unit is capable of operating on average at over 90 percent of capacity, as shown in Figure 10.1.2.4.2-1, landfill biogas production changes over time as biogas emissions first increase after the landfill is first created, reach a peak, and then decline.[1002] To account for changing biogas emissions rates over time, we assume that the genset is sized to process the anticipated maximum methane emissions from the landfill, but then these genset units would be underutilized at other times during its lifetime. To account for this issue, we assume that gensets average 75% of their total biogas consumption capacity over their lifetime. While we do not have any data for agricultural digesters, we believe that these facilities would also have varying rates of biogas production over time depending on changes in herd size and operating conditions. Thus we have applied the same 75% assumption to them.

Figure 10.1.2.5.2-1: Example of LFG Generation, Collection, and Utilization Curve in LFGcost-Web



The cost information provided in Tables 10.1.2.5.2-2 and 3 is based on 2008 dollars, which are adjusted to 2021 dollars. One cost advantage of using biogas for producing electricity compared to using it directly as compressed natural gas in vehicles is that the biogas only needs minor clean-up (i.e., removing excess moisture content and particulates) before feeding it to a genset to produce electricity.[1003] Thus, the feed biogas for electricity generation is assumed to cost $1.1 per thousand cubic feet to represent the landfill gas production cost as described in the biogas section, but would not incur the $6.6 per thousand cubic feet clean-up costs.

[1002] Landfill Gas Energy Cost Model (LFCcost-Web) version 3.5 – Users Manual; Environmental Protection Agency; March 2021.
[1003] Renewable Natural Gas Production; Alternative Fuels Data Center; Department of Energy https://afdc.energy.gov/fuels/natural_gas_renewable.html#:~:text=With%20minor%20cleanup%2C%20biogas%20can,to%20a%20higher%20purity%20standard.; downloaded June 2022.

Table 10.1.2.5.2-2: Cost for a 150 kW Generation Set for a Small Ag Digester (net electricity production 128 kW)*

	Cost Category (2008 dollars)	Cost (Thousand dollars/yr)	c/kWh (2021 dollars)
Installed Capital Cost	2300 x KW capacity	$42.2	3.76
Annual O&M Cost**	0.024 x kWh	$29.3	2.61
Fuel Use Rate	36FT3/kWh	$62.8	5.58
Total Cost		$134.3	11.95

* Capable of operating at 93% of capacity, but assumed to typically operate at 75% of capacity due to variable biogas production; parasitic efficiency is 93%.
** O&M = operating and maintenance costs.

Table 10.1.2.5.2-3: Cost for a 5 MW Generation Set for a Medium Size Landfill (net electricity production 3.5 MW)*

	Cost Category (2008 dollars)	Cost (million dollars/yr)	c/kWh (2021 dollars)
Installed Capital Cost	1300 x KW capacity +1,100,000	$8.5 million	3.04
Interconnect	0.025 x kWh	$278,000	0.10
Annual O&M Cost**	11,290 Btu/kWh		2.69
Fuel Use Rate	36 ft3/kWh	$713/million ft^3	2.70
Total Cost			8.54

* Capable of operating at 93% of capacity, but assumed to typically operate at 75% of capacity due to variable biogas production; parasitic efficiency is 93%.
** O&M = operating and maintenance costs.

Table 10.1.2.5.2-4 summarizes the estimated electricity production costs for the various different scenarios for gensets installed at biogas source sites for producing renewable electricity.

Table 10.1.2.5.2-4: Summary of Renewable Electricity Production Costs from Biogas Feedstocks (c/kWh)

Biogas Source	Production Cost
Small Ag Digester	11.95
Large Ag Digester; Small Landfill	9.04
Medium Landfill	8.54
Large Landfill	8.18

10.1.3 Blending and Fuel Economy Cost

Certain renewable fuels, namely gasoline, biodiesel, and renewable diesel, are typically blended into petroleum fuels. There are costs and in some cases cost savings associated with such blending. In addition, these renewable fuels have relatively lower energy per gallon leading to lower fuel economy (miles driven per gallon). In this section, we consider blending and fuel economy costs for ethanol blended as E10, E15, and E85, as well as for biodiesel and renewable diesel.

10.1.3.1 Ethanol

10.1.3.1.1 E10

Ethanol has physical properties when blended into gasoline which affect its value as a fuel or fuel additive. Ethanol has a very high octane content, a high blending Reid Vapor Pressure (RVP) at low concentrations, and is low in energy content relative to the gasoline pool that it is blended into. Ethanol has essentially zero sulfur or benzene, adding to ethanol's value because refineries must meet sulfur and benzene fuel regulations. Each of these properties can have a different cost impact depending on the gasoline it is being blended into (reformulated gasoline (RFG) versus conventional gasoline (CG), winter versus summer gasoline, premium versus regular, and blended at 10% versus E15 or E85). These physical properties are also valued differently from a refiner's perspective compared to that of the consumer. Refiners value ethanol's octane because they can lower the octane of the gasoline the ethanol is being blended into, reducing their refining costs. Refiners dislike ethanol's high blending RVP when blending ethanol in gasoline (usually RFG) at 10% because they must remove some low value gasoline blendstock material (usually butane) to accommodate the ethanol if the gasoline they are producing does not receive a 1 psi RVP waiver. However, refiners are not concerned about ethanol's low energy content when blending it into gasoline since they sell gasoline on volume, not energy content, and consumers do not appear to demand a discount for E10. Rather, this is usually just an issue for the consumers who do not travel as far on a gallon of fuel with lower energy content. Depending on the fuel they are purchasing, the lower energy content will be either obvious to consumers (i.e., E85), impacting their purchase decisions, or not (i.e., E10; most consumers do not notice its lower energy content in comparison to E0, particularly now that almost all gasoline is E10). Since this is a social cost analysis which incorporates all the costs to society, the fuel economy effect is included in the overall cost estimates, although not included with the blending value estimated in this section.

Ethanol's total blending value is estimated in two different steps based on the output from two different refinery modeling cases conducted by ICF/Mathpro.[1004] In the first step, ethanol's blending value is estimated while blended into E10 conventional and reformulated gasolines. The blending value (derived primarily from octane, but also reflecting its low sulfur and benzene content and RVP cost) of ethanol at 10% was estimated for the purpose of estimating ethanol's RVP cost. The refinery modeling cases were for a 2020 year case assuming that crude oil would be priced at $72/bbl.[1005] By averaging the costs separately for conventional and reformulated gasolines, the refinery modeling output from the first case allowed us to estimate ethanol's volatility cost for blending ethanol into E10 reformulated gasoline. The refinery modeling output from the second case, which modeled ethanol's removal from the conventional gasoline pool, allowed us to estimate ethanol's replacement cost—replacing both its volume and octane and including the cost of installing the capital necessary to replace ethanol's octane and volume.

[1004] EPA's contract was with ICF Incorporated, LLC, which in turn retained Mathpro for some aspects of the work.
[1005] The crude oil price has a first order effect on the blending value and volatility cost for blending ethanol into gasoline. Since the crude oil price used in the refinery modeling cost analysis is about the same as the projected crude oil price for 2021 and 2022, it was not necessary to adjust ethanol's estimated blending cost to any other dollar value.

The refinery modeling output from the first modeling case is summarized in Tables 10.1.3.1.1-1 and 2, which summarize the refinery model's marginal blending values (also termed shadow prices) for both ethanol and gasoline.

Table 10.1.3.1.1-1: Refinery Model's Ethanol Value (c/gal)[a]

	PADD 1		PADD 2		PADD 3		PADD 4		PADD 5	
Ethanol	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**
RFG										
Premium	188	196	193	199	193	184			102	202
Regular	197	202	203	206	203	190			108	205
CG with Waiver										
Premium	218	196	214	199	213	184	211	190	225	201
Regular	96	85	94	86	94	80	93	82	233	205
CG No Waiver										
Premium	190	0								
Regular	200	0								
7.8 RVP with Waiver										
Premium			217	0	215	0	216	0	274	0
Regular			225	0	225	0	226	0	268	0
7.8 RVP No Waiver										
Premium	189	222			193	184				
Regular	198	142			202	189				
7.0 RVP with Waiver										
Premium			218	0						
Regular			226	0						
7.0 RVP No Waiver										
Premium										
Regular										

[a] Premium means premium grade gasoline; regular means regular gasoline grade. Values are reported for each gasoline grade/type produced in each PADD. Blank cells mean that the gasoline type/grade is not produced in that PADD.

Table 10.1.3.1.1-2: Refinery Model's Gasoline Value (c/gallon)[a]

	PADD 1		PADD 2		PADD 3		PADD 4		PADD 5	
	Summer	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**
Gasoline										
RFG										
Premium	196	182	191	179	190	171			199	183
Regular	189	178	186	175	183	168			190	180
CG with Waiver										
Premium	192	182	188	179	187	172	178	167	173	182
Regular	185	178	182	175	181	168	172	163	164	179
CG No Waiver										
Premium	192	181								
Regular	185	177								
7.8 RVP with Waiver										
Premium			190	178	189	171	180	167	192	0
Regular			184	174	183	168	174	163	182	0
7.8 RVP No Waiver										
Premium	195	0			189	172				
Regular	188	0			183	168				
7.0 RVP with Waiver										
Premium			191	179						
Regular			186	175						
7.0 RVP No Waiver										
Premium										
Regular										

[a] Premium means premium grade gasoline; regular means regular gasoline grade. Values are reported for each gasoline grade/type produced in each PADD. Blank cells mean that the gasoline type/grade is not produced in that PADD.

Ethanol's blending value is calculated by subtracting gasoline's marginal value from ethanol's marginal value for the same category of gasoline in Tables 10.1.3.1.1-1 and 2. For example, ethanol's value for blending with regular grade summertime CG with the waiver is $96.14 per barrel, compared to the gasoline which is $77.89 per barrel. Thus, the refinery model values ethanol $18.25 per barrel more than gasoline, or about $0.43 per gallon. Table 10.1.3.1.1-3 summarizes the calculated blending values for ethanol in summer gasoline after the blending values for the various PADDs were volume-weighted together and the costs were converted over to cents per gallon.[1006]

[1006] The summertime ethanol blending values for California RFG were very negative, which the contractor thought could be due to low butane prices. Regardless of the cause, these negative ethanol blending costs were considered outliers and, thus, were not included in our average of ethanol blending costs.

Table 10.1.3.1.1-3: Ethanol's Blending Value in Summer Gasoline ($/gal assuming a crude oil price of $72/bbl))

Gasoline Type	Gasoline Grade	Summer
CG	Regular	0.32
	Premium	0.20
RFG	Regular	0.11
	Premium	0.01

Ethanol's volatility cost for blending into RFG is estimated by subtracting ethanol's blending value in reformulated gasoline from ethanol's blending value in conventional gasoline. Thus, ethanol's volatility's cost is 21 and 19 cents per gallon in regular and premium grade gasolines, respectively.

The results from the first modeling cases summarized in the first step demonstrate ethanol's considerable blending value on a day-to-day basis in the marketplace. However, it does not capture the full blending value of ethanol were a refiner to be faced with the cost of replacing it in the gasoline pool (i.e., if it were not part of the available fuel volume and octane supply and other sources of volume and octane supply had to replace it). This situation was modeled in the second step which relies on refinery modeling cases in which ethanol is removed from the conventional gasoline pool, and thus provided an estimate of ethanol's replacement cost. As shown in Tables 10.1.3.1.1-4 and 5, this second case revealed that ethanol's very high octane and volume would require significant investment at refineries to replace and this is reflected in ethanol's much higher blending value when accounting for these additional costs.

Table 10.1.3.1.1-4 summarizes ethanol's marginal costs by different gasoline types and refinery regions for both the reference case (all gasoline with ethanol) and the low biofuel cases (conventional gasoline without ethanol) which replaced ethanol in the gasoline pool with refinery sourced alternatives. Two different ethanol replacement cases were modeled: "Low Biofuel #1" is a reformate-centric case while "Low Biofuel #2" is an alkylate centric case.[1007] The much lower marginal values for PADD 1 can be explained because Mathpro allowed PADD 3 refineries to satisfy PADD 1's need for replacing ethanol's volume and octane through its exports into the PADD 1 after initial refinery model runs showed PADD 1's marginal costs for replacing ethanol were exceedingly high.

[1007] Reformate is a gasoline blendstock produced by a refinery unit named the reformer. Reformers react a low-octane stream from the crude distillation tower which boils in the gasoline boiling range over a catalyst to convert (reform) low octane hydrocarbons to aromatic compounds which are very high in octane. Alkylate is a gasoline blendstock produced by a refinery unit named the alkylation unit. The alkylation unit reacts isobutylene with isobutane and normal butane in acid to branched chain paraffins which are high in octane.

Table 10.1.3.1.1-4: Gasoline Marginal Values for Reference Case and Ethanol Marginal Values for the Low-Biofuel Cases ($/barrel assuming crude oil priced at $72/bbl)[a]

PADD of Gasoline Origin	Type	Grade	Gasoline Marginal Values		Ethanol Marginal Values: Low-Biofuel #1 Reformate Centric		Ethanol Marginal Values: Low-Biofuel #2 Alkylate Centric	
			Summer	Winter	Summer	Winter	Summer	Winter
PADD 1	RFG	Prem	95.737	83.936	108.37	100.88		
		Reg	91.452	81.349	115.98	105.97		
	Conv.	Prem	92.680	83.890	123.02	100.87		
		Reg	88.927	81.346	136.43	105.88		
PADD 2	RFG	Prem	88.087	81.685	132.42	110.28	113.45	96.62
		Reg	84.803	79.771	145.38	116.02	122.86	101.61
	Conv.	Prem	85.549	81.248	149.08	110.41	126.74	96.25
		Reg	82.457	79.447	161.21	115.79	135.55	100.93
PADD 3	RFG	Prem	85.424	78.308	121.69	94.72	118.51	89.77
		Reg	81.863	76.395	134.67	98.45	131.29	94.48
	Conv.	Prem	83.644	78.784	133.95	95.13	129.37	89.91
		Reg	79.975	76.755	146.78	98.46	142.00	94.55
PADD 4	RFG	Prem	79.756	77.014	135.5	115.2	150.1	103.1
		Reg	77.367	75.066	149.0	124.0	168.1	110.0
	Conv.	Prem	81.785	82.073	136.5		151.2	
		Reg	81.702	81.993	150.1		169.2	
PADD 5	RFG	Prem	96.890	83.676	37.68	96.05		
		Reg	91.607	82.013	62.46	97.37		
	Conv.	Prem	77.631	82.999	118.14	98.01		
		Reg	73.384	81.116	126.14	97.68		

[a] Low biofuel case means no biofuel in the conventional gasoline pool.

The difference between ethanol and gasoline marginal values is calculated, converted to cents per gallon, and then volume-weighted to summarize them on a national average basis by gasoline grade and season in Table 10.1.3.1.1-5.

Table 10.1.3.1.1-5: Marginal Ethanol Replacement Cost by Gasoline Grade and Season (cents/ethanol gallon, crude oil priced at $72/bbl)

		Low Biofuel #1 Reformate-centric		Low Biofuel #2 Alkylate-centric	
		Summer	Winter	Summer	Winter
Conv.	Prem	124.58	50.79	112.04	32.65
	Reg	165.11	66.83	144.23	48.19

Although the ethanol replacement cost was based on a refinery modeling case when ethanol was solely removed from conventional gasoline, it would likely be about the same for reformulated gasoline (RFG) as well, so we assumed that they were the same for RFG.[1008] However, it is necessary to add in ethanol's volatility cost for RFG, which for ethanol's removal would be a cost savings. The 21 and 19 cent per gallon volatility cost for regular and premium gasoline, respectively, is subtracted from ethanol's replacement cost to estimate the ethanol replacement cost for RFG. The ethanol replacement costs for both CG and RFG are shown in Table 10.1.3.1.1-6. The ethanol replacement costs are then further aggregated to national, year-round averages for each octane replacement scenario and summarized at the bottom of the table.

Table 10.1.3.1.1-6: Aggregated Ethanol Marginal Replacement Cost (cents/gallon)

		Low Biofuel #1 Reformate-centric		**Low Biofuel #2 Alkylate-centric**	
		Summer	**Winter**	**Summer**	**Winter**
Conv.	Prem	124.58	50.79	112.04	32.65
	Reg	165.11	66.83	144.23	48.19
RFG	Prem	105.58	50.79	93.04	32.65
	Reg	144.11	66.83	123.23	48.19
		82.23		68.65	

Refiners would pursue the lowest cost means to produce their fuels. Therefore, for evaluating the cost of using ethanol in gasoline at 10 volume percent, the lower cost, alkylate-centric cost of 68.65 cents per gallon was used for ethanol's blending cost for ethanol blended as E10. This 68.65 cents per gallon cost represents ethanol's average nationwide blending replacement cost in U.S. gasoline. This can be thought of as the additional value or cost savings per gallon of ethanol that results from blending 10% ethanol into gasoline today.

10.1.3.1.2 Higher Level Ethanol Blends

While there is a considerable blending cost savings associated with blending ethanol as E10, there currently is not a savings for blending ethanol as E15 or E85. The blending costs for higher level ethanol blends is considerably different from that for E10 in large part due to the inability in most instances to take advantage of the octane benefit associated with the additional ethanol. Furthermore, the 1 psi RVP waiver which applies for blending E10 gasoline in summer conventional gasoline does not apply to blending E15, requiring a lower RVP and therefore higher cost gasoline blendstock. However, this is only an added cost in the summer and only in conventional gasoline areas.

There have been, and there continue to be, steps taken to facilitate the blending of E15 into summertime conventional gasoline. EPA granted E15 a 1 psi waiver that took effect in the summer of 2019; however, this waiver was struck down by a federal court in 2021. For summer 2022, EPA granted numerous emergency waivers to allow E15 to continue to be sold with a 1 psi RVP waiver. More recently, a number of states petitioned EPA to allow them to remove the 1 psi waiver for blending E10 gasoline, and if the 1 psi waiver for E10 were to be removed, the same

[1008] Both RFG and CG must meet many of the same gasoline property specifications, including sulfur and benzene, as well as ASTM standards (ASTM D4814).

lower RVP, higher cost gasoline blendstock would be required for both ethanol blends in summertime conventional gasoline in those states.

E15 could potentially realize a blending cost benefit based on the increased octane for the additional ethanol if refiners could create and distribute a low RVP, low octane E15 blendstock for oxygenate blending (BOB). However, this would require a widespread shift by refineries, pipelines, and terminals in an entire geographical region to produce and distribute another even lower octane BOB specially designed for producing E15 instead of E10.[1009] This would most likely only occur if E15 becomes the predominant gasoline used in that region because of the limitations of the distribution system and experience with the historic conversion to E10. Since this could not feasibly happen during the time period of this rulemaking, we have not included any octane blending benefit for the additional ethanol blended into E15 in excess of the ethanol blended in E10 (the additional 5%).[1010] Thus, the gasoline BOB used to produce E15 in the winter months is the same as that used for producing E10, resulting in a higher octane fuel than what it can be priced at. In the summer months, E15 would also incur the additional RVP control costs.

There also is not a blending cost benefit for ethanol blended as E85 resulting from its high octane beyond that which is already being realized when blending E10. When producing E85, ethanol's high octane results in significant overcompliance with the minimum octane standard. Refiners do not produce a low octane BOB for producing E85 to realize a cost savings. Conversely, ethanol plants produce E85 by adding a denaturant to ethanol, which typically is a low cost, low octane, high RVP, hydrocarbon commonly called natural gas liquids (NGL). Thus, E85 produced from NGLs does realize a cost savings. But NGLs are also lower in energy density, offsetting the potential cost savings to consumers. Regardless, there is no RVP blending cost for E85 because the high portion of ethanol results in lower RVP instead of higher RVP; therefore, a lower RVP blendstock is not needed for producing E85. In fact, to adjust for the lower RVP of E85 blends, E85 is actually blended at roughly 74% ethanol on average over both the summer and winter, instead of 85%, to have sufficiently high RVP to avoid RVP minimum limits.[1011]

The societal cost of using ethanol must include ethanol's lower energy density (fuel economy effect). Ethanol has about 33% lower energy density than gasoline blendstock (CBOB

[1009] Some refiners may have extra tankage available to allow producing and storing a lower octane, E15 blendstock to enable selling E15 over its own terminal rack to local retail stations. Refinery rack gasoline sales, however, are usually a small portion of the refinery's gasoline sales.

[1010] The reformulated gasoline pool always took advantage of ethanol's high octane as it was needed to cause a reduction in aromatics to reduce the emissions of air toxics under the Complex Model – the compliance tool of the RFG program. So when ethanol replaced methyl tertiary butyl ether (MTBE) as the oxygenate in 2005 when the RFG oxygen requirement was rescinded, refiners took advantage of ethanol's high octane content. The CG pool, however, could not take advantage of ethanol's high octane until an entire U.S. gasoline market (i.e., Midwest) was blended with ethanol, and then that gasoline market shifted over all at once to a suboctane blendstock for oxygenate blending (CBOB). Reviewing CG aromatics levels (high octane aromatics decrease when refiners produce suboctane CBOB), refiners switched the CG pool over to low octane CBOB over the years from 2008 to 2013 which is around the time when the U.S. reached the E10 blendwall.

[1011] E85 can have RVP levels which are too low which makes starting a parked car difficult. When blended at about 70% ethanol, the RVP of the ethanol-gasoline blend is a little higher than E85 blends improving cold starts.

and RBOB).[1012] Accounting for ethanol's lower energy density adds about 80¢ per gallon of ethanol for all the ethanol blends to account for the additional cost to consumers for having to purchase a greater volume of less energy dense fuel to travel the same distance.

10.1.3.2 Biodiesel and Renewable Diesel

Biodiesel and renewable diesel fuel have properties that could cause a cost savings or incur a cost. Both fuels have higher cetane value relative to petroleum diesel.[1013,1014] Although ICF/Mathpro considered the possibility of the petroleum refining industry taking advantage of that property, they concluded that most markets are not cetane limited and that as a result refiners likely would not take advantage of this property of biodiesel and renewable diesel.[1015] At this time, we do not have any evidence that refiners are capitalizing on biodiesel and renewable diesel's higher cetane value.

Conversely, a blending cost could be incurred for biodiesel due to the addition of additives to prevent oxidation and lower pour or cloud point. The need to add pour point additives is primarily a cold weather issue and likely contributes to the lower observed blending rates of biodiesel into diesel fuel in the winter compared to the summer, particularly in northern areas. However, for our analysis, no additive costs were included for biodiesel because we do not have a good estimate for them.

As with ethanol, the societal cost of using biodiesel and renewable diesel must include their lower energy density in comparison to petroleum-based diesel fuel, which impacts fuel economy. Accounting for this fuel economy effect adds about 18 and 11 cents per gallon to the societal cost of biodiesel and renewable diesel, respectively.

10.1.4 Distribution and Retail Costs

In this part of the chapter, we evaluate the costs of distributing biofuels from the places where they are produced to retail stations as well as the costs of dispensing these fuels at those retail stations.

10.1.4.1 Ethanol

10.1.4.1.1 Distribution Costs

Distribution costs are the freight costs to distribute the ethanol, although the total distribution costs could also include the amortized capital costs of newly or recently installed distribution infrastructure. A significant amount of capital has already been invested to enable ethanol to be blended nationwide as E10, and a small amount of ethanol as E85 and E15.

[1012] Frequently Asked Questions: How much ethanol is in gasoline, and how does it affect fuel economy?; Energy Information Administration; https://www.eia.gov/tools/faqs/faq.php?id=27&t=10
[1013] Animal Fats for Biodiesel Production; Farm Energy; January 31, 2014.
[1014] McCormick, Robert; Renewable Diesel Fuel; NREL; July 18, 2016.
[1015] Modeling a No-RFS Case; ICF Incorporated; Work Assignment 0,1-11, EPA contract EP-C-16-020; July 17, 2018.

Virtually all terminals, including those co-located with refineries, standalone product distribution terminals, and port terminals, have made investments over the last 15-plus years to enable the distribution and blending of ethanol. Thus, these capital costs are considered sunk and no additional capital cost is explicitly included in our analysis. However, in the part of the analysis where we estimate ethanol's distribution costs using spot ethanol prices, as described below, we may inherently be including some distribution capital costs which are still being recovered.

As part of the effort by ICF/Mathpro to estimate use of renewable fuels in the absence of the RFS program, ICF estimated distribution costs for ethanol and biodiesel. We used these cost estimates for this rulemaking.[1016] ICF estimated ethanol's distribution costs based on ethanol spot prices that are available from the marketplace. The spot prices likely represent the operating and maintenance costs, and any capital costs which are being recovered. Certain publications, including OPIS and ARGUS, publish ethanol spot prices for certain cities and these spot prices were consulted for estimating ethanol's distribution costs. These spot prices are tracked because they represent unit train origination and receiving locations where the custody of the ethanol changes hands in the distribution system. Since nearly all the ethanol is being produced in the Midwest, the ICF distribution cost analysis assumed that the ethanol is collected together in Chicago by truck or manifest rail at an average cost of 7 cents per gallon and then moved out of the Midwest to other areas mostly using unit trains. For the ethanol consumed in the Midwest, the ethanol is likely to be moved by trucks directly to the terminals in the Midwest. For the areas adjacent to the Midwest, the ethanol is assumed to be moved by truck for the areas nearest to the Midwest (i.e., Colorado and Wyoming), and by manifest train for the adjacent areas further out (i.e., Utah and Idaho). These various means for distributing ethanol, and their associated costs, were accounted for when estimating the ethanol's distribution cost to and within each region.

Once the ethanol is moved to a unit train or manifest train receiving terminal, there are many other terminals in these areas which must also receive the ethanol. Ethanol must then be moved either by truck or, if further away, by manifest train from the unit train receiving terminals to the other terminals. Since many of these other terminals do not have sidings for rail car offloading, the manifest train ethanol must be offloaded to trucks at tank car-truck transfer locations before it can be received by these other terminals. A simple analysis revealed that each unit train receiving terminal must then service, on average, an area of 31 thousand square miles (equivalent to a 180 x 180 miles) to make the ethanol available to the various terminals in the area. ICF estimated that, on average, the further distribution of ethanol from these unit train receiving terminals to the rest of the terminals would cost an additional 9 or 11 cents per gallon, depending on the PADD. Since ICF completed its analysis, we discovered that most corn ethanol plants are capable of sourcing unit trains from their plants. Thus, the 7 cent per gallon transportation cost from corn ethanol plants to Chicago is not necessary and this cost was removed from the estimated cost to each destination.[1017] Table 10.1.4.1.1-1 provides the estimate of ethanol distribution costs for the various parts of the country estimated by ICF, and as revised to remove the 7¢ per gallon transportation cost.

[1016] Modeling a No-RFS Case; ICF Incorporated; Work Assignment 0,1-11, EPA contract EP-C-16-020; July 17, 2018.
[1017] Rail congestion, cold weather raise ethanol spot prices; US Energy Information Administration; April 3, 2014.

Table 10.1.4.1.1-1: Ethanol Distribution Costs for Certain Cities or Areas

Location		Distribution Cost (¢/gal) to:			Total (¢/gal)	
		Hub/Terminal				
PADD	Area	To Chicago	From Chicago	Blending Terminal	ICF Estimate	Revised Estimate
PADD 1	Florida/Tampa	7.0	17.8	11.0	35.8	28.8
	Southeast/Atlanta		11.7	11.0	29.7	22.7
	VA/DC/MD		9.7	11.0	27.7	20.7
	Pittsburgh		6.2	11.0	24.2	17.2
	New York		7.7	11.0	25.7	18.7
PADD 2	Chicago		0.0	11.0	18.0	11.0
	Tennessee		9.7	11.0	27.7	20.7
PADD 3	Dallas		4.5	11.0	22.5	15.5
PADD 4			6.2	11.0	24.2	17.2
PADD 5	Los Angeles		16.4	9.0	32.4	25.4
	Arizona		16.4	9.0	32.4	25.4
	Nevada		12.4	9.0	28.4	21.4
	Northwest		12.4	9.0	28.4	21.4

We volume-weighted the various revised regional distribution cost estimates for PADDs 1 through 5 to derive a PADD-average ethanol distribution cost for all PADDs. Table 10.1.4.1.1-2 summarizes the estimated average ethanol distribution cost by PADD, and the average for the U.S adjusted to 2021 dollars.

Table 10.1.4.1.1-2: Average Ethanol Distribution Cost by PADD and the U.S.

Region	Gasoline Volume (kgals/day)	Average Ethanol Distribution Cost (¢/gal)
PADD 1	123,700	22.0
PADD 2	102,400	11.0
PADD 3	68,500	15.5
PADD 4	15,100	17.2
PADD 5	63,400	24.4
U.S. Average	373,100	18.1
U.S. Average 2021$		19.7

10.1.4.1.2 Retail Costs

The infrastructure at retail needed to make E10 available has been in place for many years. As a result, no additional retail costs are assumed for E10. However, this is not the case for E15 and E85. Additional investments are needed to make them available at retail. The E15 and E85 volumes that we are using in this costs analysis are summarized in Chapter 6.5.2.

The retail costs for E15 and E85 are estimated based on the investments that are needed to be made to offer such ethanol blends. To this end, we reviewed literature and conferred with EPA's Office of Underground Storage Tanks on what might be considered "typical" for E15 and E85 equipment installations for a typical sized retail station selling these blends.[1018,1019,1020,1021] For the typical retail station revamp to sell E15 the station is assumed to have an underground storage tank already compatible with E15 that it would convert over to store E15, but would still require 4 new dispensers to dispense the E15 - each dispenser is estimated to cost $20,000 for a total cost of $80,000 (assuming only 4 dispensers for a retail outlet), and this cost per dispenser increases to $24,500 when adjusted to 2021 dollars.[1022] In addition, these retail stations are assumed to invest in additional equipment changes to make their hardware compatible with E15 (e.g., pipes, pipe connectors, sealants including pipe dope and elastomers, pumps, and hardware associated with underground storage tanks) at a cost of $15,000. Thus, the total investment for a typical retail station revamp is $108,000.

The E85 stations are also assumed to have an existing underground storage it could use for storing E85, but would require some equipment modification costing $15,000 to allow the very high ethanol concentration to be stored in that tank and other equipment. The E85 station would also be required install a new E85-compatible dispenser, costing $24,500, for a total cost of $39,500 (assuming only one dispenser at a retail outlet is provided for E85).[1023]

Retail stations can incur costs which are higher or lower than the retail revamp costs we estimate for offering E15 and E85. If the retail station already has dispensers, tanks and other equipment that can offer E15 or E85 fuel, then perhaps only a few thousand dollars would need to be spent to make some dispenser parts compatible with the higher concentration ethanol. On the other hand, if the retail station needs the new dispensers and also needs to install a separate storage tank and other equipment to store and dispense E15 or E85, then the installation costs would be much higher. The retail revamp costs to offer higher ethanol blends estimated here attempts to find representative costs for this large cost range.

To estimate the per-gallon cost, it is necessary to estimate the volume of E85 and E15 sold at each station which offers these blends. These per-station volume estimates were based on data collected by USDA through their BIP program and made available to EPA.[1024] The total volumes of E15 and E85 sold were divided by the estimated number of E15 and E85 retail stations to estimate the volume per retail station. As a result, retail stations offering E15 are estimated to sell 147 thousand gallons of E15 per year while retail stations offering E85 are estimated to sell 78 thousand gallons of E85 per year. Using the amortization factor shown in Table 10.1.2.1.1-1, and amortizing these retail costs over the volume of ethanol in E15 and E85

[1018] Moriarity, K.; E15 and Infrastructure; National Renewable Energy Laboratory; May 2015

[1019] E15's Compatibility with UST Systems; Office of Underground Storage Tanks, Environmental Protection Agency; January 2020.

[1020] UST System Compatibility with Biofuels; Environmental Protection Agency; July 2020.

[1021] Conversations with Ryan Haerer, Office of Underground Storage Tanks; Spring 2022

[1022] Renkes, Robert; Scenarios to Determine Approximate Cost for E15 Readiness; Prepared by the Petroleum Equipment Institute for the United States Department of Agriculture; September 6, 2013.

[1023] Because only a small percentage of the motor vehicle fleet is comprised of fuel flexible vehicles (FFVs) which can refuel on E85, typically a retail station only offers E85 from a single dispenser at the retail station.

[1024] "Communication with USDA on the BIP program 1-19-22," available in the docket.

(15% for E15 and 74% for E85), covering the cost of capital for the retail equipment adds 54 and 7 cents per gallon to the ethanol portion of E15 and E85, respectively. When solely amortizing this retail cost solely over the 5% and 64% of ethanol that is incremental to E10, the cost increases by 1.61 and 8.5 cents per gallon of ethanol in E15 and E85 in excess of E10, respectively.

10.1.4.2 Biodiesel and Renewable Diesel Distribution Costs

Biodiesel distribution costs were determined by ICF under contract to EPA based on an estimate of biodiesel being moved by rail and by truck, within each PADD, and between PADDs.[1025] While biodiesel production is more spread out across the country than ethanol, a significant amount must still be moved long distances to match the production to the demand. The internal PADD rail costs were estimated to be 15 cents per gallon and truck movements for shorter fuel movements were estimated based on distance moved. Movement of these fuels between PADDs was assumed to be made by rail for most areas and also by ship from the Gulf Coast to the West Coast. ICF relied on EIA reports for biofuel movements between PADDs. Based on these analyses, the inter-PADD movements are estimated to cost 15 to 32 cents per gallon, depending on the distance that the biodiesel must travel.

Renewable diesel fuel distribution costs are assumed to be the same as biodiesel. Because renewable diesel is very similar in quality as diesel fuel, it can more readily be blended in more places in the diesel fuel distribution system, including at refineries, where the renewable diesel fuel would be moved by the same distribution system as diesel fuel. Thus, if renewable diesel is used locally its distribution costs would likely be lower than biodiesel. However, much of the renewable diesel is expected to be distributed to the West Coast to help meet the Low Carbon Fuel Standard programs there.

Table 10.1.4.2-1 summarizes the biodiesel and renewable diesel distribution costs for each PADD taking into account the amount of fuel that is distributed within PADDs and between PADDs, and shows the national average distribution cost and that average cost adjusted to 2021 prices.

[1025] Modeling a No-RFS Case; ICF Incorporated; Work Assignment 0,1-11, EPA contract EP-C-16-020; July 17, 2018.

Table 10.1.4.2-1: Estimated Biodiesel and Renewable Diesel Fuel Distribution Cost by PADD

Destination Location	PADD Total Transportation Cost (¢/gal)
PADD 1	21.6
PADD 2	15.0
PADD 3	16.0
PADD 4	25.0
PADD 5	23.8
U.S. Avg.	17.7
U.S. Average 2021$	19.2

10.1.4.3 Renewable Natural Gas (RNG)

10.1.4.3.1 Distribution Costs

Renewable natural gas (RNG) which is gathered from landfill off-gassing and cleaned up must then be transported to where it can be used. Typically, this RNG will end up in a nearby natural gas pipeline, but in some rare cases it also could be compressed or liquified for dispensing into the onboard CNG or LNG tanks of a local truck fleet at or near the landfill site.

Information on the length of pipeline needed to bring landfill gas to a nearby natural gas pipeline is not readily available, but we made some assumptions to estimate this distance. Landfills are generally located near to, although not in, urban areas to keep the transportation costs lower for hauling the waste to the landfill. The landfill gas is estimated to be moved 5 miles to access a commercial natural gas pipeline. For installing each mile of pipeline, it is estimated to cost $1 million, and adds up to $5.3 million in 2021 dollars for the entire 5 mile pipeline.[1026] A typical volume case was modeled of 600 standard cubic feet per minute to estimate the cost for a typical sized landfill.[1027] When the pipeline capital costs are amortized over that typical volume of landfill gas, the pipeline capital cost is estimated to cost $1.91 per million BTU.[1028]

Once the RNG is transported through the new pipeline to the natural gas pipeline, it incurs a cost for distribution through the existing natural gas pipeline. Landfills are located near urban areas which are destination areas for natural gas pipelines. This means that the distribution costs for RNG in the natural gas pipeline would be less than that for natural gas which is being distributed longer distances from natural gas production areas. Natural gas will incur both variable and fixed operating costs in the upstream pipelines, which RNG will avoid by being injected downstream. Furthermore, the addition of biogas downstream in the natural gas pipeline system can help the natural gas distribution system avoid capital investments that would

[1026] Landfill Gas Energy Cost Model (LFGcost-Web); Version 3.5; https://www.epa.gov/lmop
[1027] Economic Analysis of the US Renewable Natural Gas Industry; The Coalition of Renewable Natural Gas; December 2021.
[1028] The 5.3 million capital cost is amortized over the biogas volume by first multiplying it by the capital cost amortization factor (0.11) to derive a annual average cost, and then dividing this volume by the annual volume of biogas which is estimated to be flowing at 600 cubic feet per minute.

otherwise be necessary to debottleneck the upstream natural gas pipeline system to meet commercial and industrial sector demand increases. If we assume that RNG would be injected into a natural gas pipeline at least large enough to serve commercial consumers, the RNG distribution cost can be based on commercial natural gas distribution costs which are represented by the natural gas prices to commercial consumers. As summarized in Table 10.2.2-2, distribution of natural gas to commercial consumers is estimated to cost $5.47 per million cubic feet. We could not find detailed cost information for the distribution of commercial natural gas through different parts of the distribution system that would allow us to scale the commercial natural gas distribution costs to the portion of the natural gas pipeline used by RNG. For this reason, half of the commercial natural gas distribution cost, or about $2.7 per million cubic feet, is assumed to apply to biogas for distribution to the natural gas pipeline.[1029]

While this cost analysis assumes the biogas is being produced entirely at landfills, it is worthwhile to consider the situation other RNG producers are likely to face to distribute their biogas. Like landfills, RNG production at wastewater treatment plants and municipal waste digesters are located near cities and thus would likely have distribution costs similar to landfills. Conversely, agricultural waste digesters are much more likely to be located in rural areas further away from both natural gas pipelines and urban areas. The distribution costs for RNG producers using agricultural waste digesters would likely be higher. Some of these rural locations may be so remote that the RNG could be considered stranded and not readily available for use as transportation fuel, although such stranded locations could perhaps still provide RNG to local truck fleets which distribute agricultural products.[1030]

10.1.4.3.2 Retail Costs

Retail facilities to dispense RNG are more expensive compared to other transportation fuel retail costs. One information source provided an estimate that a larger sized CNG retail facility would cost about $4.78 per million BTU, so this was used for the RNG retail cost.[1031]

10.1.4.4 Renewable Electricity

Once the biogas is consumed by generator sets to produce electricity, it is necessary to distribute the electricity from where it is produced to where it can be consumed. AEO 2022 projects two values for distributing electricity in 2024, the first year that eRINs could be generated under this proposal: 1.46¢ per kilowatt-hour for electricity transmission, and 3.15¢ per kilowatt-hour for electricity distribution. The transmission cost of the electricity is for moving it from where it is produced to where it can be transformed (to a lower voltage) for the eventual consumption by consumers. The distribution cost of the electricity is the cost for distributing the electricity to the consumer after it has been transformed to a lower voltage. Since landfills and

[1029] Biogas producers tell us that they are being charged an equivalent distribution price that natural gas producers are being charged which essentially assumes that they are using the entire natural gas pipeline. This pricing scheme, though, does not represent the true social cost for distributing biogas, and a separate distribution cost is estimated for biogas.
[1030] The term “stranded” means the cost to recover and use the biogas is too high to justify installing the equipment collect upgrade and distribute it for commercial use.
[1031] Permitting CNG and LNG Stations, Best Practices Guide for Host Sites and Local Permitting Authorities; prepared for The California Statewide Alternative Fuel and Fleets Project by Clean Fuel Connection, Inc.

digesters at waste water treatment plants are small electricity producers near urban areas, we presume that the electricity generated would be for local distribution downstream of the electricity transmission system. Therefore, we assumed that the transmission cost which exists for conventional electricity, would not apply for RNG-derived electricity and that only the 3.15¢ per kilowatt-hour distribution cost would apply.

10.2 Gasoline, Diesel Fuel, Natural Gas and Electricity Costs

10.2.1 Production Costs

As renewable fuel use increases or decreases, the volume of petroleum-based products, such as gasoline and diesel fuel, would decrease or increase, respectively. This change in finished refinery petroleum products results in a change in refinery industry costs. The change in costs would essentially be the volume of fuel displaced multiplied by the cost for producing the fuel.

In addition, there could be a situation where we may need to account for capital investments made by the refining industry. For example, increasing renewable fuel standards could reduce capital investments refiners would otherwise make to increase refined product production above previous levels. In this case increased renewable fuel capital investments would offset decreased refining industry investments. However, we have not assumed for this analysis that there would be any reduction in refining industry investments considering the current situation. After the economic impact of the COVID-19 pandemic, Energy Information Administration (EIA) data shows that gasoline and diesel fuel demand are lower now and as of early 2022, only diesel fuel is expected to increase above previous levels.[1032] Furthermore, light-duty and heavy-duty greenhouse gas standards will continue to phase-in, continuing to reduce transportation fuel demand.[1033,1034,1035,1036] Thus, we would not anticipate there to be refined product investment regardless of the proposed renewable fuel volumes and thus no savings that would offset renewable fuel investments.

10.2.1.1 Gasoline and Diesel Fuel Production Costs

The production cost of gasoline and diesel fuel are based on the projected wholesale price for gasoline and diesel fuel provided in AEO 2022.[1037] Current gasoline prices are much higher,

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[1032] 2022 Annual Energy Outlook; Table 12 Petroleum and Other Liquid Prices, and Table 57 Component of Selected Petroleum Product Prices; March 3, 2022.

[1033] Environmental Protection Agency, Department of Transportation; Final rule for Model Year 2012-2016 Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; May 7, 2010.

[1034] Revised 2023 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions Standards; Environmental Protection Agency, December 30, 2021.

[1035] Environmental Protection Agency, Department of Transportation; Final Rule for Phase 1 Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium-Duty and Heavy-Duty Engines and Vehicles; September 15, 2011.

[1036] Environmental Protection Agency, Department of Transportation; Final Rule for Phase 2 Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium-Duty and Heavy-Duty Engines and Vehicles; October 25, 2016.

[1037] 2022 Annual Energy Outlook; Table 4a. U.S. Petroleum and Other Liquids Supply, Consumption and Inventories; March 3, 2022.

so a sensitivity cost analysis is conducted at higher petroleum prices and presented in Chapter 10.4.2.3 which assumes crude oil prices are priced much higher than those in AEO 2022. The projected Brent crude oil prices and gasoline and diesel fuel wholesale prices in 2023 through 2025 are summarized in Table 10.2.1.1-1.

Table 10.2.1.1-1 Estimated Gasoline Production Costs

	Gasoline			Diesel Fuel		
	2023	**2024**	**2025**	**2023**	**2024**	**2025**
Brent Crude Oil Prices ($/bbl)	61	66	67	61	66	67
Wholesale Prices - assumed to be Production Costs ($/gal)	1.82	1.81	1.79	1.97	2.08	2.08

10.2.1.2 Natural Gas Production Cost

For estimating the cost of biogas relative to natural gas, it is necessary to estimate the production cost of fossil natural gas. The natural gas production cost can be estimated using natural gas spot prices. In its AEO 2022, EIA projects the natural gas spot price for Henry Hub to average $3.49 per thousand cubic feet in 2023 and decrease to $3.00 per thousand cubic feet in 2025.[1038] The Henry Hub spot price most closely represents the natural gas field price, and thus is a proxy for its production cost.

10.2.1.3 Electricity Generation Cost

It is necessary to provide an estimate of the cost of producing electricity generated by conventional means to be able to assess the relative cost of the electricity generated by converting biogas to electricity for eRINs. AEO 2022 estimates the cost for generating electricity to be 5.91¢ per kilowatt-hour in 2024, and we used this as the reference cost for comparing biogas-produced electricity for eRINs.

10.2.2 Gasoline, Diesel Fuel, Natural Gas, and Electricity Distribution and Blending Cost

10.2.2.1 Gasoline and Diesel Fuel

Gasoline and diesel fuel distribution costs from refineries to terminals are estimated as the difference between wholesale prices and terminal prices (which we estimated based on historical sales for resale prices). This results in estimated gasoline and diesel fuel distribution costs to the terminal of 5 and 8 cents per gallon, respectively.

We also estimated the distribution costs from terminals to retail stations. To do so, we first calculated the retail costs of gasoline, less taxes. We calculated this by subtracting average federal and state taxes, which are 55¢ per gallon for gasoline and 64¢ gallon for diesel fuel, from historical gasoline and diesel fuel retail prices. Then, we calculated the difference between historical retail prices (less taxes) and historical terminal prices (estimated as sales for resales

[1038] 2022 Annual Energy Outlook; Table 13 Natural Gas Supply, Disposition, and Prices; March 3, 2022.

prices) to estimate the costs for terminal and retail distribution. The resulting terminal and retail distribution costs for gasoline and diesel fuel are estimated to be 20 and 40 cents per gallon for gasoline and diesel fuel, respectively. These various prices and estimated costs are summarized in Table 10.2.2-1.

Table 10.2.2.1-1: Estimated Gasoline and Diesel Fuel Distribution and Retail Costs ($/gal)

	Gasoline				**Diesel Fuel**			
	2017	**2018**	**2019**	**Average**	**2017**	**2018**	**2019**	**Average**
Bulk Price	1.64	1.94	1.74	1.77	1.62	2.05	1.86	1.85
Sales for Resale	1.69	1.98	1.81	1.83	1.69	2.13	1.96	1.93
Retail Price	2.42	2.72	2.60	2.58	2.65	3.18	3.06	2.96
Taxes	0.55	0.55	0.55	0.55	0.64	0.64	0.64	0.64
Distribution Costs	0.05	0.04	0.07	0.05	0.07	0.08	0.08	0.08
Retail Costs	0.18	0.19	0.24	0.20	0.32	0.41	0.46	0.40

We then apply the estimated gasoline and diesel fuel distribution costs to the projected wholesale gasoline and diesel fuel prices in Table 10.2.1.1-1 for each year to estimate the gasoline and diesel fuel prices from refinery to retail. These gasoline and diesel fuel prices are summarized in Table 10.2.2.1-2.

Table 10.2.2.1-2: Projected Gasoline and Diesel Production Costs ($/gal)

		2023	**2024**	**2025**
	Brent Crude Oil Prices	61.0	66.0	67.0
Gasoline	Retail Cost minus taxes	2.08	2.07	2.05
	Terminal and Retail Costs	0.20	0.20	0.20
	Terminal Costs			
	Distribution Cost	0.05	0.05	0.05
	Production Cost (from Table 10.2.1.1-1)	1.82	1.81	1.79
Diesel Fuel	Retail Cost minus taxes	2.44	2.55	2.55
	Terminal and Retail Costs	0.40	0.40	0.40
	Terminal Costs	2.05	2.16	2.16
	Distribution Cost	0.08	0.08	0.08
	Production Cost (from Table 10.2.1.1-1)	1.97	2.08	2.08

We acknowledge that, currently, gasoline and diesel fuel prices are much higher than these price projections and could remain higher during the years of this proposed rulemaking. In Chapter 10.4.2.3 we provide the results of a cost sensitivity analysis which assumes a higher crude oil price.

10.2.2.2 Natural Gas

EIA projects natural gas prices downstream of natural gas production fields which can be used to estimate natural gas distribution costs.[1039] The three principal natural gas consumers are industrial, commercial, and residential. Industrial consumers consume the largest natural gas volumes per facility, and due to the very large consumption, the distribution costs are lowest. Commercial entities are medium sized consumers, and their distribution costs are higher than industrial consumers. Residential consumers, because of their very low consumption, must pay a much larger distribution cost to maintain the distribution system for much lower consumption to each home. EIA also provides a price for natural gas sold into the transportation sector, although this price includes road taxes which would need to be omitted for the purposes of this cost analysis, so we did not use EIA's natural gas to transportation sector cost.[1040]

The varying costs for these different natural gas categories permit estimating natural gas distribution costs for natural gas consumed by motor vehicles. Natural gas produced and distributed to retail outlets to refuel natural gas trucks and cars most likely falls in the category of midsized consumers, or commercial users. The distribution costs of natural gas can therefore be estimated by subtracting the projected Henry Hub prices from the projected commercial prices. Thus, Henry Hub prices projected in AEO 2022 were subtracted from the commercial prices for 2023 through 2025. Table 10.2.2.2-1 summarizes the calculation of natural gas distribution costs. To put the natural gas costs on the same footing as the biogas, we also add $4.61 per million BTU for retail costs.[1041]

Table 10.2.2.2-1: Natural Gas Distribution Cost ($/thousand cubic feet)

	2023	2024	2025
Commercial Prices	8.84	8.52	8.38
Henry Hub Prices	3.49	3.17	3.00
Pipeline Distribution Costs	5.47	5.46	5.48
Retail Station Costs	4.78	4.78	4.78
Total Distribution & Retail Station Costs	10.25	10.24	10.26

10.2.2.3 Conventional Electricity

It is also necessary to project the distribution cost for electricity produced by conventional means to enable a downstream electricity comparison cost to the renewable electricity produced from biogas. Since most electricity is produced at large generation facilities, it must first be transmitted from those facilities to the population centers before being transformed to a lower voltage and distributed to the various homes and businesses. AEO 2022 estimates 1.46¢ per kilowatt-hour for transmission of the electricity from the generation facilities to population areas, and 3.15¢ per kilowatt-hour for electricity distribution. Both of these costs

[1039] Table 13 Natural Gas Supply, Disposition and Prices; Annual Energy Outlook 2022.
[1040] Taxes are not included in social cost estimates because they are not true costs, only transfer payments.
[1041] Permitting CNG and LNG Stations, Best Practices Guide for Host Sites and Local Permitting Authorities; prepared for The California Statewide Alternative Fuel and Fleets Project by Clean Fuel Connection, Inc.

are added to the conventional electricity generation costs to estimate a national average cost for electricity to consumers.

10.3 Fuel Energy Density and Fuel Economy Cost

To estimate the change in fossil fuel volume that would occur with these changes in renewable fuel volumes and to estimate the fuel economy cost summarized in Chapter 10.4.1, it was necessary to estimate the energy density of each fuel. Table 10.3-1 contains the estimated energy densities for the various renewable fuels and petroleum fuels analyzed for this cost analysis.

Table 10.3-1: Lower Heating Value (LHV) Energy Densities

LHV Energy Density (GREET 2017)	
	BTU/gal
Gasoline (E0)[a]	114,200
Diesel Fuel	128,450
Pure Ethanol	76,330
Natural Gas Liquids	83,686
Denatured Ethanol	76,477
E10 Gasoline	110,428
E15 Gasoline	108,542
E85[b]	86,285
Biodiesel	119,550
Renewable Diesel	122,887
Crude Oil	129,670

[a] From Chevron Paper.[1042]
[b] Assumed to contain 74% ethanol.

To account for the fuel economy effect for the cost analysis, the change in fossil fuel volume displaced by a change in renewable fuel volume is estimated by the relative energy content of the renewable and fossil fuels. However, if the energy density is not the same between the fossil fuel and renewable fuel displacing it, the energy equivalent replacement is not one-for-one on a volume basis. For example, ethanol contains about 33% lower energy per volume than the gasoline it is displacing, such that 100 gallons of ethanol would displace 67 gallons of gasoline. The fuel economy effect is therefore inherent in the cost analysis and is not reported out separately.

For the individual fuels cost summary in Chapter 10.4.1, it is desirable to report out a specific fuel economy effect. To do so, the difference in energy density between the renewable fuel and fossil fuel is divided by the fossil fuel energy density and then multiplied times the fossil fuel cost at retail, before taxes, to estimate the fuel economy effect.

[1042] Diesel Fuels Technical Review; Chevron Global Marketing; 2007.

10.4 Costs

10.4.1 Individual Fuels Cost Summary

Table 10.4.1-1 summarizes the estimated overall societal costs (including production, distribution, blending, and fuel economy) for the renewable fuels analyzed for this rulemaking for the years 2023–2025. These costs do not account for the per-gallon federal cellulosic biofuel and biodiesel tax subsidies, nor do they consider taxes or tax subsidies more generally, as these are transfer payments which are not relevant in the estimation of societal costs. Nor do these costs consider state or local infrastructure support funding or the funding from USDA's Blends Infrastructure Incentive Program (HBIIP) which offsets half of the investment costs for revamping retail stations to be compatible with E85 and E15.[1043] A separate line item is added for E15 and E85 which only adds in ½ of the retail cost to help illustrate the impact that the HBIIP program would have on the costs for these fuels. The costs of renewable fuels other than biogas are primarily influenced by the feedstock costs, which can vary significantly depending on a wide range of factors domestically and internationally, especially since many of them are also agricultural commodities.

To put the different fuels on an equivalent basis for the miles driven, the societal cost analysis also needs to account for each fuel's impact on fuel economy, which is first discussed in Chapter 10.3. While these costs may not always be reflected in the sales prices among the market participants (e.g., if refiners sell, and consumers buy, gasoline based on volume, not energy content), the varying impacts on fuel economy among the fuels nevertheless still result in different costs to consumers in operating their vehicles and therefore must be accounted for in a social cost analysis. The cost associated with the impact of renewable fuels on fuel economy costs are determined relative to the fuels they are assumed to displace; ethanol displaces gasoline, biodiesel and renewable diesel displace diesel fuel, and RNG displaces natural gas.[1044] To the extent that RINs representing RNG incentivize some incremental growth in sales of CNG/LNG trucks at the expense of diesel fueled trucks, then some RNG could also displace diesel fuel. However, this is expected to be a relatively minor occurrence for the volumes and timeframe of this proposal, and so is not included in this cost analysis.

The cost is shown for two different pathways for RNG. The first is RNG which is cleaned up, distributed through a natural gas pipeline, and used as CNG. This cost is expressed in both dollars per million BTU and dollars per ethanol-equivalent gallon. The second RNG pathway is RNG which, for the most part, is raw RNG from a landfill being converted onsite to electricity. Both of these RNG pathways represent the production cost for a midsize landfill as summarized in Table 10.1.2.5.2-4. Estimated costs for larger or smaller RNG producers, such as other sized landfills or agricultural digesters, could be substituted for the mid-size landfall cost used in the

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[1043] Higher Blends Infrastructure Incentive Program; United States Department of Agriculture (USDA); https://www.rd.usda.gov/hbiip

[1044] Fuel economy costs are calculated by multiplying the total of petroleum fuel production, distribution and retail costs by the difference in energy density (BTU per gallon) between the petroleum fuel being displaced and the renewable fuel, and the result of that operation is divided by the energy density of the petroleum fuel. For ethanol blended as E10 as an example: (denatured ethanol production + distribution + blending cost) * (E10 gasoline energy density - denatured ethanol energy density)/denatured ethanol energy density.

cost comparison to gain an understanding of the relative cost for these other RNG producer scenarios. Table 10.4.1-1 is divided into two subparts, “a” and “b.”

Table 10.4.1-1a: Renewable Fuels Costs estimated for 2023–2025 ($/gallon unless otherwise noted; 2021$)

		Production Cost			Blending Cost	Distribution Cost	Retail Cost	Fuel Economy Cost
		2023	2024	2025				
Corn Starch Ethanol	E10	1.94	1.89	1.85	-0.65	0.43		0.69
	E15 w ½ Retail Costs	1.94	1.89	1.85		0.43	0.81	0.69
	E15 w/Retail Costs	1.94	1.89	1.85		0.43	1.61	0.69
	E85 w/1/2 Retail Costs	1.94	1.89	1.85		0.43	0.04	0.69
	E85 w/Retail Costs	1.94	1.89	1.85		0.43	0.09	0.69
Biodiesel	Soy Oil	5.74	5.41	5.09		0.57		0.17
	Corn Oil	4.03	3.88	3.76		0.57		0.17
	Waste Oil	4.80	5.20	5.67		0.57		0.17
	Palm Oil	3.85	3.68	3.53		0.57		0.17
Renewable Diesel	Soy Oil	6.23	5.88	5.52		0.57		0.11
	Corn Oil	4.41	4.24	4.10		0.57		0.11
	Waste Oil	5.23	5.65	6.14		0.57		0.11
	Palm Oil	4.22	4.03	3.86		0.57		0.11
Cellulosic	Pyrolysis Diesel	3.35	3.35	3.35		0.57		0.11
	Pyrolysis Naphtha	3.35	3.35	3.35	0.20	0.38		0.05
	RNG ($/gal Ethaool)	0.57	0.57	0.57		0.42	0.39	
	RNG ($/mmBTU)	7.49	7.49	7.49		5.47	5.12	
	RNG electricity (c/kWh)	8.54	8.54	8.54		3.15		

[a] Fuel economy cost is per fuel being displaced—ethanol and pyrolysis naphtha displace gasoline, renewable diesel and pyrolysis diesel displace diesel fuel, and biogas displaces natural gas.
[b] It is important to note that in estimating the social cost for this rulemaking the fuel economy cost for ethanol blended into E10 is included since this is a cost that consumers will bear. However, when refiners are considering whether to blend ethanol, such as for estimating volumes for the No RFS baseline, they do not consider the fuel

economy effect and this distinction is important for understanding ethanol's relative economic viability in the marketplace.

[c] For modeling the societal costs of E15 and E85 shown in Chapters 10.4.2 and 10.4.3, the cost analysis is conducted for the entire volume of E15 and E85, and includes the blending cost savings for the E10 BOB used to blend with E15 and E85. For the cost analysis shown here, the cost for E15 and E85 is solely for the ethanol volume above that blended at 10 volume percent and therefore does not include any blending value for E10 BOBs to represent the marginal cost for the ethanol volume above E10.

Table 10.4.1-1b: Renewable Fuels Costs estimated for 2023 - 2025 ($/gallon unless otherwise noted; 2021$)

		Total Cost		
		2023	**2024**	**2025**
Corn Starch Ethanol	E10	2.41	2.36	2.32
	E15 w ½ Retail Costs	3.87	3.82	3.78
	E15 w/Retail Costs	4.67	4.62	4.58
	E85 w/1/2 Retail Costs	3.10	3.06	3.02
	E85 w/Retail Costs	3.15	3.10	3.06
Biodiesel	Soy Oil	6.48	6.16	5.83
	Corn Oil	4.77	4.63	4.50
	Waste Oil	5.54	5.94	6.41
	Palm Oil	4.59	4.42	4.26
Renewable Diesel	Soy Oil	6.91	6.56	6.20
	Corn Oil	5.09	4.92	4.78
	Waste Oil	5.91	6.33	6.82
	Palm Oil	4.90	4.71	4.54
Cellulosic	Pyrolysis Diesel	4.03	4.03	4.03
	Pyrolysis Naphtha	3.78	3.78	3.78
	RNG ($/gal Ethaool)	1.38	1.38	1.38
	RNG ($/mmBTU)	18.08	18.08	18.08
	RNG electricity (c/kWh)	11.69	11.69	11.69

The distribution costs for the biofuels are nationwide averages, which does not capture the substantial difference depending on the destination. For example, ethanol distribution costs from the ethanol plants to terminals can vary from under 10 cents per gallon for local distribution in the Midwest, to over 30 cents per gallon for moving the ethanol to the coasts. Thus, total ethanol cost blended as E10 can vary from around 2.38 to 2.58 per gallon. Biogas distribution includes both the amortized capital cost of transporting the biogas to a nearby pipeline as well as the amortized retail distribution capital costs, since the retail facilities for natural gas trucks are relatively expensive.

Table 10.4.1-2 summarizes production and distribution costs for each category of fossil transportation fuel—gasoline, diesel fuel, natural gas, and conventional (fossil-based) electricity. For gasoline and diesel, production costs are based on prices in AEO 2022.[1045] Natural gas and conventional electricity projected spot prices from the AEO 2022 are used to represent both feedstock and production costs.

[1045] EIA, Annual Energy Outlook 2022, Energy Information Administration, March, 2022.

The distribution costs for gasoline and diesel fuel are typical for these fuels. While they can vary depending on the transportation distance, the differences between high and low distribution costs for gasoline and diesel fuel are likely lower than that for renewable fuels due to the well-established pipeline distribution system for petroleum fuels. The natural gas distribution costs are based on the difference between the projected price for natural gas sold to commercial entities and the projected natural gas spot price, which reflects the price at the point of production.

Table 10.4.1-2: Gasoline, Diesel Fuel, and Natural Gas Costs for 2023–2025 (2021$)

	Production Cost			Distribution Cost	Retail Cost	Total Cost		
	2023	2024	2025			2023	2024	2025
Gasoline ($/gal)	1.82	1.81	1.79	0.26		2.08	2.07	2.05
Diesel Fuel ($/gal)	1.97	2.08	2.08	0.47		2.44	2.55	2.55
Natural Gas ($/million BTU)	3.49	3.17	3.00	4.89	5.12	13.51	13.19	13.02
Electricity (¢/kWh)	6.23	5.91	5.73	4.61		10.84	10.52	10.34

Table 10.4.1-3 compares the data from Tables 10.4.1-1 and 2 to show the relative cost of the renewable fuels with the fossil fuels or conventional electricity they are assumed to displace.

Table 10.4.1-3: Relative Renewable Fuel Costs for 2023–2025 ($/gal unless otherwise noted, 2021$)

Biofuel Category	Biofuel	Net Cost by Year		
		2023	2024	2025
Corn Starch Ethanol	E10	0.33	0.30	0.27
	E15 w/1/2 Retail Costs	1.79	1.75	1.73
	E15 w/Retail Costs	2.60	2.56	2.54
	E85 w/1/2 Retail Costs	1.03	0.99	0.97
	E85 w/Retail Costs	1.07	1.03	1.01
Biodiesel	Soy Oil	4.04	3.60	3.28
	Corn Oil	2.33	2.07	1.95
	Waste Oil	3.10	3.39	3.86
	Palm Oil	2.15	1.87	1.72
Renewable Diesel	Soy Oil	4.47	4.00	3.65
	Corn Oil	2.65	2.37	2.23
	Waste Oil	3.47	3.77	4.27
	Palm Oil	2.46	2.15	1.98
Cellulosic Biofuels	Pyrolysis Diesel	1.59	1.48	1.48
	Pyrolysis Naphtha	1.71	1.72	1.74
	Biogas ($/mmBTU)	4.58	4.90	5.07
	Biogas (c/kWh)	0.85	1.17	1.35

10.4.2 Costs Relative to the No RFS Baseline

In this section, we summarize the estimated costs for the changes in renewable fuel volumes described in Chapter 3.2 (changes relative to the No RFS baseline volumes described in Chapter 2). For this analysis we considered all societal costs, including production, blending, and distribution costs, and differences in energy density.

10.4.2.1 Volumes

An important first step for the cost analysis is understanding the change in both renewable fuel volumes and the associated change in the fossil fuel volume, which is calculated based on its energy content relative to the renewable fuel that it is displaced by. Table 10.4.2.1-1 summarizes the renewable and fossil fuel changes relative to the No RFS baseline, and Table 10.4.2.1-2 summarizes the volumes associated with the supplemental standard for 2023.

Table 10.4.2.1-1: Renewable Fuel and Fossil Fuel Volume Changes Relative to the No RFS Baseline (million gallons, except where noted)

Change in Renewable Fuel Volume				Change in Fossil Fuel Volume			
Fuel Type	**2023**	**2024**	**2025**	**Fuel Type**	**2023**	**2024**	**2025**
Cellulosic biofuel - Total							
CNG - landfill biogas (MMft^3)	26,771	31,638	37,169	Natural Gas	-26,771	-31,638	-37,169
Electricity - Biogas	0	0	0		0	0	0
Naphtha - Wood biomass	0	1	3	Gasoline	0	1	3
Diesel/Jet - Wood biomass	0	2	4	Diesel Fuel	0	2	3
Non-cellulosic adv. - Total							
Biodiesel - Soy	728	695	661	Diesel Fuel	-678	-646	-615
Biodiesel -FOG	200	200	200	Diesel Fuel	-186	-186	-186
Biodiesel - Corn Oil	120	120	120	Diesel Fuel	-112	-112	-112
Biodiesel - Canola	240	240	240	Diesel Fuel	-223	-223	-223
Renewable Diesel - Soy	879	1,026	1,032	Diesel Fuel	-841	-981	-988
Renewable Diesel - FOG	272	325	383	Diesel Fuel	-260	-311	-367
Renewable Diesel - Corn	78	84	90	Diesel Fuel	-74	-80	-86
Conventional - Total							
Ethanol - E10	-84	-96	-106	Gasoline	56	64	71
Ethanol - E15	84	101	113	Gasoline	-56	-67	-76
Ethanol - E85	262	272	282	Gasoline	-175	-182	-189
Change in Biogas Volume	26,771	31,638	37,169	-	-	-	-
Change in Ethanol Volume	262	276	290	-	-	-	-
Change in Biodiesel Volume	1,288	1,255	1,221	-	-	-	-
Change in Renewable Diesel Volume	1,229	1,437	1,512	-	-	-	-
Change in Gasoline Volume	-	-	-	-	-175	-184	-192
Change in Diesel Fuel Volume	-	-	-	-	-2,374	-2,538	-2,574
Change in Natural Gas Volume	-	-	-	-	-26,771	-31,638	-37,169
Change in Imported Gasoline					5	5	6
Change in Imported Diesel Fuel					70	75	76
Total Change in Crude Oil					-2,580	-2,755	-2,799
Change in Domestic Crude Oil					-12	-13	-13
Change in Imported Crude Oil					-2,568	-2,742	-2,785

Table 10.4.2.1-2 Supplemental Standard Renewable Fuel and Petroleum Fuel Volume Changes

Change in Renewable Fuel Volume				Change in Petroleum Fuel Volume			
	2023	**2024**	**2025**		**2023**	**2024**	**2025**
Supplemental Std. RD Soy Oil	147	0	0	Diesel Fuel	-141	0	0

The change in gasoline and diesel volume for each case is used to estimate the change in crude oil based on its relative energy content. The change in petroleum demanded and its effect on both imported crude oil, domestic crude oil, and imported petroleum products, is projected based on these effects by a comparison of two separate economic cases: the Low Economic

Growth Case and the Reference Case, modeled by EIA in its AEO 2022.[1046] The AEO Low Economic Growth Case estimates lower refined product demand than that of the Reference case, and due to the reduced refined product demand the AEO estimates changes in reduced imports of crude oil refined products. The two AEO cases project that for a volume of reduced gasoline or diesel fuel, 102 percent of that gasoline or diesel reduction would be attributed to reduced crude oil imports and imports of refined product would increase by 3 percent. Based on these correlations, Table 10.4.2.1-3 summarizes the projected change in petroleum imports expected from the increased consumption of renewable biofuels over the years 2023 to 2025 relative to the No RFS baseline, and Table 10.4.2.1-4 shows the same information, but also accounts for the Supplemental Standard. In both tables, we consider the projected change in imported petroleum products only as well as the projected change in all imported fuels, including imported renewable diesel and imported sugar cane ethanol. The change in crude oil volume and imported petroleum products is used for the energy security analysis contained in Chapter 5.

Table 10.4.2.1-3: Projected Change in Petroleum Imports Due to Increased Renewable Fuel Consumption Relative to the No RFS Baseline (million gallons)

	2023	2024	2025
Change in Imported Gasoline	5	5	6
Change in Imported Diesel Fuel	70	75	76
Total Change in Crude Oil	-2,580	-2,755	-2,799
Change in Domestic Crude Oil	-12	-13	-13
Change in Imported Crude Oil	-2,568	-2,742	-2,785

Table 10.4.2.1-4: Projected Change in Petroleum Imports Due to Increased Renewable Fuel Consumption Relative to the No RFS Baseline; accounts for the Supplemental Standard imports (million gallons)

	2023	2024	2025
Change in Imported Gasoline	5	5	6
Change in Imported Diesel Fuel	74	75	76
Total Change in Crude Oil	-2,724	-2,755	-2,799
Change in Domestic Crude Oil	-13	-13	-13
Change in Imported Crude Oil	-2,711	-2,742	-2,785

10.4.2.2 Cost Impacts Relative to the No RFS Baseline

Table 10.4.2.2-1 summarizes the component cost (production, distribution, blending retail) of each biofuel fuel type for 2023 through 2025 compared to the fossil fuel it is displacing, and Table 10.4.2.2-2 provides this information for the supplemental standard.

[1046] "Change in product demand on imports", spreadsheet available in the docket.

Table 10.4.2.2-1 Renewable and Petroleum Fuel Costs for 2023 to 2025 (million dollars; year 2021 dollars)

		Renewable Fuel			Petroleum Fuel		
		Production	Distribution	Blending	Production	Distribution	Total
2023	Cellulosic biofuel						
	CNG - landfill biogas	208	282	0	-94	-305	92
	Electricity - Biogas	0	0	0	0	0	0
	Naphtha - Wood biomass	0.0	0.0	0.0	0.0	0.0	0.0
	Diesel/Jet - Wood biomass	0.0	0.0	0.0	0.0	0.0	0.0
	Non-cellulosic adv.						
	Biodiesel - Soy	4,175	418	0	-1,335	-321	2,938
	Biodiesel -FOG	958	115	0	-366	-88	618
	Biodiesel - Corn Oil	484	69	0	-221	-53	280
	Biodiesel - Canola	1,377	138	0	-440	-106	968
	Renewable Diesel - Soy	5,479	504	0	-1,657	-398	4,933
	Renewable Diesel - FOG	1,421	156	0	-512	-123	941
	Renewable Diesel - Corn	314	45	0	-147	-35	176
	Conventional						
	Ethanol - E10	-163	-36	55	102	14	-28
	Ethanol - E15	163	37	-37	-103	-14	46
	Ethanol - E85	507	114	-23	-319	-45	234
2024	Cellulosic biofuel						
	CNG - landfill biogas	246	334	0	-100	-360	119
	Electricity - Biogas	0	0	0	0	0	0
	Naphtha - Wood biomass	4.5	0.3	0.3	-2.4	-0.3	2.4
	Diesel/Jet - Wood biomass	5.9	1.0	0.0	-3.3	-0.8	2.8
	Non-cellulosic adv.						
	Biodiesel - Soy	3,761	123	0	-1,274	-306	2,304
	Biodiesel -FOG	1,039	35	0	-366	-88	620
	Biodiesel - Corn Oil	467	21	0	-221	-53	215
	Biodiesel - Canola	1,299	42	0	-440	-106	796
	Renewable Diesel - Soy	6,027	183	0	-2,041	-464	3,704
	Renewable Diesel - FOG	1,834	57	0	-612	-147	1,132
	Renewable Diesel - Corn	325	15	0	-158	-38	144
	Conventional						
	Ethanol - E10	-181	-42	63	116	16	-28
	Ethanol - E15	190	44	-44	-122	-17	51
	Ethanol - E85	514	118	-24	-329	-47	232
2025	Cellulosic biofuel						
	CNG - landfill biogas	289	392	0	-112	-423	146
	Electricity - Biogas	0	0	0	0	0	0
	Naphtha - Wood biomass	18.2	1.2	1.1	-4.7	-0.7	4.8
	Diesel/Jet - Wood biomass	23.7	4.0	0.0	-6.7	-1.6	5.6
	Non-cellulosic adv.						
	Biodiesel - Soy	3,367	117	0	-1,212	-291	1,980
	Biodiesel -FOG	1,133	35	0	-366	-88	714
	Biodiesel - Corn Oil	452	21	0	-221	-53	200
	Biodiesel - Canola	1,222	42	0	-440	-106	719
	Renewable Diesel - Soy	5,702	183	0	-2,055	-468	3,363
	Renewable Diesel - FOG	2,355	68	0	-723	-174	1,527
	Renewable Diesel - Corn	337	16	0	-169	-41	143
	Conventional						
	Ethanol - E10	-195	-46	69	126	18	-28
	Ethanol - E15	210	49	-49	-136	-19	54
	Ethanol - E85	521	123	-25	-338	-10	271

Table 10.4.2.2-2 Renewable Fuel and Petroleum Fuel Costs for the 2023 Supplemental Standard (million dollars; 2021$)

	Renewable Fuel			Fossil Fuel		
	Production	**Distribution**	**Blending**	**Production**	**Distribution**	**Total**
Supplemental Std. RD Soy Oil	916	84	0	-277.0	-66.0	657.1

To estimate the per-gallon cost on the total gasoline, diesel, and natural gas pools, the projected total volumes for each of these fuels was obtained from AEO 2022 and summarized in Table 10.4.2.2-3.[1047]

Table 10.4.2.2-3: Total Gasoline, Diesel Fuel and Natural Gas Volumes

	2023	2024	2025	Units
Gasoline Volume	139.8	139.7	139.2	Billion gallons
Diesel Volume	55.5	55.3	55.3	Billion gallons
Natural Gas Volume	30.5	30.7	30.5	Trillion cubic feet

The costs are aggregated for each fossil fuel type and expressed as per-gallon and per thousand cubic feet costs in Table 10.4.2.2-4 for 2023 through 2025.

Table 10.4.2.2-4: Total Annual Rule Cost Relative to the No RFS baseline (2021$)

		Total Cost (million $)	Per-Unit Cost	Units
2023	Gasoline	252	0.18	cents/gallon gasoline
	Diesel Fuel	10,855	19.56	cents/gallon diesel
	Natural Gas	92	0.3015	$/K FT3 natural gas
	Total	11,199	5.73	cents/gallon gasoline and diesel
2023 with Suppl. Std.	Gasoline	252	0.18	cents/gallon gasoline
	Diesel Fuel	11,512	20.74	cents/gallon diesel
	Natural Gas	92	0.3015	$/K FT3 natural gas
	Total	11,856	6.07	cents/gallon gasoline and diesel
2024	Gasoline	258	0.18	cents/gallon gasoline
	Diesel Fuel	8,919	16.12	cents/gallon diesel
	Natural Gas	119	0.3873	$/K FT3 natural gas
	Total	9,295	4.77	cents/gallon gasoline and diesel
2025	Gasoline	303	0.22	cents/gallon gasoline
	Diesel Fuel	8,651	15.63	cents/gallon diesel
	Natural Gas	146	0.4795	$/K FT3 natural gas
	Total	9,100	4.68	cents/gallon gasoline and diesel

[1047] EIA, Annual Outlook 2022, Energy Information Administration, March 3, 2022.

10.4.2.3 Petroleum Cost Sensitivity Analysis

A sensitivity cost analysis is conducted to provide a sense of the impact of higher crude oil prices on societal costs. For this sensitivity case, the prices for renewable fuels feedstocks, the renewable fuel byproducts, and utilities are assumed to be the same. The only difference is that crude oil is assumed to be priced at $110 per barrel, and this is modeled by increasing both gasoline and diesel fuel prices by 97 cents per gallon, which approximates the impact of this higher crude oil price on gasoline and diesel fuel wholesale prices. No change in natural gas prices is assumed for this analysis. Table 10.4.2.3-1 summarizes the societal costs based on these assumptions. As one would expect, increasing the crude oil price from about $65 per barrel to $110 per barrel and holding other prices constant reduces the relative cost of renewable fuels, in this case by an estimated 22 percent. In reality other prices are typically also impacted by crude oil prices to varying degrees, but this sensitivity analysis nevertheless provides some sense of the impact of crude oil price changes.

Table 10.4.2.3-1 Total Sensitivity Cost at $110/bbl Crude Oil Price with and without the Supplemental Standard (year 2021 dollars)

		Total Cost (million $)	Per-Unit Cost	Units
2023	Gasoline	83	0.06	cents/gallon gasoline
	Diesel Fuel	8,559	15.42	cents/gallon diesel
	Natural Gas	92	0.3015	$/K FT3 natural gas
	Total	8,734	4.47	cents/gallon gasoline and diesel
2023 with Suppl. Std.	Gasoline	83	0.06	cents/gallon gasoline
	Diesel Fuel	9,080	16.36	cents/gallon diesel
	Natural Gas	92	0.3015	$/K FT3 natural gas
	Total	9,255	4.74	cents/gallon gasoline and diesel
2024	Gasoline	77	0.06	cents/gallon gasoline
	Diesel Fuel	6,461	11.68	cents/gallon diesel
	Natural Gas	119	0.3873	$/K FT3 natural gas
	Total	6,658	3.41	cents/gallon gasoline and diesel
2025	Gasoline	112	0.08	cents/gallon gasoline
	Diesel Fuel	6,156	11.12	cents/gallon diesel
	Natural Gas	146	0.4795	$/K FT3 natural gas
	Total	6,414	3.30	cents/gallon gasoline and diesel

10.4.3 Costs Relative to the Year 2022 Volumes

10.4.3.1 Volumes

In this section, we summarize the results of our analysis estimating the costs for changes in the use of renewable fuels relative to the year 2022 renewable fuels volumes estimated to occur under the 2022 RFS renewable fuel obligation (RVO). This analysis is conducted the same way as that conducted for the No RFS baseline analysis, with the only difference being the baseline volumes. Table 10.4.3.1-1 summarizes the cost and cost savings of each biofuel fuel type compared to the fossil fuel it is displacing for the years 2023 to 2025.

Table 10.4.3.1-1: Renewable Fuel and Fossil Fuel Volume Changes Relative to Year 2022 Volumes (million gallons, except where noted)

Change in Renewable Fuel Volume				Change in Fossil Fuel Volume			
Fuel Type	**2023**	**2024**	**2025**	**Fuel Type**	**2023**	**2024**	**2025**
Cellulosic biofuel							
CNG - landfill biogas (MMFT3)	6,564	13,570	21,461	Natural Gas	-6,564	-13,570	-21,461
Electricity - Biogas							
Naphtha - Wood biomass	0	1	3	Gasoline	0.0	1.3	2.6
Diesel/Jet - Wood biomass	0	2	4	Diesel Fuel	0.0	1.7	3.4
Non-cellulosic adv.							
Biodiesel - Soy	-32	-65	-99	Diesel Fuel	-30	-61	-92
Biodiesel -FOG	-11	-11	-11	Diesel Fuel	-11	-11	-11
Biodiesel - Corn Oil	1	1	1	Diesel Fuel	1	1	1
Biodiesel - Canola	-5	-5	-5	Diesel Fuel	-4	-4	-4
Renewable Diesel - Soy	-129	17	24	Diesel Fuel	124	-17	-23
Renewable Diesel - FOG	62	115	174	Diesel Fuel	-60	-110	-167
Renewable Diesel - Corn	11	16	22	Diesel Fuel	-10	-16	-21
Conventional							
Ethanol - E10	76	44	-2	Gasoline	-51	-29	1
Ethanol - E15	18	35	47	Gasoline	-12	-23	-32
Ethanol - E85	11	21	31	Gasoline	-7	-14	-21
Renewable Diesel - Palm	-155	-155	-155	Diesel Fuel	144	144	144
Change in Biogas Volume	6,564	13,570	21,461	-	-	-	-
Change in Ethanol Volume	29	100	77	-	-	-	-
Change in Biodiesel Volume	-47	-80	-113	-	-	-	-
Change in Renewable Diesel Volume	-211	-3	72	-	-	-	-
Change in Gasoline Volume	-	-	-	-	-19	-65	-49
Change in Diesel Fuel Volume	-	-	-	-	155	-71	-169
Change in Natural Gas Volume	-	-	-	-	-6,564	-13,570	-21,461
Change in Imported Gasoline					1	2	1
Change in Imported Diesel Fuel					-5	2	5
Total Change in Crude Oil					140	-132	-217
Change in Domestic Crude Oil					1	-1	-1
Change in Imported Crude Oil					140	-131	-216

These volumes would need to be adjusted to account for the supplemental standard which applies in 2022 and 2023. Since the supplemental volumes applies in 2022, the baseline year for conducting this cost analysis, 2023 volumes would not change relative to the 2022 baseline volumes, but the renewable diesel volumes decrease in 2024 and 2025 as summarized the volumes in Table 10.4.3.1-2.

Table 10.4.3.1-2: Soy Renewable Diesel and Diesel Fuel Volume Changes Relative to Year 2022 Volumes due to the Supplemental Standard (million gallons)

Change in Renewable Fuel Volume				Change in Petroleum Fuel Volume			
	2023	2024	2025		2023	2024	2025
Supplemental Std. RD Soy Oil	0	-147	-147	Diesel Fuel	0	-141	-141

10.4.3.2 Costs

Table 10.4.3.2-1 summarizes the component cost (production, distribution, blending, retail costs, which are costs to enable sale of the renewable fuel) for each biofuel fuel type for 2023 through 2025 compared to the fossil fuel it is assumed to displace.

Table 10.4.3.2-1: Renewable Fuel and Petroleum Fuel Costs Relative to Year 2022 Volumes (million dollars; 2021$)

		Renewable Fuel			Petroleum Fuel		
		Production	**Distribution**	**Blending**	**Production**	**Distribution**	**Total**
2023	Cellulosic biofuel						
	CNG - landfill biogas	51	69	0	-23	-75	23
	Electricity - Biogas	0	0	0	0	0	0
	Naphtha - Wood biomass	0.0	0.0	0.0	0.0	0.0	0.0
	Diesel/Jet - Wood biomass	0.0	0.0	0.0	0.0	0.0	0.0
	Non-cellulosic adv.						
	Biodiesel - Soy	-54	-7	0	21	6	-34
	Biodiesel -FOG	5	1	0	-2	-1	3
	Biodiesel - Corn Oil	-27	-3	0	9	2	-18
	Biodiesel - Canola	0	0	0	0	0	0
	Renewable Diesel - Soy	326	36	0	-118	-34	210
	Renewable Diesel - FOG	43	6	0	-20	-6	23
	Renewable Diesel - Corn	0	0	0	0	0	0
	Conventional						
	Ethanol - E10	148	20	-50	-93	-13	11
	Ethanol - E15	35	5	-8	-22	-3	7
	Ethanol - E85	21	3	-1	-13	-2	8
	Renewable Diesel - Palm	-654	-89	0	284	11	-448
2024	Cellulosic biofuel						
	CNG - landfill biogas	105	143	0	-43	-154	51
	Electricity - Biogas	0	0	0	0	0	0
	Naphtha - Wood biomass	9.1	0.6	0.5	4.5	0.3	
	Diesel/Jet - Wood biomass	11.8	2.0	0.0	5.9	1.0	
	Non-cellulosic adv.						
	Biodiesel - Soy	-59	-7	0	22	6	-37
	Biodiesel -FOG	5	1	0	-3	-1	3
	Biodiesel - Corn Oil	-25	-3	0	9	2	-16
	Biodiesel - Canola	0	0	0	0	0	0
	Renewable Diesel - Soy	651	66	0	-229	-63	425
	Renewable Diesel - FOG	64	9	0	-33	-9	32
	Renewable Diesel - Corn	0	0	0	0	0	0
	Conventional						
	Ethanol - E10	83	11	-29	-53	-8	5
	Ethanol - E15	65	9	-15	-42	-6	11
	Ethanol - E85	40	5	-2	-25	-4	14
	Renewable Diesel - Palm	-624	-89	0	300	11	-402
2025	Cellulosic biofuel						
	CNG - landfill biogas	167	226	0	-64	-244	84
	Electricity - Biogas	0	0	0	0	0	0
	Naphtha - Wood biomass	9.1	0.6	0.5	-4.7	-0.7	4.8
	Diesel/Jet - Wood biomass	11.8	2.0	0.0	-7.0	-1.6	5.2
	Non-cellulosic adv.						
	Biodiesel - Soy	-64	-7	0	22	6	-43
	Biodiesel -FOG	5	1	0	-3	-1	2
	Biodiesel - Corn Oil	-24	-3	0	9	2	-15
	Biodiesel - Canola	0	0	0	0	0	0
	Renewable Diesel - Soy	1,070	100	0	-346	-96	727
	Renewable Diesel - FOG	84	13	0	-44	-12	40
	Renewable Diesel - Corn	0	0	0	0	0	0
	Conventional						
	Ethanol - E10	-3	0	1	2	0	0
	Ethanol - E15	88	12	-21	-57	-8	14
	Ethanol - E85	58	8	-3	-37	-5	20
	Renewable Diesel - Palm	-598	-89	0	300	11	-376

The costs are aggregated for each fossil fuel type and costs expressed as per-gallon gasoline and diesel fuel, and per thousand cubic feet of natural gas, in Table 10.4.3.2-2.

Table 10.4.3.2-2: Total Costs Relative to Year 2022 Volumes (2021$)

		Total Cost (million $)	Per-Unit Cost	Units
2023	Gasoline	26	0.02	cents/gallon gasoline
	Diesel Fuel	-968	-1.74	cents/gallon diesel
	Natural Gas	23	0.07	$/K FT3 natural gas
	Total	-920	-0.47	cents/gallon gasoline and diesel
2024	Gasoline	33	0.02	cents/gallon gasoline
	Diesel Fuel	-150	-0.27	cents/gallon diesel
	Natural Gas	51	0.17	$/K FT3 natural gas
	Total	-66	-0.03	cents/gallon gasoline and diesel
2025	Gasoline	39	0.03	cents/gallon gasoline
	Diesel Fuel	115	0.21	cents/gallon diesel
	Natural Gas	84	0.28	$/K FT3 natural gas
	Total	238	0.12	cents/gallon gasoline and diesel

The total costs associated with the proposed volumes relative to the 2022 baseline does not include the supplemental standard which applies in 2022 and 2023. If we include these supplemental volumes and their associated costs, the total costs after 2023 are adjusted lower based on the cost figures in Table 10.4.3.2-3 (e.g., 317 million lower cost in 2024).

Table 10.4.3.2-3: Adjustments to the Estimated Total Costs to Account for the Supplemental Standard (million dollars)

	Renewable Fuel			Fossil Fuel		
	Production	Distribution	Blending	Production	Distribution	Total
2023	0	0	0	0.1	0.0	-0.1
2024	-592	-84	0	293	67	-317
2025	-567	-84	0	293	67	-293

10.5 Estimated Fuel Price Impacts

In this section we estimate the impact of the use of renewable fuels on the cost to consumers of transportation fuel and the cost to transport goods. We have estimated cost to consumers of transportation fuel by assessing the fuel price impacts associated with this rulemaking. We do so based on the cost of renewable fuels (less available federal tax credits) and accounting for the cross-subsidy implemented through the RIN system. We have also used estimates of the fuel price impacts of this rule to estimate the cost to transport goods discussed in Chapter 10.5.5.

10.5.1 RIN Cost and RIN Value

Before estimating fuel price impacts, we first estimated the RIN cost (i.e., the cost added to each gallon of petroleum fuel to account for the RIN obligation on the fuel) and RIN value (i.e., the value of the RINs associated with the renewable fuel in the fuel blend) associated with producing petroleum and renewable fuels, respectively. Because RIN prices can be impacted by a wide variety of different factors (including the prices of renewable fuels and petroleum-based fuels, oil prices, commodity prices, etc.), we are not able to project what RIN prices will be in the future. We can, however, use the average RIN prices over the last 12 months (through June 2022) as an estimate of future RIN prices, as shown in Table 10.5.1-1.

Table 10.5.1-1: Average RIN Prices (July 2021 – June 2022)

RFS Standard	RIN Type	Average RIN Price (July 2021 – June 2022)	2022 Percentage Standards	2023 Proposed Percentage Standard	2024 Proposed Percentage Standard	2025 Proposed Percentage Standard
Cellulosic Biofuel (D3)	D3	$3.06	0.35%	0.41%	0.82%	1.23%
Biomass-Based Diesel (D4)	D4	$1.52	2.33%	2.54%	2.60%	2.67%
Other Advanced Biofuel[a] (D5)	D5	$1.54	0.48%	0.38%	0.38%	0.38%
Conventional Renewable Fuel[b] (D6)	D6	$1.28	8.57%[c]	8.73%[d]	8.75%	8.77%

[a] Other advanced biofuel is not a fuel category for which a percentage standard is established, but is calculated by subtracting the cellulosic biofuel and biomass-based diesel standards from the advanced biofuel standard.
[b] Conventional renewable fuel is not a fuel category for which a percentage standard is established, but is calculated by subtracting the advanced biofuel standard from the total renewable fuel standard.
[c] Includes the 2022 total renewable fuel supplemental standard.
[d] Includes the 2023 total renewable fuel supplemental standard.

We then calculated the RIN cost for petroleum fuel by weighting the RIN price for each D code by their respective RFS standard and summing the total. The results are shown in Table 10.5.1-2.

Table 10.5.1-2: Estimated RIN Costs for Petroleum Fuel for 2023-2025

Year	RIN Cost ($/Gallon)
2022	$0.16
2023	$0.17
2024	$0.18
2025	$0.20

Finally, we calculated RIN values for fuels. For gasoline-ethanol blends, we multiplied the average D6 RIN price by the ethanol content of each blend (i.e., 10% for E10, 15% for E15, and an average ethanol content of 74% for E85). For biodiesel and renewable diesel, we multiplied the average D4 RIN price by the equivalence value of each fuel (i.e., 1.5 for biodiesel and 1.7 for renewable diesel). The results are shown in Table 10.5.1-3.

Table 10.5.1-3: Estimated RIN Values for Fuels

Fuel	RIN Value ($/Gallon)
E10	$0.13
E15	$0.19
E85	$0.95
Biodiesel	$2.29
Renewable Diesel	$2.59

10.5.2 Estimated Fuel Price Impacts (Gasoline)

In this section we have estimated the fuel price impacts of the 2023-2025 candidate volumes on gasoline relative to the No RFS and 2022 baselines. First we estimated the total cost of gasoline-ethanol blends for the candidate volumes. We began with the production cost for each fuel,[1048] added the RIN cost associated with the gasoline portion of the fuel, and then subtracted the RIN value associated with the ethanol portion of each fuel, which gave us each fuel's net cost per gallon. We then multiplied each fuel's net cost by its volume from Table 6.5.2-3. As shown in Tables 10.5.2-1 through 3, we estimate that total gasoline costs would range from $288-290 billion per year.

Table 10.5.2-1: Gasoline Total Cost – 2023 (Candidate Volumes)

	E0	E10	E15	E85
Cost to Produce ($/gal)	$2.08	$2.04	$2.14	$2.29
RIN Cost ($/gal)	$0.17	$0.15	$0.14	$0.04
RIN Value ($/gal)	$0.00	-$0.13	-$0.19	-$0.95
Net Cost ($/gal)	$2.24	$2.06	$2.09	$1.38
Volume (mil gal)	2,128	136,643	561	353
Total Blend Cost ($bil)	$4.8	$282.0	$1.2	$0.5
Total Cost ($bil)	$288.5			

[1048] Note that for purposes of this fuel price impacts assessment, we only looked at the cost to produce and distribute fuel to retail stations for sale to consumers (i.e., we subtracted out of the fuel economy cost for each fuel).

Table 10.5.2-2: Gasoline Total Cost – 2024 (Candidate Volumes)

	E0	E10	E15	E85
Cost to Produce ($/gal)	$2.08	$2.04	$2.13	$2.25
RIN Cost ($/gal)	$0.18	$0.16	$0.16	$0.05
RIN Value ($/gal)	$0.00	-$0.13	-$0.19	-$0.95
Net Cost ($/gal)	$2.26	$2.07	$2.09	$1.35
Volume (mil gal)	2,128	136,323	671	367
Total Blend Cost ($bil)	$4.8	$282.4	$1.4	$0.5
Total Cost ($bil)	$289.1			

Table 10.5.2-3: Gasoline Total Cost – 2025 (Candidate Volumes)

	E0	E10	E15	E85
Cost to Produce ($/gal)	$2.08	$2.03	$2.12	$2.22
RIN Cost ($/gal)	$0.20	$0.18	$0.17	$0.05
RIN Value ($/gal)	$0.00	-$0.13	-$0.19	-$0.95
Net Cost ($/gal)	$2.27	$2.08	$2.10	$1.32
Volume (mil gal)	2,128	135,871	756	381
Total Blend Cost ($bil)	$4.8	$282.6	$1.6	$0.5
Total Cost ($bil)	$289.5			

Next we estimated the total cost of gasoline-ethanol blends under the No RFS and 2022 baselines. We began with the production cost for each gasoline-ethanol blend and multiplied by the volume of each blend under the respective baseline.[1049] As shown in Tables 10.5.2-4 through 6, we estimate that total gasoline costs under the No RFS baseline range from $285-288 billion per year. As shown in Tables 10.5.2-7 through 9, we estimate that total gasoline costs under the 2022 baseline range from $285-286 billion per year.

Table 10.5.2-4: Gasoline Total Cost – 2023 (No RFS Baseline)

	E0	E10	E15	E85
Cost to Produce ($/gal)	$2.08	$2.04	$2.14	$2.29
Volume (mil gal)	2,128	138,850	0	0
Total Blend Cost ($bil)	$4.4	$283.3	$0.0	$0.0
Total Cost ($bil)	$287.7			

[1049] For purposes of the No RFS baseline analysis, we assumed that E0 volumes were held constant relative to the candidate volumes scenario and that there would not be any volumes of E15 or E85. E10 volumes were calculated by totaling ethanol production for each year from Table 2.1-1 and dividing by 0.1.

Table 10.5.2-5: Gasoline Total Cost – 2024 (No RFS Baseline)

	E0	E10	E15	E85
Cost to Produce ($/gal)	$2.08	$2.04	$2.13	$2.25
Volume (mil gal)	2,128	138,650	0	0
Total Blend Cost ($bil)	$4.4	$282.2	$0.0	$0.0
Total Cost ($bil)	$286.6			

Table 10.5.2-6: Gasoline Total Cost – 2025 (No RFS Baseline)

	E0	E10	E15	E85
Cost to Produce ($/gal)	$2.08	$2.03	$2.12	$2.22
Volume (mil gal)	2,128	138,280	0	0
Total Blend Cost ($bil)	$4.4	$280.9	$0.0	$0.0
Total Cost ($bil)	$285.3			

Table 10.5.2-7: Gasoline Total Cost – 2023 (2022 Baseline)

	E0	E10	E15	E85
Cost to Produce ($/gal)	$2.08	$2.04	$2.14	$2.29
RIN Cost ($/gal)	$0.16	$0.15	$0.15	$0.15
RIN Value ($/gal)	$0.00	-$0.13	-$0.19	-$0.95
Net Cost ($/gal)	$2.24	$2.06	$2.08	$1.38
Volume (mil gal)	2,128	135,972	440	339
Total Blend Cost ($bil)	$4.8	$280.0	$0.9	$0.5
Total Cost ($bil)	$286.1			

Table 10.5.2-8: Gasoline Total Cost – 2024 (2022 Baseline)

	E0	E10	E15	E85
Cost to Produce ($/gal)	$2.08	$2.04	$2.13	$2.25
RIN Cost ($/gal)	$0.16	$0.15	$0.14	$0.04
RIN Value ($/gal)	$0.00	-$0.13	-$0.19	-$0.95
Net Cost ($/gal)	$2.24	$2.05	$2.08	$1.35
Volume (mil gal)	2,128	135,972	440	339
Total Blend Cost ($bil)	$4.8	$279.3	$0.9	$0.5
Total Cost ($bil)	$285.5			

Table 10.5.2-9: Gasoline Total Cost – 2025 (2022 Baseline)

	E0	E10	E15	E85
Cost to Produce ($/gal)	$2.08	$2.03	$2.12	$2.22
RIN Cost ($/gal)	$0.16	$0.15	$0.14	$0.04
RIN Value ($/gal)	$0.00	-$0.13	-$0.19	-$0.95
Net Cost ($/gal)	$2.24	$2.05	$2.07	$1.32
Volume (mil gal)	2,128	135,972	440	339
Total Blend Cost ($bil)	$4.8	$278.8	$0.9	$0.4
Total Cost ($bil)	$284.9			

Finally, we calculated the fuel price impacts on gasoline by dividing the net cost of gasoline each year (i.e., the difference between the total cost of gasoline for the candidate volumes and the total cost of gasoline under the No RFS baseline) by the total volume of gasoline projected for each year. As shown in Table 10.5.2-10, we estimate that the fuel price impacts on gasoline under the No RFS baseline range from 0.6–3.1¢ per gallon. As shown in Table 10.5.2-11, we estimate that the fuel price impacts on gasoline under the 2022 baseline range from 1.7–3.3¢ per gallon.

Table 10.5.2-10: Gasoline Fuel Price Impacts (No RFS Baseline)

	2023	2024	2025
Total Cost (candidate volumes) ($/bil)	$288.5	$289.1	$289.5
Total Cost (No RFS) ($bil)	$287.7	$286.6	$285.3
Net Cost ($bil)	$0.8	$2.5	$4.2
Total Volume (bil gal)	139.7	139.5	139.1
Fuel Price Impact (¢/gal)	0.6¢	1.8¢	3.1¢

Table 10.5.2-11: Gasoline Fuel Price Impacts (2022 Baseline)

	2023	2024	2025
Total Cost (candidate volumes) ($/bil)	$288.5	$289.1	$289.5
Total Cost (2022) ($bil)	$286.1	$285.5	$284.9
Net Cost ($bil)	$2.4	$3.7	$4.6
Total Volume (bil gal)	139.7	139.5	139.1
Fuel Price Impact (¢/gal)	1.7¢	2.6¢	3.3¢

10.5.3 Estimated Fuel Price Impacts (Diesel)

In this section we have estimated the fuel price impacts of the 2023-2025 candidate volumes on diesel relative to the No RFS and 2022 baselines. First we estimated the total cost of diesel, biodiesel, and renewable diesel for the candidate volumes. We began with the production cost for each fuel,[1050] and then either added the RIN cost (for diesel) or subtracted the RIN value and tax credit (for biodiesel and renewable diesel) associated with each fuel, which gave us each fuel's net cost per gallon. We then multiplied each fuel's net cost by its volume from Preamble

[1050] Note that for purposes of this fuel price impacts assessment, we only looked at the cost to produce and distribute fuel to retail stations for sale to consumers (i.e., we subtracted out of the fuel economy cost for each fuel).

Table VII.C-1 (diesel) or Table 3.1-1 (biodiesel and renewable diesel). As shown in Tables 10.5.3-1 through 3, we estimate that total diesel costs would range from $138-139 billion per year.

Table 10.5.3-1: Diesel Total Cost – 2023 (Candidate Volumes)

		Biodiesel			Renewable Diesel		
	Diesel	**Corn**	**FOG**	**Soybean**	**Corn**	**FOG**	**Soybean**
Cost to Produce ($/gal)	$2.44	$4.60	$5.37	$6.31	$4.98	$5.80	$6.81
RIN Cost ($/gal)	$0.17	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RIN Value ($/gal)	$0.00	-$2.29	-$2.29	-$2.29	-$2.59	-$2.59	-$2.59
Tax Credit ($/gal)	$0.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00
Net Cost ($/gal)	$2.61	$1.31	$2.08	$3.02	$1.39	$2.21	$3.21
Volume (mil gal)	49,400	207	347	1,167	112	707	1,026
Total Blend Cost ($bil)	$129.0	$0.3	$0.7	$3.5	$0.2	$1.6	$3.3
Total Cost ($bil)	$138.6						

Table 10.5.3-2: Diesel Total Cost – 2024 (Candidate Volumes)

		Biodiesel			Renewable Diesel		
	Diesel	**Corn**	**FOG**	**Soybean**	**Corn**	**FOG**	**Soybean**
Cost to Produce ($/gal)	$2.44	$4.46	$5.77	$5.99	$4.82	$6.22	$6.45
RIN Cost ($/gal)	$0.18	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RIN Value ($/gal)	$0.00	-$2.29	-$2.29	-$2.29	-$2.59	-$2.59	-$2.59
Tax Credit ($/gal)	$0.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00
Net Cost ($/gal)	$2.63	$1.17	$2.49	$2.70	$1.22	$2.63	$2.86
Volume (mil gal)	49,250	207	347	1,133	118	760	1,026
Total Blend Cost ($bil)	$129.3	$0.2	$0.9	$3.1	$0.1	$2.0	$2.9
Total Cost ($bil)	$138.6						

Table 10.5.3-3: Diesel Total Cost – 2025 (Candidate Volumes)

		Biodiesel			Renewable Diesel		
	Diesel	**Corn**	**FOG**	**Soybean**	**Corn**	**FOG**	**Soybean**
Cost to Produce ($/gal)	$2.44	$4.33	$6.24	$5.66	$4.67	$6.72	$6.10
RIN Cost ($/gal)	$0.20	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RIN Value ($/gal)	$0.00	-$2.29	-$2.29	-$2.29	-$2.59	-$2.59	-$2.59
Tax Credit ($/gal)	$0.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00
Net Cost ($/gal)	$2.64	$1.05	$2.96	$2.38	$1.08	$3.12	$2.50
Volume (mil gal)	49,250	207	347	1,100	124	819	1,032
Total Blend Cost ($bil)	$130.0	$0.2	$1.0	$2.6	$0.1	$2.6	$2.6
Total Cost ($bil)	$139.1						

Next we estimated the total cost of diesel under the No RFS and 2022 baselines. We began with the production cost for each fuel and subtracted the tax credit (for biodiesel and renewable diesel) associated with each fuel, which gave us each fuel's net cost per gallon. We then multiplied each fuel's net cost by its volume under the respective baseline.[1051] As shown in Tables 10.5.3-4 through 6, we estimate that total diesel costs under the No RFS baseline to be $131 billion per year. As shown in Tables 10.5.3-7 through 9, we estimate that total diesel costs under the 2022 baseline range from $137–138 billion per year.

Table 10.5.3-4: Diesel Total Cost – 2023 (No RFS Baseline)

		Biodiesel			Renewable Diesel		
	Diesel	**Corn**	**FOG**	**Soybean**	**Corn**	**FOG**	**Soybean**
Cost to Produce ($/gal)	$2.44	$4.60	$5.37	$6.31	$4.98	$5.80	$6.81
Tax Credit ($/gal)	$0.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00
Net Cost ($/gal)	$2.44	$3.60	$4.37	$5.31	$3.98	$4.80	$5.81
Volume (mil gal)	51,919	86	147	199	34	438	0
Total Blend Cost ($bil)	$126.9	$0.3	$0.6	$1.1	$0.1	$2.1	$0.0
Total Cost ($bil)	$131.1						

Table 10.5.3-5: Diesel Total Cost – 2024 (No RFS Baseline)

		Biodiesel			Renewable Diesel		
	Diesel	**Corn**	**FOG**	**Soybean**	**Corn**	**FOG**	**Soybean**
Cost to Produce ($/gal)	$2.44	$4.46	$5.77	$5.99	$4.82	$6.22	$6.45
Tax Credit ($/gal)	$0.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00
Net Cost ($/gal)	$2.44	$3.46	$4.77	$4.99	$3.82	$5.22	$5.45
Volume (mil gal)	51,794	86	147	199	34	438	0
Total Blend Cost ($bil)	$126.5	$0.3	$0.7	$1.0	$0.1	$2.3	$0.0
Total Cost ($bil)	$131.0						

Table 10.5.3-6: Diesel Total Cost – 2025 (No RFS Baseline)

		Biodiesel			Renewable Diesel		
	Diesel	**Corn**	**FOG**	**Soybean**	**Corn**	**FOG**	**Soybean**
Cost to Produce ($/gal)	$2.44	$4.33	$6.24	$5.66	$4.67	$6.72	$6.10
Tax Credit ($/gal)	$0.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00
Net Cost ($/gal)	$2.44	$3.33	$5.24	$4.66	$3.67	$5.72	$5.10
Volume (mil gal)	51,831	86	147	199	34	438	0
Total Blend Cost ($bil)	$126.6	$0.3	$0.8	$0.9	$0.1	$2.5	$0.0
Total Cost ($bil)	$131.3						

[1051] For purposes of the No RFS baseline analysis, we assumed that total diesel energy demand was held constant relative to the candidate volumes scenario in order to calculate petroleum diesel fuel volumes.

Table 10.5.3-7: Diesel Total Cost – 2023 (2022 Baseline)

		Biodiesel			Renewable Diesel			
	Diesel	**Corn**	**FOG**	**Soybean**	**Corn**	**FOG**	**Soybean**	**Palm**
Cost to Produce ($/gal)	$2.44	$4.60	$5.37	$6.31	$4.98	$5.80	$6.81	$4.79
RIN Cost ($/gal)	$0.16	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RIN Value ($/gal)	$0.00	-$2.29	-$2.29	-$2.29	-$2.59	-$2.59	-$2.59	-$2.59
Tax Credit ($/gal)	$0.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00
Net Cost ($/gal)	$2.61	$1.31	$2.08	$3.02	$1.39	$2.21	$3.21	$1.20
Volume (mil gal)	49,312	205	358	1,204	101	644	1,008	155
Total Blend Cost ($bil)	$128.5	$0.3	$0.7	$3.6	$0.1	$1.4	$3.2	$0.2
Total Cost ($bil)	$138.2							

Table 10.5.3-8: Diesel Total Cost – 2024 (2022 Baseline)

		Biodiesel			Renewable Diesel			
	Diesel	**Corn**	**FOG**	**Soybean**	**Corn**	**FOG**	**Soybean**	**Palm**
Cost to Produce ($/gal)	$2.44	$4.46	$5.77	$5.99	$4.82	$6.22	$6.45	$4.60
RIN Cost ($/gal)	$0.16	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RIN Value ($/gal)	$0.00	-$2.29	-$2.29	-$2.29	-$2.59	-$2.59	-$2.59	-$2.59
Tax Credit ($/gal)	$0.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00
Net Cost ($/gal)	$2.61	$1.17	$2.49	$2.70	$1.22	$2.63	$2.86	$1.01
Volume (mil gal)	49,312	205	358	1,204	101	644	1,008	155
Total Blend Cost ($bil)	$128.5	$0.2	$0.9	$3.3	$0.1	$1.7	$2.9	$0.2
Total Cost ($bil)	$137.8							

Table 10.5.3-9: Diesel Total Cost – 2025 (2022 Baseline)

		Biodiesel			Renewable Diesel			
	Diesel	**Corn**	**FOG**	**Soybean**	**Corn**	**FOG**	**Soybean**	**Palm**
Cost to Produce ($/gal)	$2.44	$4.33	$6.24	$5.66	$4.67	$6.72	$6.10	$4.43
RIN Cost ($/gal)	$0.16	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RIN Value ($/gal)	$0.00	-$2.29	-$2.29	-$2.29	-$2.59	-$2.59	-$2.59	-$2.59
Tax Credit ($/gal)	$0.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00
Net Cost ($/gal)	$2.61	$1.05	$2.96	$2.38	$1.08	$3.12	$2.50	$0.84
Volume (mil gal)	49,312	205	358	1,204	101	644	1,008	155
Total Blend Cost ($bil)	$128.5	$0.2	$1.1	$2.9	$0.1	$2.0	$2.5	$0.1
Total Cost ($bil)	$137.4							

Finally, we calculated the fuel price impacts on diesel by dividing the net cost of diesel each year (i.e., the difference between the total cost of diesel for the candidate volumes and the total cost of diesel under the No RFS baseline) by the total volume of diesel, biodiesel, and renewable diesel projected for each year. As shown in Table 10.5.3-10, we estimate that the fuel price impacts on diesel under the No RFS baseline range from 14.1–14.9¢ per gallon. As shown in Table 10.5.3-11, we estimate that the fuel price impacts on diesel under the 2022 baseline range from 0.8–3.2¢ per gallon.

Table 10.5.3-10: Diesel Fuel Price Impacts (No RFS Baseline)

	2023	2024	2025
Total Cost (candidate volumes) ($/bil)	$138.6	$138.6	$139.1
Total Cost (No RFS) ($bil)	$131.1	$131.0	$131.3
Net Cost ($bil)	$7.5	$7.6	$7.9
Total Volume (bil gal)	53.0	52.8	52.9
Fuel Price Impact (¢/gal)	14.1¢	14.4¢	14.9¢

Table 10.5.3-11: Diesel Fuel Price Impacts (2022 Baseline)

	2023	2024	2025
Total Cost (candidate volumes) ($/bil)	$138.6	$138.6	$139.1
Total Cost (No RFS) ($bil)	$138.2	$137.8	$137.4
Net Cost ($bil)	$0.4	$0.8	$1.7
Total Volume (bil gal)	53.0	52.8	52.9
Fuel Price Impact (¢/gal)	0.8¢	1.5¢	3.2¢

10.5.4 Overall Net Fuel Price Impacts

In this section we have estimated the overall fuel price impacts of the candidate volumes relative to the No RFS and 2022 baselines by totaling the gasoline and diesel net costs and dividing by the total volume of gasoline, diesel, biodiesel, and renewable diesel projected for each year. As shown in Table 10.5.4-1, we estimate the overall fuel price impacts under the No RFS baseline range from 4.3–6.3¢ per gallon. As shown in Table 10.5.4-2, we estimate the overall fuel price impacts under the 2022 baseline range from 1.4–3.3¢ per gallon.

Table 10.5.4-1: Overall Fuel Price Impacts (No RFS Baseline)

	2023	2024	2025
Total Net Cost ($bil)	$8.3	$10.1	$12.1
Total Volume (bil gal)	192.7	192.3	192.0
Fuel Price Impact (¢/gal)	4.3¢	5.3¢	6.3¢

Table 10.5.4-2: Overall Fuel Price Impacts (2022 Baseline)

	2023	2024	2025
Total Net Cost ($bil)	$2.7	$4.4	$6.3
Total Volume (bil gal)	192.7	192.3	192.0
Fuel Price Impact (¢/gal)	1.4¢	2.3¢	3.3¢

10.5.5 Fuel Price Impacts of Alternative Scenarios

In previous years a number of stakeholders have raised concerns about the impact of high RIN prices—particularly D6 RINs—on the price of gasoline and diesel. Because the RFS program functions as a cross-subsidy—placing an obligation to acquire RINs on producers and importers of gasoline and diesel while at the same time providing for the generation of tradable credits (RINs) by producers and importers of renewable fuels—we would not expect that higher RIN prices would impact the overall cost of transportation fuel. EPA has regularly reviewed the available market data and has concluded that the RIN and fuels markets are operating as expected, and that higher RIN prices are not expected to result in higher costs for transportation fuel.[1052]

While we do not expect that higher RIN prices would result in an overall increase in the price of transportation fuel, they can have differing impacts on the price of fuel blends with different quantities of renewable fuel. In general, higher RIN prices reduce the price of fuel blends with higher proportions of renewable fuel and increase the price of fuel blends with lower proportions of renewable fuel.[1053] Further, because gasoline is generally blended with renewable fuel that generates D6 RINs (corn ethanol) and diesel is generally blended with renewable fuel that generates D4 RINs (biodiesel and renewable diesel), the impact of the RFS program on gasoline and diesel prices can vary depending on the relative prices of D6 and D4 RINs. Finally, as discussed in Chapter 1.9.2, because RIN obligations are placed on refiners and importers of gasoline and diesel, RINs generated for non-liquid transportation fuels can result in transferring money from the liquid fuels market to other markets. While these transfers do not increase the price of transportation fuel on the whole, they are expected to increase the price of liquid transportation fuels such as gasoline and diesel.

In this chapter we provide additional estimates of the impacts of the RFS program on fuel prices. The first scenario we consider is one in which the advanced biofuel volume requirement is increased without correspondingly increasing the total renewable fuel volume requirement such that the implied volume of conventional renewable fuel falls below the E10 blendwall. We refer to this alternative as the "Below the Blendwall" scenario. In this scenario the price of D6 RINs is expected to be significantly lower than the prices observed in recent years. We then consider the impact of increasing the cellulosic biofuel volume requirements to account for the generation of eRINs in 2024 and 2025 on the price of gasoline and diesel. Each of these scenarios, and the expected impact on RIN prices, is described in more detail below.

10.5.5.1 Below the Blendwall Alternative Scenario

The Below the Blendwall scenario is one in which EPA increases the advanced biofuel volume requirement without correspondingly increasing the total renewable fuel volume requirement such that the implied volume of conventional renewable fuel falls below the E10 blendwall. This scenario results in a higher advanced biofuel percentage standard for each year from 2023–2025, but the percent standards for the other categories of renewable fuel remain the same. To account for the impact of reducing the implied conventional biofuel volume below the E10 blendwall, we reduced the D6 RIN price in this scenario to $0.01. The prices for the other RIN types (D3, D4, and D5) are assumed to be the same in this scenario as in the assessment of the fuel price impacts of the candidate volumes. As a simplifying assumption, we have assumed that the same mix of renewable fuels would be used to meet the volume requirements in this alternative scenario as would be used to meet the candidate volumes. The required percent standards and RIN prices used for this scenario are shown in Table 10.5.5.1-1. The RIN cost and

[1052] EPA recently considered the available market data on the impact of RIN prices on the price of transportation fuel in the context of the June 2022 Denial of Petitions for RFS Small Refinery Exemptions.
[1053] See "A Preliminary Assessment of RIN Market Dynamics, RIN Prices, and Their Effects," memorandum by Dallas Burkholder, US EPA.

RIN value for petroleum fuels and fuel blends are shown in Tables 10.5.5.1-2 and 3. The calculations used to determine the values in these tables are identical to those used in Chapters 10.5.1 for the candidate volumes.

Table 10.5.5.1-1: Average RIN Prices and Percent Standards (Below the Blendwall Scenario)

RFS Standard	RIN Type	RIN Price	2022 Percentage Standards	2023 Proposed Percentage Standard	2024 Proposed Percentage Standard	2025 Proposed Percentage Standard
Cellulosic Biofuel (D3)	D3	$3.06	0.35%	0.41%	0.82%	1.23%
Biomass-Based Diesel (D4)	D4	$1.52	2.33%	2.54%	2.60%	2.67%
Other Advanced Biofuel[a] (D5)	D5	$1.54	0.48%	1.23%	1.24%	1.26%
Conventional Renewable Fuel[b] (D6)	D6	$0.01[c]	8.57%[d]	7.88%[e]	7.89%	7.89%

[a] Other advanced biofuel is not a fuel category for which a percentage standard is established, but is calculated by subtracting the cellulosic biofuel and biomass-based diesel standards from the advanced biofuel standard.
[b] Conventional renewable fuel is not a fuel category for which a percentage standard is established, but is calculated by subtracting the advanced biofuel standard from the total renewable fuel standard.
[c] For this scenario we assumed that the 2022 D6 RIN price (used for the 2022 baseline) remained at $1.28 (the average observed D6 RIN price from July 2021 – June 2022).
[d] Includes the 2022 total renewable fuel supplemental standard.
[e] Includes the 2023 total renewable fuel supplemental standard.

Table 10.5.5.1-2: Estimated RIN Costs for Petroleum Fuel for 2023-2025 (Below the Blendwall Scenario)

Year	RIN Cost ($/Gallon)
2022	$0.16
2023	$0.07
2024	$0.08
2025	$0.10

Table 10.5.5.1-3: Estimated RIN Values for Fuels (Below the Blendwall Scenario)

Fuel	2022 RIN Value ($/Gallon)	2023–2025 RIN Value ($/Gallon)
E10	$0.13	$0.00
E15	$0.19	$0.00
E85	$0.95	$0.01
Biodiesel	$2.29	$2.29
Renewable Diesel	$2.59	$2.59

We then estimated the fuel price impacts of the Below the Blendwall scenario on gasoline relative to the No RFS and 2022 baselines. First we estimated the total cost of gasoline-ethanol blends under the Below the Blendwall scenario. We began with the production cost for each fuel,[1054] added the RIN cost associated with the gasoline portion of the fuel, and then subtracted the RIN value associated with the ethanol portion of each fuel, which gave us each fuel's net cost per gallon. We then multiplied each fuel's net cost by its volume from Table 6.5.2-3. As shown in Tables 10.5.5.1-4 through 6, we estimate that total gasoline costs would range from $294–295 billion per year.

Table 10.5.5.1-4: Gasoline Total Cost – 2023 (Below the Blendwall Scenario)

	E0	E10	E15	E85
Cost to Produce ($/gal)	$2.08	$2.04	$2.14	$2.29
RIN Cost ($/gal)	$0.07	$0.06	$0.06	$0.02
RIN Value ($/gal)	$0.00	$0.00	$0.00	-$0.01
Net Cost ($/gal)	$2.15	$2.10	$2.19	$2.30
Volume (mil gal)	2,128	136,643	561	353
Total Blend Cost ($bil)	$4.6	$287.4	$1.2	$0.8
Total Cost ($bil)	$294.0			

Table 10.5.5.1-5: Gasoline Total Cost – 2024 (Below the Blendwall Scenario)

	E0	E10	E15	E85
Cost to Produce ($/gal)	$2.08	$2.04	$2.13	$2.25
RIN Cost ($/gal)	$0.08	$0.08	$0.07	$0.02
RIN Value ($/gal)	$0.00	$0.00	$0.00	-$0.01
Net Cost ($/gal)	$2.16	$2.11	$2.20	$2.27
Volume (mil gal)	2,128	136,323	671	367
Total Blend Cost ($bil)	$4.6	$287.7	$1.5	$0.8
Total Cost ($bil)	$294.6			

Table 10.5.5.1-6: Gasoline Total Cost – 2025 (Below the Blendwall Scenario)

	E0	E10	E15	E85
Cost to Produce ($/gal)	$2.08	$2.03	$2.12	$2.22
RIN Cost ($/gal)	$0.10	$0.09	$0.08	$0.03
RIN Value ($/gal)	$0.00	$0.00	$0.00	-$0.01
Net Cost ($/gal)	$2.17	$2.12	$2.20	$2.24
Volume (mil gal)	2,128	135,871	756	381
Total Blend Cost ($bil)	$4.6	$287.9	$1.7	$0.9
Total Cost ($bil)	$295.0			

We then compared the estimated total cost of gasoline in each year to the No RFS and 2022 baselines. The total cost of gasoline for each baseline and year can be found in Tables

[1054] Note that for purposes of this fuel price impacts assessment, we only looked at the cost to produce and distribute fuel to retail stations for sale to consumers (i.e., we subtracted out of the fuel economy cost for each fuel).

10.5.2-4 through 9. Finally, we calculated the fuel price impacts on gasoline by dividing the net cost of gasoline each year (i.e., the difference between the total cost of gasoline for the Below the Blendwall scenario and the total cost of gasoline under the No RFS and 2022 baselines) by the total volume of gasoline projected for each year. As shown in Table 10.5.5.1-7, we estimate that the fuel price impacts on gasoline under the No RFS baseline range from 4.5–7.0¢ per gallon. As shown in Table 10.5.5.1-8, we estimate that the fuel price impacts on gasoline under the 2022 baseline range from 5.6–7.3¢ per gallon.

Table 10.5.5.1-7: Gasoline Fuel Price Impacts (No RFS Baseline)

	2023	2024	2025
Total Cost (candidate volumes) ($/bil)	$294.0	$294.6	$295.0
Total Cost (No RFS) ($bil)	$287.7	$286.6	$285.3
Net Cost ($bil)	$6.3	$8.0	$9.7
Total Volume (bil gal)	139.7	139.5	139.1
Fuel Price Impact (¢/gal)	4.5¢	5.7¢	7.0¢

Table 10.5.5.1-8: Gasoline Fuel Price Impacts (2022 Baseline)

	2023	2024	2025
Total Cost (candidate volumes) ($/bil)	$294.0	$294.6	$295.0
Total Cost (2022) ($bil)	$286.1	$285.5	$284.9
Net Cost ($bil)	$7.8	$9.1	$10.1
Total Volume (bil gal)	139.7	139.5	139.1
Fuel Price Impact (¢/gal)	5.6¢	6.6¢	7.3¢

We next estimated the fuel price impacts of the Below the Blendwall scenario on diesel relative to the No RFS and 2022 baselines. Similar to our calculations for gasoline, we first estimated the total cost of diesel, biodiesel, and renewable diesel under the Below the Blendwall scenario. We began with the production cost for each fuel,[1055] and then either added the RIN cost (for diesel) or subtracted the RIN value and tax credit (for biodiesel and renewable diesel) associated with each fuel, which gave us each fuel's net cost per gallon. We then multiplied each fuel's net cost by its volume from Preamble Table VII.C-1 (diesel) or Table 3.1-1 (biodiesel and renewable diesel). As shown in Tables 10.5.5.1-9 through 11, we estimate that total diesel costs would be $134 billion per year.

[1055] Note that for purposes of this fuel price impacts assessment, we only looked at the cost to produce and distribute fuel to retail stations for sale to consumers (i.e., we subtracted out of the fuel economy cost for each fuel).

Table 10.5.5.1-9: Diesel Total Cost – 2023 (Below the Blendwall Scenario)

		Biodiesel			Renewable Diesel		
	Diesel	**Corn**	**FOG**	**Soybean**	**Corn**	**FOG**	**Soybean**
Cost to Produce ($/gal)	$2.44	$4.60	$5.37	$6.31	$4.98	$5.80	$6.81
RIN Cost ($/gal)	$0.07	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RIN Value ($/gal)	$0.00	-$2.29	-$2.29	-$2.29	-$2.59	-$2.59	-$2.59
Tax Credit ($/gal)	$0.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00
Net Cost ($/gal)	$2.51	$1.31	$2.08	$3.02	$1.39	$2.21	$3.21
Volume (mil gal)	49,400	207	347	1,167	112	707	1,026
Total Blend Cost ($bil)	$124.2	$0.3	$0.7	$3.5	$0.2	$1.6	$3.3
Total Cost ($bil)	$133.7						

Table 10.5.5.1-10: Diesel Total Cost – 2024 (Below the Blendwall Scenario)

		Biodiesel			Renewable Diesel		
	Diesel	**Corn**	**FOG**	**Soybean**	**Corn**	**FOG**	**Soybean**
Cost to Produce ($/gal)	$2.44	$4.46	$5.77	$5.99	$4.82	$6.22	$6.45
RIN Cost ($/gal)	$0.08	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RIN Value ($/gal)	$0.00	-$2.29	-$2.29	-$2.29	-$2.59	-$2.59	-$2.59
Tax Credit ($/gal)	$0.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00
Net Cost ($/gal)	$2.53	$1.17	$2.49	$2.70	$1.22	$2.63	$2.86
Volume (mil gal)	49,250	207	347	1,133	118	760	1,026
Total Blend Cost ($bil)	$124.5	$0.2	$0.9	$3.1	$0.1	$2.0	$2.9
Total Cost ($bil)	$133.7						

Table 10.5.5.1-11: Diesel Total Cost – 2025 (Below the Blendwall Scenario)

		Biodiesel			Renewable Diesel		
	Diesel	**Corn**	**FOG**	**Soybean**	**Corn**	**FOG**	**Soybean**
Cost to Produce ($/gal)	$2.44	$4.33	$6.24	$5.66	$4.67	$6.72	$6.10
RIN Cost ($/gal)	$0.10	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RIN Value ($/gal)	$0.00	-$2.29	-$2.29	-$2.29	-$2.59	-$2.59	-$2.59
Tax Credit ($/gal)	$0.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00
Net Cost ($/gal)	$2.54	$1.05	$2.96	$2.38	$1.08	$3.12	$2.50
Volume (mil gal)	49,250	207	347	1,100	124	819	1,032
Total Blend Cost ($bil)	$125.2	$0.2	$1.0	$2.6	$0.1	$2.6	$2.6
Total Cost ($bil)	$134.3						

We then compared the estimated total cost of diesel in each year to the No RFS and 2022 baselines. The total cost of diesel for each baseline and year can be found in Tables 10.5.3-4 through 9. Finally, we calculated the fuel price impacts on diesel by dividing the net cost of diesel each year (i.e., the difference between the total cost of diesel for the Below the Blendwall scenario and the total cost of diesel under the No RFS and 2022 baselines) by the total volume of diesel, biodiesel, and renewable diesel projected for each year. As shown in Table 10.5.5.1-12, we estimate that the fuel price impacts on diesel under the No RFS baseline range from 5.0–5.8¢

per gallon. As shown in Table 10.5.5.1-13, we estimate that the fuel price impacts on diesel under the 2022 baseline range from (9.6)–(7.2)¢ per gallon.

Table 10.5.5.1-12: Diesel Fuel Price Impacts (No RFS Baseline)

	2023	2024	2025
Total Cost (candidate volumes) ($/bil)	$133.7	$133.7	$134.3
Total Cost (No RFS) ($bil)	$131.1	$131.0	$131.3
Net Cost ($bil)	$2.6	$2.8	$3.1
Total Volume (bil gal)	53.0	52.8	52.9
Fuel Price Impact (¢/gal)	5.0¢	5.3¢	5.8¢

Table 10.5.5.1-13: Diesel Fuel Price Impacts (2022 Baseline)

	2023	2024	2025
Total Cost (candidate volumes) ($/bil)	$133.7	$133.7	$134.3
Total Cost (No RFS) ($bil)	$138.2	$137.8	$137.4
Net Cost ($bil)	-$5.1	-$4.7	-$3.8
Total Volume (bil gal)	53.0	52.8	52.9
Fuel Price Impact (¢/gal)	-9.6¢	-8.9¢	-7.2¢

We estimated the overall fuel price impacts of the Below the Blendwall scenario relative to the No RFS and 2022 baselines by totaling the gasoline and diesel net costs and dividing by the total volume of gasoline, diesel, biodiesel, and renewable diesel projected for each year. As shown in Table 10.5.5.1-14, we estimate the overall fuel price impacts under the No RFS baseline range from 4.6–6.7¢ per gallon. As shown in Table 10.5.5.1-15, we estimate the overall fuel price impacts under the 2022 baseline range from 1.4–3.3¢ per gallon. We note that the overall fuel price impacts of the Below the Blendwall scenario are similar to those of the candidate volumes relative to the No RFS baseline and that the cost impacts of these two scenarios are identical relative to the 2022 baseline. The relative impacts on gasoline and diesel, however, are significantly different, with higher price impacts for gasoline and lower price impacts for diesel under the Below the Blendwall scenario.

Table 10.5.5.1-14: Overall Fuel Price Impacts (No RFS Baseline)

	2023	2024	2025
Total Net Cost ($bil)	$8.9	$10.8	$12.8
Total Volume (bil gal)	192.7	192.3	192.0
Fuel Price Impact (¢/gal)	4.6¢	5.6¢	6.7¢

Table 10.5.5.1-15: Overall Fuel Price Impacts (2022 Baseline)

	2023	2024	2025
Total Net Cost ($bil)	$2.7	$4.4	$6.3
Total Volume (bil gal)	192.7	192.3	192.0
Fuel Price Impact (¢/gal)	1.4¢	2.3¢	3.3¢

10.5.5.2 Impact of eRINs on Fuel Prices

In this chapter, we consider the impact of the proposed eRIN volumes on the price of gasoline and diesel, which we believe may be of interest for at least two reasons. First, in this action we are proposing a regulatory structure to allow for the generation of RINs for electricity used as transportation fuel for the first time. This would enable the generation of RINs for a new fuel type that has the potential to generate significant quantities of RINs through 2025 and in future years. Second, while the value of RINs generated for liquid renewable fuel (e.g., ethanol, biodiesel, and renewable diesel) represents transfers within the liquid fuel pool and does not increase the total price of liquid transportation fuel (e.g., gasoline and diesel), the value of eRINs represents transfers from the liquid fuel pool to other markets, and thus increases the total price of liquid transportation fuel.

The mechanism through which eRIN volume requirements are expected to impact the price of gasoline and diesel is through their contribution to the total RIN obligation for each gallon of gasoline or diesel refined or imported into the U.S. While there is not a separate eRIN volume obligation, eRINs are expected to represent over half of the available cellulosic RINs by 2025. We can therefore estimate the impact of the eRIN volume requirement (technically the portion of the cellulosic biofuel volume requirement expected to be met with eRINs) by considering the volume obligation expected to be met with eRINs and the projected cellulosic RIN price in each year. The resulting expected fuel price impact on gasoline and diesel is shown in Table 10.5.5.2-1. Because the same volume obligations apply to both gasoline and diesel, and the fuel price impact of eRINs is due to its contribution to the volume obligations, the expected price impact is the same for both gasoline and diesel. Further, because no eRINs would be generated or required to be used under either the No RFS or 2022 baseline, the expected fuel price impact of eRINs is the same under either baseline.

Table 10.5.5.2-1: Projected Impact of eRINs on the Price of Gasoline and Diesel

	2023	2024	2025
eRIN Volume (mil RINs)	0	600	1,200
Cellulosic (D3) RIN Price ($/RIN)	$3.06	$3.06	$3.06
Total eRIN Price Impact ($bil)	$0.00	$1.84	$3.67
Gasoline and Diesel Volume (bil gal)[a]	192.7	192.3	192.0
eRIN Price Impact (¢/gal)	0.0¢	1.0¢	1.9¢

[a] Sum of the projected consumption of all gasoline/ethanol blends (from Table 6.5.2-3), diesel (from Preamble Table VII.C-1), and biodiesel and renewable diesel (from Table 3.1-1).

10.5.6 Cost to Transport Goods

In this chapter we consider the impact of the use of renewable fuels on the cost to transport goods. Since most goods being transported utilize diesel fuel powered trucks (as opposed to gasoline or natural gas vehicles), we focus on the impacts on diesel fuel prices. Reviewing the price estimates in Table 10.5.4-1, the projected price increase for diesel fuel relative to the No RFS baseline ranged from 14.1¢ per gallon in 2023 to 14.9¢ per gallon in 2025. As a worst case scenario, we will use the projected diesel fuel price increase of 14.9¢ per gallon for estimating the impact on the cost to transport goods.

The impact of fuel price increases on the price of goods is based upon a study conducted by USDA. USDA analyzed the impact of fuel prices on the wholesale price of produce from 2000 to 2009 when fuel prices ramped up because crude oil prices increased from an average of $30 per barrel to over $90 per barrel.[1056] Their study found that a 100% increase in fuel prices resulted in a 25% increase in produce prices. Assuming a baseline diesel fuel retail price of $2.55/gal in 2025 as summarized in Table 10.2.2-1 and adding 60¢ per gallon state and federal taxes to it, the projected 14.9¢ per gallon increase in diesel fuel price amounts to a 4.7 percent increase in diesel fuel prices. Applying the 25% ratio from the USDA study would indicate that the 2025 candidate volumes incremental to the No RFS baseline would then increase the wholesale price of produce by about 1.18%. If produce being transported by a diesel truck costs $3 per pound, the increase in that products' price due to the projected impact of the candidate volumes would be $0.035 per pound.[1057] Transport of food by other means such as rail or barge would be expected to impact food prices less than transport by truck since rail and barge transport are both more efficient and fuel costs would likely have a lower impact those modes of transportation costs. This estimate of the impact on food prices is only an order of magnitude type estimate since impacts on food prices vary greatly depending on the distance that the particular food travels by truck.

[1056] Volpe, Richard; How Transportation Costs Affect Fresh Fruit and Vegetable Prices; United States Department of Agriculture; November 2013.
[1057] Comparing Prices on Groceries; May 4, 2021: http://www.coupons.com/thegoodstuff/comparing-prices-on-groceries

Chapter 11: Screening Analysis

11.1 Summary

This chapter discusses EPA's screening analysis evaluating the potential impacts of the RFS standards for 2023, 2024, and 2025 on small entities. The Regulatory Flexibility Act (RFA), as amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities (referred to as a "No SISNOSE finding"). Pursuant to this requirement, EPA has prepared a screening analysis for this rule.

We conducted the screening analyses by looking at the potential impacts on small entities and compared the cost-to-sales ratio to a threshold of 1%.[1058] Specifically, we compared obligated parties' cost of compliance (whether they acquire RINs by purchasing renewable fuels with attached RINs and blending these fuels into transportation fuel or by purchasing separated RINs) with the ability for the obligated parties to recover these compliance costs through higher prices for the gasoline and diesel they sell with what would be expected in the absence of the RFS program. Based on our recent analysis of the data, we have determined that all obligated parties—including small refiners—fully recover the costs of RFS compliance through higher sales prices on gasoline and diesel.[1059] Given this, the cost-to-sales ratio of this rule is less than 1%. Therefore, EPA finds that these standards would not have a significant economic impact on a substantial number of small entities.

11.2 Background

11.2.1 Overview of the Regulatory Flexibility Act (RFA)

The RFA was amended by SBREFA to ensure that concerns regarding small entities are adequately considered during the development of new regulations that affect those entities. The RFA requires us to carefully consider the economic impacts that our rules may have on small entities. The elements of the initial regulatory flexibility analysis accompanying a proposed rule are set forth in 5 U.S.C. § 603, while those of the final regulatory flexibility analysis accompanying a final rule are set forth in section 604. However, section 605(b) of the statute provides that EPA need not conduct the section 603 or 604 analyses if we certify that the rule will not have a significant economic impact on a substantial number of small entities.

[1058] A cost-to-sales ratio of 1% represents a typical agency threshold for determining the significance of the economic impact on small entities. See "Final Guidance for EPA Rulewriters: Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act," November 2006.
[1059] See "April 2022 Denial of Petitions for RFS Small Refinery Exemptions," EPA-420-R-22-005, April 2022. See also "June 2022 Denial of Petitions for RFS Small Refinery Exemptions," EPA-420-R-22-011, June 2022.

11.2.2 Need for the Rulemaking and Rulemaking Objectives

A discussion on the need for and objectives of this action is located in Preamble Section I. CAA section 211(o) requires EPA to promulgate regulations implementing the RFS program, and to annually establish renewable fuel standards that are used by obligated parties to determine their individual RVOs.

11.2.3 Definition and Description of Small Entities

Small entities include small businesses, small organizations, and small governmental jurisdictions. For the purposes of assessing the impacts of a rule on small entities, a small entity is defined as: (1) a small business according to the Small Business Administration's (SBA) size standards; (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; or (3) a small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field.

Small businesses (as well as large businesses) would be regulated by this rule, but not small governmental jurisdictions or small organizations as described above. As set by SBA, the categories of small entities that would potentially be directly affected by this rulemaking are described in Table 11.2.3-1.

Table 11.2.3-1: Small Business Definitions

Industry	Defined as small entity by SBA if less than or equal to:	NAICS[a] code
Gasoline and diesel refiners	1,500 employees[b]	324110

[a] North American Industrial Classification System.

[b] EPA has included in past fuels rulemakings a provision that, in order to qualify for small refiner flexibilities, a refiner must also produce no greater than 155,000 barrels per calendar day (bpcd) crude capacity. See 40 CFR 80.1442(a).

EPA used the criteria for small entities developed by SBA under the North American Industry Classification System (NAICS) as a guide. Information about the characteristics of refiners comes from sources including EIA, oil industry literature, and previous rules that have affected the refining industry. In addition, EPA found employment information for companies meeting the SBA definition of "small entity" using the business information database Hoover's Inc. (a subsidiary of Dun & Bradstreet). These refiners fall under the Petroleum Refineries category, 324110, as defined by NAICS.

Small entities that would be subject to this rulemaking include domestic refiners that produce gasoline and/or diesel. Based on 2022 EIA refinery data,[1060] EPA believes that there are about 35-40 refiners of gasoline and diesel subject to the RFS regulations. Of these, EPA believes that there are currently 8 refiners (owning 12 refineries) producing gasoline and/or diesel that meet the small entity definition of having 1,500 employees or fewer.

[1060] Data available at https://www.eia.gov/petroleum/refinerycapacity/archive/2022/refcap2022.php.

11.2.4 Reporting, Recordkeeping, and Other Compliance Requirements

Registration, reporting, and recordkeeping are necessary to track compliance with the RFS standards and transactions involving RINs. However, these requirements are already in place under the existing RFS regulations.[1061] While EPA is making revisions to the RFS requirements in this action, we do not anticipate that there will be any significant cost on directly regulated small entities.

11.3 Screening Analysis Approach

We believe the most appropriate way to consider the impacts of the 2023–2025 RFS standards on obligated parties is to compare their cost of compliance with the ability for the obligated parties to recover these compliance costs through the higher prices for the gasoline and diesel they sell that result from the market-wide impact of the RFS program. EPA has determined that while there is a cost to all obligated parties to acquire RINs (including small refiners), obligated parties recover that cost through the higher sales prices they receive for the gasoline and diesel they sell due to the market-wide impact of the RFS standards on these products.[1062] EPA has examined available market data and concluded that the costs of compliance with the RFS program are being passed downstream, as current wholesale gasoline and diesel prices enable obligated parties to recover the cost of the RINs.[1063] When viewed in light of this data, there is no net cost of compliance with the RFS standards (cost of compliance with the RFS standards minus the increased revenue due to higher gasoline and diesel prices that result from implementing the RFS program) to obligated parities, including small refiners. This is true whether obligated parties acquire RINs by purchasing renewable fuels with attached RINs or by purchasing separated RINs.

11.4 Cost-to-Sales Ratio Result

The final step in our methodology is to compare the total estimated costs to relevant total estimated revenue from the sales of gasoline and diesel in the U.S. in 2023–2025. Since the RFS standards are proportional to the volume of gasoline and diesel produced by each obligated party, all obligated parties (including small refiners) are expected to experience costs (and recover those costs) to comply with the RFS standards that are proportional to their sales volumes. As discussed in Chapter 11.3, all obligated parties—including small refiners—recover their RFS compliance costs and thus they have no net cost of compliance. Therefore, the cost-to-sales ratio for all small refiners is 0%.

[1061] Prior to issuing our 2009 proposal for the general RFS regulatory program regulations required to implement the amendments enacted pursuant to EISA, we analyzed the potential impacts on small entities of implementing the full RFS program through 2022 and convened a Small Business Advocacy Review Panel (SBAR Panel) to assist us in this evaluation. This information is located in the RFS2 rulemaking docket (Docket ID No. EPA-HQ-OAR-2005-0161).

[1062] For a further discussion of the ability of obligated parties (including small refiners) to recover the cost of RINs, see "April 2022 Denial of Petitions for RFS Small Refinery Exemption," EPA-420-R-22-005, April 2022 and "June 2022 Denial of Petitions for RFS Small Refinery Exemption," EPA-420-R-22-011, June 2022.

[1063] Id.

11.5 Conclusion

Based on our outreach, fact-finding, and analysis of the potential impacts of this rule on small businesses, we have concluded that there is no net cost to small refiners resulting from the RFS program. Since obligated parties have been shown to recover their RFS compliance costs through the resulting higher market prices for their petroleum products, there are no net costs of the rule on small businesses, resulting in a cost-to-sales ratio of 0.00%.