Renewable Fuel Standard (RFS) Program: Standards for 2023–2025 and Other Changes

Regulatory Impact Analysis

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

This technical report does not necessarily represent final EPA decisions or positions. It is intended to present technical analysis of issues using data that are currently available. The purpose in the release of such reports is to facilitate the exchange of technical information and to inform the public of technical developments.

United States
Environmental Protection
Agency

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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, through 2022 EPA must also translate them into percentage standards that obligated parties then use to determine the compliance obligations that they must meet every year. As discussed in Preamble Section VII, we are continuing to use percentage standards as the implementing mechanism for 2023–2025.

In this action we are establishing the applicable volume targets for all four categories of renewable fuel for the years 2023, 2024, and 2025, as well as establishing 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 establishing 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 Regulatory Impact Analysis (RIA) supports our rulemaking in several ways. First, this RIA 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 support memoranda to the docket. Second, this RIA supports the 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 final volumes in this rule, including both quantified and unquantified impacts. Tables ES-2 and 3 contain more detail on the annual costs and energy security benefits respectively. 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 RIA 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 Final 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	$513 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	$23.8 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.).

Table ES-2: Fuel Costs of the 2023-2025 Volumes (2022 dollars, millions)[a]

Year	Discount Rate		
	0%	3%	7%
2023			
Excluding Supplemental Standard	$8,110	$8,110	$8,110
Including Supplemental Standard	$8,738	$8,738	$8,738
2024	$7,352	$7,138	$6,871
2025	$8,455	$7,970	$7,385
Cumulative Discounted Costs			
Excluding Supplemental Standard	$23,917	$23,218	$22,366
Including Supplemental Standard	$24,545	$23,846	$22,994

[a] These costs represent the costs of producing and using biofuels relative to the petroleum fuels they displace. They do not include other factors, such as the potential impacts on soil and water quality or potential GHG reduction benefits.

Table ES-3: Energy Security Benefits of the 2023-2025 Volumes (2022 dollars, millions)

Year	Discount Rate		
	0%	3%	7%
2023			
Excluding Supplemental Standard	$180	$180	$180
Including Supplemental Standard	$192	$192	$192
2024	$161	$156	$150
2025	$175	$165	$153
Cumulative Discounted Benefits			
Excluding Supplemental Standard	$515	$501	$483
Including Supplemental Standard	$528	$513	$495

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: Candidate Volumes and Volume Changes
This chapter identifies the specific biofuel types and associated feedstocks that are projected to be used to meet the final volume requirements.

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

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 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 final 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
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 …." CAA section 211(o)(2)(B)(ii). 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 the Energy Policy Act of 2005 (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 the 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 the EPAct. While the 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,

[1] "Timeline - A Very Short History of MTBE in the US," available at https://www.icis.com/explore/resources/news/2006/07/05/1070674/timeline-a-very-short-history-of-mtbe-in-the-us.

[2] "Clinton-Gore Administration Acts To Eliminate MTBE, Boost Ethanol," available at https://www.epa.gov/archive/epapages/newsroom_archive/newsreleases/2054b28bf155afaa852568a80066c805.html

refiners now had increased disincentives to continue using MTBE after 2005. In addition, although the oxygen requirement for RFG was removed in the EPAct, the emission standards for 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 for the RFS program were amended by the Energy Independence and Security Act of 2007 (EISA), replacing the single total renewable fuel standard with four nested standards (cellulosic biofuel, BBD, advanced biofuel, and total renewable fuel). EPA implemented these changes through what became known as 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: 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 document, "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 "reset" authority at CAA section 211(o)(7)(F) was also introduced by EISA. It requires EPA, after 2015, to modify the volumes in the tables in CAA section 211(o)(2)(B) in compliance with CAA section 211(o)(2)(B)(ii) if EPA either: waives 20 percent of the volumes in any table in CAA section 211(o)(2)(B) for two consecutive years or waives 50 percent of the volumes in one year.

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

[7] CAA section 211(o)(7).
[8] Obligated parties are producers and importers of gasoline and diesel. See 40 CFR 80.1406.

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 only once, for the 2016 compliance year, based on a finding of inadequate domestic supply.[9] However, the D.C. Circuit vacated EPA's use of this waiver authority in *Americans for Clean Energy v. EPA*, 864 F.3d 691 (D.C. Cir. 2017) ("*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 completing 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 in any given year. The first is that the percentage standards are based on projected volumes of non-renewable gasoline and diesel consumption provided by the U.S. Energy Information Administration (EIA), which typically deviate to some degree from what actually occurs. For compliance years 2007–2022, the EIA source for such projections was the Short Term Energy Outlook (STEO);[11] for compliance years 2023 and later, the EIA source for such projections is the Annual Energy Outlook (AEO).

Since the first percentage standard was applied in 2007, this forecast has both over- and under-predicted actual consumption. 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, 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, 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."

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[9] 80 FR 77420 (December 14, 2015).
[10] 87 FR 36900 (July 1, 2022).
[11] CAA section 211(o)(3)(A).
[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.

Obligated parties have the flexibility to use RINs representing renewable fuel produced in the previous year, often called "carryover RINs," to demonstrate compliance rather than by using RINs representing current year renewable fuel production.[13,14] The nationwide total number of carryover RINs grew dramatically in the early years of the RFS program, and obligated parties have at times drawn down the total number of carryover RINs 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 carryover RINs to make up the shortfall. See Chapter 1.10 for further discussion of carryover RINs.

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.[15] 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.[16] 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 Low Carbon Fuel Standard (LCFS) programs.

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 section.

Finally, exemptions given to small refineries in past years 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. Small refineries may request these exemptions 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 compliance year, EPA's standard-setting process only

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[13] This flexibility is a function of the two-year life of RINs as discussed more fully in Chapter 1.9.

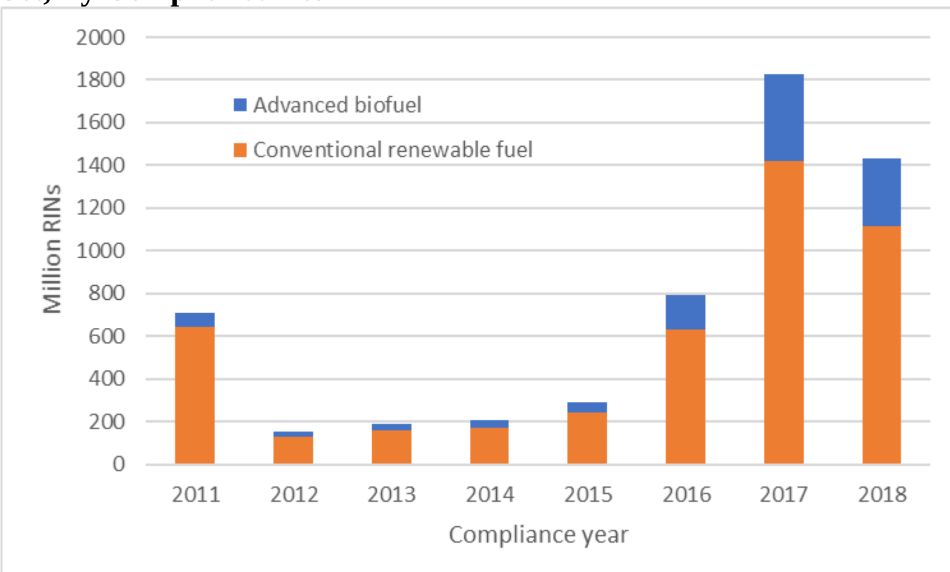
[14] The use of previous-year RINs for compliance with the applicable standards is limited to 20% of an obligated party's Renewable Volume Obligation (RVO). See 40 CFR 80.1427(a)(5).

[15] 80 FR 77506 (December 14, 2015).

[16] 80 FR 77457 (December 14, 2015).

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.[17] 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.

Figure 1.2-1: Volume of SREs Granted After the Applicable Percentage Standards Were Set, By Compliance Year[a]



[a] No SREs have been granted for years after RFS 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. However, as a result of subsequent EPA action, these small refineries were required to resubmit their RFS annual compliance reports with zero deficit carryforward and no additional RIN retirements. See "April 2022 Alternative RFS Compliance Demonstration Approach for Certain Small Refineries," EPA-420-R-22-006, April 2022; see also "June 2022 Alternative RFS Compliance Demonstration Approach for Certain Small Refineries," EPA-420-R-22-012, June 2022.

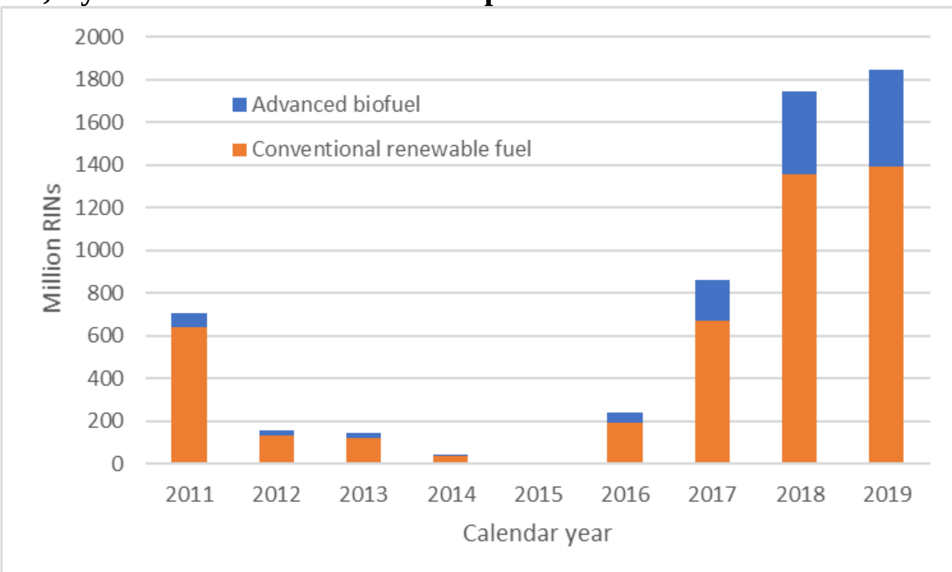
As shown in Figure 1.2-1, SREs granted after the standards were set varied significantly by compliance year. However, these SREs did not necessarily translate into an equivalent reduction in actual consumption of renewable fuel. Other factors also played a role in determining whether and when actual consumption was affected by SREs.[18] 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.

[17] 75 FR 76805 (December 9, 2010).

[18] Another action that decoupled actual consumption from a specific year's RFS standards is the Alternative RIN Retirement Schedule, which provides additional time and opens a broader range of RIN vintages for small refineries to comply with their 2020 RFS obligations through a series of quarterly retirement deadlines through February 1, 2024. 87 FR 54158 (September 2, 2022).

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 the following years, rather than in the RFS compliance year to which they applied, as shown in Figure 1.2-2. This was often due to EPA granting the SREs after the compliance year had passed.

Figure 1.2-2: 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, as a result of subsequent EPA action, these small refineries were required to resubmit their RFS annual compliance reports with zero deficit carryforward and no additional RIN retirements. See "April 2022 Alternative RFS Compliance Demonstration Approach for Certain Small Refineries," EPA-420-R-22-006, April 2022; see also "June 2022 Alternative RFS Compliance Demonstration Approach for Certain Small Refineries," EPA-420-R-22-012, June 2022.

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 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 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 number of carryover RINs may have increased. Finally, as discussed above, higher-than-projected gasoline and diesel demand could offset the effect of SREs to some degree.

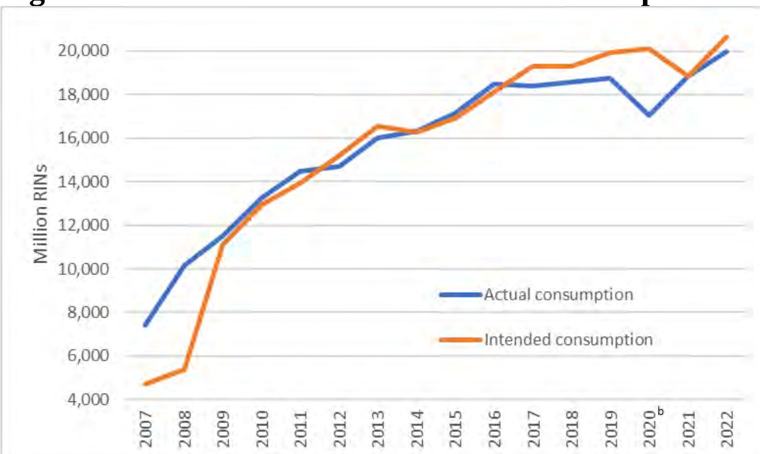
In the final rule that established the original 2020 standards, EPA revised the RFS regulations to account for a projection of exempt small refinery volumes, increasing the 2020 percentage standards applicable to non-exempt refineries.[19] Given that EPA subsequently made a decision not to exempt any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

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

the original 2020 percentage standards were applicable to a larger volume of gasoline and diesel, effectively increasing the renewable fuel requirements.[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.

Figure 1.2-3: 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 2007–2022 (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 251 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 2022. 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.

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[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 (July 1, 2022).

Economic factors are coupled with the use of carryover RINs for compliance, the number of carryover RINs available, 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.

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.

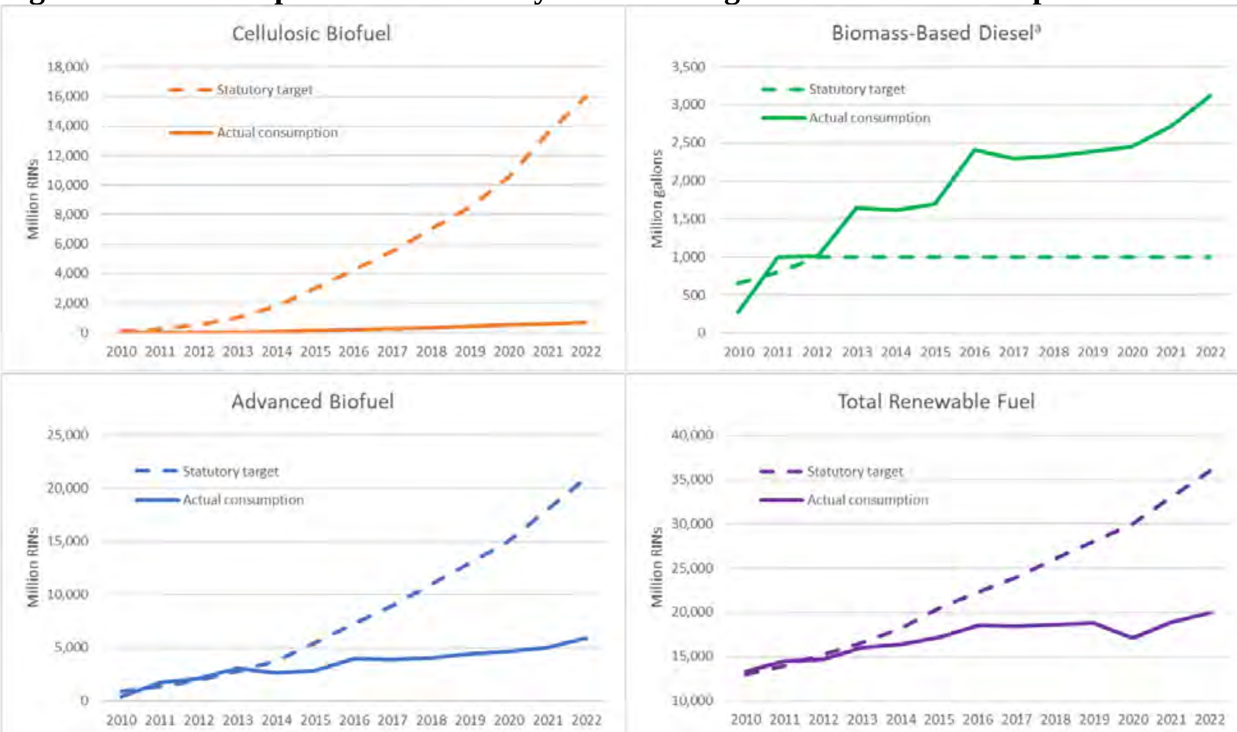
This section highlights the aspirational nature of the statutory volume targets, especially for cellulosic biofuel and its carry-through impact on advanced biofuel and total renewable fuel. This section also highlights the difficulty in projecting the ability of the market to meet applicable standards 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

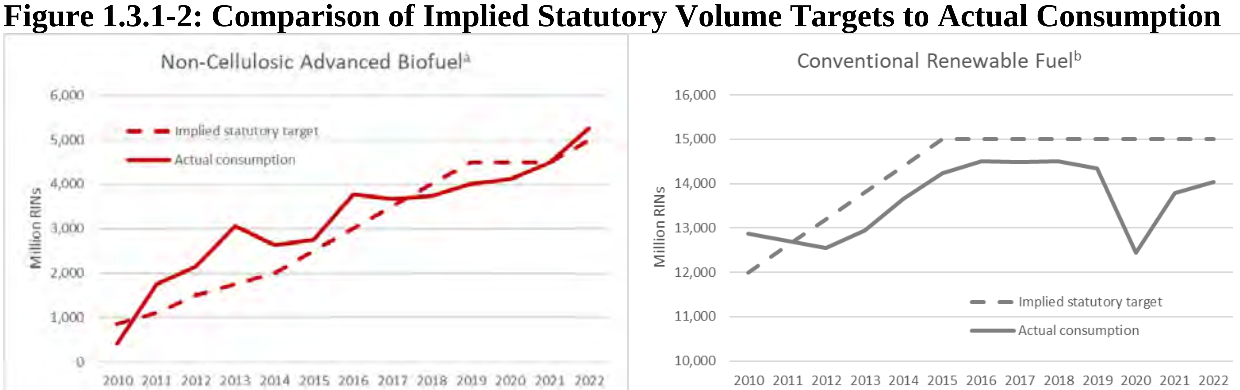


Source for actual consumption: EMTS

[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

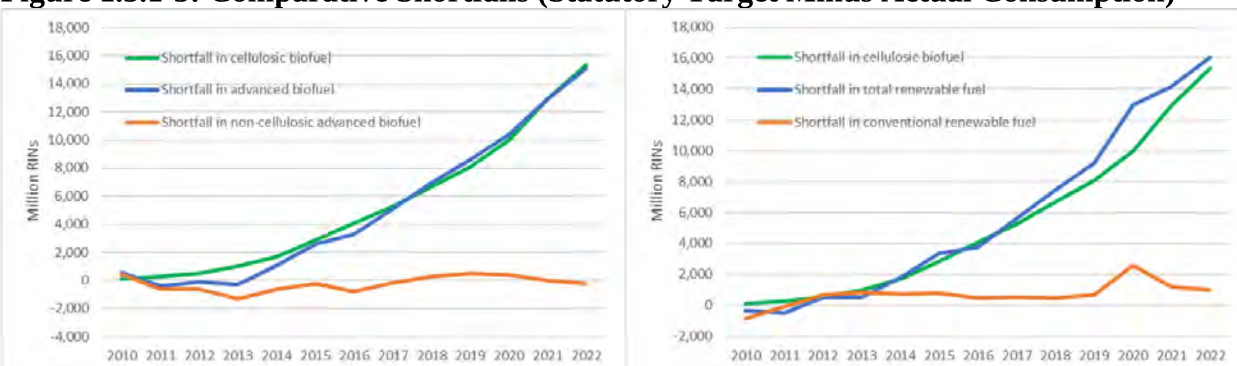
[a] Non-cellulosic advanced biofuel represents D4 and D5 RINs.

[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 number of carryover RINs 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)

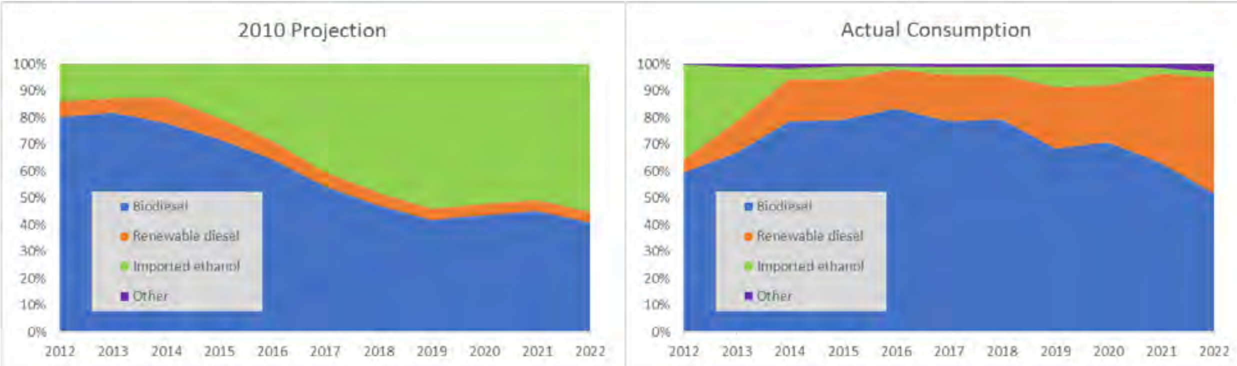


Source for actual consumption: EMTS

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.

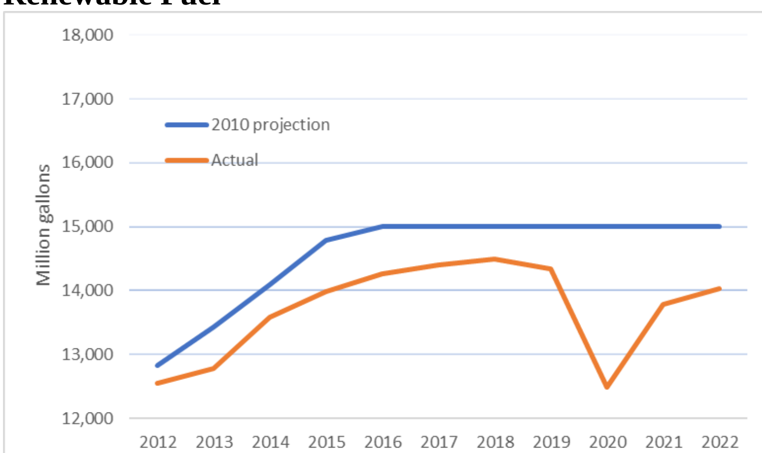
Figure 1.3.2-1: Volumetric Proportions of Each Fuel Type in Non-Cellulosic Advanced Biofuel



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

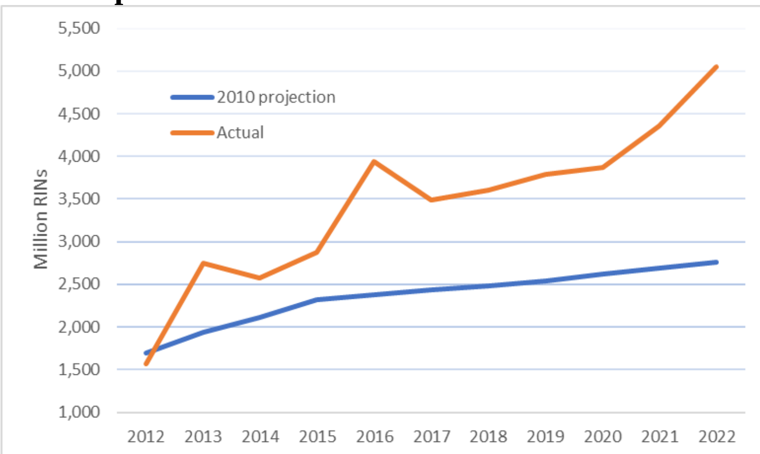
Actual consumption of imported sugarcane ethanol has been considerably lower than in the 2010 projection, and consumption of advanced biodiesel and renewable diesel has been higher. This outcome for imported sugarcane ethanol is mirrored in the outcome for total ethanol: actual consumption of ethanol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

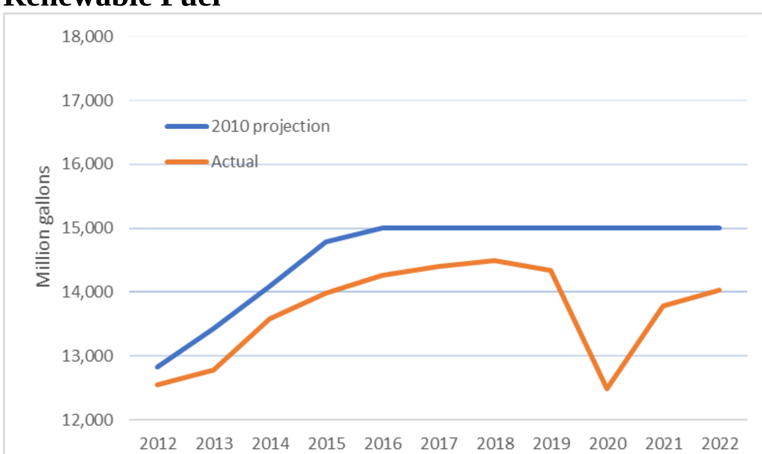
Figure 1.3.2-3: Actual Versus 2010 Projection of Biodiesel + Renewable Diesel Consumption in Non-Cellulosic Renewable Fuel



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.

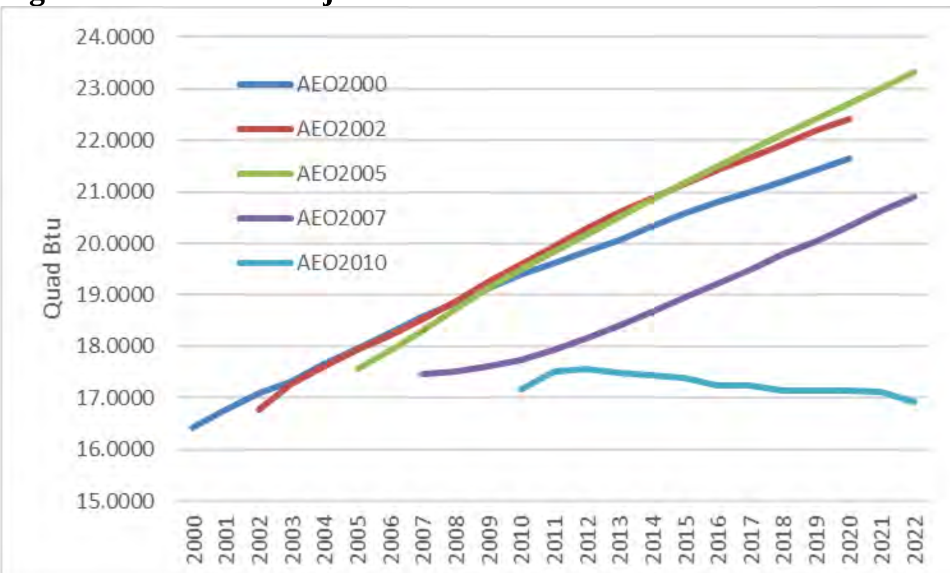
Figure 1.3.2-4: Actual Versus 2010 Projection of Ethanol Consumption in Conventional Renewable Fuel



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

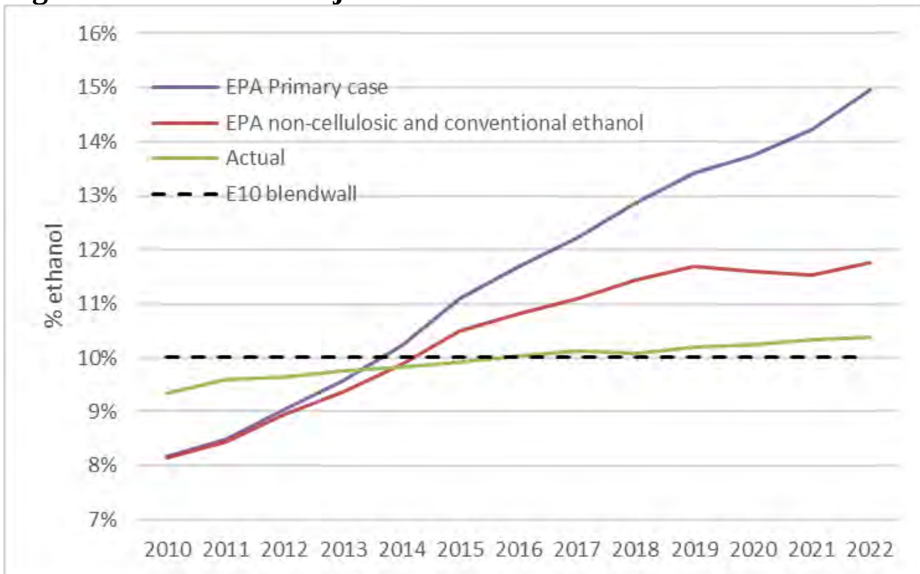
The expectation at the time that EISA was enacted in 2007 was that the implied conventional renewable fuel volume requirement could be met entirely with ethanol as E10 without the nation as a whole exceeding an average ethanol content of 10.00%, and without the need for E15 or E85. This expectation was 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

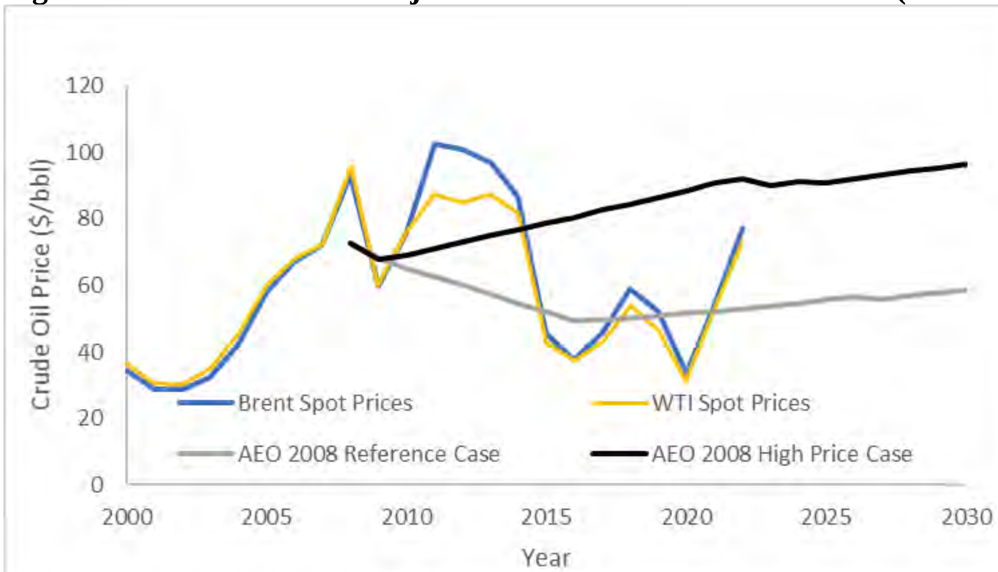
This section compares crude oil prices with crude oil price projections, and discusses observed changes in petroleum imports, refinery margins, and transportation fuel demand prior to and during the years of the implementation of the RFS program.

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.

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,

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

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 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. crude 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. That trend was expected to continue because the eventual increase in U.S. tight oil crude oil production 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 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

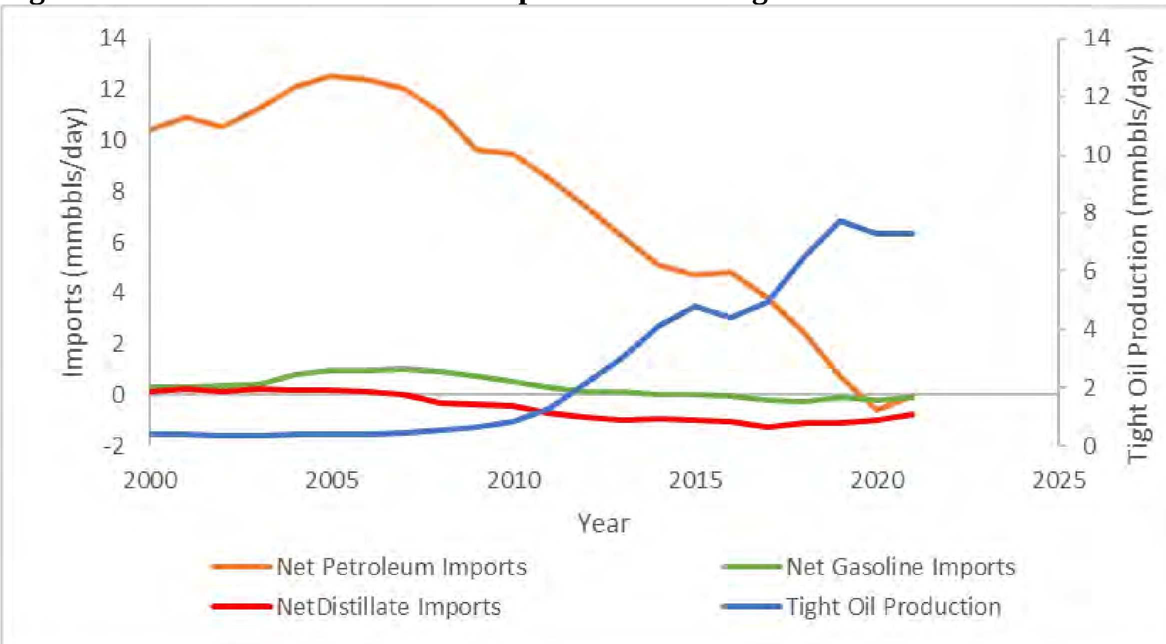

Figure 1.4.2-1 shows that net petroleum imports (crude oil and refined product net imports) increased from just over 10 million barrels per day (bpd) in 2000 to a maximum of about 12.5 million bpd in 2005. After peaking in 2005 when EPAct was passed, net petroleum imports started to decrease, very slowly 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 consumption increased from about 2 billion gallons (0.13 million bpd) in 2000 to over 14 billion gallons (0.91 million bpd) in 2015.[31,32] Biodiesel consumption increased from 10 million gallons in 2001 to over 1 billion gallons (0.07 million bpd) in 2013, and biodiesel and renewable diesel consumption totaled over 2 billion gallons

[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.

(0.13 million bpd) 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 petroleum import volume of 12.5 million bpd.

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)

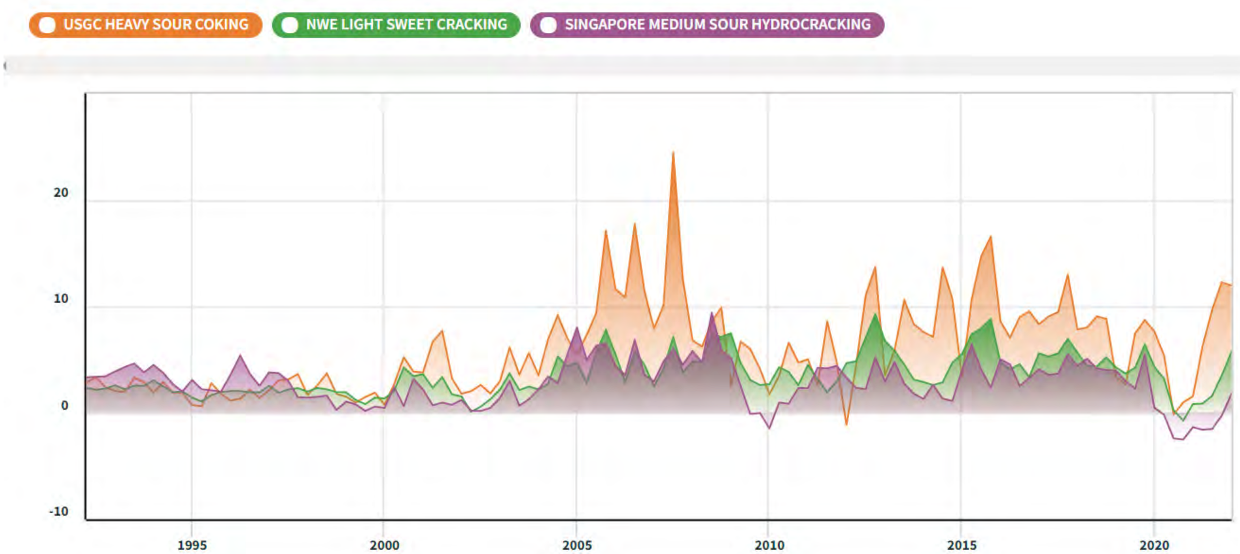

Figure 1.4.3-1 shows that from 1993–2004, refinery margins were modest, and the Singapore refinery in particular experienced zero or near-zero margins over much of 1998–2004. From 2004–2009, crude oil prices were rising and it was a much better period for these refineries' margins, particularly for the 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. The blending of corn ethanol into E10 gasoline played an important role in improving refinery margins in the 2005 to 2007 timeframe.[41] 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

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

[41] Economics of Blending 10 Percent Corn Ethanol into Gasoline; Office of Transportation and Air Quality, Environmental Protection Agency; (EPA-420-R-22-034, December 2022.

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 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.[42]

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 2000–2021, 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.[43,44]

Figure 1.4.4-1: Actual and Projected Transportation Fuel Demand

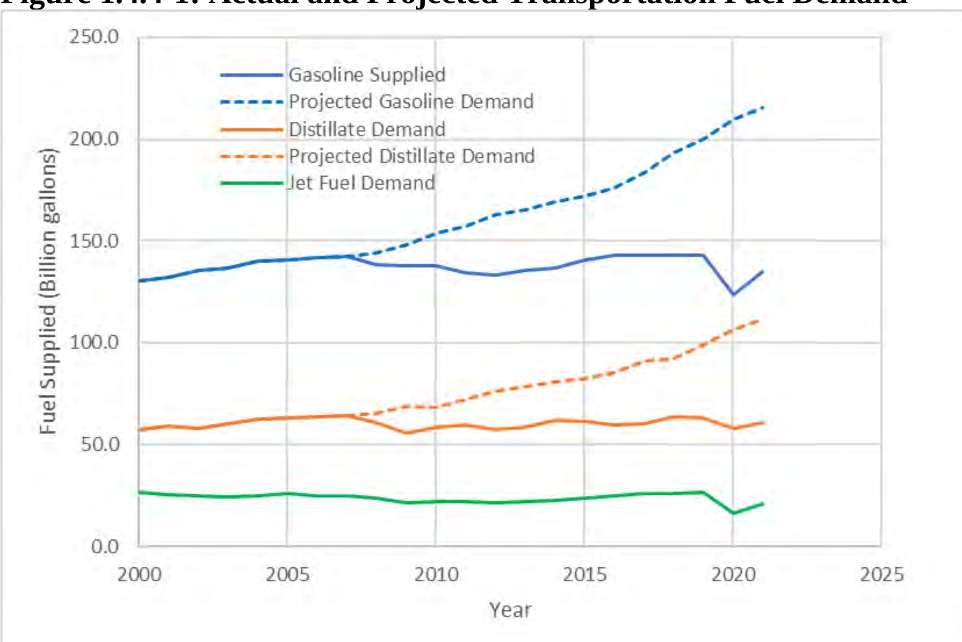

Figure 1.4.4-1 shows that both gasoline and distillate demand increased up to 2007. During previous years, gasoline and distillate demand was increasing 1.3% and 1.7% per year on average, respectively. The dashed lines in Figure 1.4.4-1 show projected gasoline and distillate

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

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

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

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.[45] EPA and NHTSA also established GHG/CAFE standards for new heavy-duty vehicles and their trailers.[46] The phase 1 and phase 2 heavy-duty GHG standards began to phase-in in 2014 and will continue to do so through 2027.[47] In addition, EPA proposed additional light-duty, medium-duty and heavy-duty standards which will affect the greenhouse gas emissions, and thus the fuel economy of, future motor vehicles.[48] [49] If finalized, these proposed rules would further reduce the petroleum consumption of the motor vehicle fleet. 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

[45] 75 FR 25324 (May 7, 2010) and 86 FR 74434 (December 30, 2021).
[46] 76 FR 57106 (September 15, 2011).
[47] 81 FR 73478 (October 25, 2016).
[48] Proposed Rulemaking: Multi-Pollutant Emissions Standards for Model Years 2027 and Later Light-Duty and Medium-Duty Vehicles, 88 FR 29184 (May 5, 2023).
[49] Proposed Rulemaking: Greenhouse Gas Emissions Standards for Heavy-Duty Vehicles – Phase 3, 88 FR 25926 (April 27, 2023).

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.[50]

1.5 Cellulosic Biofuel

Actual production of cellulosic biofuel through 2022 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.[51] 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[52] for the production of biogas from landfills, sewage and waste treatment plants, and manure digesters to generate advanced biofuel (D5) RINs.[53] 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.[54]

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[50] Transportation Research Center at Argonne National Laboratory, https://www.anl.gov/es/light-duty-electric-drive-vehicles-monthly-sales-updates.

[51] Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis. EPA-420-R-10-006. February 2010.

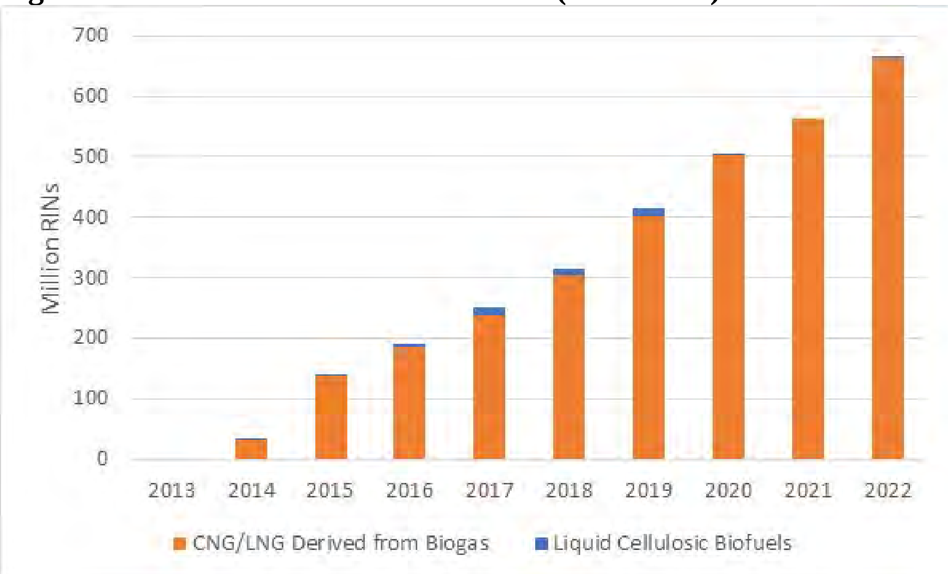
[52] A pathway is a combination of feedstock, production process, and fuel type. EPA has evaluated a number of different pathways to determine the category of renewable fuel that fuel produced using the various pathway qualifies for. The list of generally applicable pathways can be found in 40 CFR 80.1426(f).

[53] 75 FR 14872 (March 26, 2010).

[54] 79 FR 42128 (July 18, 2014).

Following this decision, production of CNG/LNG derived from biogas increased rapidly, from approximately 33 million RINs in 2014 to over 660 million RINs in 2022.[55] Through 2022, over 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 2025. Actual cellulosic biofuel production for each year from 2014–2022 is shown in Figure 1.5-1.

Figure 1.5-1: Cellulosic RINs Generated (2013–2022)



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.[56] The actual supply of biodiesel and renewable diesel in 2022 was 1.74 billion gallons and 1.36 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.

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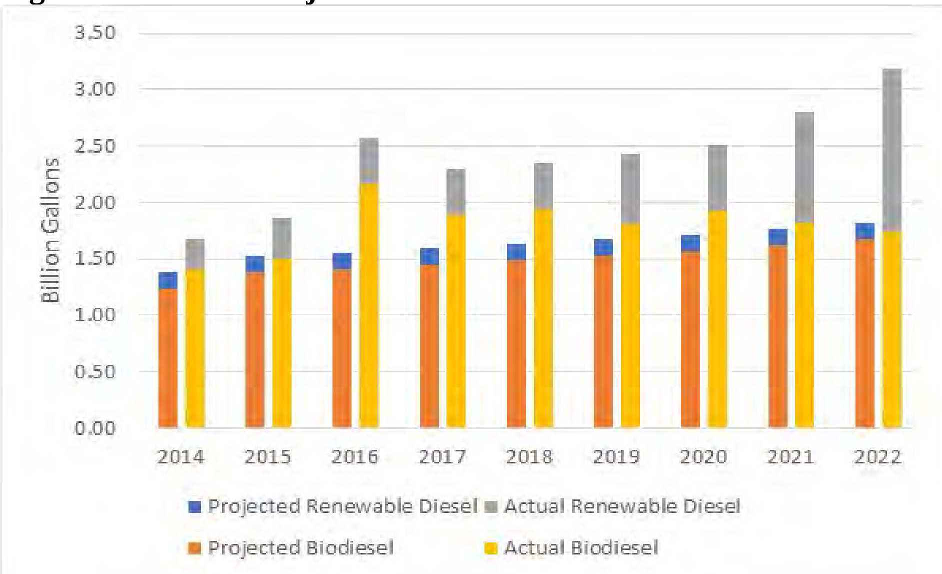
[55] One RIN can be generated for each ethanol-equivalent gallon of renewable fuel. One gallon of ethanol is eligible to generate one RIN; other types of fuel generate RINs based on their energy content per gallon relative to ethanol. For CNG/LNG derived from biogas, every 77,000 BTU of qualifying biogas generates one RIN.

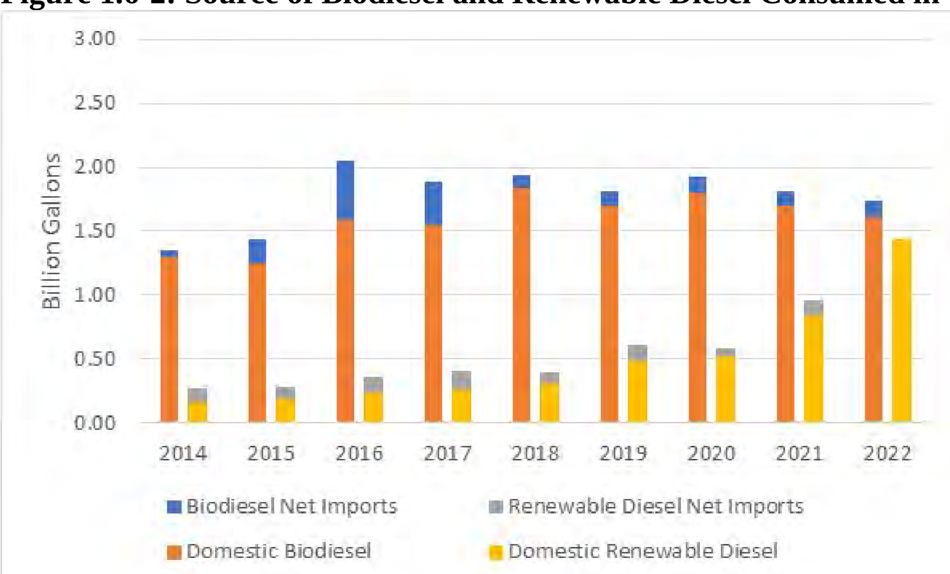
[56] 2022 is the most recent year for which data are available for comparison.

Figure 1.6-1: 2010 Projected vs. Actual Biodiesel and Renewable Diesel Supply (2014–2022)



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. (2014–2022)



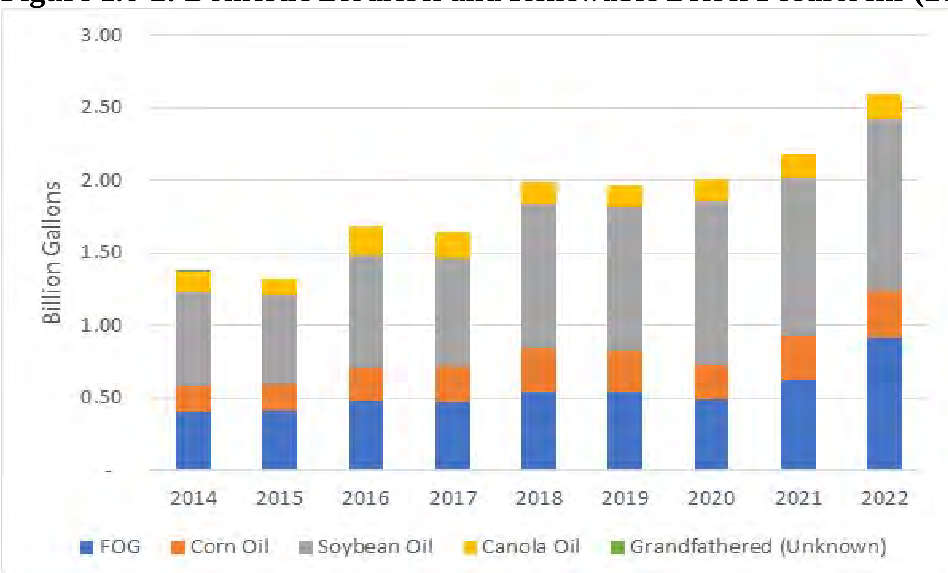
The reason that the supply of biodiesel and renewable diesel has been much higher than projected in the RFS2 rule is primarily related to challenges associated with consuming ethanol as higher-level blends with gasoline (i.e., greater that 10% ethanol), which we discuss further in Chapter 1.7. The limited use of higher-level ethanol blends, together with lower than projected gasoline demand, resulted in total ethanol consumption in 2020 – 2022 (12.68, 13.94, and 13.98 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).[57] Since the

[57] 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.

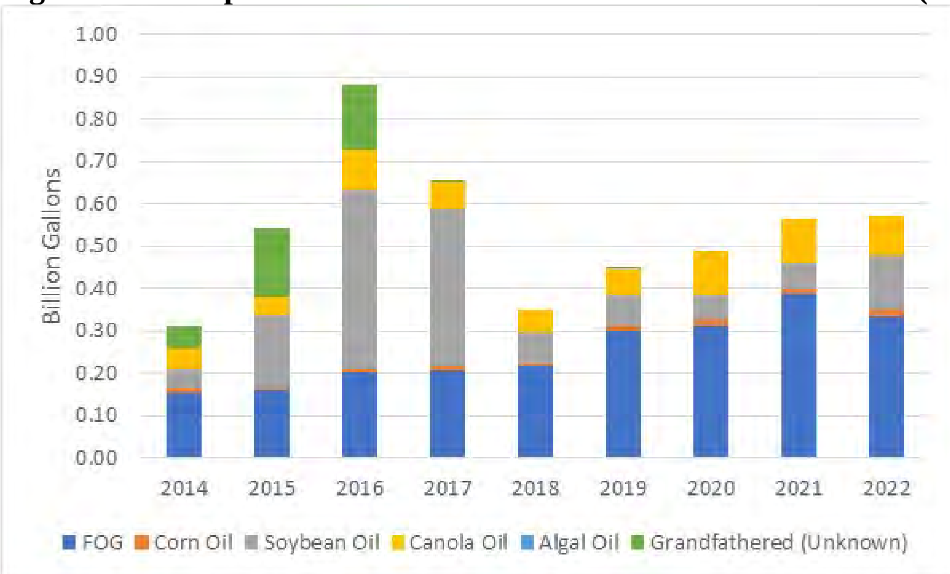
Figure 1.6-2: Domestic Biodiesel and Renewable Diesel Feedstocks (2014–2022)



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 (2014–2022)



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 2022. Domestic biodiesel production in 2022 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 ethanol projections being over-ambitious (since corn oil is a co-product of ethanol production), and demand for this feedstock in animal feed and other sectors.

Domestic renewable diesel production in 2022 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 2022, 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 2022, as well as in previous years. By 2022, 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.[58] These data, particularly the significant decrease in imported biodiesel and renewable diesel from 2016 – 2018 after the U.S. announced tariffs on imported biodiesel from Argentina and Indonesia, also highlight the importance of U.S. trade policy on the supply of these fuels.

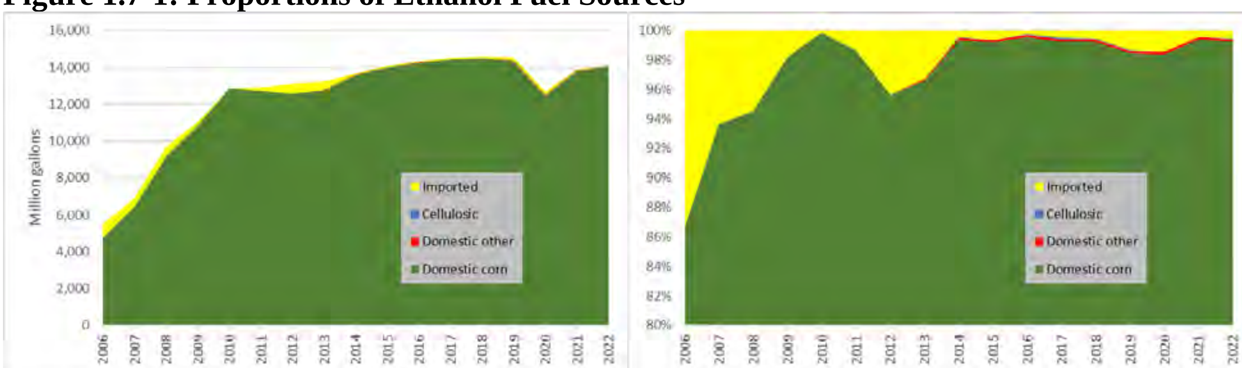
[58] Source: EMTS.

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.[59] 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.[60,61] 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 2022, ethanol accounted for 78% of the 18.1 billion gallons of biofuel consumed in the U.S.[62]

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

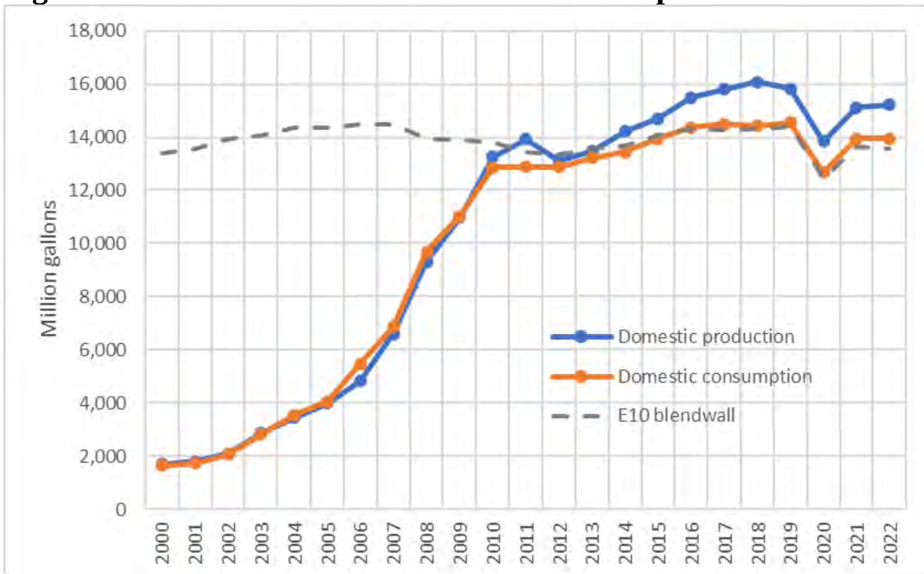


Source: EMTS. Note that the figure of the proportion of ethanol fuel sources ranges from 80% to 100%.

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.

[59] EIA's Monthly Energy Review, April 2021, Tables 10.3 and 10.4. Comparison is based on ethanol-equivalence.
[60] Id.
[61] In 2020 and 2021, total ethanol consumption dropped significantly as a result of the COVID-19 pandemic.
[62] "RIN supply as of 2-21-23," available in the docket for this action.

Figure 1.7-2: Domestic Production and Consumption of Ethanol

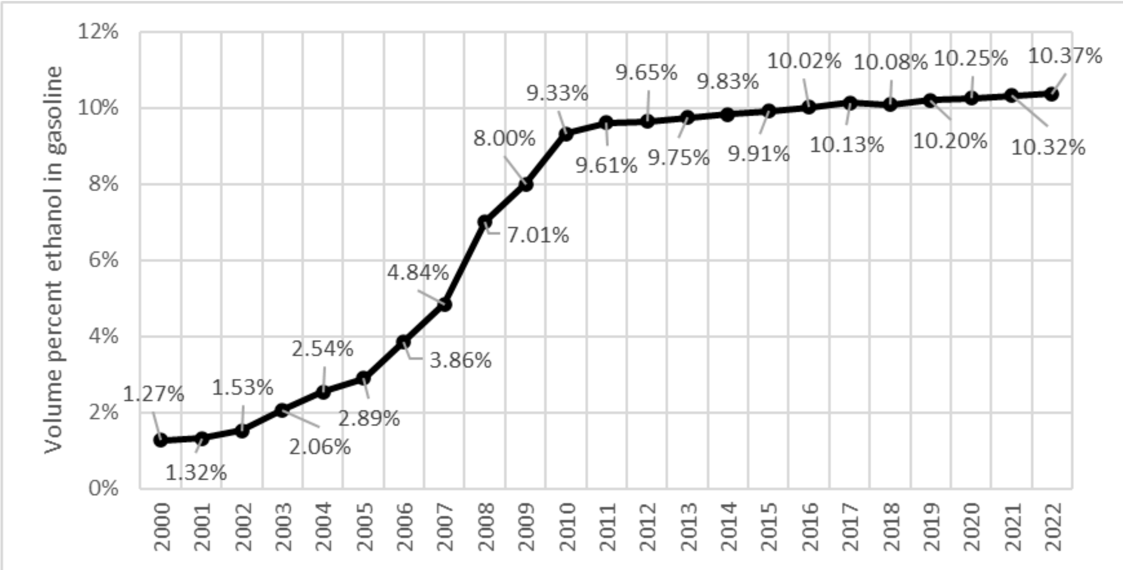


Source: Domestic consumption from EIA's Monthly Energy Review. The E10 blendwall was derived from total gasoline energy demand. Domestic production = domestic consumption – imports + exports.

The E10 blendwall appears to have been a decisive 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.[63] Ethanol production exceeded domestic consumption through exports.

[63] As discussed further in Chapter 1.10, a comparison of historical gasoline + diesel volumes reported by obligated parties with gasoline + diesel estimated by EIA revealed a significant difference. Insofar as EIA estimates of gasoline consumption are lower than actual consumption, the nationwide average ethanol concentration calculated from those gasoline consumption estimates are then higher than actuals. However, even if this is the case, we would expect the general trend shown in Figure 1.7-3 to be unchanged.

Figure 1.7-3: Nationwide Average Concentration of Ethanol in Gasoline Consumed in the U.S.



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

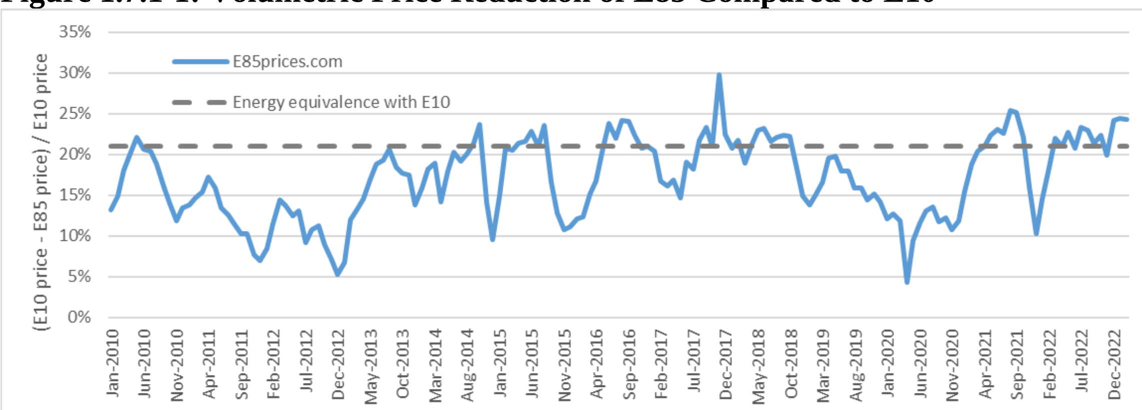
The earliest form of a higher-level ethanol blend was E85. In 1996, the first FFV was produced that could operate on fuel containing up to 85% denatured ethanol (83% ethanol).[64] Starting in 2007, ASTM International limited the maximum ethanol content of E85 to 83% in specification D5798, with a minimum ethanol content of 51%. EIA assumes that the annual, nationwide average ethanol concentration of E85 is 74%.[65]

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

[64] "Alternative Fuel Ford Taurus," available in the docket for this action.
[65] "AEO2022 Table 2," available in the docket for this action. See footnote 11.

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).[66,67] 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.

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.

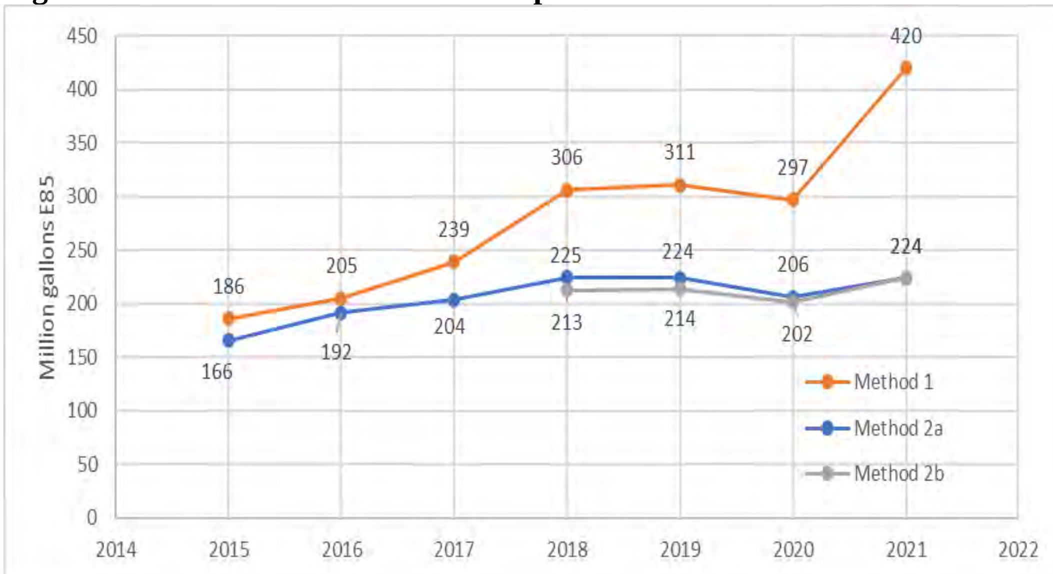
EPA has estimated the nationwide volume of E85 consumed in past years using two different methods.[68] The results of those analyses are shown in Figure 1.7.1-2.

[66] 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.

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

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

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. The resulting estimates of E15 and E85 volumes for 2023, 2024, and 2025 that are used in the cost analysis are provided in Chapter 6.5.2.

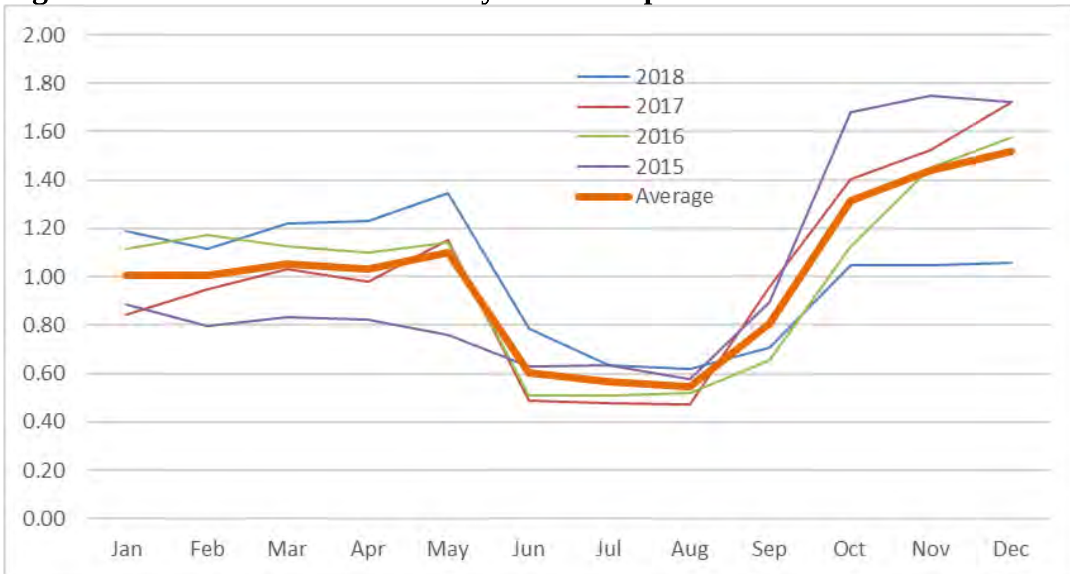
1.7.2 E15

In 2011, gasoline containing up to 15% ethanol was permitted to be used in model year (MY) 2001 and newer vehicles.[69] E15 has since been offered at an increasing number of retail service stations.[70] 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.[71] 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.[72]

[69] 76 FR 4662 (January 26, 2011).
[70] See Chapter 6.4.3.
[71] 54 FR 11883(March 22, 1989).
[72] Minnesota is the only source of data on E15 sales by month of which we are aware.

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

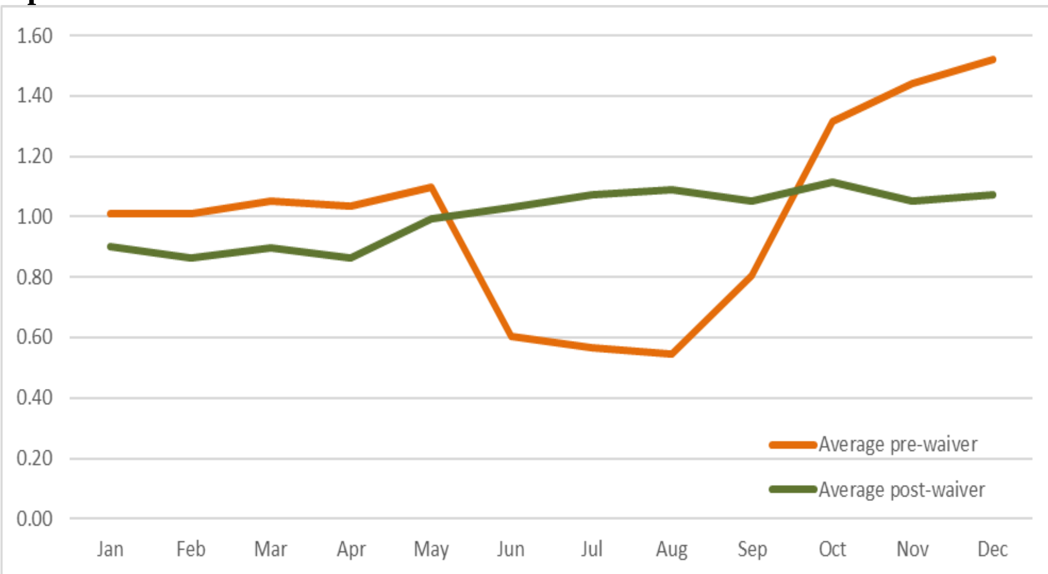


Source: Minnesota Commerce Department
[a] Normalized values derived by dividing the monthly E15 sales volume per station by the annual average E15 sales volume per station.

In 2019, EPA extended the 1-psi waiver to E15 by regulation.[73] 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.[74] 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. EPA subsequently issued emergency fuel waivers for the summer of 2022, and the summer for 2023 that allowed E15 to take advantage of the 1-psi waiver to address issues related to fuel price and supply.[75] Insofar as the 1-psi waiver for E15 had an impact on summer sales of E15, therefore, it did so only for 2019–2022. For these years, data from Minnesota on per-station sales of E15 indicates that those sales were no longer seasonal as they were prior to 2019.

[73] 84 FR 26980 (June 10, 2019).
[74] "Estimating the impacts of the 1psi waiver for E15," memorandum from David Korotney to EPA docket EPA-HQ-OAR-2019-0136.
[75] On April 28, 2023 EPA also issued an emergency fuel waiver for E15 RVP that took effect May 1, 2023

Figure 1.7.2-1: Normalized Monthly E15 Sales per Station in Minnesota; Before and After 1-psi Waiver[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.

On March 6, 2023, EPA proposed to remove the 1-psi waiver for E10 in eight states.[76,77] If this proposal is finalized, the net result would be that E10 and E15 are treated the same in these states with regard to RVP beginning with the summer of 2024, and there may be no reduction in summer sales of E15 compared to other months in these states.

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 2012–2022.[78]

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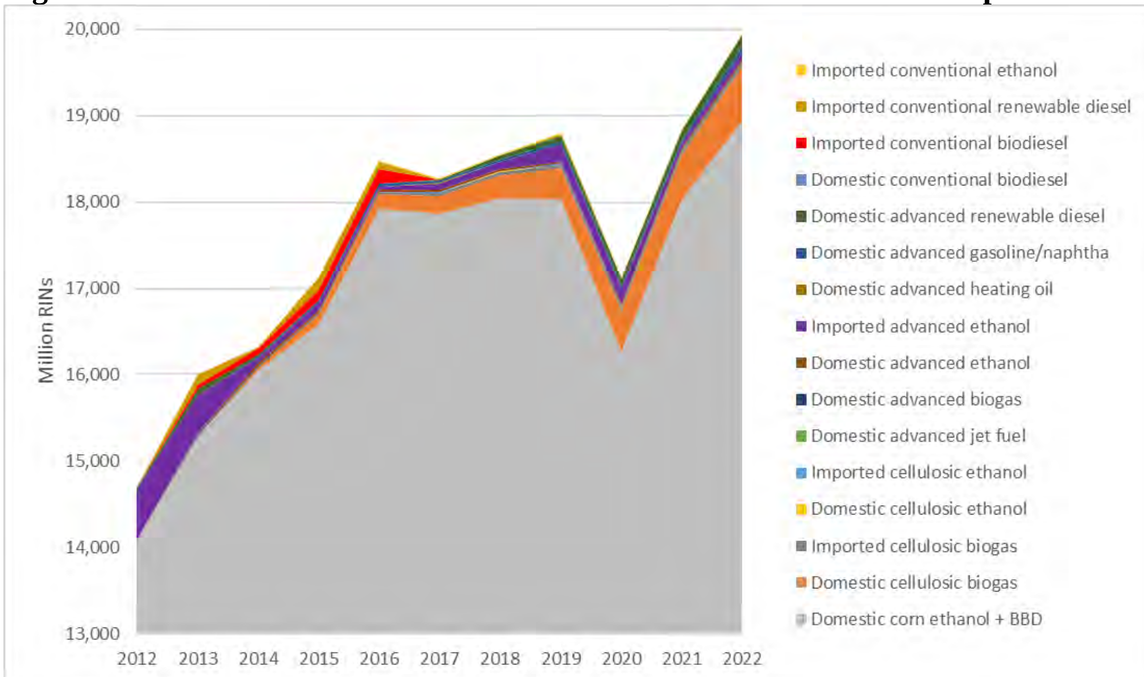
[76] "Request from States for Removal of Gasoline Volatility Waiver" 88 FR 13758 (March 6, 2023).
[77] Illinois, Iowa, Minnesota, Missouri, Nebraska, Ohio, South Dakota, and Wisconsin.
[78] Detailed data prior to 2012 on RIN generation, adjustments to account for invalid RINs, and exports is less robust and is therefore not presented here.

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

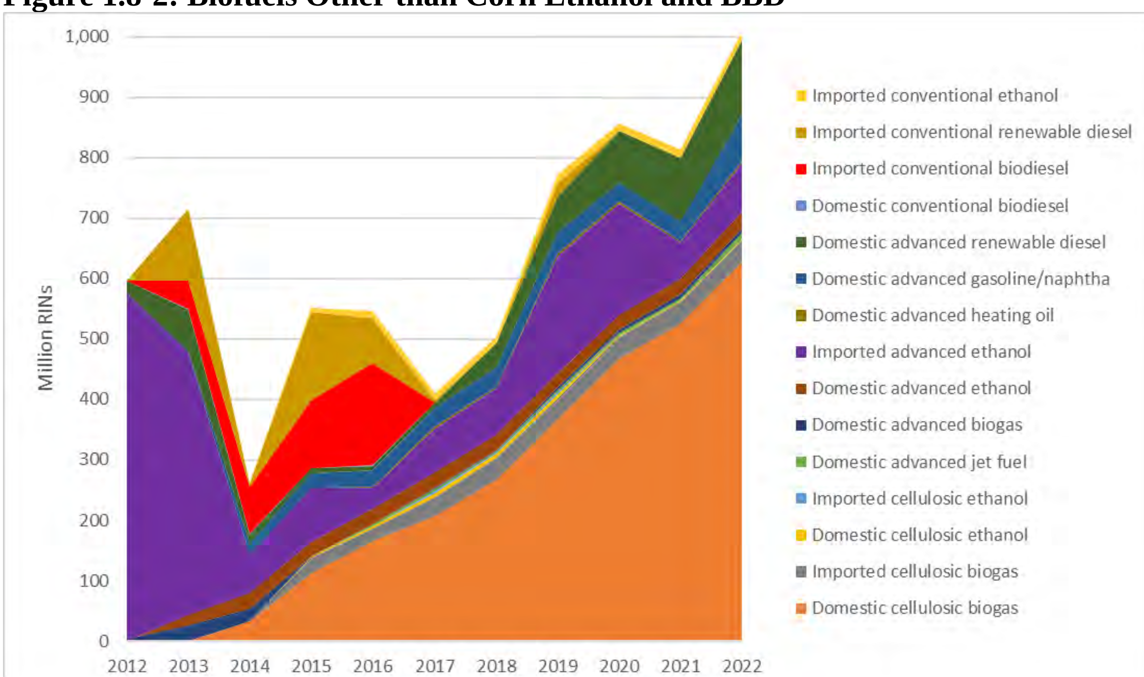


Source: EMTS

[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.

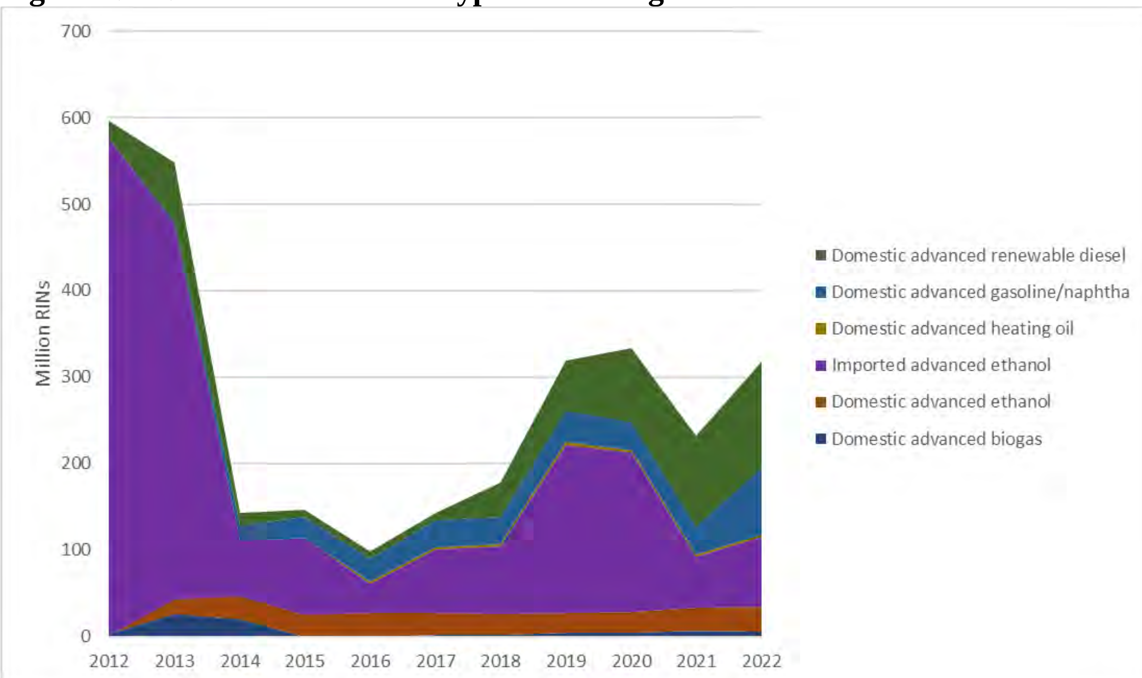
[b] Fuel type and D code of exports is known, but whether the exported fuel was originally produced domestically or was imported is not known. For purposes of this chart, exports were assumed to be distributed to domestic production and imports in proportion to the relative production volumes of each.

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 2012–2022, 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,[79] gasoline/naphtha, and ethanol were of approximately similar magnitude and demonstrated no consistent increasing or decreasing trends between 2012–2022. Domestic advanced biogas fell to near zero in 2015 after biogas from landfills was recategorized as cellulosic biofuel in 2014.[80] 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.

[79] Small quantities of renewable diesel are not BBD but are nonetheless advanced biofuel.
[80] 79 FR 42128 (July 18, 2014).

1.9 RIN System and Prices

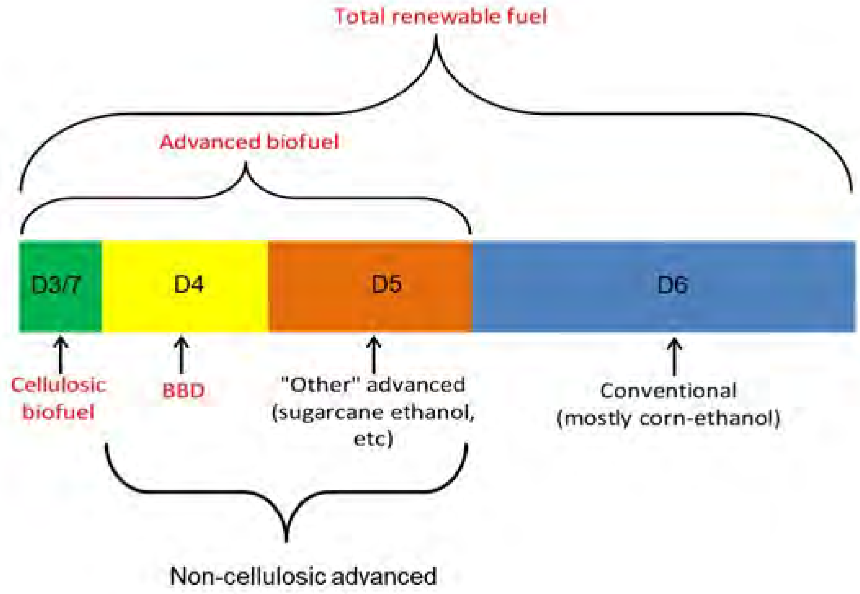
1.9.1 RIN System

RINs were created by EPA under CAA section 211(o)(5) as a flexible credit and compliance 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.[81] 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).[82] 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.

[81] 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).
[82] 40 CFR 80.1425(g).

Figure 1.9-1: Nested Structure of the RFS Program

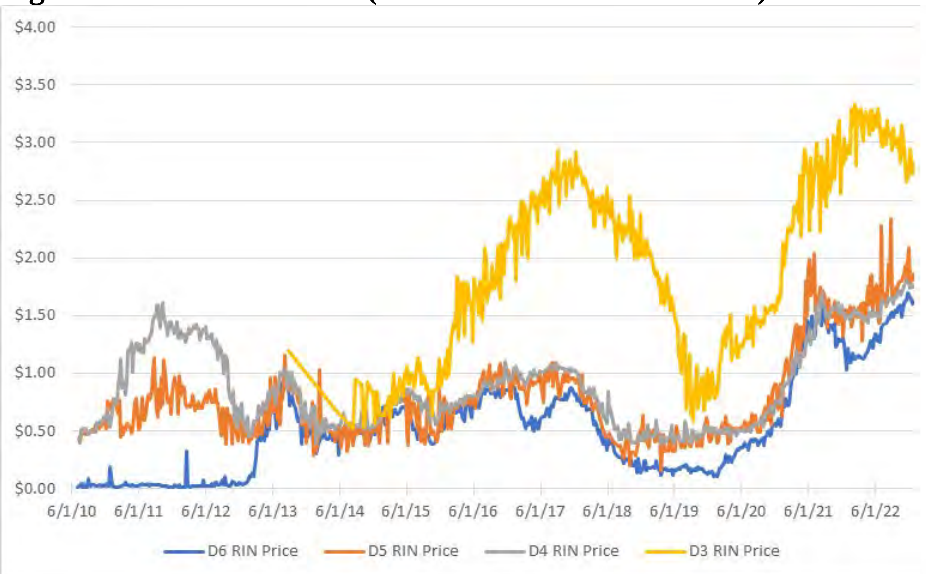


1.9.2 RIN Prices

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.[83] 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.

[83] 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 (June 2010 – December 2022)



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.[84] 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 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).

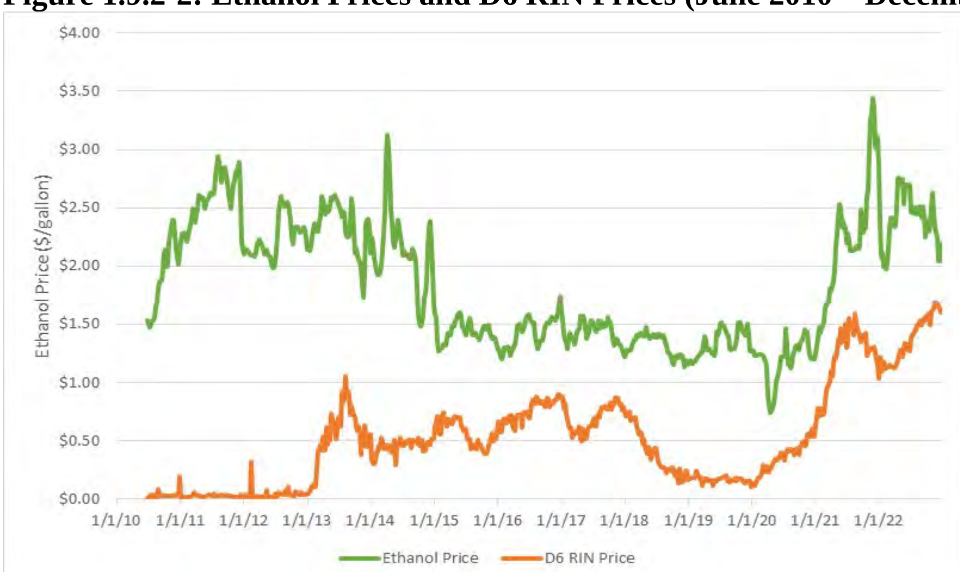
In subsequent years, D6 RIN prices have varied significantly, but they have never returned to the low prices observed prior to 2013. It is also notable that, from 2013–2016, D6 RIN prices remained close to, but slightly less than, D4 and D5 RIN prices. During this time, obligated parties were purchasing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

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

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 $1.50–2.00 by the end of 2022. 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.[85] 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).[86]

Figure 1.9.2-2: Ethanol Prices and D6 RIN Prices (June 2010 – December 2022)



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

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

[86] 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.

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.[87] 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.[88] 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 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).[89] 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

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[87] “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.

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

[89] 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.

credit is in effect."[90] 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.

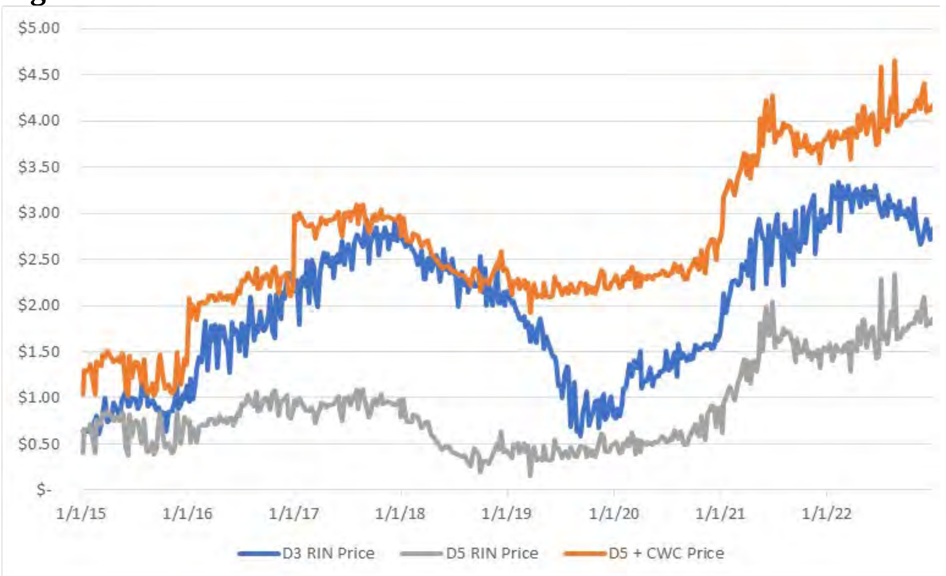
Data on cellulosic RIN (D3 and D7) prices were not generally available until 2015. This is likely due to the fact that prior to 2015, the market for cellulosic RINs was too small to support commercial reporting services; very few cellulosic RINs were generated and traded in years prior to 2016. From 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).[91] This is as expected, since obligated parties can satisfy their 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.[92] 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 and remaining between the D5 RIN price and the D5 plus CWC price through the end of 2022.

[90] 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.

[91] CAA section 211(o)(7)(D)(ii) established a price cap mechanism for cellulosic biofuel RINs. In implementing this provision, 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).

[92] 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.

Figure 1.9.2-3: D3 RIN Prices and D5 RIN Price Plus CWC Price[93]



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 (CWC plus the D5 RIN price) and protects these parties from excessively high cellulosic RIN prices. The CWC price is also informational to potential cellulosic biofuel producers. Potential cellulosic 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 from 2010 to 2022 to set the required volume of cellulosic biofuel at the volume expected to be produced each year,[94] 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

[93] 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.
[94] CAA section 211(o)(7)(D).

type of cellulosic biofuel.[95] 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 $3.02 in 2022.[96] Thus, the total cost associated with the 630 million cellulosic RINs required for compliance in 2022 was approximately $1.9 billion. Therefore, the cellulosic biofuel requirement likely increased the price of gasoline and diesel sold in the U.S. in 2022 by approximately $0.01 per gallon.[97] These transfers are expected to increase significantly through 2025 as a result of the cellulosic biofuel volumes we are finalizing in this rule. For example, using the average cellulosic RIN price for May 2022 – April 2023 (the last six months for which data are available) of $2.79 and the final cellulosic biofuel volume for 2025 of 1.38 billion gallons, we estimate that the cost associated with cellulosic RIN purchases would be $3.85 billion, and would be expected to increase the price of gasoline and diesel in 2025 by approximately $0.02 per gallon.[98]

1.10 Carryover RIN Projections

This section details the calculations performed by EPA to project the number of available carryover RINs in the context of developing the final 2023-2025 RFS standards. While the actual number of carryover RINs available for use by obligated parties to use towards these standards will not be known until after compliance with the preceding year's standards is complete, we are able to project these values by using 2021 compliance data and assumptions about RIN generation relative to RIN obligations in 2022. Chapter 1.10.1 calculates the number of carryover RINs available after compliance with the 2021 standards. Chapter 1.10.2 projects the number of carryover RINs that will be available for compliance with the 2023-2025 standards. Chapter 1.10.3 provides historical data on the number of available carryover RINs. Chapter 1.10.4 summarizes EMTS data on RIN retirements and errors.

1.10.1 Number of Available Carryover RINs After Compliance With the 2021 Standards

In order to calculate the number of 2021 carryover RINs available for compliance with the 2022 standards, we began with the 2021 RFS compliance year data in Table 1.10.1-1. From this data, we calculated that approximately 20.39 billion total RINs were retired for compliance

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[95] 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.
[96] Average D3 RIN price in 2022 according to EMTS RIN price data.
[97] In the February 2023 STEO, EIA forecasted gasoline and diesel consumption in 2022 at 8.78 million bpd (134.6 billion gallons per year) and 3.68 million bpd (56.4 billion gallons per year) respectively. Dividing the total cost of cellulosic RINs in 2021 ($1.9 billion) by the total consumption of gasoline and diesel (191.0 billion gallons) results in an estimated cost of $0.01 per gallon of gasoline and diesel as a result of the cellulosic biofuel requirement.
[98] In the 2023 AEO, EIA forecasted gasoline and diesel consumption in 2025 at 138.4 billion gallons and 52.4 billion gallons respectively. Dividing the total cost of cellulosic RINs in 2025 ($3.85 billion) by the total consumption of gasoline and diesel (190.8 billion gallons) results in an estimated cost of $0.020 per gallon of gasoline and diesel as a result of the cellulosic biofuel requirement.

in the 2021 compliance year.[99] Of this total, approximately 18.58 billion 2021 RINs and 1.81 billion 2020 carryover RINs were used.

Table 1.10.1-1: RINs Retired by Obligated Parties and Exporters in the 2021 Compliance Year[a]

RIN Type	RIN Year		Total
	2020	2021	
D3	40,866,327	538,249,180	579,115,507
D4	79,946,630	4,757,209,816	4,837,156,446
D5	34,020,833	229,546,265	263,567,098
D6	1,650,618,764	13,058,319,692	14,708,938,456
D7	0	0	0
Total	1,805,452,554	18,583,324,953	20,388,777,507

[a] RINs include those retired by companies with an RVO as a gasoline/diesel fuel importer or refiner, as well as RINs retired by companies with an RVO as renewable fuel exporters. Renewable fuel exporters include exporters of neat renewable fuel, as well as exporters of renewable fuel blended with other fuels (including, but not limited to, gasoline, diesel fuel, heating oil, and jet fuel). See Table 1.10.4-1 for more detailed data.

Next, we calculated the net number of RINs that were generated in 2021. To do this, we took the total number of RINs generated in 2021 and then removed any RINs that were generated in error, as well as any RINs that were retired for purposes other than satisfying an obligated party or exporter RVO (e.g., for spills, remedial actions, enforcement obligations, etc.). Using the data in Table 1.10.1-2, we calculated that a net of approximately 19.72 billion RINs were generated in 2021.

Table 1.10.1-2: 2021 Net RINs Generated[a]

RIN Type	Total RINs Generated[b]	RIN Errors[c]	Other RIN Retirements[d]	Net RINs Generated[e]
D3	568,414,154	5,205,881	188,456	563,019,817
D4	4,873,631,040	1,952,566	56,904,276	4,814,774,198
D5	233,872,099	830,150	142,240	232,899,709
D6	14,258,274,476	13,588,686	139,641,775	14,105,044,015
D7	247,518	0	0	247,518
Total	19,934,439,287	21,577,283	196,876,747	19,715,985,257

[a] Data from April 2023 and compiled from https://www.epa.gov/system/files/other-files/2023-05/availablerins_Apr2023.csv and https://www.epa.gov/system/files/other-files/2023-05/retiretransaction_Apr2023.csv.
[b] The total number of RINs generated includes those RINs generated for exported fuel.
[c] See Table 1.10.4-2 for more detailed data.
[d] See Table 1.10.4-3 for more detailed data.
[e] Net RINs Generated = Total RINs Generated – (RIN Errors + Other RIN Retirements).

To determine the total number of 2021 carryover RINs available for compliance with the 2022 standards, we then subtracted the number of 2021 RINs retired in the 2021 compliance year

[99] Includes RINs retired in the 2021 compliance year to satisfy 2020 compliance deficits.

from the net number of 2021 RINs generated. We calculate that there are approximately 1.13 billion 2021 carryover RINs available, as shown in Table 1.10.1-3.

Table 1.10.1-3: 2021 Carryover RINs

RIN Type	Net 2021 RINs Generated	2021 RINs Retired for Compliance	2021 Carryover RINs
D3	563,019,817	538,249,180	24,770,637
D4	4,814,774,198	4,757,209,816	57,564,382
D5	232,899,709	229,546,265	3,353,444
D6	14,105,044,015	13,058,319,692	1,046,724,323
D7	247,518	0	247,518
Total	19,715,985,257	18,583,324,953	1,132,660,304

Obligated parties are also able to carryforward a compliance deficit from one year to the next year,[100] increasing their RVO for 2022 and effectively decreasing the number of 2021 carryover RINs available for compliance with the 2022 standards. In order to account for this, we calculate the effective number of 2021 carryover RINs available for compliance with the 2022 standards by subtracting out the 2021 compliance deficits, which have to be satisfied at the time of compliance with the 2022 standards.[101] We note, however, that 2021 compliance deficits exceeded the number of available 2021 carryover RINs for several standards, which means that there was a shortfall in the number of RINs available to comply with these standards in 2021 and that some obligated parties had to carry forward a deficit into 2022. After accounting for this adjustment, the effective number of 2021 carryover RINs available for compliance with the 2022 standards are shown in Table 1.10.1-4.[102]

[100] See 40 CFR 80.1427(b).
[101] The compliance deadline for the 2022 standards will be the first quarterly reporting deadline after the effective date of this action.
[102] In other words, the number of available carryover RINs is effectively reduced in light of the volume of 2021 deficits carried forward to 2022. We note, moreover, that these numbers could change based on, for instance, enforcement actions or obligated parties truing up their RVOs pursuant to the attest engagement required by 40 CFR 80.1464.

Table 1.10.1-4: Effective 2021 Carryover RINs[a]

RFS Standard	RIN Type	2021 Carryover RINs	2021 Compliance Deficits	Net Surplus/ Deficit[b]	Effective 2021 Carryover RINs
Cellulosic Biofuel	D3+D7	25,018,155	32,558,093	-7,539,938	0
Non-Cellulosic Advanced Biofuel[c]	D4+D5	60,917,826	457,984,877	-397,067,051	0
Conventional Renewable Fuel[d]	D6	1,046,724,323	553,171,784	493,552,539	493,552,539

[a] Data current as of May 17, 2023, and compiled from Table 5 at https://www.epa.gov/fuels-registration-reporting-and-compliance-help/annual-compliance-data-obligated-parties-and.
[b] Net Surplus/Deficit = Carryover RINs – Compliance Deficits. Negative values represent a shortfall in the number of RINs available to comply with the applicable standard and are counted as zero for purposes of determining the effective number of available carryover RINs.
[c] Non-cellulosic advanced biofuel is not an RFS standard category but is calculated by subtracting the number of cellulosic RINs from the number of advanced RINs.
[d] Conventional renewable fuel is not an RFS standard category but is calculated by subtracting the number of advanced RINs from the number of total renewable fuel RINs.

1.10.2 Number of Available Carryover RINs for 2023-2025

Given the uncertainty of the impact of compliance with the 2022 standards on the number of available carryover RINs, we are unable to provide a quantitative analysis of the number of carryover RINs that may be available for compliance with the 2023-2025 standards.[103] However, if we assume that the uncertainties result in neither a net gain nor net loss of excess RINs for 2022, then the carryover RINs that we projected to be available in Chapter 1.10.1 would represent the number of carryover RINs available for compliance with the 2023-2025 standards, as shown in Table 1.10.2-1.[104]

[103] Sources of uncertainty that could potentially increase the number of carryover RINs include lower actual gasoline and diesel fuel use than the projection used to derive the standards. Sources of uncertainty that could potentially decrease the number of carryover RINs include enforcement actions and higher actual gasoline and diesel fuel use than the projection used to derive the standards.
[104] The actual number of RINs that will be available for use by obligated parties to use towards the 2023-2025 standards will not be known until the compliance deadline for the preceding compliance year. Even after this date, however, this number could change based on, for instance, obligated parties truing up their RVOs pursuant to the attest engagement required by 40 CFR 80.1464 or enforcement actions.

Table 1.10.2-1: Projected Carryover RINs for 2023-2025

RFS Standard	RIN Type	Projected Effective Carryover RINs
Cellulosic Biofuel	D3+D7	0
Non-Cellulosic Advanced Biofuel[a]	D4+D5	0
Conventional Renewable Fuel[b]	D6	493,552,539

[a] Non-cellulosic advanced biofuel is not an RFS standard category but is calculated by subtracting the number of cellulosic RINs from the number of advanced RINs.
[b] Conventional renewable fuel is not an RFS standard category but is calculated by subtracting the number of advanced RINs from the number of total renewable fuel RINs.

We note that while we project that there will effectively be no cellulosic biofuel or non-cellulosic advanced biofuel carryover RINs available for compliance with the 2023-2025 standards, this does not mean that actual carryover RINs will not be available in these years. As discussed in Chapter 1.10.1, the actual number of carryover RINs available relative to the "effective" number is a function of the volume of RIN deficits that obligated parties carry forward from one year into the next. For example, if obligated parties carry forward a significant volume of RIN deficits, then the absolute number of carryover RINs available for compliance with the following year's standards will be larger than were obligated parties to carry forward a smaller volume of RIN deficits.

1.10.3 Carryover RIN History

In order to provide a historical perspective on the number of available carryover RINs, we calculated the absolute and effective number of carryover RINs for each year since 2013 using the same methodology described in Chapter 1.10.1. The results are provided in Table 1.10.3-1 and Figures 1.10.3-1 through 3 and represent the number of RINs of a given vintage available for compliance with the subsequent year's standard (e.g., the number of available carryover RINs in 2021 are those 2021 RINs that can be used to comply with the 2022 standards).

Table 1.10.3-1: Number of Available Carryover RINs History (million RINs)

Compliance Year	Cellulosic Biofuel		Non-Cellulosic Advanced Biofuel		Conventional Renewable Fuel	
	Absolute[a]	Effective[b]	Absolute[a]	Effective[b]	Absolute[a]	Effective[b]
2013	0	0	565	538	1,088	1,046
2014	12	12	467	445	1,373	1,254
2015	39	39	372	367	1,248	1,242
2016	39	34	888	826	1,947	1,623
2017	29	9	844	727	3,061	2,517
2018	54	51	645	619	2,896	2,800
2019	53	41	221	23	2,186	1,743
2020	42	12	131	0	1,764	1,178
2021	25	0	61	0	1,047	494

[a] Represents the absolute number of carryover RINs that are available for compliance with the subsequent year's standards and does not account for carryforward deficits.
[b] Represents the effective number of carryover RINs that are available for compliance with the subsequent year's standards after accounting for carryforward deficits. Standards for which deficits exceed the number of available carryover RINs are represented as zero.

Figure 1.10.3-1: Number of Available Conventional Renewable Fuel Carryover RINs

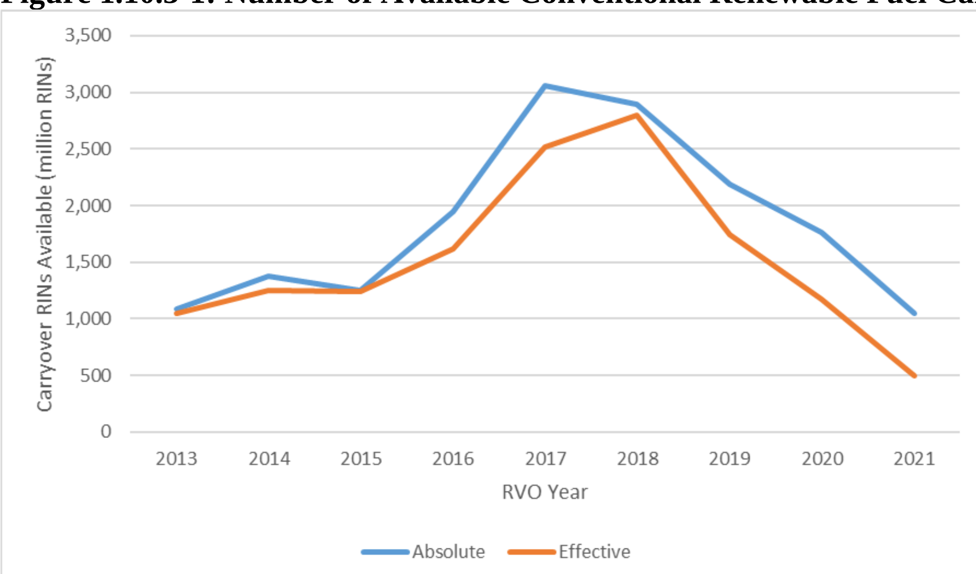


Figure 1.10.3-2: Number of Available Non-Cellulosic Advanced Biofuel Carryover RINs

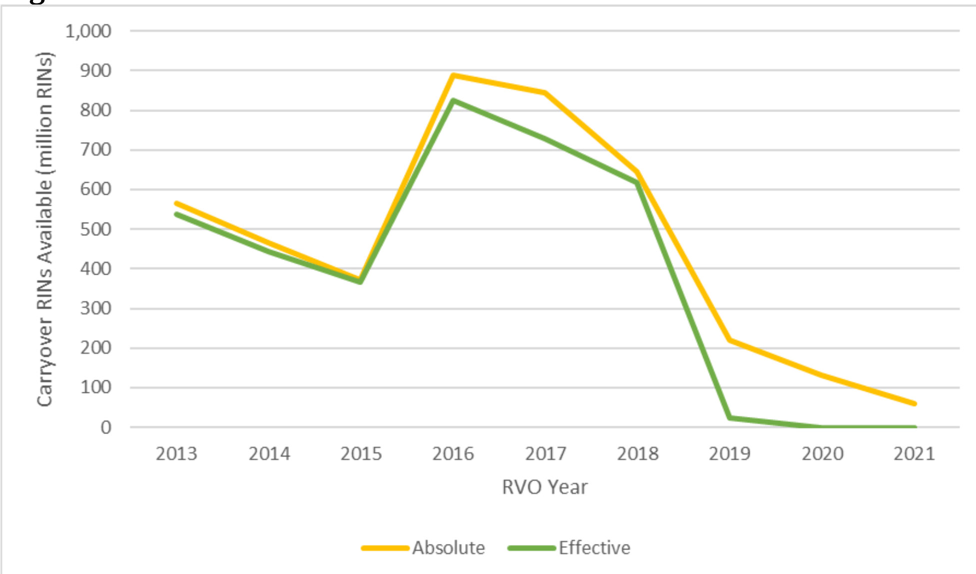
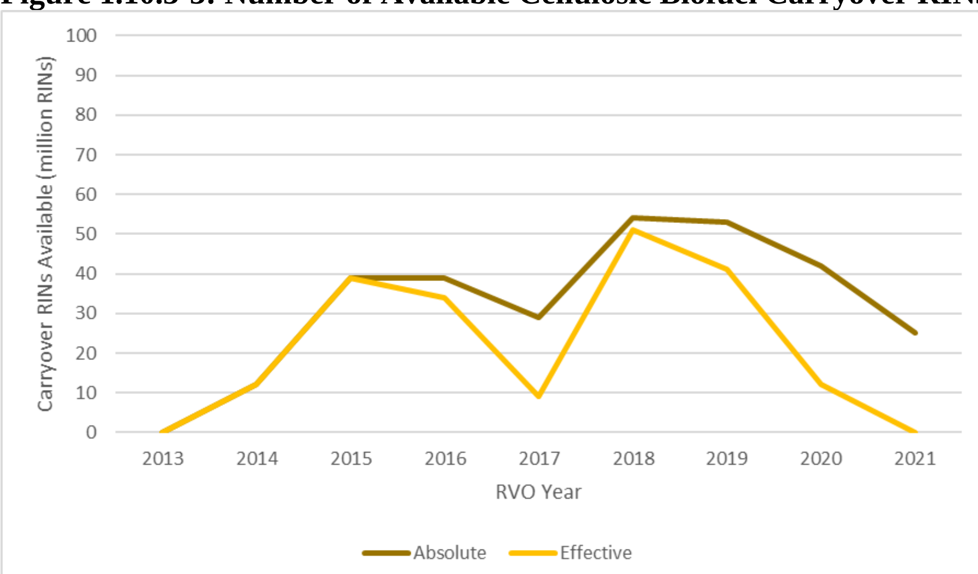


Figure 1.10.3-3: Number of Available Cellulosic Biofuel Carryover RINs



1.10.4 EMTS RIN Data

Table 1.10.4-1: RINs Retired by Importers, Refiners, and Exporters in the 2021 Compliance Year[a]

RIN Type	Year	Importers	Refiners	Exporters	Total
D3	2020	1,278,365	39,587,962	0	40,866,327
	2021	20,458,104	517,791,076	0	538,249,180
D4	2020	3,113,161	72,344,765	4,488,704	79,946,630
	2021	166,008,756	4,046,472,627	544,728,433	4,757,209,816
D5	2020	259,135	33,761,698	0	34,020,833
	2021	7,816,733	221,242,368	487,164	229,546,265
D6	2020	45,309,368	1,582,509,068	22,800,328	1,650,618,764
	2021	506,006,642	12,255,894,529	296,418,521	13,058,319,692
D7	2020	0	0	0	0
	2021	0	0	0	0
Total		750,250,264	18,769,604,093	868,923,150	20,388,777,507

[a] Data current as of May 17, 2023, and compiled from Table 3 at https://www.epa.gov/fuels-registration-reporting-and-compliance-help/annual-compliance-data-obligated-parties-and.

Table 1.10.4-2: 2021 RIN Errors[a]

RIN Type	Import Volume Correction	Invalid RIN	Volume error correction	Total
Retirement Code	*30*	*50*	*60*	--
D3	0	5,205,881	0	5,205,881
D4	0	1,622,929	329,637	1,952,566
D5	0	824,414	5,736	830,150
D6	0	9,859,895	3,728,791	13,588,686
D7	0	0	0	0
Total	0	17,513,119	4,064,164	21,577,283

[a] Data from April 2023 and compiled from https://www.epa.gov/system/files/other-files/2023-05/retiretransaction_Apr2023.csv.

Table 1.10.4-3: Other 2021 RIN Retirements[a]

RIN Type	Reported spill	Contaminated or spoiled fuel	Renewable fuel used in an ocean-going vessel	Enforcement Obligation
Retirement Code	*10*	*20*	*40*	*70*
D3	0	0	0	0
D4	6,277	170,062	46,179	37,458
D5	0	36,820	0	0
D6	15,723	80,910	0	621,738
D7	0	0	0	0
Total	22,000	287,792	46,179	659,196

RIN Type	Renewable fuel used or designated to be used in any application that is not transportation fuel heating oil or jet fuel	Delayed RIN Retire per 80.1426(g)(3) only	Remedial action - Retirement pursuant to 80.1431(c)
Retirement Code	*90*	*100*	*110*
D3	0	0	188,456
D4	47,826,467	0	638,669
D5	0	0	105,420
D6	135,074,542	0	3,650,317
D7	0	0	0
Total	182,901,009	0	4,582,862

RIN Type	Remediation of Invalid RIN Use for Compliance	Voluntary RIN Retirement	Feedstock using renewable fuel with RINs	Total
Retirement Code	*130*	*160*	*170*	--
D3	0	0	0	188,456
D4	0	0	8,179,164	56,904,276
D5	0	0	0	142,240
D6	198,545	0	0	139,641,775
D7	0	0	0	0
Total	198,545	0	8,179,164	196,876,747

[a] Data from April 2023 and compiled from https://www.epa.gov/system/files/other-files/2023-05/retiretransaction_Apr2023.csv.

1.11 Gasoline and Diesel Projections

This section reviews the accuracy of the projected volumes of gasoline and diesel used to calculate the percentage standards. In Chapter 1.11.1, we discuss the differences between EIA's projections of gasoline and diesel volumes and those volumes reported by obligated parties under the RFS program. In Chapter 1.11.2, we provide possible explanations for these differences. In Chapter 1.11.3, we detail the calculations used to create an additional adjustment factor to EIA's gasoline and diesel volumes in order to improve their agreement with those volumes reported by obligated parties.

1.11.1 Difference Between EIA and Obligated Party Reported Volumes

In the 2020–2022 final rule, we revised the 2020 percentage standards such that the required volumes of renewable fuel for each RFS category were set to the actual volumes of those renewable fuels used in that year, as provided by EMTS RIN generation data.[105] In tandem, we used the actual volumes of gasoline and diesel used in 2020, taken from EIA's STEO Data Browser, to calculate the revised percentage standards for 2020. Based on these calculations, we expected that the obligated volume of gasoline and diesel reported by obligated parties for 2020 would be virtually identical to the volume provided by EIA such that the total number of RINs required to be retired for 2020 compliance would equal the volume of total renewable fuel used to establish the revised 2020 total renewable fuel percentage standard. This would result in neither a net gain nor net loss of RINs in the number of available carryover RINs as described in the 2020–2022 final rule. We used the same approach to establish the 2021 standards in that same action—namely, using the actual volumes of renewable fuel and gasoline and diesel to calculate the 2021 percentage standards, with the expectation that the number of available carryover RINs would remain static going into 2022, and allow us to establish market-forcing standards for 2022.[106]

Upon review of the 2020 compliance report data submitted on December 1, 2022, however, we noticed an unexpected and significant difference between the volume of obligated gasoline and diesel reported by obligated parties and the volume of gasoline and diesel provided by EIA that we used to calculate the revised 2020 percentage standards. Specifically, obligated parties reported a total obligated gasoline and diesel volume of 167.4 billion gallons, whereas the 2020 percentage standards were based on a total gasoline and diesel volume of 158.2 billion gallons. As a result, rather than the intended 17.13 billion RINs being required for 2020 compliance, obligated parties reported a total RVO of 18.11 billion RINs for 2020. In other words, this 9-billion-gallon discrepancy in the gasoline and diesel volume resulted in a total 2020 RVO 980 million RINs more than the actual volume of renewable fuels used in 2020 that was intended.

A similar difference was observed upon review of the 2021 compliance report data submitted on March 31, 2023. Specifically, obligated parties reported a total obligated gasoline and diesel volume of 177.1 billion gallons, whereas the 2021 percentage standards were based on a total gasoline and diesel volume of 168.4 billion gallons. As a result, rather than the intended

[105] 87 FR 39600, 39602 (July 1, 2022).
[106] 87 FR 39600, 39602–03 (July 1, 2022).

18.84 billion RINs being required for 2021 compliance, obligated parties reported a total RVO of 19.82 billion RINs for 2021. In other words, this 9-billion-gallon discrepancy in the gasoline and diesel volume resulted in a total 2021 RVO 980 million RINs more than the actual volume of renewable fuels used in 2021 that was intended.

In order to determine whether this difference between obligated party-reported and EIA gasoline and diesel volumes was an issue limited to the 2020 and 2021 compliance years—possibly attributable to the onset of the COVID-19 pandemic—we made the same comparison for all compliance years dating back to 2013. To do so, we made an adjustment to the gasoline and diesel volumes reported by obligated parties to better align it with EIA's estimate of non-renewable gasoline and diesel volumes. Small refineries that receive an exemption from their RFS obligations under 40 CFR 80.1441 are not required to submit a compliance report for the year in which they receive an exemption and, as a result, the volumes of gasoline and diesel they produce in that year are not reported to EPA.[107] To adjust for this, we added the unreported volume of gasoline and diesel from exempt small refineries—using the volumes projected by the exempted small refineries in their small refinery exemption (SRE) petitions—to the total obligated volume of gasoline and diesel reported by obligated parties.[108] The results are provided in Table 1.11.1-1.

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[107] EIA's estimate is based on the total volume of gasoline and diesel consumed in the United States in a given year, irrespective of where or by whom the fuel was produced. This means that fuel produced by exempt small refineries is included in EIA's estimates, but is not captured in the volumes reported to EPA.

[108] While for most years we were able to simply add the estimated volume of exempt gasoline and diesel from EPA's SRE website (Table 1, https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rfs-small-refinery-exemptions) to the total reported volume of gasoline and diesel for that year (Table 1, https://www.epa.gov/fuels-registration-reporting-and-compliance-help/annual-compliance-data-obligated-parties-and), a different approach was used for 2018. For this year, EPA had initially exempted over 13.4 billion gallons of gasoline and diesel, but in the "April 2022 Denial of Petitions for RFS Small Refinery Exemptions," EPA-420-R-22-005 ("April 2022 SRE Denial Action"), EPA subsequently denied all of those previously-granted SRE petitions upon remand and the total reported exempt volume of gasoline and diesel is now listed as 0 gallons on the SRE website. In a companion action issued at the same time, the "April 2022 Alternative RFS Compliance Demonstration Compliance Approach for Certain Small Refineries," EPA-420-R-22-006 ("April 2022 Compliance Action"), EPA allowed the 31 small refineries covered by the April 2022 SRE Denial Action to resubmit their 2018 RFS annual compliance reports with zero deficit carryforward and no additional RIN retirements. In analyzing the 2018 data, however, only 2.8 billion gallons of additional gasoline and diesel has been reported since the April 2022 SRE Denial Action, and so much of that initially exempt 13.4 billion gallons seemingly remains unreported. As such, we added 10.6 billion gallons (13.4 – 2.8 = 10.6) to the reported volume of gasoline and diesel for 2018.

Table 1.11.1-1: Adjusted Volumes of Gasoline and Diesel (billion gallons)

Year	Reported Volume of Gasoline and Diesel[a]	Unreported SRE Volumes[b]	Total Adjusted Volume of Gasoline and Diesel	EIA Actual Volume of Gasoline and Diesel[c]	Absolute Difference	Relative Difference
2013	173.0	2.0	175.0	171.1	-3.9	-2.2%
2014	175.9	2.3	178.2	174.6	-3.6	-2.0%
2015	178.4	3.1	181.5	178.0	-3.5	-1.9%
2016	173.6	7.0	180.6	178.5	-2.1	-1.2%
2017	167.4	16.1	183.4	179.5	-3.9	-2.1%
2018	176.0	10.6	186.6	182.1	-4.5	-2.4%
2019	187.4	0.0	187.4	180.7	-6.7	-3.6%
2020	167.4	0.0	167.4	157.7	-9.7	-5.8%
2021	177.1	0.0	177.1	171.5	-5.6	-3.2%

[a] Source: Table 1, https://www.epa.gov/fuels-registration-reporting-and-compliance-help/annual-compliance-data-obligated-parties-and.
[b] Source: Table 1, https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rfs-small-refinery-exemptions (for all years except 2018). For 2018, see footnote 108.
[c] Source: EIA STEO Data Browser (adjusted to exclude fuel used in Alaska and ocean-going vessels).

As the figures in Table 1.11.1-1 demonstrate, the volume of gasoline and diesel reported by obligated parties and adjusted to reflect unreported SRE volumes has been consistently greater than the volume reported by EIA.[109] More importantly for purposes of the present discussion, this difference has grown in recent years, leading to the retirement of more RINs by obligated parties in 2020 and 2021 than EPA intended.

It is significant that the difference between the adjusted reported volume of gasoline and diesel by obligated parties and the volume reported by EIA is consistently in one direction (i.e., EIA's volume of gasoline and diesel has always been below the adjusted reported volume of gasoline and diesel by obligated parties) and appears to be growing in magnitude. When the obligated volume of gasoline and diesel (used by obligated parties for compliance) is higher than volume of gasoline and diesel provided by EIA (used by EPA to set the standards), the percentage standards are consequentially more stringent than necessary to achieve the intended renewable fuel volumes. This is due to the fact that, in simple terms, percentage standards are calculated by dividing renewable fuel volume by gasoline and diesel volume. For 2020 and 2021, the ultimate result of this difference in gasoline and diesel volumes is that approximately 980 million RINs and 880 million RINs, respectively, will be retired by obligated parties in excess of

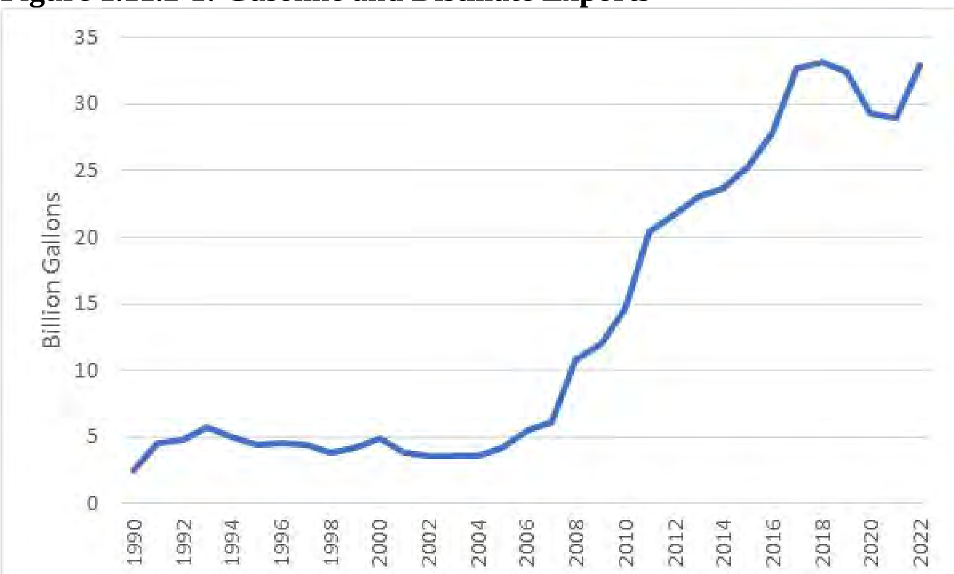
[109] This difference went largely unnoticed until now because, until recently, in many years we had granted significant numbers of SREs such that the volume of gasoline and diesel reported to EPA was below that of EIA's projected volume of gasoline and diesel used to calculate the percentage standards. See, e.g., 2016–2018 in Table 1, https://www.epa.gov/fuels-registration-reporting-and-compliance-help/annual-compliance-data-obligated-parties-and. In other words, SREs were masking the discrepancy and it was not until 2020—when the percentage standards were revised retroactively to the actual volumes and no SREs were granted—that it became apparent that there was an issue with the gasoline and diesel volumes used to set the standards in comparison to the volumes used for compliance.

the level that we intended, leading to an unanticipated drawdown of the number of available carryover RINs.[110]

1.11.2 Possible Reasons for Difference Between EIA and Obligated Party Reported Volumes

At the time the RFS program was created, exports of gasoline and diesel averaged around 4-5 billion gallons per year. Since that time, however, at the same time renewable fuel use has expanded, exports of gasoline and diesel have grown significantly and now average around 30 billion gallons per year, as shown in Figure 1.11.2-1. For the reasons discussed in the following sections, we believe that exported gasoline and diesel is the main source of the difference discussed in Chapter 1.11.1.

Figure 1.11.2-1: Gasoline and Distillate Exports



Data Source: EIA Finished Motor Gasoline and Distillate Fuel Oil Export Data

1.11.2.1 Treatment of Exports Under the RFS Program

While EPA's implementation of the RFS program is intended to impose an obligation exclusively on gasoline and diesel that is consumed in the U.S.,[111] only gasoline and diesel that a refiner designates for export at the refinery[112] is actually able to be excluded from incurring an

[110] In the 2020–2022 final rule, EPA expected that the number of available carryover RINs would remain static after compliance with the 2020 and 2021 standards. However, as discussed in Chapter 1.10 and Preamble Section III.C.4, the effective number of available carryover RINs has been significantly and unexpectedly drawn down as a result of 2020 and 2021 compliance.

[111] Gasoline and diesel used outside the RFS covered area is specifically excluded from incurring an RVO under 40 CFR 1407(f)(5).

[112] We have always intended that exported gasoline and diesel obligated under the RFS program be treated consistently with how exported gasoline and diesel is treated under EPA's fuel quality regulations. In order for a fuel to be exempt from EPA's fuel quality standards, the fuel must be segregated from non-exempted fuel from the point

RVO.[113] Conversely, a refiner remains responsible for satisfying the RVO associated with the fuel it produces even if that fuel is sold in the U.S. but is later redesignated for export downstream. We believe that the majority of the exported gasoline and diesel volumes over the years have likely been excluded by obligated parties in their RVO calculations in order to avoid the added cost of the RIN obligation.

However, a considerable portion of these gasoline and diesel exports are also likely exported by downstream parties opportunistically (i.e., downstream parties redesignate fuel that was intended to be used domestically as instead fuel for export) in situations where market pricing supports it despite the RIN cost differential. These exports show up as exported volume collected by the U.S. Census Bureau in EIA data, but are not accounted for by obligated parties in the volumes reported to EPA (i.e., obligated parties report an obligated volume of gasoline and diesel that likely includes some volume of fuel that was in fact exported downstream).

In past years, this difference was consistently around 2-3% based on the data shown in Table 1.11.1-1. However, in 2020 and 2021 the difference increased significantly. The timing of this corresponded to significant changes domestically and internationally in gasoline and diesel prices, which may have increased the opportunity for exports to occur by downstream parties despite the RIN cost associated with the exported fuel. While we sought comment in the 2020 proposed rule on creating a mechanism by which refiners could exclude gasoline and diesel that is redesignated for export by a downstream party,[114] we did not finalize such provisions in the 2020 final rule.[115]

1.11.2.2 Treatment of Exports by EIA

While the treatment of exports under the RFS program is likely a significant contributor to the difference in obligated party and EIA gasoline and diesel volumes, it is likely that the treatment of exports by EIA is also a contributor. Using EIA's reported volumes of gasoline and ethanol consumption, the average concentration of ethanol in gasoline is calculated to have been 10.39% in 2022. However, this is an impossibly high number given what we know about consumption of E15 and E85 in the United States. Specifically, the number of retail service stations offering these two fuel blends is too small to support the necessary sales volumes for the

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of designation to the point that the fuel is ultimately exported (40 CFR 1090.645) and the fuel must be designated for export prior to leaving the facility where it was produced (40 CFR 1090.1005(b)). As noted in the Fuels Regulatory Streamlining Rule, these provisions were transferred from 40 CFR part 80 (see 85 FR 78430–31, December 4, 2020).

[113] When the RFS regulatory provisions were designed, EPA allowed obligated parties to exclude exported gasoline and diesel volumes that they themselves exported or controlled to the point of export, but for implementation streamlining reasons did not account for downstream opportunistic exports. For example, if an entity took delivery of gasoline or diesel off a pipeline, but chose to export the fuel rather than sell it domestically, the upstream refinery that produced the fuel would still incur an RVO for the volumes in question. This was also at a time when RIN prices were low and renewable fuels were being blended into the gasoline and diesel fuel pools in excess of the RFS program mandates, so any excess renewable fuel obligation that this may have created was negligible.

[114] 84 FR 36801 (July 29, 2019).

[115] As part of the 2020 final rule, we stated that "While we are not at this time expanding the NTDF redesignation provisions to allow refiners to exclude exporter gasoline, we may consider doing so in the future." "Renewable Fuel Standard Program - Standards for 2020 and Biomass-Based Diesel Volume for 2021 and Other Changes: Response to Comments," Chapter 9.1, pg 194.

average ethanol concentration to be that high. Since EIA's estimate of overall ethanol consumption mirrors very closely that reported to EPA in EMTS, the implication is that the consumption volume of gasoline reported by EIA is likely an underestimate of the actual volumes consumed in the U.S.

Based on recent discussions with EIA, we believe that some portion of gasoline is being exported after being blended with renewable fuel (e.g., E10), but is being reported to EIA as E0. This means that the ethanol portion of this exported gasoline is being incorrectly subtracted from the total volume of gasoline consumed in the U.S., resulting in EIA's gasoline volumes being lower than they should be. A similar issue with exports of diesel fuel may exist, but because of how biodiesel and renewable diesel is blended, we believe this is less likely to be a significant volume.

1.11.3 Gasoline and Diesel Projection Adjustment

As discussed in the previous section, at the outset of RFS program implementation, exports of gasoline and diesel were relatively low and there was comparatively little opportunistic exporting of obligated fuel by downstream entities. Today, however, exports of gasoline and diesel have increased substantially. We now have reason to believe that a non-trivial volume of this exported fuel is obligated gasoline and diesel that downstream parties have redesignated for export because they are able to make a profit doing so even with the RIN obligation attached to the fuel.

Without a mechanism by which obligated parties can account for this fuel when calculating their production of obligated fuel, the nationwide volume of gasoline and diesel reported by obligated parties is expected to remain higher than EIA's reported volume of gasoline and diesel consumed in the U.S. As a result, compliance with the RFS standards is likely to require higher volumes of renewable fuels than were intended by EPA in establishing the percentage standards using EIA's projections. This bias is clearly not providing an accurate projection of the volume of gasoline and diesel reported by obligated parties for RFS compliance, and therefore requires that we make a correction to maintain program integrity.

In this final rule we are not in a position to finalize and implement the mechanism on which we sought comment in the 2020 proposed rule given the time available. Doing so would also not address the portion of the difference attributable to exports in EIA's projections. However, in light of the unintended consequences of the difference between the volumes of gasoline and diesel reported by obligated parties and those reported by EIA, we are compelled to take steps to more accurately project the gasoline and diesel volumes for 2023-2025 that will be reported by obligated parties such that the renewable fuel volumes ultimately required by the RFS percentage standards would be expected to match the volumes used in Preamble Section VII.C to calculate those percentage standards. As discussed above, the total adjusted volume of gasoline and diesel reported by obligated parties has been consistently higher than the volume of gasoline and diesel reported by EIA, upon whose forecast we are basing our percentage standards. In using EIA's forecasts, we have, in the past, required more renewable fuel than our rulemakings intended, which has resulted in a corresponding drawdown of the number of available carryover RINs.

In order to better match the percentage standards with the volumes we are promulgating, we are applying an additional adjustment factor to EIA's projected volume of gasoline and diesel used to calculate the percentage standards in order to make it more representative of the gasoline and diesel volumes obligated parties are expected to report when they ultimately comply with the 2023-2025 standards.[116] This factor will increase the projected gasoline and diesel volumes beyond those projected by EIA for each of these three years, thereby slightly lowering the percentage standards in order to compensate for the difference between EIA's projected volume of gasoline and diesel and the volume reported by obligated parties. This adjustment does not affect EPA's determination of the renewable fuel volumes used in setting the percentage standards. Rather, it is a necessary step to ensure that the actual renewable fuel volumes required to be consumed in the market match the targeted volumes.

To determine this adjustment factor, we compared EIA's forecasts of gasoline and diesel in previous AEOs to the actual volume of gasoline and diesel reported by obligated parties.[117] While we currently have compliance data through 2021, we believe that the sudden and dramatic reduction of gasoline and diesel production in 2020 as a result of the COVID-19 pandemic warrants the exclusion of 2020 from any comparison of forecast versus actual data. As such, we limited our comparison to the 2013–2019 and 2021 compliance years.

Under the presumption that AEO forecasts of gasoline and diesel are likely to be less accurate for years further into the future, we conducted our analysis separately for one-year forecasts, two-year forecasts, and three-year forecasts. For instance, the volumes for 2016 that were forecast in AEO2016 represented one-year forecasts, the volumes for 2017 that were forecast in AEO2016 represented two-year forecasts, and so on. We used future gasoline and diesel forecasts for AEO2011 through AEO2021 for forecast years 2013 through 2021, adjusted downward to remove all renewable fuel, consumption in Alaska, and consumption by ocean-going vessels to be consistent with the volumes used to calculated percentage standards and the production volumes reported by obligated parties. We then compared the resulting adjusted AEO forecasts to the volumes reported by obligated parties for the same years. The results are shown in Tables 1.11.3-1 through 3.

[116] We note that we already make several other adjustments to EIA's projected gasoline and diesel volumes, including subtracting volumes of gasoline and diesel used in Alaska and volumes of diesel used in ocean-going vessels. These adjustments—including the new AEO projection adjustment factor—are simply intended to more accurately reflect the actual volume of gasoline and diesel reported by obligated parties.

[117] As discussed in Preamble Section VII.A, while we previously relied on EIA's STEO as our source of projected gasoline and diesel volumes, for this action covering years through 2025 we must use EIA's AEO for gasoline and diesel projections and therefore need to evaluate its projections—rather than STEO's—against the gasoline and diesel volumes reported by obligated parties in order to calculate the adjustment factors.

Table 1.11.3-1: Comparison of One-Year AEO Forecasts and Corresponding Obligated Party Reported Volumes of Gasoline and Diesel

AEO Edition	Target Year	Gasoline + Diesel Volume (billion gallons)			Percent Difference
		AEO Forecast[a]	Adjusted AEO Forecast[b,c]	Obligated Party Reported Volume	
2013	2013	186.9	170.8	175.0	2.4%
2014	2014	188.1	172.5	178.2	3.3%
2015	2015	196.2	178.7	181.5	1.5%
2016	2016	200.0	180.7	180.6	0.0%
2017	2017	202.2	182.8	183.4	0.3%
2018	2018	202.5	181.6	186.6	2.8%
2019	2019	204.1	182.9	187.4	2.5%
2021	2021	193.6	173.2	177.1	2.2%

[a] Gasoline and diesel consumption derived from AEO Table 11.
[b] Adjustments include subtraction of renewable fuels, consumption in Alaska, and consumption by ocean-going vessels.
[c] Ethanol consumed in gasoline and E85 derived from AEO Table 2. Biodiesel, renewable diesel, and other biomass-derived liquids consumption derived from AEO Table 11. Consumption in Alaska and ocean-going vessels consistent with the volumes used to establish the applicable percentage standards.

Table 1.11.3-2: Comparison of Two-Year AEO Forecasts and Corresponding Obligated Party Reported Volumes of Gasoline and Diesel

AEO Edition	Target Year	Gasoline + Diesel Volume (billion gallons)			Percent Difference
		AEO Forecast[a]	Adjusted AEO Forecast[b,c]	Obligated Party Reported Volume	
2012	2013	191.8	175.5	175.0	-0.3%
2013	2014	188.3	171.8	178.2	3.8%
2014	2015	190.8	174.9	181.5	3.8%
2015	2016	196.5	179.0	180.6	0.9%
2016	2017	201.5	181.9	183.4	0.8%
2017	2018	199.0	179.2	186.6	4.1%
2018	2019	198.7	177.8	187.4	5.4%

[a] Gasoline and diesel consumption derived from AEO Table 11.
[b] Adjustments include subtraction of renewable fuels, consumption in Alaska, and consumption by ocean-going vessels.
[c] Ethanol consumed in gasoline and E85 derived from AEO Table 2. Biodiesel, renewable diesel, and other biomass-derived liquids consumption derived from AEO Table 11. Consumption in Alaska and ocean-going vessels consistent with the volumes used to establish the applicable percentage standards.

Table 1.11.3-3: Comparison of Three-Year AEO Forecasts and Corresponding Obligated Party Reported Volumes of Gasoline and Diesel

AEO Edition	Target Year	Gasoline + Diesel Volume (billion gallons)			Percent Difference
		AEO Forecast[a]	Adjusted AEO Forecast[b,c]	Obligated Party Reported Volume	
2011	2013	199.6	182.1	175.0	-3.9%
2012	2014	193.0	176.3	178.2	1.1%
2013	2015	189.6	172.7	181.5	5.1%
2014	2016	191.8	175.9	180.6	2.7%
2015	2017	192.6	174.2	183.4	5.3%
2016	2018	200.6	180.7	186.6	3.3%
2017	2019	198.9	178.9	187.4	4.8%

[a] Gasoline and diesel consumption derived from AEO Table 11.
[b] Adjustments include subtraction of renewable fuels, consumption in Alaska, and consumption by ocean-going vessels.
[c] Ethanol consumed in gasoline and E85 derived from AEO Table 2. Biodiesel, renewable diesel, and other biomass-derived liquids consumption derived from AEO Table 11. Consumption in Alaska and ocean-going vessels consistent with the volumes used to establish the applicable percentage standards.

While the percent difference values appeared to exhibit a slightly increasing trend over time, there was also considerable variability. Under the premise that data from more recent years is likely to provide a better basis for making future projections than data for earlier years, we used a weighted average of percent differences for all years where the weighting was higher for more recent years and lower for earlier years. Specifically, the weighting factor for any given year was twice as large as the weighting factor for the previous year. This approach is consistent with that taken to project volumes of imported sugarcane ethanol and other advanced biofuel as discussed in Chapters 6.3 and 6.4, respectively. The resulting weighted averages of the percent differences are shown in Table 1.11.3-4.

Table 1.11.3-4: Weighted Average of Percent Differences Between Adjusted AEO Forecasts and Obligated Party Reported Volumes of Gasoline and Diesel

One-year forecasts	2.2%
Two-year forecasts	4.1%
Three-year forecasts	4.2%

Given the variability in the percent difference values shown in Tables 1.11.3-1 through 3, we believe that taking the average of these three values in Table 1.11.3-4 to produce a single adjustment factor for simplicity’s sake makes the most sense. Therefore, we have chosen to use the average of the values from Table 1.11.3-4 as the adjustment factor when calculating the applicable percentage standards for all three years 2023–2025. This value is 3.5%. In Preamble Section VII.C, we have used this adjustment factor to increase the projected volumes for 2023–2025.

Chapter 2: Baselines

This document contains a collection of analyses examining factors identified in 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 final volumes for 2023–2025. This chapter describes our derivation of the No RFS baseline, as well as an alternative baseline representing actual renewable fuel consumption in 2022.

The No RFS baseline represents our projection of the world as it would exist if EPA did not establish volume requirements for 2023–2025.[118] 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 for 2023–2025, we note that this baseline is a hypothetical scenario because we have a statutory requirement to establish volume requirements for each year.[119] Moreover, the statute places a few key conditions on the volume requirements for years after those established in the statute,[120] and these conditions would not permit the volumes to be set equivalent to the No RFS baseline. The No RFS baseline volumes projected in this chapter 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.[121] Nevertheless, the No RFS baseline is an appropriate point of reference since it allows us to estimate the impacts of this 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 RFS volume requirements for these years.[122] 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 volumes and the No RFS baseline represent the volume changes that we analyzed for this rule. These volume changes, as detailed in Chapter 3, are the starting point for the analyses presented in this document, except where noted.

[118] Or, alternatively, if EPA established volume requirements at levels lower than what the market would have supplied anyway.
[119] CAA section 211(o)(2)(B)(ii).
[120] See Preamble Section II.C.3.
[121] 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.
[122] The analyses conducted to make this projection are described in Chapter 2.1.

In some cases, the volume changes between the No RFS baseline and the candidate volumes was 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 were insufficient and potentially misleading. For example, the candidate volume for total domestic ethanol consumption is 660–787 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,[123] and both imports and exports of biodiesel and renewable diesel.[124] 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 action. Nevertheless, we believe that the No RFS baseline better represents the overall impacts of taking an action to establish volume requirements for 2023–2025 versus not taking that action.

[123] See Chapter 6.6.
[124] See Chapter 6.2.4.

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.[125]

For the gasoline and diesel fuel prices, we use the most recent wholesale price projections by the Annual Energy Outlook 2023. Since the Energy Information Administration models much of the RFS program in its AEO modeling, some price impacts of the RFS program are likely represented in these wholesale gasoline and diesel fuel prices. The RFS impact on the AEO gasoline and diesel fuel prices will slightly bias the analysis conducted for the No RFS Baseline, however, the impact is minimal and within the accuracy of the No RFS Baseline analysis.

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

[125] The spreadsheets used to estimate the No RFS baseline for corn ethanol "Corn Ethanol No RFS Baseline for SET Final Rule" and biodiesel and renewable diesel "Biodiesel Renewable Diesel No RFS Baseline for SET final rule" are available in the docket for this action.

blended at higher blend percentages of 15% and 51-83% (i.e., E15 and E85, respectively).[126] This section discusses the blending economics of ethanol and estimates the No RFS baseline for all three of these ethanol fuel blends.

2.1.1.1 E10

The cost of blending ethanol into gasoline at 10% was analyzed by EPA in a peer reviewed technical report.[127] 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

[126] E85 (Flex Fuel), Alternative Fuels Data Center, https://afdc.energy.gov/fuels/ethanol_e85.html.
[127] "Economics of Blending 10 Percent Corn Ethanol into Gasoline," EPA-420-R-22-034, November 2022.

of assessing the overall social costs of ethanol use, but does not factor into the decision to blend ethanol as E10.

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	2.45
2024	2.13
2025	1.89

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.[128] 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.

[128] 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.[129] It is likely that refiners make their decision on

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

producing BOBs based on the economics of producing finished gasoline at terminals. In the case 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.[130] 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. The ethanol replacement costs were estimated based on a certain set of modeling conditions—projected prices for the year 2020 with crude oil priced at $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 of 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.

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

Gasoline Type	Gasoline Grade	Year		
		2023	2024	2025
Conventional Gasoline	Summertime Regular	2.10	2.12	1.98
	Summertime Premium	1.58	1.60	1.50
Reformulated Gasoline	Summer Regular	1.81	1.83	1.71
	Summer Premium	1.30	1.31	1.23
Conventional and Reformulated	Winter Regular	0.85	0.86	0.80
	Winter Premium	0.65	0.65	0.61

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.[131] The California LCFS program is estimated to provide ethanol a blending credit of 33¢/gal in 2019.[132,133] Several states also have

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[130] 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.

[131] States' Biofuels Statutory Citations; The National Agricultural Law Center; University of Arkansas, https://nationalaglawcenter.org/state-compilations/biofuels.

[132] 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.

[133] 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.[134] 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.[135] However, these prices were not projected for future years. Instead, we used projected refinery wholesale price data from AEO 2023 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.[136]

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[134] States' Biofuels Statutory Citations; The National Agricultural Law Center; https://nationalaglawcenter.org/state-compilations/biofuels.
[135] EIA; Spot Prices; https://www.eia.gov/dnav/pet/pet_pri_spt_s1_a.htm.
[136] 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.

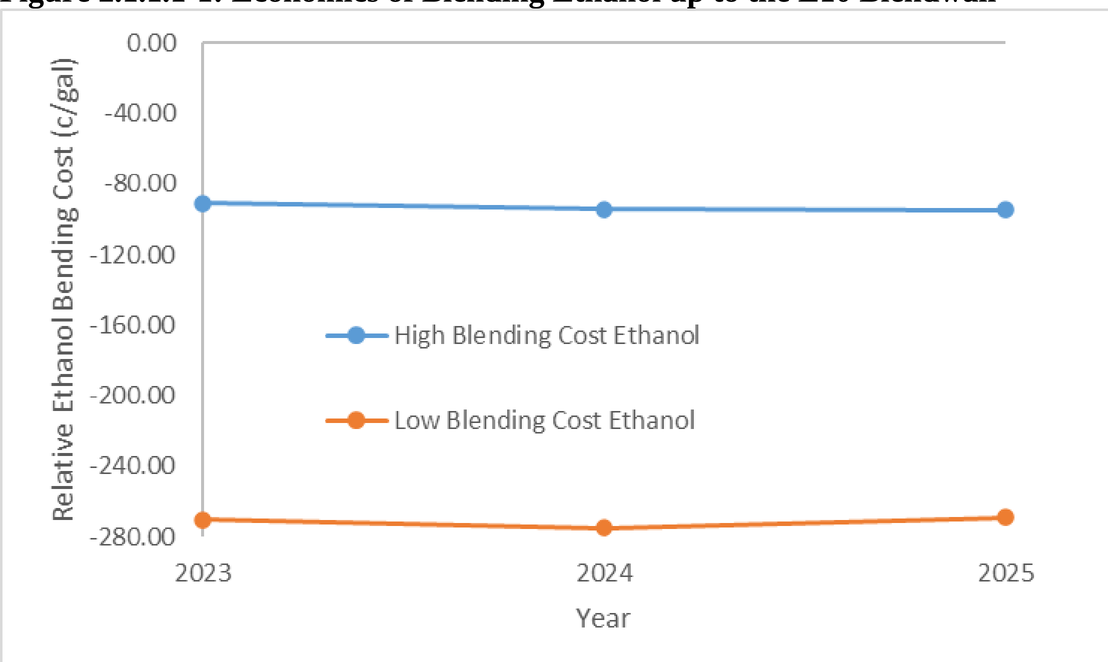
The AEO 2023 projected national average gasoline price information used to adjust gasoline prices in future years, and the national average gasoline price in 2018 that the projected gasoline prices are compared to, are summarized in Table 2.1.1.1-6. The differences in prices are additive to the state-by-state gasoline prices shown in Table 2.1.1.1-5. For example, the projected national average gasoline price in 2023 is $2.81 per gallon, which is 83¢ per gallon more than the national average gasoline price in 2018; therefore, gasoline prices in 2023 are 83¢ per gallon higher 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 2023 Projected National Average Gasoline Prices	2023	$2.81
	2024	$2.48
	2025	$2.26

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.[137]

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

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

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.

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.[138] We estimated the total cost for a typical retail station revamp to enable selling E85 to be $50,300 and that these stations sell on average 39,000 gallons of E85 per year. When amortizing this capital cost over the gallons of E85 sold, the total cost of the revamp adds 21.9¢/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)

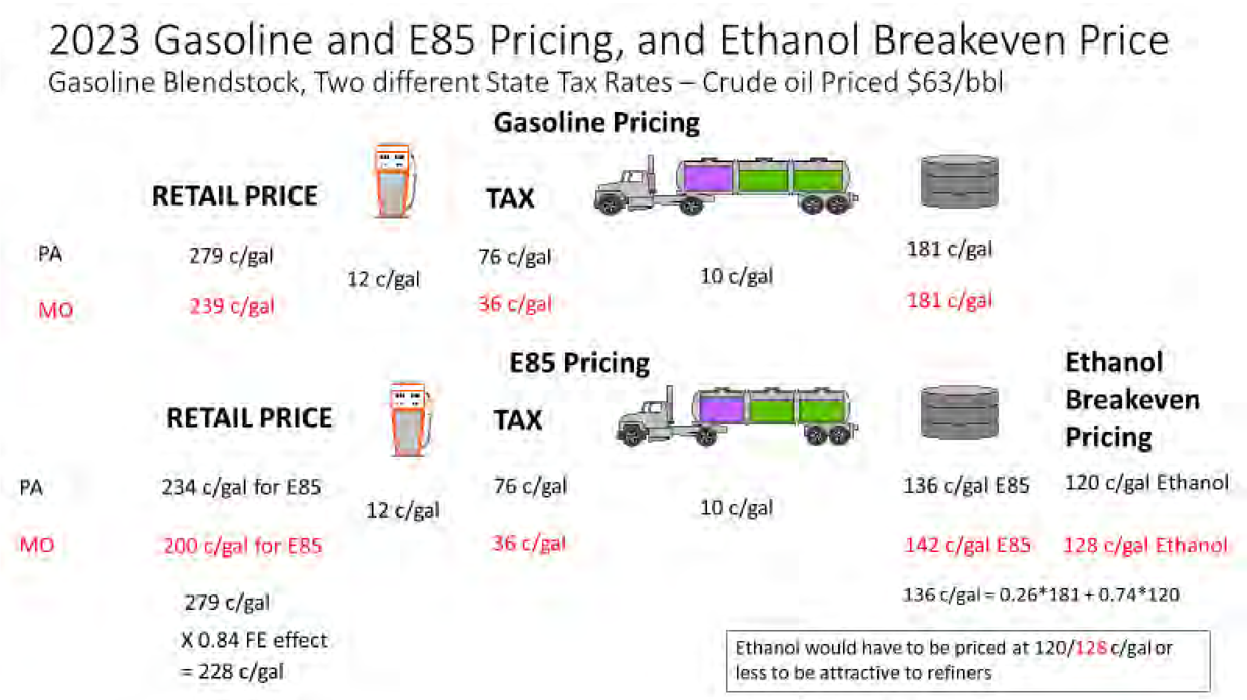
There are downstream pricing effects for E85 that require the economics of E85 be assessed differently when blending ethanol into E85 compared to blending ethanol into E10. These downstream pricing effects exist because E85 contains less energy content compared to E10—22% and 30% less when blended with 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

[138] The methodology used and the estimated costs for these revamps are discussed in Chapter 10.1.4.1.2.

information collected for E85 shows that it is typically priced 16% lower than E10 at retail.[139,140] For the No RFS analysis, we assumed that gasoline-blended E85 is priced 16% lower than E10 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



139 Retailing E85: An Analysis of Market Performance, July 2014 – August 2015; Fuels Institute; https://www.fuelsinstitute.org/Research/Reports; March 23, 2017.
140 AAA Gas Prices; https://gasprices.aaa.com; downloaded June 15, 2022.

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

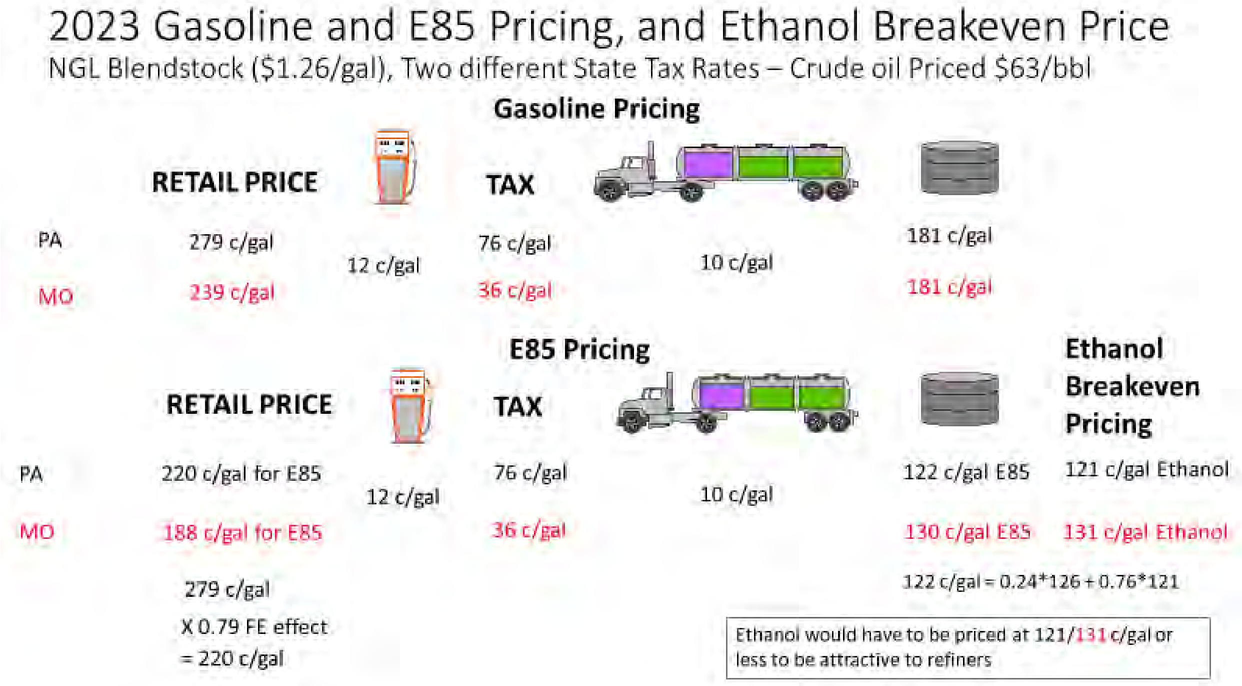


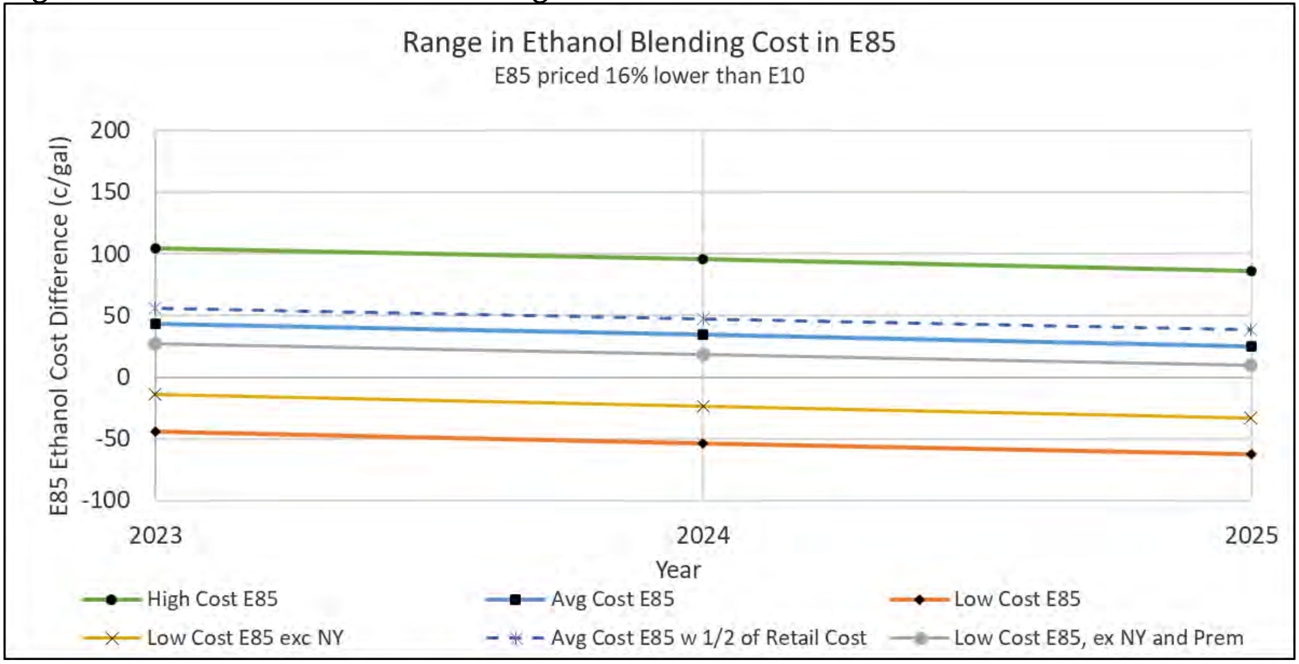
Figure 2.1.1.2-1 shows that when the E85 is blended with gasoline, the breakeven price of ethanol in E85 is 120¢/gal and 129¢/gal, which is 51¢/gal and 60¢/gal lower than the gasoline price, depending on whether the state gasoline tax is high (Pennsylvania) or low (Missouri), respectively. Similarly, 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 E85 in comparison to gasoline; 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 a couple of 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 which is over 10¢/gal over the 2023 to 2025 timeframe, 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 20¢/gal unfavorable over the years 2023 to 2025 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.[141] This retrofit cost does not have a large cost impact because E85 contains mostly ethanol, which defrays this cost.

Although our analysis shows that New York is the only state in which retail stations would potentially find it economic to offer E85 without the RFS program in place, it is not economic to do so for both regular and premium grade gasolines over all three years. This raises the question about whether E85 would be sold there without RFS program. For the No RFS baseline, we assume that E85 would not be sold in New York state without the RFS program. This assumption has little impact on the total cost of the RFS program since the volume of E85

[141] 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.

sold in New York is likely quite small. New York has about 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 3.1 million gallons of E85 per year under the No RFS baseline.

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 and now again into 2023 which further allowed E15 to take advantage of the 1-psi waiver. A number of Midwestern states petitioned EPA to remove the 1-psi waiver for E10. If the E10 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, which would remove the hurdle for selling E15 in the summer months in those states. EPA proposed in a rulemaking to grant those states' request to remove the 1 psi waiver for E10 starting in 2024;[142] however, that rulemaking would need to be finalized for that proposed action to take place.[143]

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)

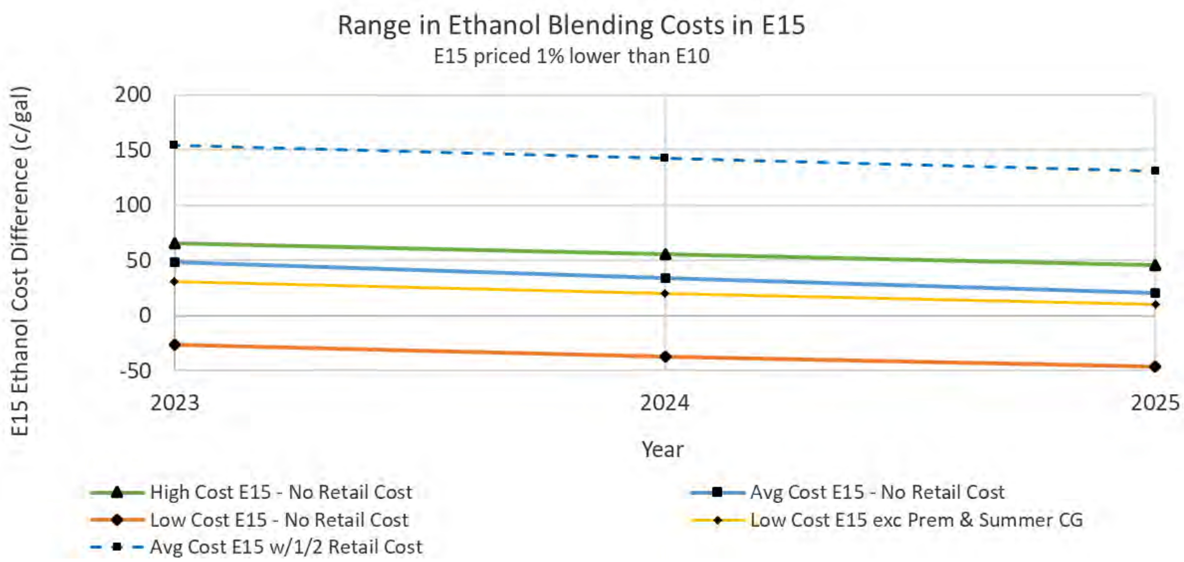
The retail costs for E15 are estimated based on the investments needed to offer E15 at retail stations and the estimated throughput at E15 stations.[144] We estimated the total cost for a typical retail station revamp to enable selling E15 to be $133,000, and that these stations sell on average 180,000 gallons of E15 per year. When amortizing this capital cost over the gallons of E15 sold, the total cost of the revamp adds 203¢/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.[145] Since E15 contains 1.8% less energy than E10, we assumed that E15 is priced 1.2%, or about 3¢/gal, less than E10.

[142] 88 FR 13758, March 6, 2023.
[143] Providing E15 with a 1-psi waiver or removing the E10 1-psi waiver—either of which would allow E15 to use the same BOB as E10—would simply remove a logistical barrier to the use of E15 during summer months. However, E15 use under a No RFS Baseline would still be governed by the relative economics of blending additional ethanol into E10 gasoline relative to continuing to use petroleum gasoline.
[144] The methodology used and the estimated costs for these revamps are discussed in Chapter 10.1.4.1.2.
[145] E85, which contains 74% ethanol and 21% less energy than E10, is typically priced 16% lower 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.

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 $132,000, and that the HBIIP program subsidized half the cost, the retail station is estimated to need to cover a cost of about $1/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 about a -40¢/gal blending cost for ethanol. However, similar to E85, this gasoline market is comprised primarily of premium gasoline, and in a few cases summertime regular grade gasoline. Since the premium gasoline market is very small, the uncertainty about summertime blending would likely dissuade retailers from wanting to sell E15. The next most economic gasoline market includes regular grade gasoline, but its ethanol blending cost is more than 20¢/gal in 2023 to 2025. If refiners and terminal operators could overcome the steep logistical hurdles of producing and moving a separate E15 BOB to terminals and eventually to retail stations, the gained ethanol replacement value described above in the discussion about the economics of E10 ethanol for the E15 BOB would more than offset the retail cost of making E15 available, and E15 could be economical in some summertime regular gasoline markets. However, we don't believe that refiners and terminal operators would create a separate E15 BOB due to the significant hurdles until the point that E15 becomes a significant portion of the gasoline market. Thus, the ethanol blending cost analysis finds the gasoline market uneconomical for E15 in the absence of the RFS program.

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

The primary type of cellulosic biofuel that we project will generate appreciable quantities of cellulosic RINs in 2023–2025 is CNG/LNG derived from biogas. We also project that some volumes of liquid cellulosic ethanol from corn kernel fiber (CKF) 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. Furthermore, it is our expectation that the majority of ethanol produced from corn kernel fiber will be produced concurrent with and in the same process as ethanol produced from the corn starch. Thus, the economics for blending ethanol from corn kernel fiber are the same as those of corn starch ethanol. This section 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 calculated the average observed annual growth rate from 2015–2021 for California and 2017–2019 for Oregon[146] 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 2021, 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

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

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	2021	2022	2023	2024	2025
California	4.3%	303	316	330	344	359
Oregon	20.3%	4	5	6	7	8
Total	N/A	307	321	336	351	367

2.1.2.2 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 most types of liquid cellulosic biofuel production in 2023–2025.

The one likely exception is ethanol produced from CKF at existing ethanol production facilities. Many corn ethanol producers have claimed that their existing facilities are capable of producing ethanol from CKF, in some cases with the addition of cellulose enzymes and in other cases using only the natural occuring enzymes from the corn kernel. In either case, we project that the cost of producing ethanol from CKF would be the same as, or only slightly more expensive than, producing ethanol from corn starch. Because ethanol produced from CKF has the potential to receive greater incentives through programs such as California’s LCFS we project that the production of ethanol from CKF in the No RFS baseline would be equal to the production of this fuel with the volumes we are finalizing in this rule.

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.[147] 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. The resulting projected biodiesel plant gate prices are summarized in Table 2.1.3.1-1 and we also list the Food and Agricultural Policy Research Institute (FAPRI) biodiesel price projections for comparison, although the FAPRI price projections are not used in our No RFS baseline analysis.

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

Projected Production Cost	**2023**	**2024**	**2025**
Soybean Oil	5.76	4.88	4.39
Corn Oil	4.85	4.13	3.72
Waste Oil	4.46	3.81	3.44
FAPRI (for comparison only)	5.49	5.12	4.99

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

[147] USDA Economic Research Service; US Bioenergy Statistics. 2021. Table 17 Biodiesel and Diesel Prices by month.

imports and exports of biodiesel into and out of each PADD, as summarized in Table 2.1.3.1-2.[148,149,150,151,152]

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.[153]

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

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148 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.

149 Table 5; Biodiesel (B100) production by petroleum administration for defense district (PADD); US Monthly biodiesel production Report; Energy Information Administration; https://www.eia.gov/biofuels/biodiesel/production

150 Exports; Petroleum and Other Liquids; Energy Information Administration; https://www.eia.gov/dnav/pet/pet_move_exp_dc_NUS-Z00_mbbl_m.htm (some values were updated since this data was downloaded which would have a negligible impact on the analysis)

151 Imports by Area of Entry; Petroleum and Other Liquids; Energy Information Administration; https://www.eia.gov/dnav/pet/pet_move_imp_dc_NUS-Z00_mbbl_m.htm (some values were updated since this data was downloaded which would have a negligible impact on the analysis)

152 Movements by Pipeline, Tanker, Barge, and Rail between PAD Districts; Petroleum and Other Liquids Energy Information Administration; https://www.eia.gov/dnav/pet/pet_move_ptb_dc_R20-R10_mbbl_m.htm

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

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 and renewable diesel into diesel as part of the American Jobs Creation Act of 2004, which has been extended multiple times over the past 18 years. Since 2005, the federal biodiesel tax subsidy has expired multiple times, but it was always reestablished sometimes retroactively, effectively, maintaining this subsidy for each and every year. In August 2022, the biodiesel tax credit was again extended to December 31, 2024 in the Inflation Reduction Act. Given this trend for offering this blending subsidy, we assume that this $1.00 per gallon biodiesel blending subsidy will continue to be in place through 2025.

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 states 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.[154] Instead, we used projected refinery wholesale price data from AEO 2023 to adjust the 2019 refinery rack price data to represent diesel rack prices in future years. We used 2019 data instead of more 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.

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

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

	2019	2023	2024	2025		2019	2023	2024	2025
Alaska	2.43	4.46	4.27	3.97	Montana	2.00	3.67	3.52	3.27
Alabama	1.93	3.53	3.38	3.15	North Carolina	1.95	3.57	3.42	3.18
Arkansas	1.94	3.56	3.41	3.17	North Dakota	1.98	3.63	3.47	3.23
Arizona	2.07	3.80	3.64	3.39	Nebraska	1.98	3.64	3.48	3.24
California	2.20	4.04	3.87	3.60	New Hampshire	1.98	3.63	3.48	3.24
Colorado	2.02	3.70	3.54	3.29	New Jersey	1.93	3.54	3.39	3.15
Connecticut	1.96	3.60	3.45	3.21	New Mexico	2.05	3.75	3.59	3.34
District of Columbia	1.95	3.58	3.42	3.19	Nevada	2.08	3.82	3.66	3.41
Delaware	1.95	3.58	3.43	3.19	New York	2.00	3.66	3.51	3.26
Florida	1.98	3.63	3.47	3.23	Ohio	1.91	3.51	3.36	3.12
Georgia	1.94	3.56	3.41	3.17	Oklahoma	1.91	3.50	3.36	3.12
Hawaii	2.17	3.97	3.80	3.54	Oregon	2.04	3.75	3.59	3.34
Iowa	1.98	3.62	3.47	3.23	Pennsylvania	1.94	3.55	3.40	3.16
Idaho	2.01	3.68	3.53	3.28	Rhode Island	1.95	3.58	3.43	3.19
Illinois	1.88	3.44	3.29	3.06	South Carolina	1.94	3.57	3.41	3.18
Indiana	1.90	3.48	3.33	3.10	South Dakota	2.00	3.67	3.51	3.27
Kansas	1.94	3.56	3.40	3.17	Tennessee	1.94	3.56	3.41	3.17
Kentucky	1.97	3.62	3.46	3.22	Texas	1.91	3.50	3.35	3.12
Louisiana	1.88	3.45	3.30	3.07	Utah	2.05	3.77	3.61	3.36
Massachusetts	1.98	3.63	3.47	3.23	Virginia	1.95	3.58	3.42	3.19
Maryland	1.95	3.58	3.42	3.19	Vermont	1.99	3.65	3.50	3.25
Maine	1.99	3.64	3.49	3.24	Washington	1.98	3.64	3.48	3.24
Michigan	1.91	3.51	3.36	3.13	Wisconsin	1.93	3.55	3.40	3.16
Minnesota	1.99	3.66	3.50	3.26	West Virginia	1.97	3.61	3.45	3.21
Missouri	1.95	3.59	3.43	3.19	Wyoming	2.12	3.89	3.73	3.47
Mississippi	1.91	3.50	3.36	3.12	U.S. Average	1.96	3.59	3.44	3.20

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—the biodiesel volume determined by the percent mandate requirement and the diesel fuel volume sold in that state in 2019, adjusted to 2023 to 2025 by the national diesel fuel demand in those years from AEO 2023 relative to the national diesel fuel demand in 2019.[155] 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%.[156] 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

[155] EIA; Prime Supplier Sales Volume; https://www.eia.gov/dnav/pet/pet_cons_prim_dcu_nus_m.htm.
[156] 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.

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 following methodology:

Using the estimated year-by-year biodiesel volumes estimated or projected by the no RFS baseline analysis would result in large volumetric swings in some years based on the changing economics of biodiesel in those years. In reality, the marketplace is unlikely to make such swings. To avoid this problem, the following steps were taken to normalize the growth and use of biodiesel:

- Biodiesel economics were assessed historically starting in 2009 through 2022, and projected in 2023 to 2025, to determine the states where biodiesel would be economical to blend, and in what volumes.
- Biodiesel demand in any one historical year was not allowed to exceed the demand that occurred under the RFS program. Since biodiesel demand has been declining in recent years, this volume was 2376 million gallons in the year 2020.
- When combined with renewable diesel, the volumetric demand for the lowest cost biogenic oils (i.e., waste oils (FOG) and corn oil) was not allowed to exceed the total projected demand for those oils that occurred in each year under the RFS program.[157]
- The maximum demand for biodiesel in any one year for a given state was then calculated to be the average of biodiesel demand for that year and the previous three years. This step attempted to reflect how potential biodiesel investors or banks would seek to assess the economics for investing in expanding biodiesel plant capacity.

[157] Since biodiesel is a less expensive process, biodiesel use of the lower cost vegetable oils took precedence over renewable diesel. However, the mandated biodiesel volume was assumed to use a mix of vegetable oils consistent with the current fractional use of vegetable oils.

Table 2.1.3.1-7 Year-by-Year Analysis of Biodiesel Volumes for the No RFS Baseline

Year	Mandated Biodiesel Volume	Economic Biodiesel Volume	4-Year Average Volume of Economic Biodiesel Volume	Best Fit of 4-Year Volume	Total of Mandated Biodiesel Volume and 4-Year Volume
2009	102	245			
2010	135	56			
2011	125	360			
2012	126	50	178	283	409
2013	126	734	300	293	419
2014	160	571	429	304	464
2015	156	78	358	314	470
2016	170	226	402	324	494
2017	181	623	374	334	515
2018	244	309	309	345	588
2019	239	240	349	355	594
2020	242	257	357	365	607
2021	252	208	254	375	627
2022	254	222	232	386	640
2023	237	294	245	396	633
2024	225	1005	432	406	631
2025	223	1186	677	416	640

Table 2.1.3.1-8 lists the states expected to consume biodiesel under the No RFS baseline in the years 2023 to 2025 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 – the volume of biodiesel would only be produced from a particular oil feedstock if it is economic to use in that year. [158] The table lists the mandated volume by each state at the top and the volume for states where it is economical to use biodiesel just below the states with mandates, although only California and North Dakota are listed separately since these states have the largest subsidies without a mandate, and tend to be economical for multiple vegetable oil feedstocks, while the projected volumes for the other states are aggregated together. In the next row in the table, the biodiesel volume by vegetable oil type is totaled.

There are several calculations which follow to convert the volume and vegetable oil feedstock types from this yearly analysis to the estimated volume and vegetable oil feedstock types under the No RFS baseline. In the next row of the table, the "Maximum Volumes" of biodiesel volume by feedstock type is listed. This is important to reflect limits on the maximum amount of biodiesel by feedstock type. Because of the favorable economics in 2024 and 2025 for

[158] Historical diesel sales volumes from EIA and projected diesel volumes in AEO 2023 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.

using FOG and corn oil vegetable feedstocks, the maximum limit of 979 and 228 million gallons of FOG and corn oil feedstocks serves to prevent the over-consumption of these vegetable oil feedstock types.[159] This establishes the Vegetable Oil Fraction which is shown in the next row of the table. The No RFS Baseline biodiesel volumes for years 2023 to 2025 from Table 2.1.3.1-7 are then reproduced in the table, multiplied by the Vegetable Oil Fraction and summarized in the last row of the table as Biodiesel Volume by Feedstock Type.

Table 2.1.3.1-8: Biodiesel in No RFS Baseline (million gal/yr)

		2023			2024			2025		
	State	Soy Oil	Corn Oil	FOG	Soy Oil	Corn Oil	FOG	Soy Oil	Corn Oil	FOG
Volume in States with Mandates	Oregon	18	3	15	17	3	14	17	3	14
	New Mexico	17	2	15	16	2	14	16	2	14
	Minnesota	57	11	49	54	11	46	53	11	46
	Washington	11	2	9	10	2	8	10	2	8
	Pennsylvania	16	2	10	15	2	9	15	2	9
Economic Volume	California		31	134	76	16	68	75	16	67
	North Dakota		5	23	13	3	12	13	3	11
	Other States						2031		317	1820
Total of Mandated and Economic Volumes		119	58	326	200	39	2202	200	356	1990
Maximum Volumes		1093	228	979	1093	228	979	1093	228	979
Biodiesel Volume by Vegetable Oil Type		119	58	326	200	39	979	200	228	979
Vegetable Oil Fraction		0.22	0.11	0.67	0.16	0.04	0.80	0.14	0.16	0.70
Volume from Table 2.1.3.1-7		633			631			640		
Biodiesel Volume by Feedstock Type		142	69	422	103	25	502	92	103	445

For the most part, this mix of vegetable oil types is used for biodiesel for estimating costs for the No RFS Baseline, however, a few minor adjustments were made to the vegetable oil feedstock types after the No RFS Baseline analysis was conducted for renewable diesel (see Chapter 2.1.3.3 below).

[159] Although FOG is the lowest priced feedstock type and economics would normally dictate using as much of that feedstock type as the lowest cost option, many biodiesel plants cannot use FOG because of the fatty acid content which causes operational problems in their plants. Also, biodiesel plants tend to be located more in the Midwest which is the agricultural centers for the production of corn and soy oil, and the plants may actually have a lower cost and more reliable option to purchase these vegetable oil types that are produced close to their plants.

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	5.76	5.62	5.10
Corn Oil	4.85	4.81	4.38
Waste Oil	4.46	4.47	4.08

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.[160]

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.[161]

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 which is very similar to those conducted for biodiesel:

- Renewable diesel economics were assessed from 2009–2025 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.

These steps are implemented in Table 2.1.3.2-2. The first column of the table shows the estimated historical and projected future renewable diesel volumes for each individual year. The next column shows the 4-year average renewable diesel volume from 2012 to 2025. The last column shows a best fit to the 4-year average volumes, and the volumes shown for 2023 to 2025 are used for the No RFS Baseline volume.

[160] Renewable diesel has properties similar to petroleum diesel, so it can displace petroleum diesel without causing vehicle compatibility or drivability issues.
[161] Historical diesel sales volumes from EIA and projected diesel volumes in AEO 2023 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 2.1.3.2-2: Year-by-Year Analysis of Renewable Diesel (million gallons)

Year	Economic Renewable Diesel Volume	4-Year Average Volume of Economic Renewable Diesel Volume	Best Fit of 4-Year Volume
2009	2		
2010	34		
2011	0		
2012	139	44	32
2013	127	75	90
2014	234	125	148
2015	386	222	206
2016	353	275	265
2017	367	335	323
2018	402	377	381
2019	621	436	439
2020	580	493	497
2021	960	641	681
2022	1439	900	883
2023	1524	1126	1085
2024	1039	1241	1287
2025	2005	1502	1489

Table 2.1.3.2-3 lists the volume of renewable diesel which is economically favorable for blending into diesel fuel for the years 2023, 2024 and 2025. Although many states are economical for renewable diesel, particularly in 2024 and 2025 the renewable diesel is essentially only being consumed in California. For this reason, we show the potential maximum volume of renewable diesel which can be consumed in California, and we aggregated the potential consumption volume in other states. The volume of economical renewable diesel is shown by vegetable oil type, assuming that the mix of vegetable oils is consistent with the percentage of vegetable oils consumed in a recent year under the RFS program. These vegetable oil quantities are just a starting point and are adjusted when estimating the mix of vegetable oils consumed by both biodiesel and renewable diesel plants under a No RFS Baseline to ensure that the vegetable oil volume is below the established maximum volumes. The final vegetable oil volumes are shown in Table 2.1.3.3-3.

Table 2.1.3.2-3: Potential Volume of Renewable Diesel by Feedstock Type (million gallons)

Year	State	Feedstock			Total
		Soybean Oil	Corn Oil	FOG	
2023	California	0	593	2,552	3,146
	Other States	0	0	1,245	1,245
2024	California	0	564	2,427	2,991
	Other States	0	133	1,164	1,297
2025	California	1,423	297	1,275	2,995
	Other States	0	239	12,654	12,893

2.1.3.3 Final No RFS Baseline Volumes for Biodiesel and Renewable Diesel

While the volume of biodiesel and renewable diesel by feedstock type were initially estimated in Tables 2.1.3.1-8 and 2.1.3.2-3, using these volumes, particularly the renewable diesel volumes, would exceed a total volume by feedstock type that reflects a reasonable growth increase from current trends, and exceed the maximum expected volume of renewable diesel estimated in Table 2.1.3.2-2. To estimate the maximum vegetable oil volumes which could be available for producing biodiesel and renewable diesel in 2023 – 2025, we reviewed the trend in vegetable oil consumption for previous years and projected their future volumes, which is summarized in Table 2.1.3.3-1.

Table 2.1.3.3-1: Maximum Vegetable Oil Volumes

Year	Soy	Corn Oil	FOG
2023	1,948	320	1,431
2024	2,128	328	1,379
2025	2,450	336	1,442

The final No RFS Baseline volumes for biodiesel and renewable diesel that result from the calculations described in Chapters 2.1.3.1 and 2.1.3.2 above are shown in Table 2.1.3.3-2. Since FOG vegetable oil is the lowest in cost, the renewable diesel plants are assumed to use this vegetable oil feedstock up to the maximum projected amount after removing the amount consumed by biodiesel plants. A similar calculation is conducted for corn oil which is the next most cost-effective vegetable oil. Both FOG and corn oil are consumed up to the maximum projected amount. In 2025, when soy oil becomes economical to use for producing renewable diesel, some soy oil renewable diesel is projected to be produced up to the maximum amount of renewable diesel estimated to be produced in that year. Some small adjustments are made to the quantities of vegetable oils projected to be consumed by biodiesel plants to make the vegetable volumes more consistent over the three years.

Table 2.1.3.3-2 Final No RFS Baseline Volumes for Biodiesel and Renewable Diesel (million gallons)

	Biodiesel			Renewable Diesel		
Year	Soy	Corn Oil	FOG	Soy	Corn Oil	FOG
2023	142	69	422	0	75	1,009
2024	210	26	395	0	303	984
2025	198	43	398	153	292	1,044

The amount of renewable diesel in the No RFS Baseline is estimated to be much higher for this final rule RIA than it was for the DRIA. This primarily reflects the improved economics for renewable diesel fuel due to the higher projected crude oil prices.

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, and the majority did so in 2022. 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, and possibly Oregon for the same reason. Some renewable diesel would continue to be consumed in these states 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 (in million RINs) and Table 2.1.5-2 (in million gallons).

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

	2023	2024	2025
Cellulosic Biofuel	343	402	444
CNG/LNG from biogas	336	351	367
Ethanol from CKF	7	51	77
Diesel/jet fuel from wood waste/MSW	0	0	0
Total Biomass-Based Diesel	2,796	3,139	3,496
Biodiesel	948	947	959
Soybean oil	212	315	297
FOG	633	593	597
Corn oil	104	39	65
Canola oil	0	0	0
Renewable Diesel	1,843	2,188	2,532
Soybean oil	0	0	261
FOG	1,715	1,673	1,775
Corn oil	128	515	496
Canola oil	0	0	0
Jet fuel from FOG	5	5	5
Other Advanced Biofuels	226	226	226
Renewable diesel from FOG	104	104	104
Imported sugarcane ethanol	95	95	95
Domestic ethanol from waste ethanol	27	27	27
Other[a]	0	0	0
Conventional Renewable Fuel	13,185	13,224	12,992
Ethanol from corn	13,185	13,224	12,992
Renewable diesel from palm oil	0	0	0

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

Table 2.1.5-2: No RFS Baseline for 2023–2025 (million gallons)

	2023	2024	2025
Cellulosic Biofuel	343	402	444
CNG/LNG from biogas	336	351	367
Ethanol from CKF	7	51	77
Diesel/jet fuel from wood waste/MSW	0	0	0
Total Biomass-Based Diesel	1,719	1,921	2,132
Biodiesel	632	621	639
Soybean oil	141	210	198
FOG	422	395	398
Corn oil	69	26	43
Canola oil	0	0	0
Renewable Diesel	1,084	1,287	1,490
Soybean oil	0	0	0
FOG	1,009	984	1,044
Corn oil	75	303	292
Canola oil	0	0	0
Jet fuel from FOG	3	3	3
Other Advanced Biofuels	183	183	183
Renewable diesel from FOG	61	61	61
Imported sugarcane ethanol	95	95	95
Domestic ethanol from waste ethanol	27	27	27
Other[a]	0	0	0
Conventional Renewable Fuel	13,185	13,224	12,992
Ethanol from corn	13,185	13,224	12,992
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 renewable fuel consumption in 2022 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 recent past.

For the proposal, 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, but we adjusted those estimates for the proposal to be more precise.[162] For this final rule, we have instead used the actual consumption volume of each type of renewable fuel as determined

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

from EMTS data. The results are shown in Table 2.2-1 (in million RINs) and Table 2.2-2 (in million gallons).

Table 2.2-1: Actual Mix of Biofuels in 2022 (million RINs)

Cellulosic Biofuel	666
CNG/LNG from biogas	665
Ethanol from CKF	1
Diesel/jet fuel from wood waste/MSW	0
Total Biomass-Based Diesel[a]	4,944
Biodiesel	2,606
Soybean oil	1,492
FOG	519
Corn oil	195
Canola oil	400
Renewable Diesel[a]	2,314
Soybean oil[a]	498
FOG	1,460
Corn oil	356
Canola oil	0
Jet fuel from FOG	24
Other Advanced Biofuels	318
Renewable diesel from FOG	124
Imported sugarcane ethanol	81
Domestic ethanol from waste ethanol	29
Other[b]	84
Conventional Renewable Fuel	14,034
Ethanol from corn	14,034
Renewable diesel from palm oil	0

[a] Includes 250 million RINs assumed to be used to meet the supplemental volume requirement for 2022.
[b] Composed of non-cellulosic biogas, heating oil, and naphtha.

Table 2.2-2: Actual Mix of Biofuels in 2022 (million gallons)

Cellulosic Biofuel	666
CNG/LNG from biogas	665
Ethanol from CKF	1
Diesel/jet fuel from wood waste/MSW	0
Total Biomass-Based Diesel[a]	3,113
Biodiesel	1,737
Soybean oil	995
FOG	346
Corn oil	130
Canola oil	267
Renewable Diesel[a]	1,361
Soybean oil[a]	293
FOG	859
Corn oil	209
Canola oil	0
Jet fuel from FOG	14
Other Advanced Biofuels	247
Renewable diesel from FOG	73
Imported sugarcane ethanol	81
Domestic ethanol from waste ethanol	29
Other[b]	65
Conventional Renewable Fuel	14,034
Ethanol from corn	14,034
Renewable diesel from palm oil	0

[a] Includes 147 million gallons assumed to be used to meet the supplemental volume requirement for 2022.
[b] Composed of non-cellulosic biogas, heating oil, and naphtha.

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	838	1,090	1,376
Biomass-based diesel	D4	5,965	6,205	6,881
Other advanced biofuel	D5	290	290	290
Conventional renewable fuel	D6	13,845	13,955	13,779

[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 and Implied Categories (million RINs)[a]

	D Code	2023	2024	2025
Cellulosic biofuel	D3 + D7	838	1,090	1,376
Non-cellulosic advanced biofuel[b]	D4 + D5	6,255	6,495	7,171
Advanced biofuel	D3 + D4 + D5 + D7	7,093	7,585	8,547
Conventional renewable fuel[b]	D6	13,845	13,955	13,779
Total renewable fuel	All	20,938	21,540	22,326

[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 Tables 3.1-3 (in million RINs) and 3.1-4 (in million gallons).[163]

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

	2023	2024	2025
Cellulosic Biofuel	838	1,090	1,376
CNG/LNG from biogas	831	1,039	1,299
Ethanol from CKF	7	51	77
Total Biomass-Based Diesel[a]	5,965	6,205	6,881
Biodiesel	2,565	2,500	2,436
Soybean oil	1,473	1,451	1,430
FOG	481	454	427
Corn oil	173	134	95
Canola oil	438	461	484
Renewable Diesel	3,376	3,681	4,421
Soybean oil	777	1,141	1,501
FOG	1,883	1,825	1,962
Corn oil	348	406	463
Canola oil	368	309	495
Jet fuel from FOG	24	24	24
Other Advanced Biofuels	290	290	290
Renewable diesel from FOG	104	104	104
Imported sugarcane ethanol	95	95	95
Domestic ethanol from waste ethanol	27	27	27
Other[b]	64	64	64
Conventional Renewable Fuel	13,845	13,955	13,779
Ethanol from corn	13,845	13,955	13,779
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.

[163] 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 will be met with soybean oil-based renewable diesel in Chapter 3.4.

Table 3.1-4: Candidate Volumes Assessed for 2023–2025 (million gallons)

	2023	2024	2025
Cellulosic Biofuel	838	1,090	1,376
CNG/LNG from biogas	831	1,039	1,299
Ethanol from CKF	7	51	77
Total Biomass-Based Diesel[a]	3,710	3,846	4,239
Biodiesel	1,710	1,667	1,624
Soybean oil	982	967	953
FOG	321	303	285
Corn oil	115	89	63
Canola oil	292	307	323
Renewable Diesel	1,986	2,165	2,601
Soybean oil	457	641	883
FOG	1,108	1,074	1,154
Corn oil	205	239	272
Canola oil	216	182	291
Jet fuel from FOG	14	14	14
Other Advanced Biofuels	232	232	232
Renewable diesel from FOG	61	61	61
Imported sugarcane ethanol	95	95	95
Domestic ethanol from waste ethanol	27	27	27
Other[b]	49	49	49
Conventional Renewable Fuel	13,845	13,955	13,779
Ethanol from corn	13,845	13,955	13,779
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,[164] 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 the conclusion that there will 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 supplemental standard.

3.2 Volume Changes Analyzed With Respect to the No RFS Baseline

For those factors for which 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.

[164] 87 FR 39600 (July 1, 2022).

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

	2023	2024	2025
Cellulosic Biofuel	495	688	932
CNG/LNG from biogas	495	688	932
Ethanol from CKF	0	0	0
Total Biomass-Based Diesel	3,169	3,066	3,385
Biodiesel	1,617	1,554	1,478
Soybean oil	1,262	1,136	1,133
FOG	-152	-139	-170
Corn oil	70	95	31
Canola oil	438	461	484
Renewable Diesel	1,533	1,493	1,889
Soybean oil	777	1,141	1,240
FOG	168	152	187
Corn oil	221	-109	-33
Canola oil	368	309	495
Jet fuel from FOG	19	19	19
Other Advanced Biofuels	64	64	64
Renewable diesel from FOG	0	0	0
Imported sugarcane ethanol	0	0	0
Domestic ethanol from waste ethanol	0	0	0
Other[a]	64	64	64
Conventional Renewable Fuel	660	731	787
Ethanol from corn	660	731	787
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	495	688	932
CNG/LNG from biogas[a]	495	688	932
Ethanol from CKF	0	0	0
Total Biomass-Based Diesel	1,991	1,925	2,107
Biodiesel	1,078	1,036	985
Soybean oil	841	757	755
FOG	-101	-92	-113
Corn oil	46	63	20
Canola oil	292	307	323
Renewable Diesel	902	878	1,111
Soybean oil	457	671	729
FOG	99	90	110
Corn oil	130	-64	-20
Canola oil	216	182	291
Jet fuel from FOG	11	11	11
Other Advanced Biofuels	49	49	49
Renewable diesel from FOG	0	0	0
Imported sugarcane ethanol	0	0	0
Domestic ethanol from waste ethanol	0	0	0
Other[b]	49	49	49
Conventional Renewable Fuel	660	731	787
Ethanol from corn	660	731	787
Renewable diesel from palm oil	0	0	0

[a] 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 E10 would be used regardless of the RFS program but there would not be any E15 or E85 use.[165] For the analyses conducted in support of this rule we generally projected that any increase in ethanol consumption would result in a gallon-for-gallon increase in ethanol production.

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.

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

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

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 volume changes in canola oil as if they were changes in soybean oil.
2. We have treated all volume changes in renewable jet fuel as if they were changes in renewable diesel.
3. We have treated all volume changes in "Other" advanced biofuel, which is dominated by naphtha, as if they were changes in renewable diesel.[166]

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

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]	495	688	932
Biodiesel from soybean oil	1,133	1,065	1,078
Biodiesel from FOG	-101	-92	-113
Biodiesel from corn oil	46	63	20
Renewable diesel from soybean oil	710	901	1,066
Renewable diesel from FOG	115	106	126
Renewable diesel from corn oil	137	-68	-21
Ethanol from corn	660	731	787

[a] 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, we determined that FOG on average consists of 71% used cooking oil (UCO) and about 29% tallow.[167] 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	-101	-92	-113
UCO	-72	-66	-80
Tallow	-29	-27	-33
Renewable diesel from FOG	113	106	126
UCO	82	75	90
Tallow	33	31	37

[166] We assumed that the feedstocks used to produce these "other" advanced biofuels were proportional to the feedstocks used to produce renewable diesel.

[167] EIA Monthly Biofuels Capacity and Feedstocks Update - Table 2b, https://www.eia.gov/biofuels/update. Average over both 2021 and 2022.

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.

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

	2023	2024	2025
Cellulosic Biofuel	172	424	710
CNG/LNG from biogas	166	374	634
Ethanol from CKF	6	50	76
Total Biomass-Based Diesel	1,271	1,511	2,187
Biodiesel	-41	-106	-170
Soybean oil	-19	-41	-62
FOG	-38	-65	-92
Corn oil	-22	-61	-100
Canola oil	38	61	84
Renewable Diesel	1,312	1,617	2,357
Soybean oil	529	893	1,253
FOG	423	365	502
Corn oil	-8	50	107
Canola oil	368	309	495
Jet fuel from FOG	0	0	0
Other Advanced Biofuels	-28	-28	-28
Renewable diesel from FOG	-20	-20	-20
Imported sugarcane ethanol	14	14	14
Domestic ethanol from waste ethanol	-2	-2	-2
Other	-20	-20	-20
Conventional Renewable Fuel	-189	-79	-255
Ethanol from corn	-189	-79	-255
Renewable diesel from palm oil	0	0	0

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

	2023	2024	2025
Cellulosic Biofuel	172	424	710
CNG/LNG from biogas[a]	166	374	634
Ethanol from CKF	6	50	76
Total Biomass-Based Diesel	744	881	1,273
Biodiesel	-27	-71	-113
Soybean oil	-13	-27	-41
FOG	-25	-43	-61
Corn oil	-15	-41	-67
Canola oil	25	41	56
Renewable Diesel	772	951	1,386
Soybean oil	311	525	737
FOG	249	215	295
Corn oil	-5	29	63
Canola oil	216	182	291
Jet fuel from FOG	0	0	0
Other Advanced Biofuels	-15	-15	-15
Renewable diesel from FOG	-12	-12	-12
Imported sugarcane ethanol	14	14	14
Domestic ethanol from waste ethanol	-2	-2	-2
Other	-15	-15	-15
Conventional Renewable Fuel	-189	-79	-255
Ethanol from corn	-189	-79	-255

[a] CNG/LNG remains 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	309	87	203
Changes in ethanol consumption attributable to changes in E15 and E85 consumption	27	95	129
Total	336	182	332

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]	166	374	634
Ethanol from CKF	6	50	76
Biodiesel from soybean oil	13	13	15
Biodiesel from FOG	-25	-43	-61
Biodiesel from corn oil	-15	-41	-67
Renewable diesel from soybean oil	517	696	1,017
Renewable diesel from FOG	244	211	292
Renewable diesel from corn oil	-5	29	62
Ethanol from corn	-189	-79	-255

[a] CNG/LNG remains in ethanol-equivalent gallons in this table

3.4 2023 Supplemental Volume Requirement

As discussed in Preamble Section V, we are establishing a supplemental volume requirement of 250 million gallons of renewable fuel that will apply in 2023, which completes our response to the *ACE* remand. Although we are requiring this supplemental volume requirement in concert with the final volumes for 2023–2025 established under CAA section 211(o)(2)(B)(ii), the 2023 supplemental volume requirement is not established under our "set" authority, but rather our outstanding obligation from 2016 to promulgate standards under CAA section 211(o)(3)(B)(i). Additionally, as we have in the past, we rely on our authority in CAA section 211(o)(2)(A)(i) to promulgate late standards.[168] It is in fact 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 is not a segregated and uniquely categorized pool of renewable fuel. For the purposes of analyzing its impacts, we have made the

[168] In promulgating the 2009 and 2010 combined BBD standard, upheld by the D.C. Circuit in *NPRA v. EPA*, 630 F.3d 145 (2010), we utilized express authority under CAA section 211(o)(2). 75 FR 14670, 14718.

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.[169] 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	0
Palm oil renewable diesel	0

[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.

[169] 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 and draft Third Triennial Report to Congress on Biofuels, which provides additional information on environmental impacts.[170,171]

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.[172] 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.[173]

In addition to the type of biofuel, other factors may affect air quality, including but not limited to the blend level, the vehicle technology, emissions control technology, and operating conditions. However, 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 to favor higher or lower volumes. First, the largest volume changes are for renewable diesel, primarily produced from soybean oil, particularly in comparison to 2022 volumes, 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. It should also be noted that

[170] 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.
[171] EPA. Biofuels and the Environment: Third Triennial Report to Congress (Draft Report, 2022). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-18/195, 2018.
[172] EPA (2023). "Health and environmental effects of pollutants discussed in Chapter 4 of Regulatory Impact Analysis (RIA) supporting final RFS standards for 2023-2025." Memorandum from Margaret Zawacki to Docket No. EPA-HQ-OAR-2021-0427, June 2023.
[173] 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.

EPA's "anti-backsliding study" (ABS), required under CAA Section 211(v)(1), examined the impacts on air quality that might result from changes in vehicle and engine emissions associated with renewable fuel volumes of ethanol under the RFS, relative to approximately 2005 levels.[174] Hoekman et al. (2018) also reviewed available literature on potential air quality impacts for E10 versus E0 across the entire lifecycle.[175] Both studies found potential increases and decreases in ambient concentration levels of pollutants, but none of them were large, even when they considered much greater changes in ethanol volumes than are being established in this rule. The Second Triennial Report to Congress on Biofuels[176] summarized information on air quality associated with biofuels and emphasized that emissions of NO_x, SO_x, CO, VOCs, NH_3, $PM_{2.5}$, and PM_{10}, can be impacted at each stage of biofuel production, distribution, and usage. The report also noted that impacts associated with feedstock and fuel production and distribution are important to consider when evaluating the air quality impacts of biofuel production and use, along with those associated with fuel usage.[177]

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 and 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 air quality impacts of processes upstream of the end-use vehicle emissions from corn ethanol. A 2009 analysis using the GREET model concluded that criteria pollutant emissions from corn ethanol production are substantially higher than for gasoline on a mass per gasoline equivalent gallon basis.[178] A significant source of

[174] EPA (2020). Clean Air Act Section 211(v)(1) Anti-Backsliding Study. https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100ZBY1.pdf.
[175] 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.
[176] 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.
[177] The Third Triennial Report to Congress on Biofuels is in progress and the AQ impacts summarized in that draft version are consistent with what was in the Second Triennial Report to Congress on Biofuels, see https://cfpub.epa.gov/ncea/biofuels/recordisplay.cfm?deid=353055.
[178] 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.

upstream emissions from corn ethanol is production facilities.[179,180] Table 4.1.1-1 summarizes corn ethanol plant emissions, using data from the 2017 National Emissions Inventory (NEI) where available.[181] For facilities not found in the 2017 NEI, we used data from the 2016 emissions modeling platform version 1[182] or inventory estimates using facility-level volume data from the EPA moderated transaction system.[183] 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

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[179] [179] 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.

[180] 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.

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

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

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

during storage and transport. The largest emission contribution is for VOCs 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.[184] Ambient measurements also indicate concentrations of several pollutants such as NO_X, formaldehyde, and SO_2 are greater directly downwind of production facilities, up to a distance of 30 kilometers.[185]

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

CO	NH_3	NOx	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 note that ethanol volumes used domestically could be sourced from imports. Thus, it is unclear what impact imports would have on domestic production and associated 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.

[184] 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.

[185] 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), 4385–97. 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 Final Volumes Relative to No RFS Baseline (short tons)

	CO	NH_3	NOx	PM_{10}	$PM_{2.5}$	SO_2	VOC
Biorefinery Emissions	7,363	279	9,046	5,219	4,089	1,854	8,909
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	495	13	1,208	251	198	92	28,677
2024 Volume Changes	548	15	1,338	278	219	102	31,762
2025 Volume Changes	590	16	1,440	299	236	110	34,195

[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.[186] 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	6.64	0.64
CO	5.49	0.55
NO_X	6.75	0.76
PM_{10}	3.89	0.21
$PM_{2.5}$	3.05	0.19
SO_2	1.38	0.27
NH_3	0.21	0.03

[186] 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 80% of the biodiesel in 2022, with most of that being domestic soybean. Data are lacking on emission and air quality impacts of either soybean oil 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 NO_X, VOCs, CO, and $PM_{2.5}$, followed by hexane extraction and then enzyme assisted aqueous extraction process (EAEP).[187] Hum et al. (2016) compared life cycle emissions for low sulfur diesel (LSD), soybean-based biodiesel, and grease trap waste (GTW)-based biodiesel.[188] This study relied on GREET-2014 for soybean-based biodiesel impacts.[189] 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 oil 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 biodiesel than distillate.

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[187] 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.

[188] 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.

[189] 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	1.19
NOx	5.91	1.63
PM_{10}	3.93	0.45
$PM_{2.5}$	2.68	0.40
SO_2	16.30	0.59
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. Emissions at this step include both evaporative losses during dispensing the fuel, diurnal tank venting processes, and exhaust emissions from combustion during vehicle operation. 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 vehicles meeting Tier 2 and Tier 3 standards.[190,191,192,193] However, because the projected changes in volume of ethanol resulting from this action 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 oxygen 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).[194] The biodiesel effects implemented in MOVES are obtained from an analysis conducted as part of the 2010 Renewable Fuel Standard Program.[195]

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

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

190 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).
191 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.
192 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.
193 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.
194 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.
195 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).

range. As a result, it has a very high cetane index and essentially zero aromatics or sulfur content.[196] Given the paucity of data at the time MOVES3 was released, and the fact that RD is chemically identical to material that comprises 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 provide a brief review of recent studies assessing its emission impacts.

In 2020, McCaffery, *et al.*, compared ULSD (ultra-low sulfur petroleum diesel) to a 98.5% RD / 1.5% ULSD blend in a 2012 Chevrolet Silverado with Duramax engine.[197] The study used the LA92 test cycle to represent real-world driving as well as eight steady-state speed-load combinations for additional data. Emissions were sampled upstream of aftertreatment to focus on the effects of the fuel itself. 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.[198] 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.[199] 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 the California Air Resources Board concluded that RD reduced emissions of PM, NOx, hydrocarbons, and CO in diesel engine exhaust compared to petroleum diesel.[200] They also observed that RD is likely to reduce exhaust PAHs, a conclusion supported by Singer, *et al.*, in a 2015 study.[201]

[196] 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.
[197] McCaffery, C., Karavalakis, G., Durbin, T. Johnson, K. (2020) Engine-Out Emission Characteristics of a Light Duty Vehicle Operating on a Hydrogenated Vegetable Oil Renewable Diesel. SAE Paper 2020-01-0337.
[198] 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,* 307–14.
[199] 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.
[200] 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.
[201] 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.

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.

4.1.4 Air Quality Modeling

As mentioned at the beginning of Chapter 4.1, air quality impacts resulting from this action 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. 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,[202] 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 analysis (LCA) GHG emissions estimates.[203] As we did in the 2020-2022 rule, 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 oil biodiesel, landfill biogas CNG) to estimate the overall GHG impacts of the candidate

[202] 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.

[203] In this section, 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.

volumes. In the 2020-2022 rule, we applied the LCA estimates that we developed in the March 2010 RFS2 rule and in subsequent agency actions. While our existing LCA estimates for the RFS program remain within the range of more recent estimates, we acknowledge that the biofuel GHG modeling framework EPA has previously relied upon is old, and that an updated framework is needed. Thus, for this rulemaking, we are updating the approach from the 2020-2022 rule to use a range of more recent LCA estimates from the scientific literature. Given the uncertainty and variation in LCA estimates, 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. 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 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. Following this, we present a range of LCA estimates from the literature. 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.

The science associated with lifecycle assessment of biofuels remains an active area of research and discussion. Recent examples include the October 2022 report from the National Academies of Science, Engineering and Medicine (NASEM) titled "Current Methods for Life Cycle Analyses of Low-Carbon Transportation Fuels in the United States (2022)."[204] While the NASEM report does not endorse any particular numerical result or model, it provides recommendations on the application of LCA methods and areas for additional research. Another example of ongoing research and discussions comes from the Administration's sustainable aviation fuel (SAF) Grand Challenge. A workgroup that includes DOE, EPA, FAA and USDA is currently examining LCA methodologies and data needs specifically related to SAF. Our model comparison exercise, discussed in a Model Comparison Exercise Technical Document included in the docket for this rulemaking, contributes to this continuing scientific research and discussion. As EPA uses LCA modeling of transportation fuels 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 transportation fuel LCA modeling capabilities. Data and findings from recent science and the modeling comparison exercise will help inform EPA's next steps on updating its lifecycle GHG estimation methodology as part of a separate action.

4.2.1 Background on Renewable Fuel GHG Analysis for the RFS Program

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 qualifying feedstocks and have lifecycle GHG emission that are at least 20% less than the baseline petroleum-based

[204] National Academies of Sciences, Engineering, and Medicine 2022. Current Methods for Life Cycle Analyses of Low-Carbon Transportation Fuels in the United States. Washington, DC: The National Academies Press. https://doi.org/10.17226/26402.

gasoline and diesel fuels.[205] 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.”[206] 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 commodity 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 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 change emissions and other crop production emissions (e.g., from increased fertilizer use) in these other countries would be considered “indirect” or “induced” 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, with associated GHG emissions.

While the term “significant indirect emissions” requires analytical judgement, prior modeling work has indicated that the indirect impacts from land use change, livestock, and crop production can result in emissions that have a large impact on the lifecycle GHG estimates. Therefore, to be consistent with the CAA requirements, our lifecycle analyses of crop-based biofuels have taken 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.

As part of the March 2010 RFS2 rule, EPA estimated lifecycle GHG emissions attributable to different various 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 analysis for the 2010 RFS2 rule, there were no models available off the shelf that could perform the type of lifecycle analysis required under our interpretation of the CAA definition of lifecycle GHG emissions. Thus, EPA developed a new modeling framework to perform the analysis. The framework we developed used multiple models and data sources.[207] 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

[205] See 42 USC 7545(o)(1), (2)(A)(i).
[206] See 42 USC 7545(o)(1)(H).
[207] 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.

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. We sought public comment on this new framework, 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,[208] distillers sorghum oil[209]) and novel production processes involving existing feedstocks (e.g., catalytic pyrolysis and upgrading of cellulosic biomass,[210] gasification and upgrading of crop residues[211]). 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."[212] Our lifecycle analyses of various pathways are also published online.[213] 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 vary considerably. In general, we have found that renewable fuels that are not expected to have significant impacts on 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.[214] In addition, most cellulosic biofuels—which are required to meet the highest statutory lifecycle

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[208] Pathways I rule. 78 FR 14190 (March 5, 2013).
[209] Sorghum oil rule. 83 FR 37735 (August 2, 2018).
[210] Pathways I rule. 78 FR 14190 (March 5, 2013).
[211] "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.
[212] See https://www.epa.gov/fuels-registration-reporting-and-compliance-help/lifecycle-greenhouse-gas-results.
[213] 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.
[214] 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.

GHG reduction threshold of 60%—are currently produced from wastes, residues, or by-products, including landfill biogas.[215]

Since the time when EPA developed that 2010 LCA methodology, multiple researchers and analytical teams have further studied and assessed the lifecycle GHG emissions associated with transportation fuels in general and crop-based biofuels in particular. While our existing LCA estimates for the RFS program remain within the range of more recent estimates, we acknowledge that the biofuel GHG modeling framework we have relied upon to date is comparatively old, and that a better understanding of these newer models and data is needed. Accordingly, EPA has initiated work to develop updated modeling 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.[216] In the proposed rule we invited public input on various aspects of biofuel GHG modeling and LCA, and in the DRIA we included a discussion and review of available models and LCA estimates. The workshop proceedings, including the workshop presentations and the comments submitted to the workshop docket, touch on a broad and complex set of topics.[217] 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. Our model comparison exercise, discussed in the Model Comparison Exercise Technical Document, contributes to this continuing scientific research and discussion. However, as explained in Preamble Section IV.A.2, we did not ultimately rely on the model comparison exercise to evaluate the candidate volumes or to inform the volumes in this final rule.

4.2.2 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 this action 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 oil 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 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

[215] 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.
[216] 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.
[217] Docket ID No. EPA-HQ-OAR-2021-0921.

of values for considering the GHG impacts of the candidate renewable fuel volumes that change relative to the No RFS baseline.[218]

To develop the range of LCA values, we conducted a high-level review of relevant literature for the biofuel pathways that would be most likely to satisfy the candidate renewable fuel volumes.[219] Based on our review, we compiled the LCA estimates in the literature for each pathway. Given that all LCA studies and models have particular strengths and weaknesses, as well as uncertainties and limitations, our goal for this compilation of literatures estimates is to consider the ranges of published estimates, not to adjudicate which particular studies, estimates or assumptions are most appropriate. We include estimates from peer-reviewed journal articles, authoritative governmental reports, and other credible publications, such as studies by non-governmental organizations. Our review is intentionally broad and inclusive, and is informed by our experience conducting LCA evaluations of transportation fuels for the RFS program. Our review includes studies that estimate the lifecycle GHG emissions associated with the relevant biofuel pathways and the petroleum-based fuels they replace. We focused on estimates of the average type of each fuel produced in the United States.[220] For example, for corn ethanol, we focused on estimates for average corn ethanol production from natural gas-fired dry mill facilities, as that is the predominant mode of corn ethanol production in the United States.[221]

We made minor changes to the LCA ranges used in the proposed rule.[222] We reviewed the public comments and searched the literature to identify new or additional studies to add to our review. However, public commenters did not identify any additional LCA estimates that we had not already considered. Likewise, our updated search of the literature did not identify any additional estimates. The one update we made was replacing estimates from the 2021 version of the Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET) Model with estimates from the 2022 version. Some of the public comments recommended removing some of the studies considered in the proposed rule. We considered these comments carefully but decided not to remove any of the studies considered in the proposed rule as they meet the broad criteria for our compilation of published estimates. We discuss these comments and our

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[218] As explained in Chapter 4.2.3, for the illustrative scenario we require an annual stream of GHG emissions for crop-based fuels, and the only available results that report an annual stream are from EPA's prior LCA modeling for the RFS program. Thus, for crop-based fuels, the range of values comes only from EPA's LCA results.
[219] Details on the sourcing of each estimate from our literature review are available in the memo, "Notes on Literature Review of Transportation Fuel Greenhouse Gas (GHG) Lifecycle Analysis (LCA)," available in the docket for this action.
[220] We note that lifecycle GHG emissions are also influenced by the use of advanced technologies and improved production practices. For example, corn ethanol produced with the adoption of advanced technologies or climate smart agricultural practices can lower LCA emissions. Corn ethanol facilities produce a highly concentrated stream of CO_2 that lends itself to carbon capture and sequestration (CCS). CCS is being deployed at ethanol plants and has the potential to reduce emissions for corn-starch ethanol, especially if mills with CCS use renewable sources of electricity and other advanced technologies to lower their need for thermal energy. Climate smart farming practices are being widely adopted at the feedstock production stage and can lower the GHG intensity of biofuels. For example, reducing tillage, planting cover crops between rotations, and improving nutrient use efficiency can build soil organic carbon stocks and reduce nitrous oxide emissions.
[221] 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.
[222] We do not include estimates from the model comparison exercise in the range of LCA estimates from the literature. as explained in Preamble Section IV.A.2, we did not ultimately rely on the model comparison exercise to evaluate the candidate volumes or to inform the volumes in this final rule.

reasoning in the summary and analysis of comments document that is part of this rulemaking package.

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. 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 attempt to include relevant studies published before March 2023. In cases where there are multiple studies that include updates to the same general model and approach, we include 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. In this section we focus on studies that estimate full lifecycle (or "well-to-wheel") GHG emissions.[223] We focus 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 discussion in relevant sections about how advanced technologies could lead to more significant emissions reductions in the future.

Many of the studies we compiled include sensitivity analysis, where parameters or other assumptions are varied to produce a number of estimates. In these cases, we include representative high and low estimates. For example, when studies report a 95% interval of estimates, we include only the central estimate (usually the default, mean or median estimate) and the estimates at the top and bottom of the 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 a very small number of cases we remove outlier estimates that are representative of localized or special circumstances. We do this in order to form a range that we believe is representative 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. While we do remove a small number of estimates that represent special circumstances, our general approach to the literature compilation is to be inclusive of a wide range of estimates based on a variety of study types and assumptions.

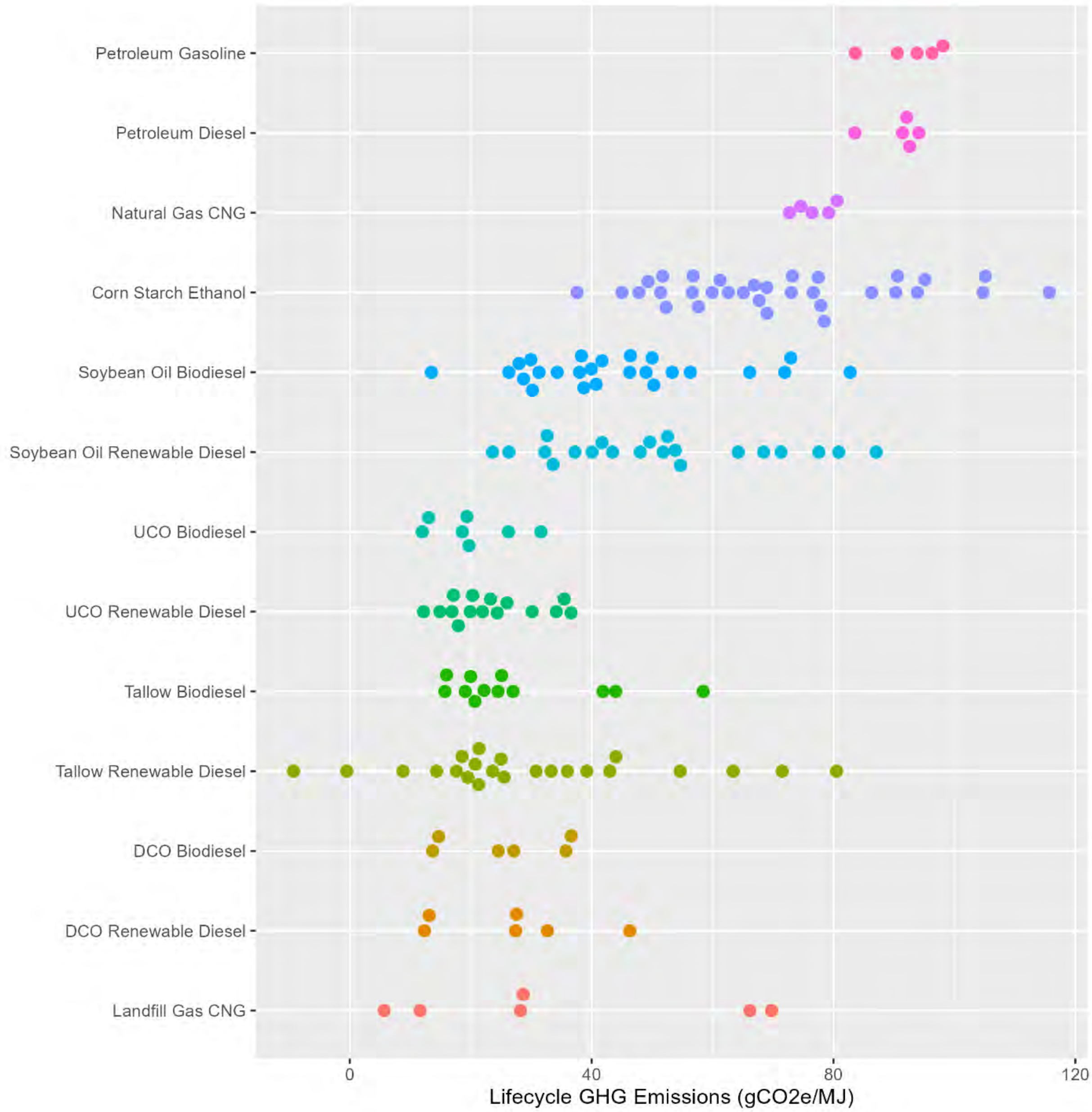
Figure 4.2.2-1 provides an overview of the lifecycle GHG estimates in our literature compilation. All of the pathways in our compilation are included with the exception of compressed natural gas (CNG) produced from manure digester biogas, as some of the estimates for this pathway (e.g., -533 gCO_2e/MJ) are so low that they skew the rest of the chart. All of the

[223] For crop-based biofuels, there are many studies that only estimate land use change GHG emissions; these studies are discussed in DRIA Chapter 4.2.2.8.

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.[224] 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.

[224] 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 4.2.2-1 Lifecycle GHG Emissions Estimates by Pathway



Notes: CNG = compressed natural gas, DCO = distillers corn oil, UCO = used cooking oil. Other than reporting all estimates in gCO_2e/MJ no effort has been made to harmonize estimates. Estimates for CNG produced from manure digester biogas are excluded, as some of the estimates for this pathway (e.g., -533 gCO2e/MJ) are so low they would skew the rest of the chart.

Figure 4.2.2-1 shows that, in general, the LCA 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.[225] Below, we summarize the

[225] 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: 108–18.

results of our literature compilation 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.

In Chapter 4.2.3, 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. Chapter 4.2.4 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.

4.2.2.1 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 when the land is converted, and there would also be foregone sequestration over time based on the carbon that would have been sequestered through plant growth and soil carbon accumulation absent the biofuel induced land use change.[226] 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

[226] 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.[227] 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. 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 4.2.3, the analyses assume 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.

4.2.2.2 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 action. 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 approach is appropriate for the conventional fuels they replace. Thus, our literature review for this action 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[228] or refining[229] are excluded from our review, as we require estimates of the

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[227] 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.

[228] See for example, Masnadi, M. S., et al. (2018). "Global carbon intensity of crude oil production." Science 361(6405): 851–53.

[229] See for example, Jing, L., et al. (2020). "Carbon intensity of global crude oil refining and mitigation potential." Nature Climate Change 10(6): 526–32.

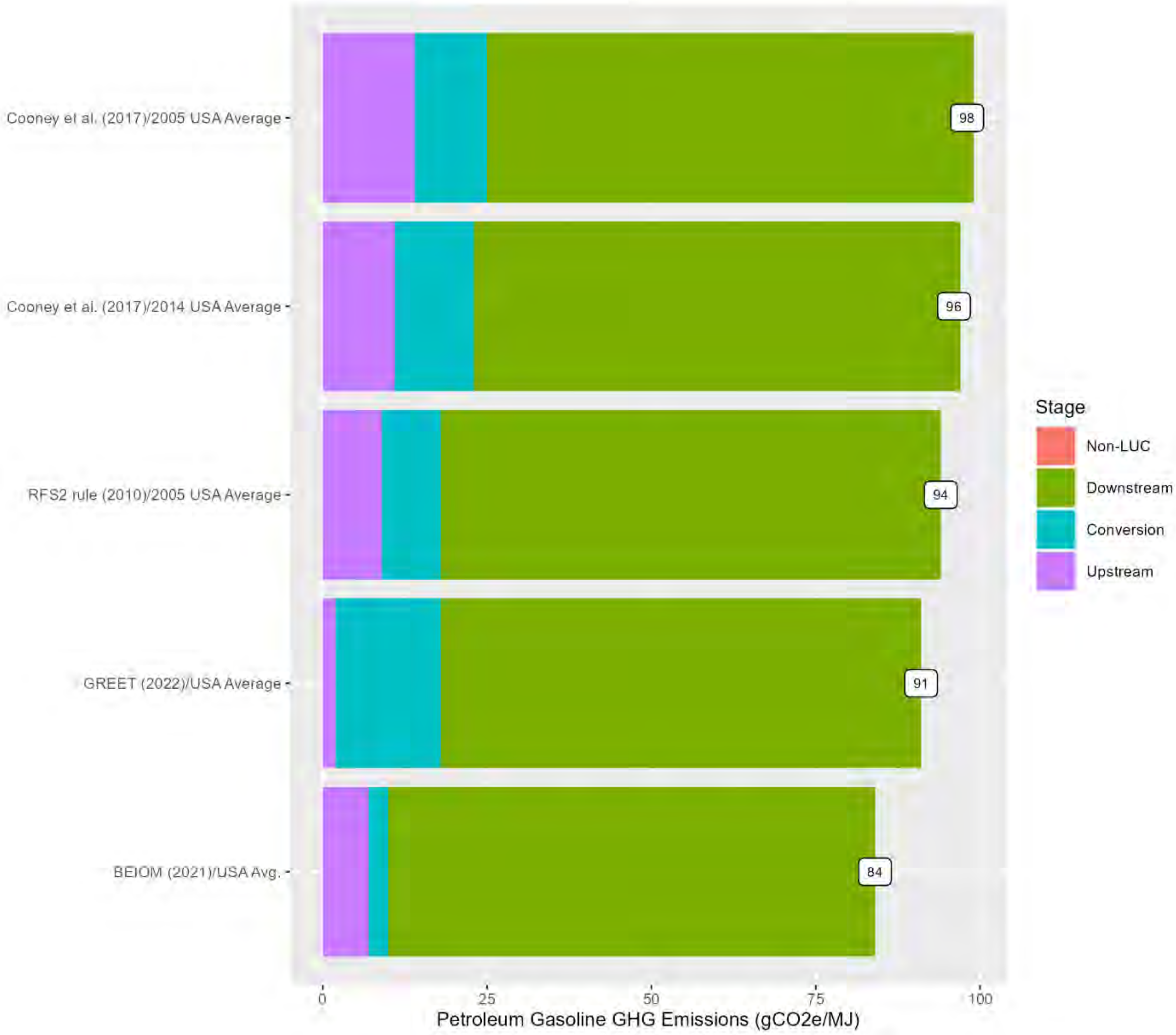
full lifecycle GHG emissions. It is not appropriate to simply sum crude oil extraction estimates with refining estimates as the properties of the crude oil from different can affect the refining emissions.

We recognize that the LCA of the average gallon of gasoline and diesel replaced by biofuels may be different than the LCA of the marginal gallons replaced. While there is at least one study that suggests the lifecycle emissions intensity of the marginal oil supplies may be higher than average oil supplies,[230] we did not identify any studies that estimate the full lifecycle GHG emissions of the marginal volumes that would most likely be displaced, including oil extraction, oil transport, refining, fuel distribution and use.

The following figures show the range of published LCA estimates for gasoline and diesel compiled from our review of relevant literature. There are two changes to these charts relative to the DRIA versions: 1) we updated estimates from GREET-2021 to GREET-2022, and 2) we updated from AR5 to AR6 GWP values, except the BEIOM estimate is still based on AR5 as we do not have results by gas for BEIOM. Updating the estimates from GREET-2021 to GREET-2022 increases the LCA estimates by 0.4 gCO_2e/MJ for gasoline and by 0.9 gCO_2e/MJ for diesel. Updating from AR5 to AR6 increased the other LCA estimates by less than 0.1 gCO2e/MJ.

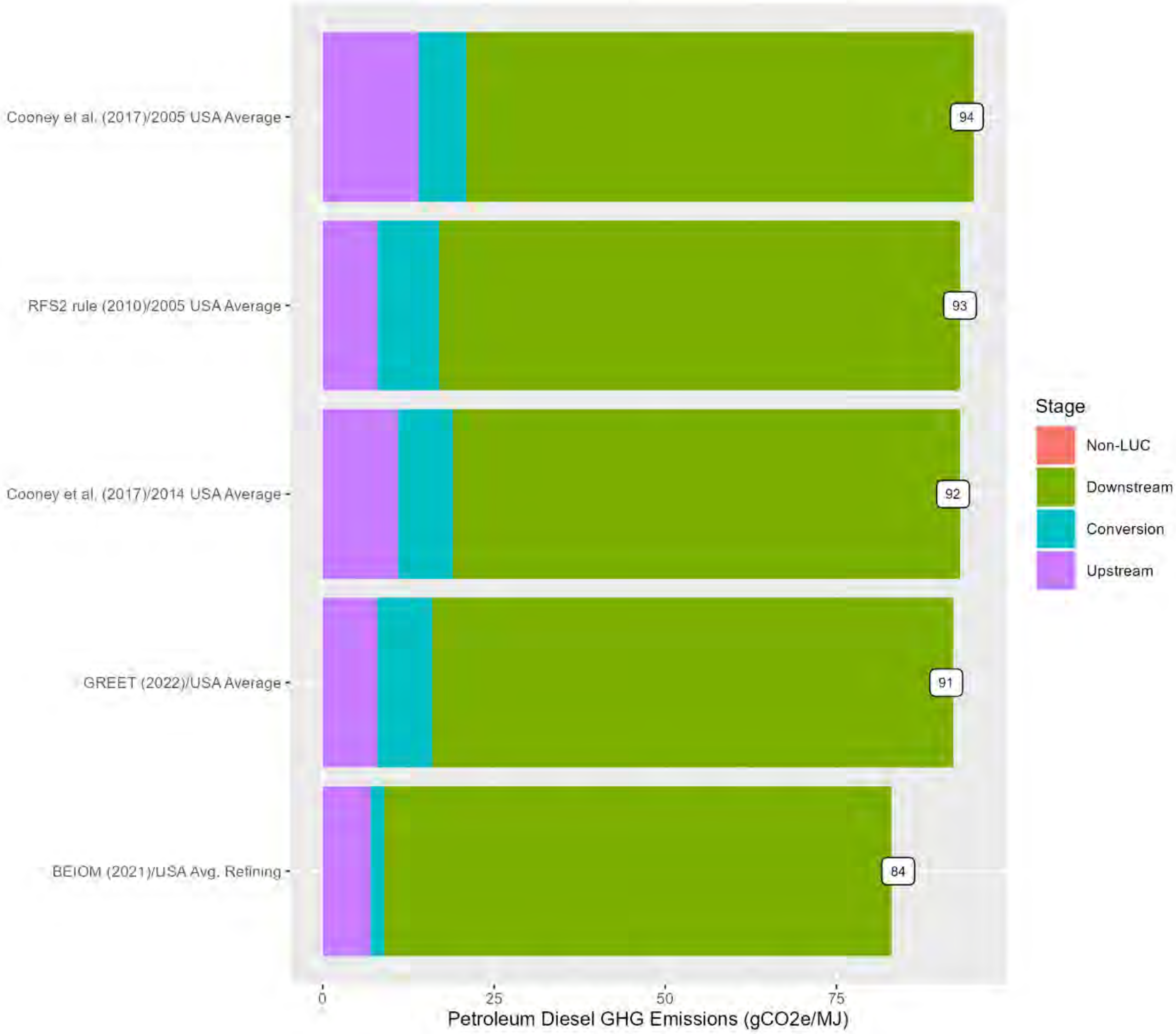
[230] Masnadi, M. S., et al. (2021). "Carbon implications of marginal oils from market-derived demand shocks." Nature 599(7883): 80–84.

Figure 4.2.2.2-1: 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. All values in this chart use 100-year AR6 GWP values, except for BEIOM which uses AR5.

Figure 4.2.2.2-2: 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. All the values in this chart use 100-year AR6 GWP values, except BEIOM which uses AR5.

The 2010 RFS2 estimates were largely based on a study by the National Energy Technology Laboratory (NETL).[231] 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) estimates are higher by approximately 4 gCO_2e/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.

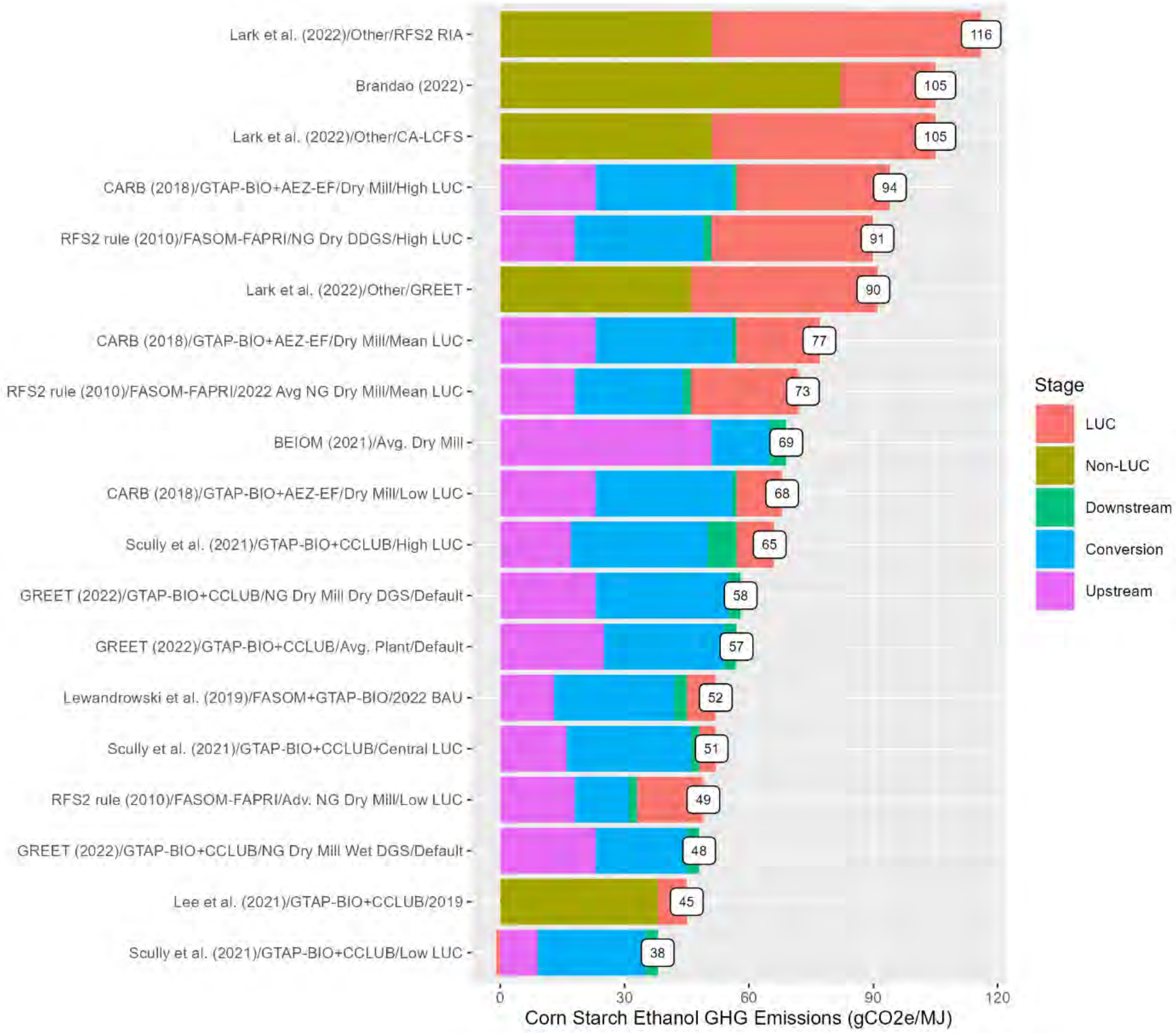
[231] U.S. EPA, (2010). 2005 Petroleum Baseline Lifecycle GHG (Greenhouse Gas) Calculations. U.S. Environmental Protection Agency, Docket Item No. EPA-HQ-OAR-2005-0161-3151. Washington DC, January.

The GREET-2022 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 within 5 gCO_2e/MJ of each other. 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.

4.2.2.3 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. Figure 4.2.2.3-1 below includes 19 estimates from these studies that are representative of the range of results that each of them reports.

Figure 4.2.2.3-1: 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 emissions 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-2022. 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.[232] 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 retrospective 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 gCO_2e/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,[233] 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.[234] Among the studies in Figure 4.2.2.2-1, conversion emissions range from 13 to 33 gCO2e/MJ.[235] The highest estimates are from CARB (2018) based on the default assumptions used in the CA-GREET3.0 model. The GREET-2022 estimate for “industrial average” dry mill corn ethanol production is 29 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.[236]

The largest source of variation between estimates are the land use change emissions, ranging from -1 to 65 gCO2e/MJ in Figure 4.2.2.3-1. The highest land use change estimates are from Lark et al. (2021), which produced estimates of U.S. land use change emissions attributable

[232] 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.

[233] 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.

[234] 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

[235] This excludes the studies that do not report disaggregated non-LUC emissions.

[236] 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.

to corn ethanol and added them to non-U.S. land use change emissions estimates from RFS2 (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.[237] For more discussion of corn ethanol land use change estimates see DRIA Chapter 4.2.2.[238]

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.

There are plausible scenarios whereby corn ethanol currently being produced at particular facilities or under certain conditions may be associated with greater lifecycle GHG emissions than the upper end of the range formed by our compilation of literature LCA estimates. For example, the GHG emissions could be higher for ethanol currently being produced from facilities fired with coal (or that use electricity produced from coal-fired power plants), ethanol produced from corn grown on marginal lands with lower yields, or in a scenario where prolonged drought or other factors substantially lowers crop yields. More generally, there are also different analytical approaches that produce higher estimates of the GHG impacts of corn ethanol production, such as estimates that consider the “carbon opportunity cost” of the land used to grow the corn feedstock, as proposed by Searchinger et al. (2018).[239] This study estimates these opportunity costs two different ways: 1) As the average direct land use change emissions associated with producing corn across the globe, or 2) As the foregone sequestration associated with not devoting the same land to regenerating forest. Based on the estimates in Searchinger et al. (2018), the carbon opportunity cost of corn ethanol using either approach is approximately 160 gCO_2e/MJ.[240] We do not include this estimate in our compilation of LCA values, as it is

[237] 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.

[238] The DRIA for the proposed rule includes a discussion of available models and land use change estimates that is not part of this RIA for the final rule. The review of studies and land use change estimates in the DRIA remains relevant, but we determined it did not bear repeating in this document as it does not factor directly into our analysis of the climate impacts of the candidate volumes.

[239] Searchinger, T. D., Wirsenius, S., Beringer, T., & Dumas, P. (2018). Assessing the efficiency of changes in land use for mitigating climate change. Nature, 564(7735), 249-253.

[240] Ibid., Extended Data Table 3 using either the COC “loss” method or the COC “gain” method.

presented as a “carbon opportunity cost”, “carbon cost” or “consumption cost,” not an LCA estimate.[241]

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.[242] 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.

4.2.2.4 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 7 studies that estimate the lifecycle GHG emissions associated with soybean oil biodiesel. The figure below includes 19 estimates of the lifecycle GHG emissions associated with soybean oil biodiesel production and use.

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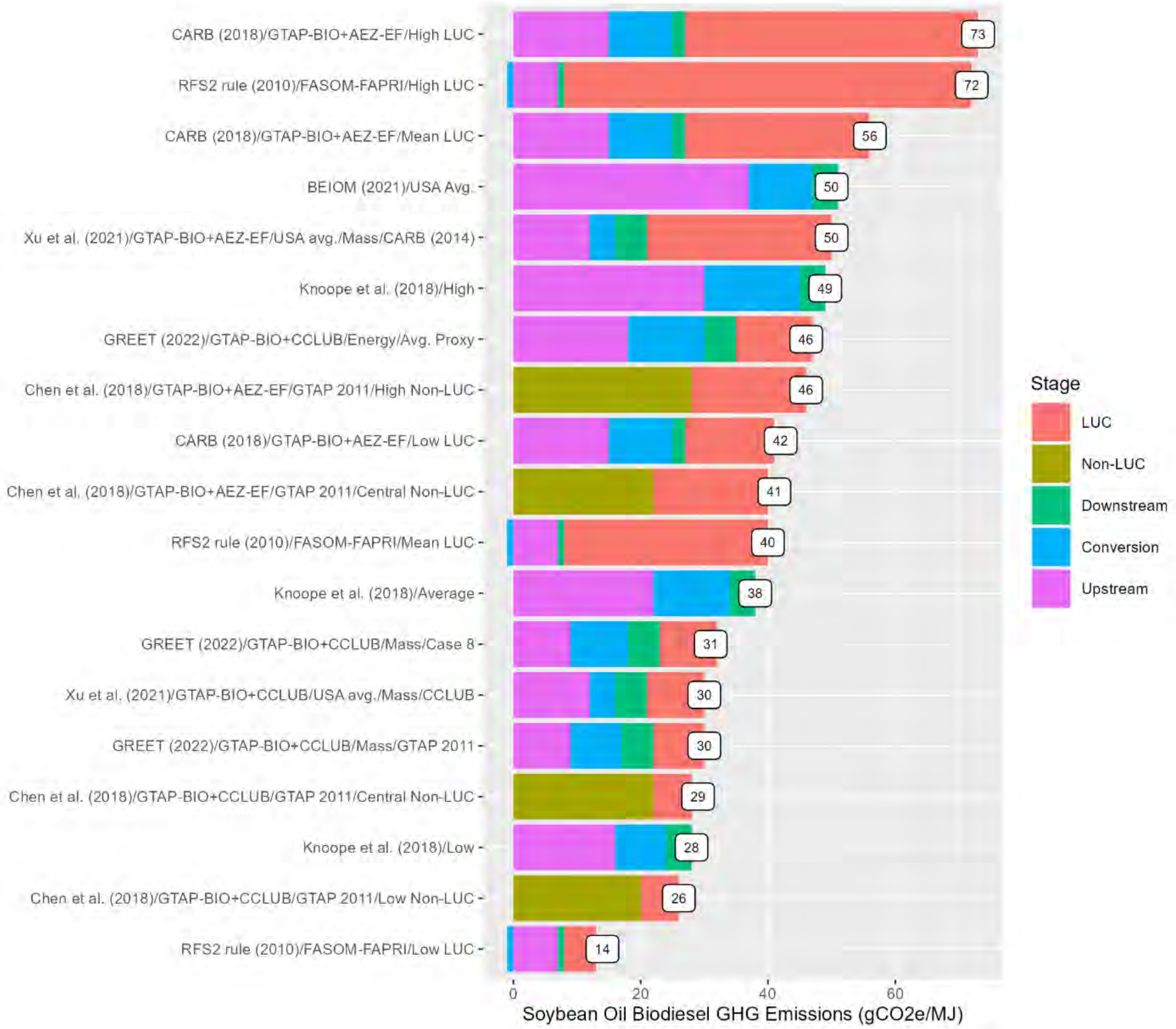
[241] Although Searchinger et al. (2018) does not present the carbon opportunity cost (COC) as an LCA estimate, the paper states that under a particular set of assumptions the COC could be treated as an ILUC estimate (p. 251, “Our biofuel COC estimates are equivalent to ILUC estimates if crops diverted to biofuels (after deducting by-products) are fully replaced at the average global carbon loss per kilogram of crop.”) Furthermore, Figure 2 in this paper combines the COC estimates with production emissions to compare the total “carbon costs” of different fuel sources, including corn ethanol and gasoline. These estimates could potentially be compared with LCA values, but for this RIA we believe it is more appropriate to consider them separately from the rest of the LCA literature. Treating the COC estimates as equivalent to ILUC requires a special set of assumptions that no other study in the literature includes. The other studies in the literature use economic models to estimate the ILUC associated with a change in biofuel production and use relative to a business as usual baseline scenario. In contrast, Searchinger et al. (2018) either assumes, 1) that land dedicated to biofuel production would otherwise be used for forest regeneration, or 2) that biofuel feedstocks are “fully replaced at the average global carbon loss per kilogram of crop.” In our view, these assumptions make the Searchinger et al. (2018) estimates categorically different from other LUC estimates in the literature, supporting our choice to consider them separately.

[242] Yoo, E., Lee, U., & Wang, M. (2022). Life-Cycle Greenhouse Gas Emissions of Sustainable Aviation Fuel through a Net-Zero Carbon Biofuel Plant Design. ACS Sustainable Chemistry & Engineering, 10(27), 8725-8732.

Figure 4.2.2.4-1: 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 RFS2 (2010) is from CARB (2018), using CARB's high estimate for soy biodiesel land use change emissions from CARB (2014). GREET-2022 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 three estimates from GREET-2022 based on different combinations of these factors to provide a representative range of estimates from GREET-2022. Chen et al. (2018) used the GREET and the GTAP-BIO models to estimate soy biodiesel carbon intensity. Chen et al. (2018) reports a range of estimates based on sensitivity analysis of the GREET input parameters and prior land use change GHG estimates based on GTAP-BIO two different sets of land conversion emissions factors. 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- and energy-based allocation approaches in the figure above.[243] The energy-based allocation approach produces a higher estimate (18 gCO_2e/MJ) than the mass-based approach (9 gCO_2e/MJ). 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 agricultural-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 estimate 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 4.2.2.4-1 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 4.2.2.4-1.[244] The highest and lowest land use change GHG estimates are from RFS2 (2010) based on the upper and lower bounds of the reported 95% 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 DRIA Chapter 4.2.2.8,[245] the range of soybean oil biodiesel land use change GHG estimates in

[243] 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.
[244] This excludes Knoope et al. (2021) and BEIOM (2021) which exclude land use change emissions.
[245] The DRIA for the proposed rule includes a discussion of available models and land use change estimates that is not part of this RIA for the final rule. The review of studies and land use change estimates in the DRIA remains relevant, but we determined it did not bear repeating in this document as it does not factor directly into our analysis of the climate impacts of the candidate volumes.

the literature is wider when we consider studies that only estimate land use change emissions, ranging from 5 to 80 gCO_2e/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 U.S. 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.[246] The difference in per-acre fuel yield means that soybean oil 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 20 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 megajoule of soybean oil biodiesel is associated with approximately 4 times as much feed coproduct as one megajoule of corn ethanol.[247] Soybean meal and distillers grains are used differently in feed rations and their nutritional contents are also not identical. However, the general comparison of the mass of each co-product 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 greater livestock production and 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.

The markets for soybean oil and meal have changed significantly over time, which may be a source of variation in soybean oil biodiesel GHG estimates in the literature. Soybean oil

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[246] 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.

[247] 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% drying).

demand and prices have grown dramatically in recent years. Surging demand for soybean oil, including for biofuel, drove soybean oil prices to record levels in 2021-2022. In past decades, soybean oil supply was primarily dictated by demand for soybean meal. Now the USDA reports that "U.S. supplies of soybean oil will largely depend on expanding the capacity of the U.S. soybean crushing industry."[248] Whereas meal used to be the primary driver of soybean crushing, USDA now reports that, "Higher soybean oil prices may improve the profitability of soybean processing in the near term; however, an excess supply of meal may cut into profits."[249]

Another key sensitivity present in the literature is uncertainty about the source of soybean oil and biodiesel supplies. The U.S. has a dominant position in the global corn and corn ethanol markets. The U.S. is also a major producer of soybeans, but other countries such as Brazil and Argentina are competitive with the U.S. in the global market for growing soybeans. Furthermore, the vegetable oil markets is highly integrated internationally. For example, soybean oil is just one part of the larger global market for vegetable oils and is often substituting with other vegetable oils, including palm oil in many use cases. Given the potential for marginal palm oil extensification into carbon-rich peat lands in Southeast Asia,[250] 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 are home to carbon-dense tropical ecosystems. 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 5 gCO_2e/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 the lowest are from RFS2 (2010).

Overall, our compilation of estimates representative of average U.S. soybean oil biodiesel production provides a range from 14 to 73 gCO_2e/MJ. The largest source of variation across studies continues to be estimated emissions associated with induced land use change. Although this is a wide range, biodiesel produced under particular conditions may produce emissions that are higher or lower than this range on a per MJ basis based on particular factors.

There are plausible scenarios whereby soy biodiesel currently being produced at particular facilities or under certain conditions may be associated with greater lifecycle GHG emissions than the upper end of the range formed by our compilation of literature LCA estimates. 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. More generally, there are also different analytical approaches that

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[248] Ates, A.M., and Bukowski, M., (2022). "Examining Record Soybean Oil Prices in 2021–22." *Amber Waves*. USDA Economic Research Service. December 21, 2022. https://www.ers.usda.gov/amber-waves/2022/december/examining-record-soybean-oil-prices-in-2021-22.

[249] Ibid.

[250] 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.

produce higher estimates of the GHG impacts of soy biodiesel production, such as estimates that consider the "carbon opportunity cost" of the land used to grow the soybean oil feedstock, as proposed by Searchinger et al. (2018).[251] This study estimates these opportunity costs two different ways: 1) as the average direct land use change emissions associated with producing soybeans across the globe, or 2) as the foregone sequestration associated with not devoting the same land to regenerating forest. Based on the estimates in Searchinger et al. (2018), the carbon opportunity cost of soy biodiesel is 300 gCO_2e/MJ with the first approach, or 270 gCO_2e/MJ using the second approach.[252] We do not include this estimate in our compilation of LCA values, as it is presented as a "carbon opportunity cost", "carbon cost" or "consumption cost," not an LCA estimate.[253]

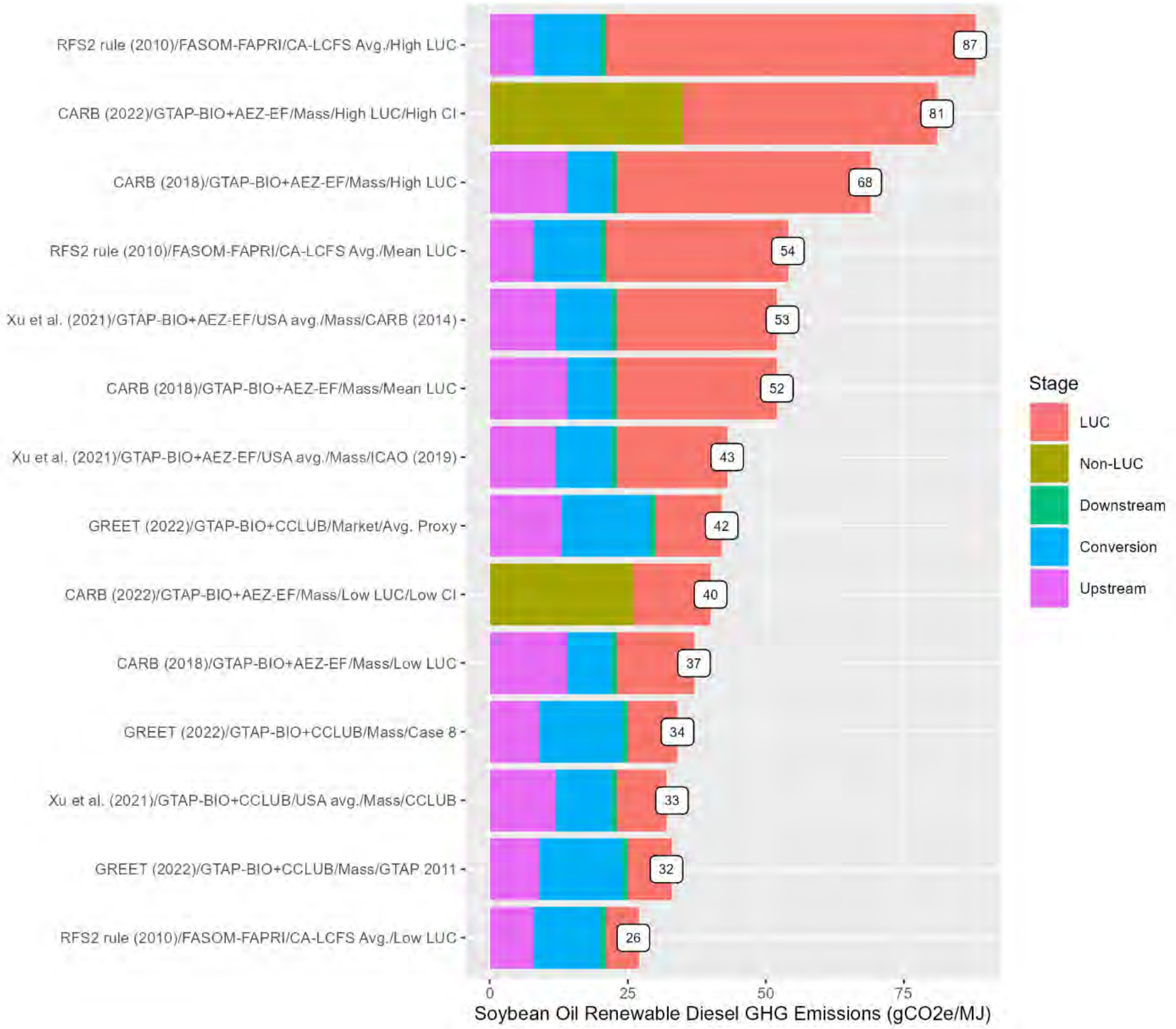
It may also be possible to produce soybean oil biodiesel with lower LCA emissions with the adoption of climate smart agricultural practices. For example, planting cover crops between soybean rotations has the potential to build soil organic carbon stocks. Collecting data on and evaluating these trends in soybean production and vegetable oil markets are areas for additional research that will inform future LCA estimates for soybean oil biodiesel.

4.2.2.5 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. Our literature review includes estimates from 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 summarizes these estimates. Relative to the DRIA version, the only changes are updating the GREET-2021 estimates to GREET-2022.

[251] Searchinger, T. D., Wirsenius, S., Beringer, T., & Dumas, P. (2018). Assessing the efficiency of changes in land use for mitigating climate change. Nature, 564(7735), 249-253.
[252] Ibid., Extended Data Table 3 using either the COC "loss" method or the COC "gain" method.
[253] Although Searchinger et al. (2018) does not present the carbon opportunity cost (COC) as an LCA estimate, the paper states that under a particular set of assumptions the COC could be treated as an ILUC estimate (p. 251, "Our biofuel COC estimates are equivalent to ILUC estimates if crops diverted to biofuels (after deducting by-products) are fully replaced at the average global carbon loss per kilogram of crop.") Furthermore, Figure 2 in this paper combines the COC estimates with production emissions to compare the total "carbon costs" of different fuel sources, including corn ethanol and gasoline. These estimates could potentially be compared with LCA values, but for this RIA we believe it is more appropriate to consider them separately from the rest of the LCA literature. Treating the COC estimates as equivalent to ILUC requires a special set of assumptions that no other study in the literature includes. The other studies in the literature use economic models to estimate the ILUC associated with a change in biofuel production and use relative to a business as usual baseline scenario. In contrast, Searchinger et al. (2018) either assumes, 1) that land dedicated to biofuel production would otherwise be used for forest regeneration, or 2) that biofuel feedstocks are "fully replaced at the average global carbon loss per kilogram of crop." In our view, these assumptions make the Searchinger et al. (2018) estimates categorically different from other LUC estimates in the literature, supporting our choice to consider them separately.

Figure 4.2.2.5-1: 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.[254] Similar to the review for soybean oil biodiesel, CARB (2018) provides a range of land use change GHG estimates and GREET (2022) includes multiple land use change scenarios and co-product allocation approaches for soybean meal. Given the relative scarcity of LCA estimates for

[254] April 2022 Canola Oil Pathways NPRM (87 FR 22823, April 18, 2022).

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.

Among the estimates in the above figure, upstream emissions range from 8 to 14 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),[255] and the highest upstream emissions are from CARB (2018). 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 4.2.2.5-1 range from 8 to 16 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-2022 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.[256] The estimate uses an energy allocation approach to account for co-products of renewable diesel production. The lowest conservation stage 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 renewable diesel 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 gCO_2e/MJ in Figure 4.2.2.4-1.[257] 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. As discussed, in DRIA Chapter 4.2.2.8,[258] 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.

[255] 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)."

[256] For more information on hydrotreating process data evaluated by EPA, see April 2022 Canola Oil Pathways NPRM (87 FR 22823), Section II.C.9.

[257] This excludes Knoope et al. (2021) and BEIOM (2021) which exclude land use change emissions.

[258] The DRIA for the proposed rule includes a discussion of available models and land use change estimates that is not part of this RIA for the final rule. The review of studies and land use change estimates in the DRIA remains relevant, but we determined it did not bear repeating in this document as it does not factor directly into our analysis of the climate impacts of the candidate volumes.

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 are all approximately 1 gCO_2e/MJ.

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 induced 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 in the Chapter 4.2.2.7 for soybean oil biodiesel. Renewable diesel carbon intensities could be reduced by consuming less hydrogen during the conversion stage, 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 published an LCA value for soybean oil renewable diesel. However, the lifecycle analysis for soybean oil jet fuel is similar 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 4.2.2.5-1: U.S. Soybean Oil Jet Fuel Estimates from ICAO (2021) (gCO_2e/MJ)

Estimate	Core[259]	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.

[259] 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.

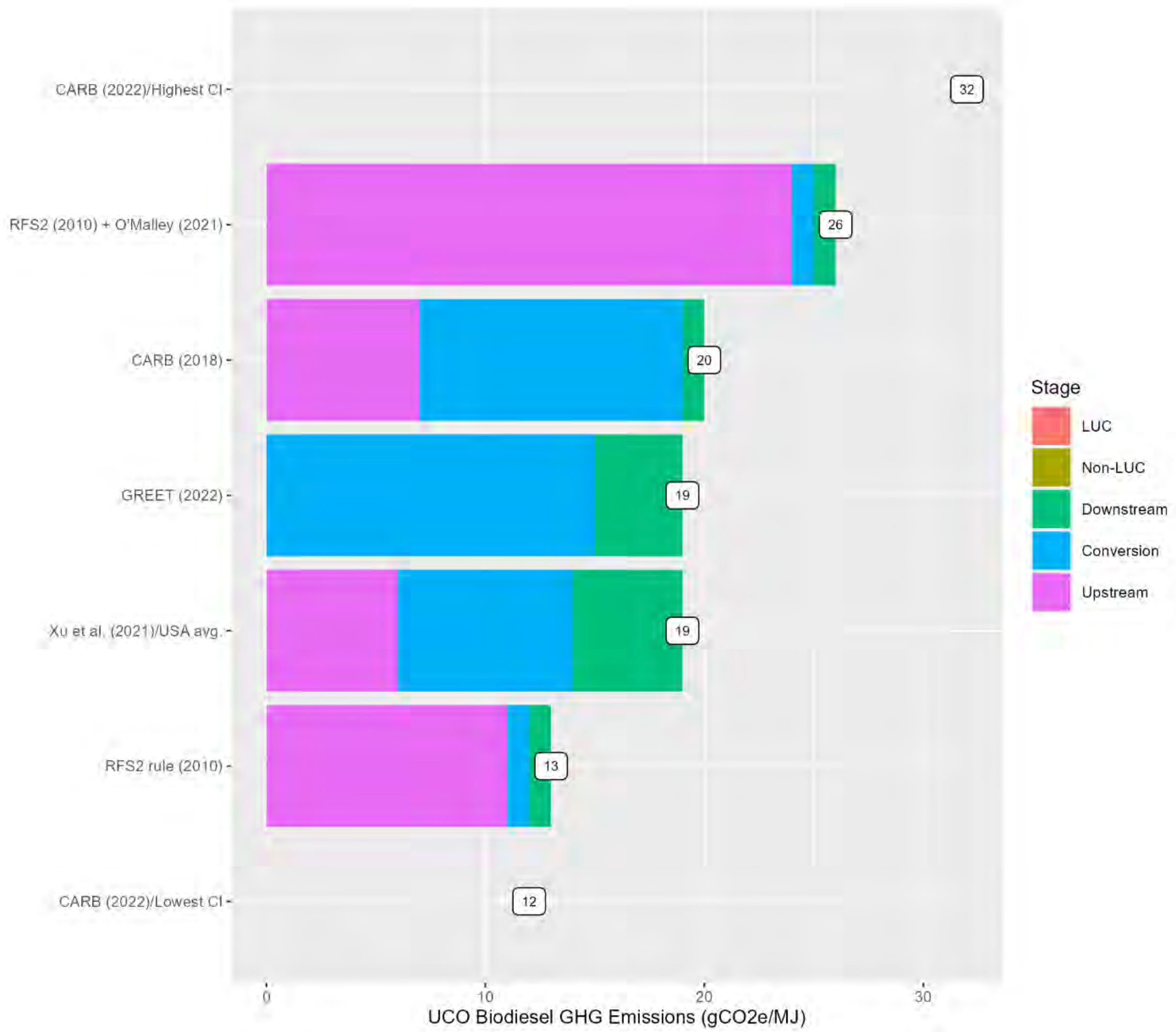
Given the similarities in the hydrotreating process, it is a relatively straightforward adjustment to modify a soybean oil jet fuel LCA to a soybean oil renewable diesel LCA.[260] If the ICAO soybean oil jet fuel LCA was adjusted for the lower energy needs for renewable diesel, the ICAO estimates for soybean oil renewable diesel would be 50 to 128 gCO_2e/MJ. If the ICAO LCA values were included in Figure 4.2.2.5-1 and Table 4.2.2.12, the overall range of values for soybean oil renewable diesel would be wider (26 gCO_2e/MJ to 128 gCO_2e/MJ).

4.2.2.6 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 4.2.2.6-1 includes the LCA estimates for UCO biodiesel, and Figure 4.2.2.6-2 includes the LCA estimates for animal tallow biodiesel. Argonne National Laboratory added UCO biodiesel and renewable diesel as new pathways in GREET-2022. Relative to the DRIA, we updated these figures here to include the GREET-2022 estimates.

[260] 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.

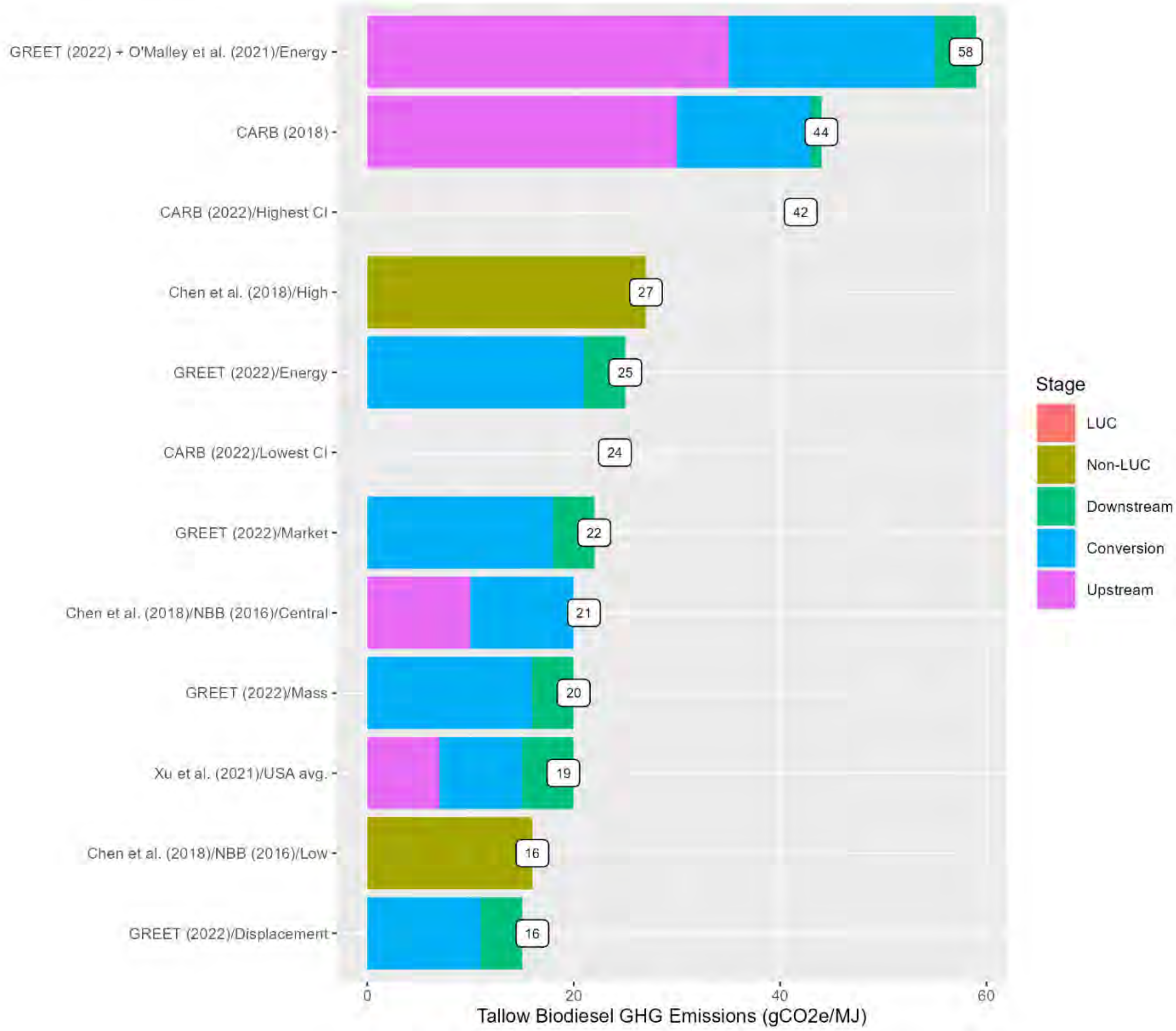
Figure 4.2.2.6-1: UCO Biodiesel Lifecycle Greenhouse Gas Estimates



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). This is not surprising given that CARB (2022) evaluates individual facilities whereas the other estimates represent a U.S. average. 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 gCO_2e/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 4.2.2.6-2: 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. 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. 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.

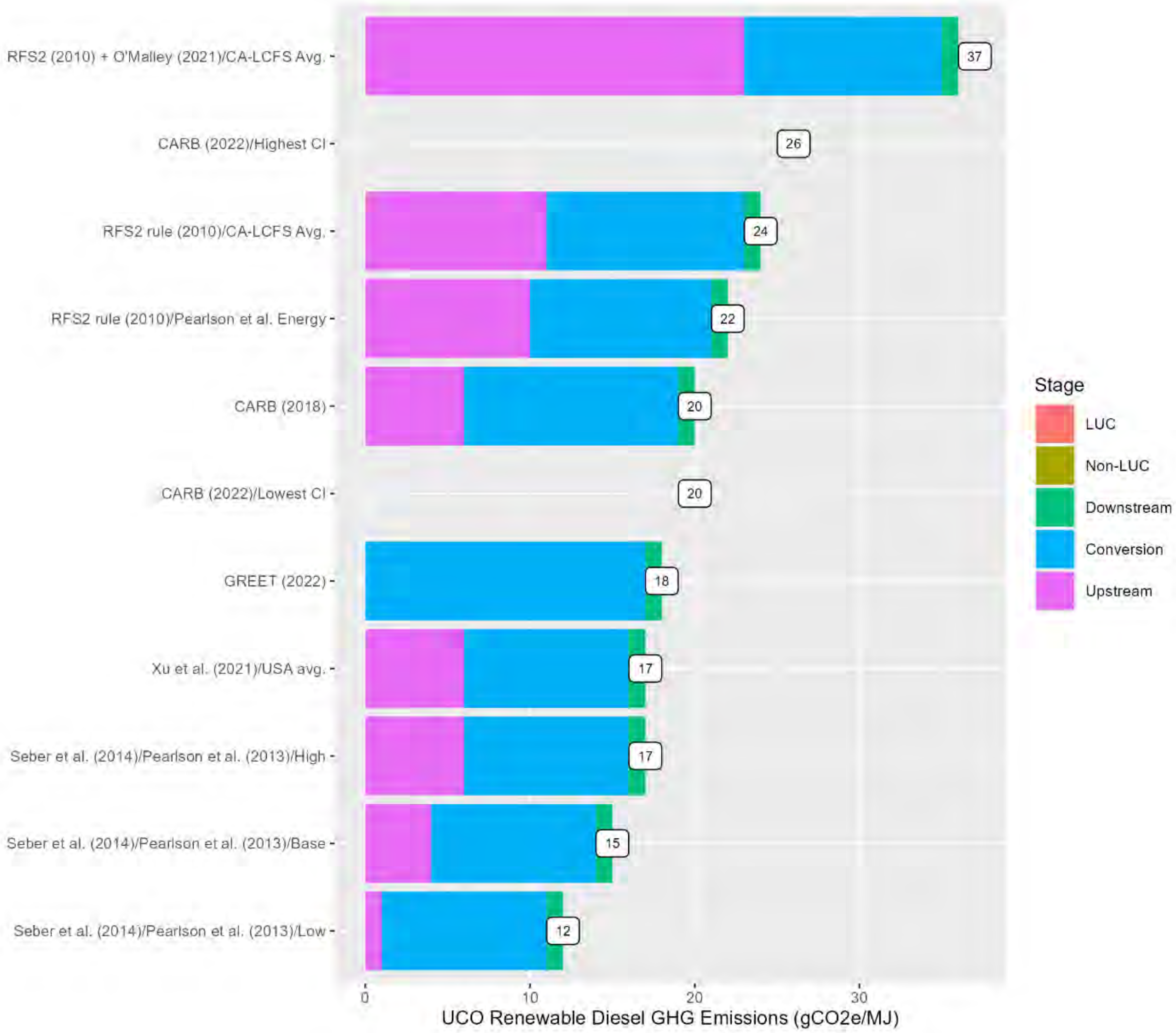
Estimates for tallow biodiesel range from 16 to 58 gCO_2e/MJ. Most of the estimates assume that tallow is a byproduct of meat production and assume zero upstream emissions from livestock production allocated to the tallow. For these estimates the ranges are primarily based on different assumptions about 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-2022.

O'Malley et al. (2021) estimates the backfilling emissions associated with using tallow as a biofuel feedstock are almost three-times greater than such emissions for UCO. The reason for the difference appears to be that, according to O'Malley et al. (2021), approximately 83% of UCO that is not currently used for biofuel is fed to swine and poultry, whereas a much greater share of tallow is used in the oleochemical industry. They assume that vegetable oils (soybean oil and palm oil) will substitute for oleochemical uses and cattle feed, and corn will substitute for cattle feed. Thus, their analysis assumes tallow will primarily be replaced with soybean and palm oil, while UCO will primarily be replaced with corn. In their GHG analysis, they assign greater LCA emissions to soybean oil and palm oil than corn, which explains that higher GHG estimates for tallow relative to UCO.

4.2.2.7 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 4.2.2.7-1 includes the LCA estimates for UCO renewable diesel, and Figure 4.2.2.7-2 includes the LCA estimates for animal tallow renewable diesel. Argonne National Laboratory added UCO biodiesel and renewable diesel as new pathways in GREET-2022. Relative to the DRIA, we update these figures to include the GREET-2022 estimates.

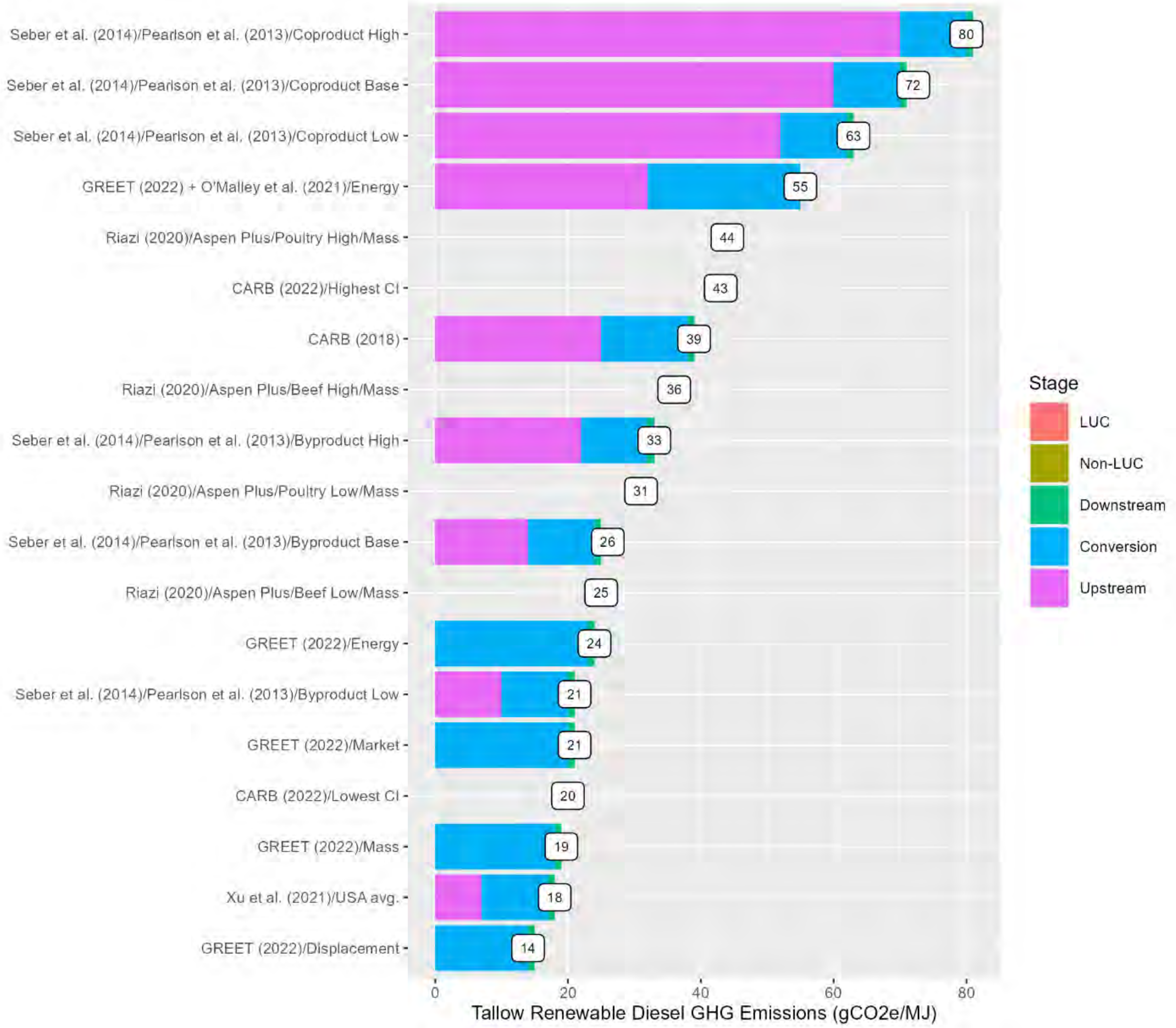
Figure 4.2.2.7-1: UCO Renewable Diesel Lifecycle Greenhouse Gas Estimates



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 gCO_2e/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 4.2.2.7-2: Animal Tallow Renewable Diesel Lifecycle Greenhouse Gas Estimates



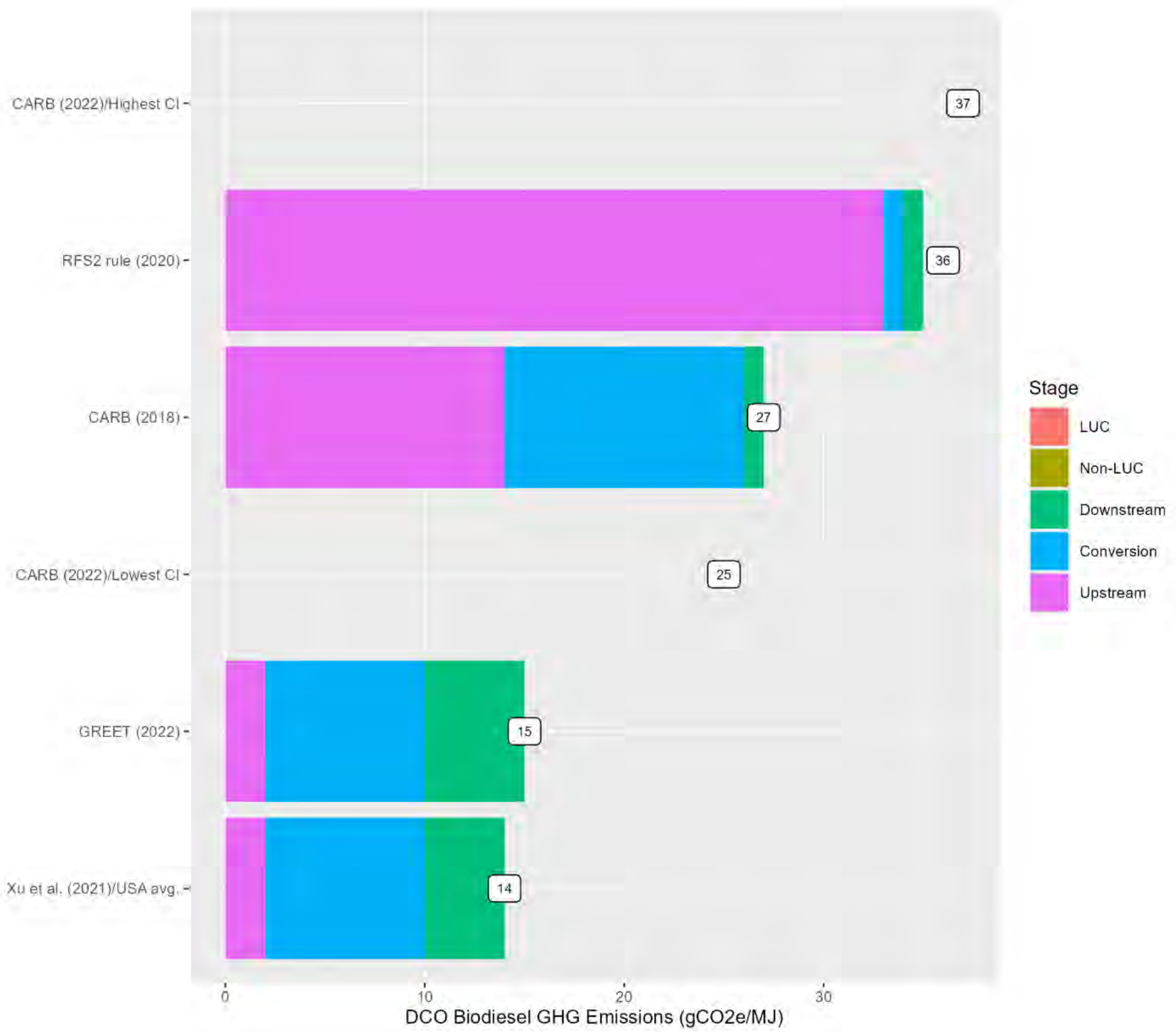
Notes: The Upstream stage includes all of the emissions associated with tallow pre-treatment/rendering and transport upstream of the biodiesel production facility. Seber et al. (2021) also includes livestock production GHG emissions in the Upstream stage. The Conversion stage includes emission associated 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), which is the only study that includes scenarios where GHG emissions 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-2022 using a displacement approach for the co-products from tallow rendering.

4.2.2.8 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 4.2.2.8-1 includes the LCA estimates for DCO biodiesel.

Figure 4.2.2.8-1: DCO Biodiesel Lifecycle Greenhouse Gas Estimates



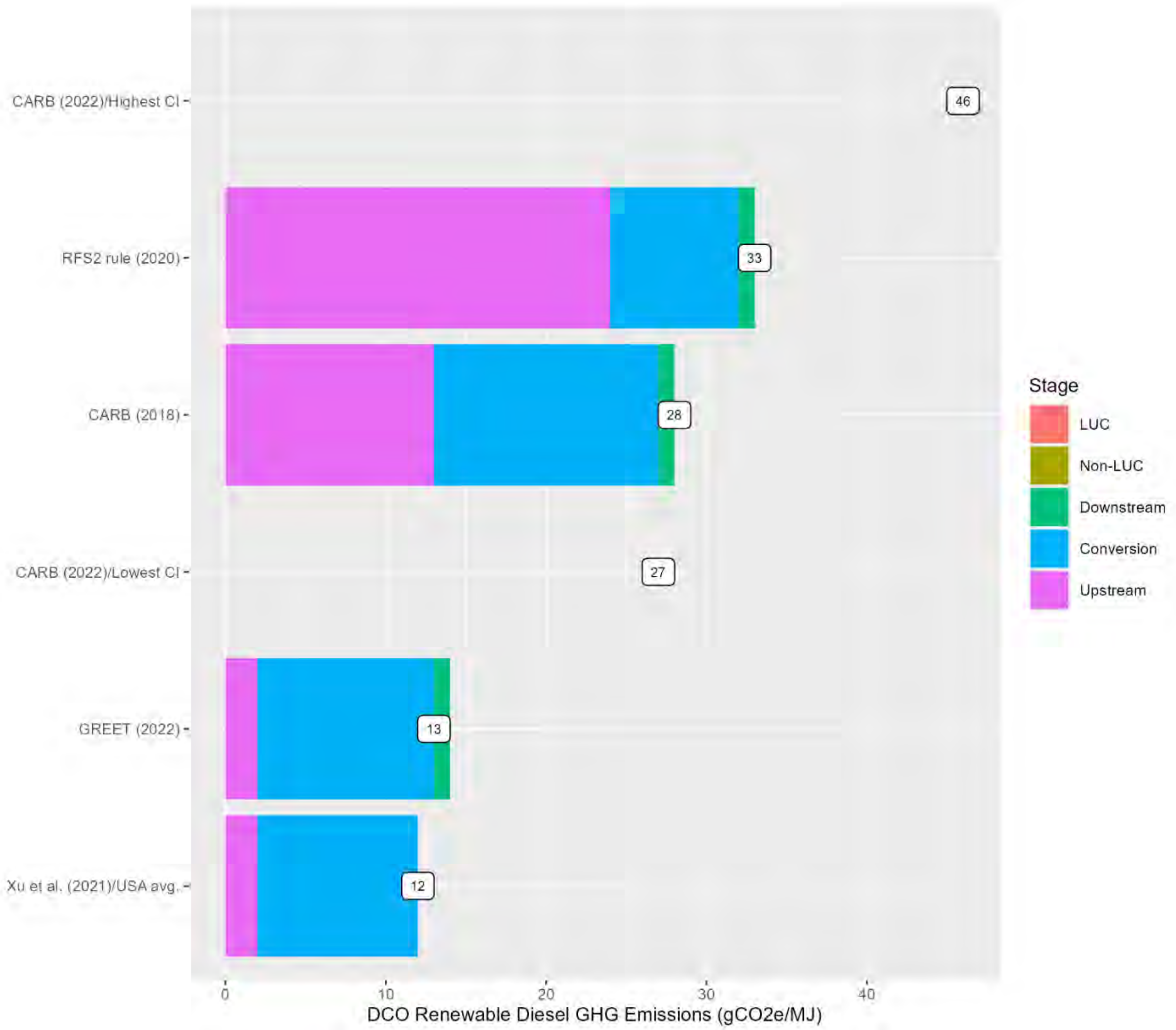
Notes: The Upstream stage includes all of the emissions associated with DCO extraction and in some cases backfilling with corn in livestock feed. The Conversion stage includes emission associated with fuel production at the biodiesel production facility. The Downstream stage includes emissions associated 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 14 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 estimates do not include emissions associated with backfilling corn or other products for the DCO.

4.2.2.9 Distillers Corn Oil Renewable Diesel

We reviewed published estimates of the GHG emissions associated with renewable diesel produced from DCO. Figure 4.2.2.9-1 includes the LCA estimates for DCO renewable diesel.

Figure 4.2.2.9-1: 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 emissions 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 Xu et al. (2021), which does not include backfilling emissions.

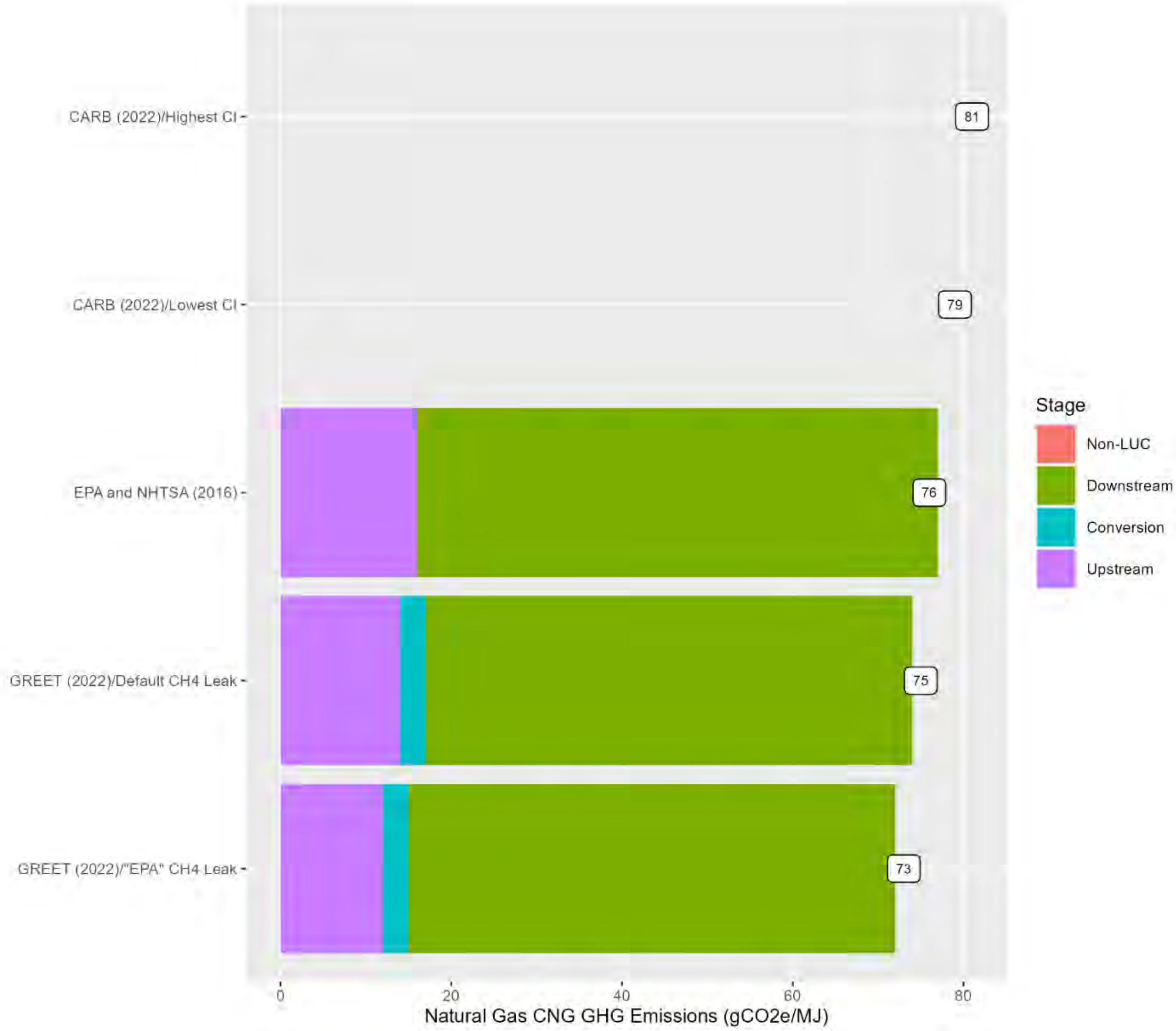
4.2.2.10 Natural Gas CNG

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 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 action includes studies that estimate the lifecycle GHG emissions associated with natural gas CNG. Figure 4.2.2.9-1 includes the range of LCA estimate for natural gas CNG identified in 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 Chapter 4.2.3, the scenario where renewable CNG replaces diesel fuel produces the 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 4.2.2.10-1: Natural Gas CNG Well-to-Wheel Greenhouse Gas Estimates



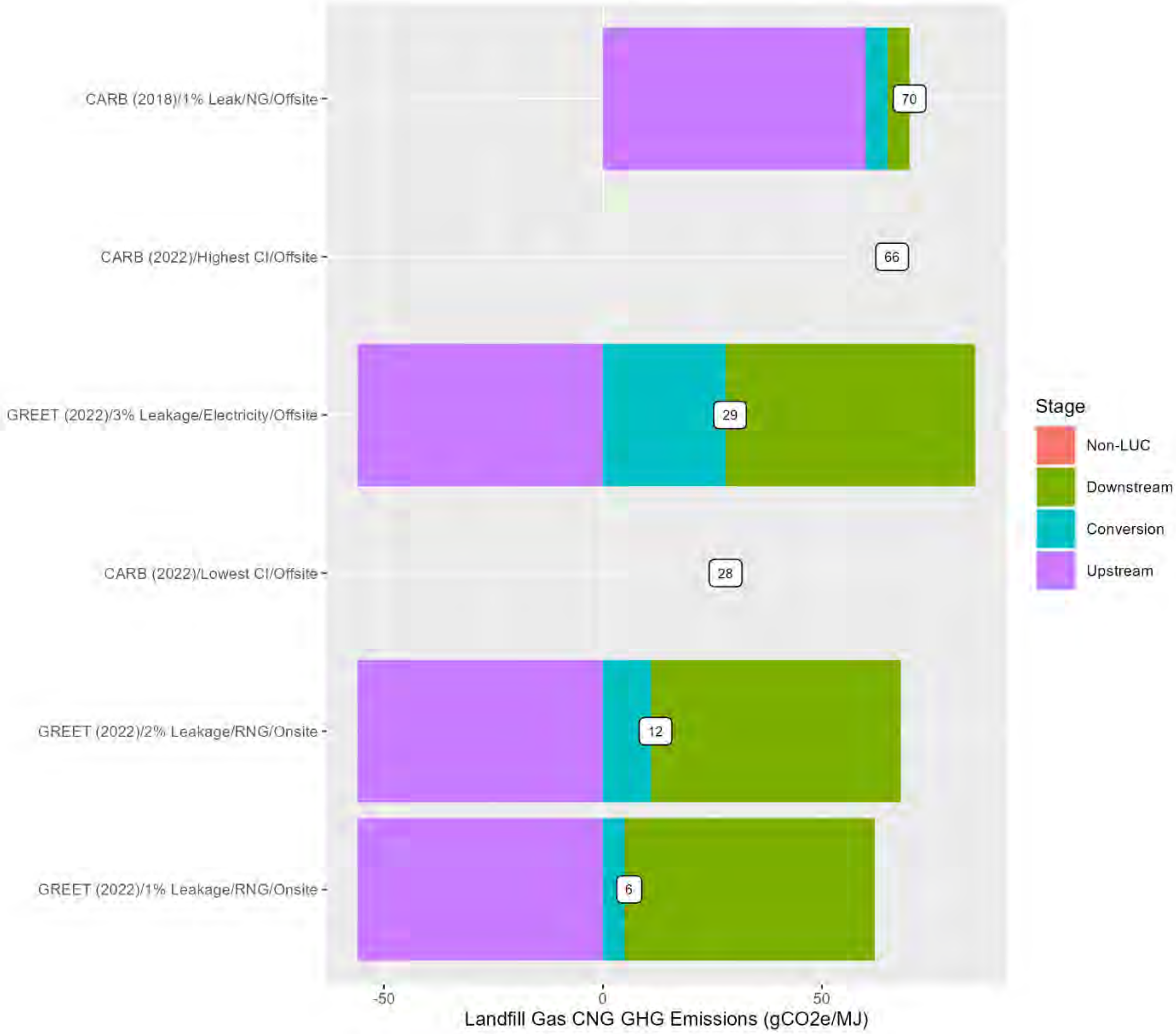
Notes: The name on the y-axis for each bar/estimate includes multiple descriptors separated by "/". In order, these descriptors are the author or other name (e.g., RFS2 rule) and a brief descriptor of the scenario modeled. The Upstream stage includes all of the emissions associated with extracting, processing 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. 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 73 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-2022. By default, GREET-2022 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 by Argonne from the EPA GHG Inventory. The highest estimates are the natural gas CNG pathways certified under the CA-LCFS program. Our review includes studies of the emissions associated with national average natural gas CNG. 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.

4.2.2.11 Landfill Biogas CNG

Our literature review did not identify many studies on the lifecycle GHG emissions associated with CNG produced from landfill gas. 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 4.2.2.11-1 includes the LCA estimates for CNG produced from landfill biogas.

Figure 4.2.2.11-1: Landfill Biogas CNG Lifecycle Greenhouse Gas Estimates



Notes: The Upstream stage includes all of the emissions associated with capturing landfill gas, processing it to pipeline quality, and transporting it to the fueling location. Downstream emission include tailpipe emissions including CO_2 emissions. In most studies upstream emissions are negative because they assume landfill gas will be flared in the counterfactual baseline scenario. Because reductions in CO_2 emissions are included in the Upstream emissions, CO_2 tailpipe emissions are included in the Downstream emissions. CARB (2018) reports more disaggregated results and excludes tailpipe CO_2 emissions. Estimates that only report total lifecycle GHG emissions are depicted only with a label and no bars.

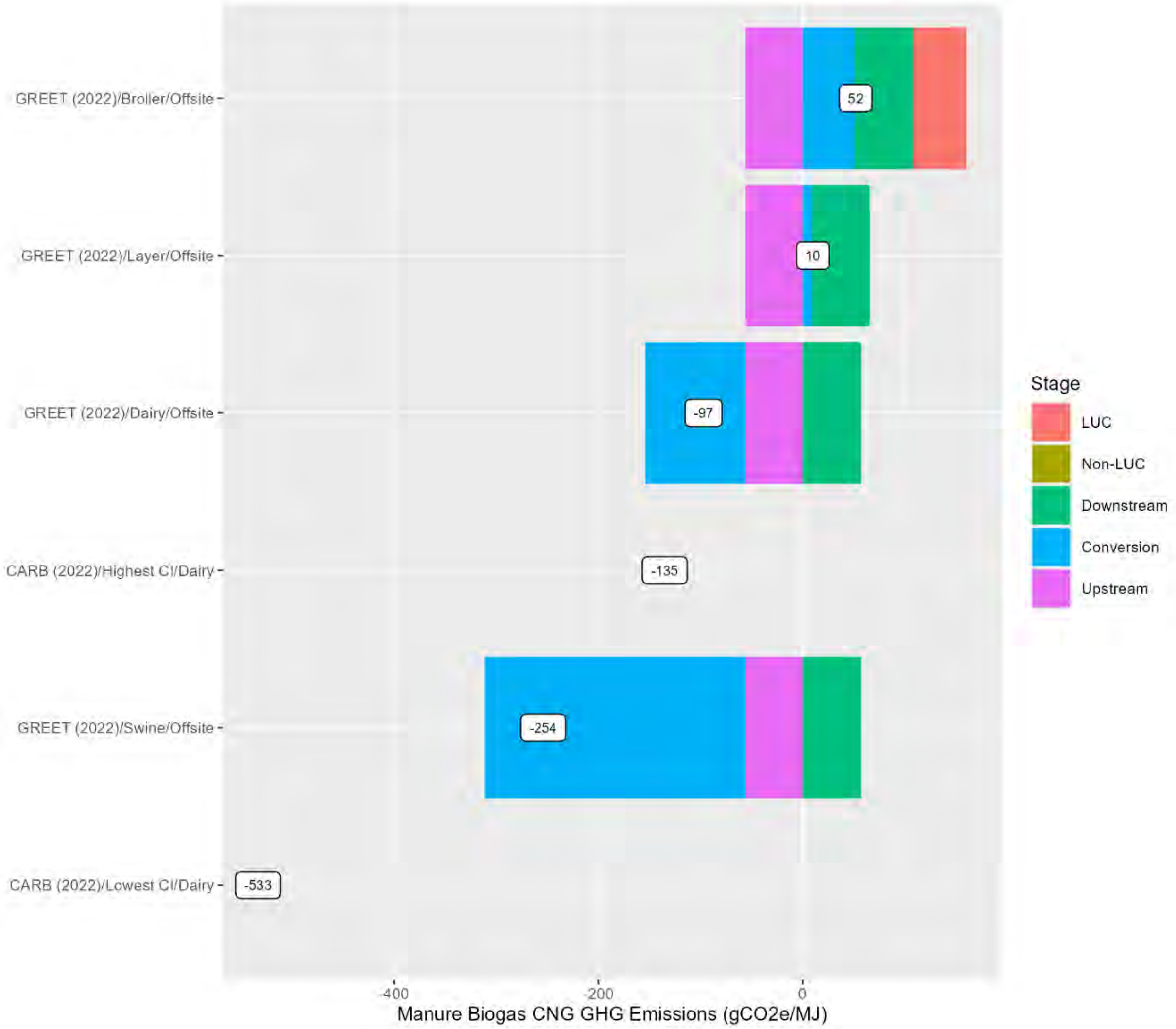
The range of estimates in Figure 4.2.2.11-1 range from 6 to 70 gCO_2e/MJ. The higher estimates are from CARB and the lower estimates are from GREET-2022. We varied two parameters in GREET-2022 to provide a range of estimates. By default, GREET-2022 assumes a 2% methane leakage rate associated with processing 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 about 6 gCO_2e/MJ. By default, GREET-2022 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-2022, onsite fueling reduces the LCA estimate by approximately 3 gCO_2e/MJ. GREET-2022 assumes that landfills will use renewable natural gas (RNG) as process fuel for gas cleanup and compression. GREET allows users to assume that landfills will instead use grid electricity to power these processes. Putting these factors together, the highest emissions scenarios that we include for GREET-2022 assumes 3% methane leakage, electricity for process energy and offsite CNG refueling.

The highest estimates are from CARB, with the very highest estimate coming from the default CA-GREET version 3.0 model. GREET-2022 includes negative upstream emissions based on reduced GHG emissions in a baseline scenario absent the use of the landfill gas as fuel. The CA-GREET model has much larger upstream GHG emissions than GREET-2022 as it does not include the relatively 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.

4.2.2.12 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 4.2.2.12-1 includes the LCA estimates for CNG produced from landfill biogas.

Figure 4.2.2.12-1: Manure Digester CNG Lifecycle Greenhouse Gas Estimates



Notes: The Upstream stage includes emissions associated with operating the digester. The Conversion stage includes emissions associated with processing the biogas to pipeline quality, and transporting it to the fueling location. Downstream emissions include tailpipe emissions including CO_2 emissions. In many of the studies, the upstream emissions are negative as they include emissions avoided relative to a counterfactual scenario where the manure is not treated in a digester. Because reductions in CO_2 emissions are included in the Upstream emissions, tailpipe CO_2 emissions are included in the Downstream stage. 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 52 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 how the manure will be treated in the baseline scenario and the associated emissions. Based on estimates from GREET-2022, CNG produced from broiler manure biogas has positive carbon intensities, as high as 52 gCO2e/MJ. The GREET manure biogas LCA estimates are extremely sensitive to the type of animal manure processed. Once again, this is due to large variations in emissions in the counterfactual baseline scenario assuming manure is treated without a digester. If the baseline emissions estimates were harmonized, the LCA estimates would not be sensitive to animal type, as the emissions associated with digester operations are similar for different types of manure.

4.2.2.13 Summary of LCA Ranges

Based on the literature review for each pathway discussed above, the range of LCA estimates are summarized in Table 4.2.2.12-1.

Table 4.2.2.13-1: Lifecycle GHG Ranges Based on Literature Review (gCO_2e/MJ)

Pathway	LCA Range
Petroleum Gasoline	84 to 98
Petroleum Diesel	84 to 94
Natural Gas CNG	73 to 81
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	16 to 58
Tallow Renewable Diesel	14 to 81
Distillers Corn Oil Biodiesel	14 to 37
Distillers Corn Oil Renewable Diesel	12 to 46
Landfill Gas CNG	6 to 70
Manure Biogas CNG	-533 to 52

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 Chapter 4.2.3.

Table 4.2.2.13-2: 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	26 to 87
Used Cooking Oil Biodiesel	12 to 32
Used Cooking Oil Renewable Diesel	12 to 37
Tallow Biodiesel	16 to 58
Tallow Renewable Diesel	14 to 81
Distillers Corn Oil Biodiesel	14 to 37
Distillers Corn Oil Renewable Diesel	12 to 46
Natural Gas CNG	73 to 81
Landfill Gas CNG	6 to 70
Manure Biogas CNG	-533 to 52

4.2.2.14 References for LCA Literature Review

For ease of reference, the following is the list of references cited in Chapter 4.2.2, unless otherwise cited with the footnote:

- BEIOM. (2021). Avelino, A. F. T., et al. “Creating a harmonized time series of environmentally-extended input-output tables to assess the evolution of the US bioeconomy - A retrospective analysis of corn ethanol and soybean biodiesel.” Journal of Cleaner Production 321: 128890.
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4.2.3 GHG Results for Illustrative Scenario

In order to estimate the monetized social cost or benefit of the candidate biofuel volumes in Chapter 4.2.4, annual streams of emissions are required. As discussed in Chapter 4.2.2.13, to develop ranges for purposes of estimating the monetized GHG impacts we rely on the high and low LCA estimates, from the ranges discussed in Chapter 4.2.2, that report annual streams of emissions.

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 established in this action 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 4.2.3-2 summarizes the annual low biofuel emission estimates and high petroleum baseline emission estimates in grams CO_2e per megajoule (Table 4.2.3-4 does the same for high biofuel and low petroleum baseline estimates). Table 4.2.3-3 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 4.2.3-5 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 4.2.3-6 through 4.2.3-8 for low biofuel/high petroleum lifecycle analysis estimates, and Tables 4.2.3-10 through 4.2.3-12 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 4.2.3-3 and 4.2.3-5 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 4.2.3-1. As discussed in Chapter 4.2.2.1, 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 4.2.3-9 and 4.2.3-13 respectively below.

Table 4.2.3-1: Volume Changes Used for Illustrative GHG Scenario

		Landfill Biogas CNG/ LNG[261]	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	248	248	-	1,133	(101)	46	710	115	137	660
	2024	344	344	-	1,065	(92)	63	901	106	(68)	731
	2025	466	466	-	1,078	(113)	20	1,066	126	(21)	787
Volume Changes Relative to Previous Year (million gallons)	2023	248	248	-	1,133	(101)	46	710	115	137	660
	2024	97	97	-	(68)	9	17	190	(9)	(205)	71
	2025	122	122	-	13	(21)	(43)	165	20	47	56

Table 4.2.3-5 shows positive net GHG emissions for the corn ethanol and soybean oil renewable diesel and biodiesel volumes in the first year of a volume increase due to the initial pulse of land use change emissions in the estimates used for this illustrative scenario. For corn ethanol, volumes increase year over year from 2023 through 2025, which results in positive emissions in 2023, 2024, and 2025 in Tables 4.2.3-6, 7, and 8 respectively. Conversely for example, as shown in Table 4.2.3-6, soybean oil 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.

[261] 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.

We separately estimate a 30-year stream of changes in GHG emissions for renewable fuel volumes from the 2023 supplemental volume requirement as described in 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.[262] Table 4.2.3-14 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.

[262] See Chapter 3.3 for more details.

Table 4.2.3-2: Gross low biofuel/high petroleum annual lifecycle analysis estimates for individual biofuels, presented in grams CO_2e per megajoule of fuel.[a]

	Landfill Biogas CNG/ LNG	Ag. Digester Biogas CNG/LNG	Wood Waste/ MSW Diesel/ Jet Fuel[b]	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	5.7	(532.7)	37.6	710.3	13.1	13.7	755.9	12.8	12.4	395.0	98.1	94.1
Year 1	5.7	(532.7)	37.6	(20.0)	13.1	13.7	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 2	5.7	(532.7)	37.6	(20.0)	13.1	13.7	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 3	5.7	(532.7)	37.6	(20.0)	13.1	13.7	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 4	5.7	(532.7)	37.6	(20.0)	13.1	13.7	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 5	5.7	(532.7)	37.6	(20.0)	13.1	13.7	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 6	5.7	(532.7)	37.6	(20.0)	13.1	13.7	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 7	5.7	(532.7)	37.6	(20.0)	13.1	13.7	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 8	5.7	(532.7)	37.6	(20.0)	13.1	13.7	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 9	5.7	(532.7)	37.6	(20.0)	13.1	13.7	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 10	5.7	(532.7)	37.6	(20.0)	13.1	13.7	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 11	5.7	(532.7)	37.6	(20.0)	13.1	13.7	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 12	5.7	(532.7)	37.6	(20.0)	13.1	13.7	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 13	5.7	(532.7)	37.6	(20.0)	13.1	13.7	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 14	5.7	(532.7)	37.6	(20.0)	13.1	13.7	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 15	5.7	(532.7)	37.6	(20.0)	13.1	13.7	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 16	5.7	(532.7)	37.6	(20.0)	13.1	13.7	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 17	5.7	(532.7)	37.6	(20.0)	13.1	13.7	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 18	5.7	(532.7)	37.6	(20.0)	13.1	13.7	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 19	5.7	(532.7)	37.6	(20.0)	13.1	13.7	(8.7)	12.8	12.4	38.9	98.1	94.1
Year 20	5.7	(532.7)	37.6	7.5	13.1	13.7	19.9	12.8	12.4	34.5	98.1	94.1
Year 21	5.7	(532.7)	37.6	7.5	13.1	13.7	19.9	12.8	12.4	34.5	98.1	94.1
Year 22	5.7	(532.7)	37.6	7.5	13.1	13.7	19.9	12.8	12.4	34.5	98.1	94.1
Year 23	5.7	(532.7)	37.6	7.5	13.1	13.7	19.9	12.8	12.4	34.5	98.1	94.1
Year 24	5.7	(532.7)	37.6	7.5	13.1	13.7	19.9	12.8	12.4	34.5	98.1	94.1
Year 25	5.7	(532.7)	37.6	7.5	13.1	13.7	19.9	12.8	12.4	34.5	98.1	94.1
Year 26	5.7	(532.7)	37.6	7.5	13.1	13.7	19.9	12.8	12.4	34.5	98.1	94.1
Year 27	5.7	(532.7)	37.6	7.5	13.1	13.7	19.9	12.8	12.4	34.5	98.1	94.1
Year 28	5.7	(532.7)	37.6	7.5	13.1	13.7	19.9	12.8	12.4	34.5	98.1	94.1
Year 29	5.7	(532.7)	37.6	7.5	13.1	13.7	19.9	12.8	12.4	34.5	98.1	94.1

[a] Parentheses indicate a reduction in GHG emissions.
[b] 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 4.2.3-3: 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.[a]

	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	(88.4)	(626.8)	(56.5)	616.2	(81.0)	(80.4)	661.8	(81.3)	(81.7)	296.9
Year 1	(88.4)	(626.8)	(56.5)	(114.1)	(81.0)	(80.4)	(102.8)	(81.3)	(81.7)	(59.2)
Year 2	(88.4)	(626.8)	(56.5)	(114.1)	(81.0)	(80.4)	(102.8)	(81.3)	(81.7)	(59.2)
Year 3	(88.4)	(626.8)	(56.5)	(114.1)	(81.0)	(80.4)	(102.8)	(81.3)	(81.7)	(59.2)
Year 4	(88.4)	(626.8)	(56.5)	(114.1)	(81.0)	(80.4)	(102.8)	(81.3)	(81.7)	(59.2)
Year 5	(88.4)	(626.8)	(56.5)	(114.1)	(81.0)	(80.4)	(102.8)	(81.3)	(81.7)	(59.2)
Year 6	(88.4)	(626.8)	(56.5)	(114.1)	(81.0)	(80.4)	(102.8)	(81.3)	(81.7)	(59.2)
Year 7	(88.4)	(626.8)	(56.5)	(114.1)	(81.0)	(80.4)	(102.8)	(81.3)	(81.7)	(59.2)
Year 8	(88.4)	(626.8)	(56.5)	(114.1)	(81.0)	(80.4)	(102.8)	(81.3)	(81.7)	(59.2)
Year 9	(88.4)	(626.8)	(56.5)	(114.1)	(81.0)	(80.4)	(102.8)	(81.3)	(81.7)	(59.2)
Year 10	(88.4)	(626.8)	(56.5)	(114.1)	(81.0)	(80.4)	(102.8)	(81.3)	(81.7)	(59.2)
Year 11	(88.4)	(626.8)	(56.5)	(114.1)	(81.0)	(80.4)	(102.8)	(81.3)	(81.7)	(59.2)
Year 12	(88.4)	(626.8)	(56.5)	(114.1)	(81.0)	(80.4)	(102.8)	(81.3)	(81.7)	(59.2)
Year 13	(88.4)	(626.8)	(56.5)	(114.1)	(81.0)	(80.4)	(102.8)	(81.3)	(81.7)	(59.2)
Year 14	(88.4)	(626.8)	(56.5)	(114.1)	(81.0)	(80.4)	(102.8)	(81.3)	(81.7)	(59.2)
Year 15	(88.4)	(626.8)	(56.5)	(114.1)	(81.0)	(80.4)	(102.8)	(81.3)	(81.7)	(59.2)
Year 16	(88.4)	(626.8)	(56.5)	(114.1)	(81.0)	(80.4)	(102.8)	(81.3)	(81.7)	(59.2)
Year 17	(88.4)	(626.8)	(56.5)	(114.1)	(81.0)	(80.4)	(102.8)	(81.3)	(81.7)	(59.2)
Year 18	(88.4)	(626.8)	(56.5)	(114.1)	(81.0)	(80.4)	(102.8)	(81.3)	(81.7)	(59.2)
Year 19	(88.4)	(626.8)	(56.5)	(114.1)	(81.0)	(80.4)	(102.8)	(81.3)	(81.7)	(59.2)
Year 20	(88.4)	(626.8)	(56.5)	(86.6)	(81.0)	(80.4)	(74.2)	(81.3)	(81.7)	(63.6)
Year 21	(88.4)	(626.8)	(56.5)	(86.6)	(81.0)	(80.4)	(74.2)	(81.3)	(81.7)	(63.6)
Year 22	(88.4)	(626.8)	(56.5)	(86.6)	(81.0)	(80.4)	(74.2)	(81.3)	(81.7)	(63.6)
Year 23	(88.4)	(626.8)	(56.5)	(86.6)	(81.0)	(80.4)	(74.2)	(81.3)	(81.7)	(63.6)
Year 24	(88.4)	(626.8)	(56.5)	(86.6)	(81.0)	(80.4)	(74.2)	(81.3)	(81.7)	(63.6)
Year 25	(88.4)	(626.8)	(56.5)	(86.6)	(81.0)	(80.4)	(74.2)	(81.3)	(81.7)	(63.6)
Year 26	(88.4)	(626.8)	(56.5)	(86.6)	(81.0)	(80.4)	(74.2)	(81.3)	(81.7)	(63.6)
Year 27	(88.4)	(626.8)	(56.5)	(86.6)	(81.0)	(80.4)	(74.2)	(81.3)	(81.7)	(63.6)
Year 28	(88.4)	(626.8)	(56.5)	(86.6)	(81.0)	(80.4)	(74.2)	(81.3)	(81.7)	(63.6)
Year 29	(88.4)	(626.8)	(56.5)	(86.6)	(81.0)	(80.4)	(74.2)	(81.3)	(81.7)	(63.6)

[a] Parentheses indicate a net reduction in GHG emissions

Table 4.2.3-4: 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[a]	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	51.9	33.4	1,044.0	39.4	36.6	1,102.7	49.3	46.3	665.1	83.6	83.5	72.7
Year 1	69.8	51.9	33.4	54.2	39.4	36.6	68.4	49.3	46.3	79.8	83.6	83.5	72.7
Year 2	69.8	51.9	33.4	54.2	39.4	36.6	68.4	49.3	46.3	79.8	83.6	83.5	72.7
Year 3	69.8	51.9	33.4	54.2	39.4	36.6	68.4	49.3	46.3	79.8	83.6	83.5	72.7
Year 4	69.8	51.9	33.4	54.2	39.4	36.6	68.4	49.3	46.3	79.8	83.6	83.5	72.7
Year 5	69.8	51.9	33.4	54.2	39.4	36.6	68.4	49.3	46.3	79.8	83.6	83.5	72.7
Year 6	69.8	51.9	33.4	54.2	39.4	36.6	68.4	49.3	46.3	79.8	83.6	83.5	72.7
Year 7	69.8	51.9	33.4	54.2	39.4	36.6	68.4	49.3	46.3	79.8	83.6	83.5	72.7
Year 8	69.8	51.9	33.4	54.2	39.4	36.6	68.4	49.3	46.3	79.8	83.6	83.5	72.7
Year 9	69.8	51.9	33.4	54.2	39.4	36.6	68.4	49.3	46.3	79.8	83.6	83.5	72.7
Year 10	69.8	51.9	33.4	54.2	39.4	36.6	68.4	49.3	46.3	79.8	83.6	83.5	72.7
Year 11	69.8	51.9	33.4	54.2	39.4	36.6	68.4	49.3	46.3	79.8	83.6	83.5	72.7
Year 12	69.8	51.9	33.4	54.2	39.4	36.6	68.4	49.3	46.3	79.8	83.6	83.5	72.7
Year 13	69.8	51.9	33.4	54.2	39.4	36.6	68.4	49.3	46.3	79.8	83.6	83.5	72.7
Year 14	69.8	51.9	33.4	54.2	39.4	36.6	68.4	49.3	46.3	79.8	83.6	83.5	72.7
Year 15	69.8	51.9	33.4	54.2	39.4	36.6	68.4	49.3	46.3	79.8	83.6	83.5	72.7
Year 16	69.8	51.9	33.4	54.2	39.4	36.6	68.4	49.3	46.3	79.8	83.6	83.5	72.7
Year 17	69.8	51.9	33.4	54.2	39.4	36.6	68.4	49.3	46.3	79.8	83.6	83.5	72.7
Year 18	69.8	51.9	33.4	54.2	39.4	36.6	68.4	49.3	46.3	79.8	83.6	83.5	72.7
Year 19	69.8	51.9	33.4	54.2	39.4	36.6	68.4	49.3	46.3	79.8	83.6	83.5	72.7
Year 20	69.8	51.9	33.4	8.4	39.4	36.6	20.9	49.3	46.3	53.6	83.6	83.5	72.7
Year 21	69.8	51.9	33.4	8.4	39.4	36.6	20.9	49.3	46.3	53.6	83.6	83.5	72.7
Year 22	69.8	51.9	33.4	8.4	39.4	36.6	20.9	49.3	46.3	53.6	83.6	83.5	72.7
Year 23	69.8	51.9	33.4	8.4	39.4	36.6	20.9	49.3	46.3	53.6	83.6	83.5	72.7
Year 24	69.8	51.9	33.4	8.4	39.4	36.6	20.9	49.3	46.3	53.6	83.6	83.5	72.7
Year 25	69.8	51.9	33.4	8.4	39.4	36.6	20.9	49.3	46.3	53.6	83.6	83.5	72.7
Year 26	69.8	51.9	33.4	8.4	39.4	36.6	20.9	49.3	46.3	53.6	83.6	83.5	72.7
Year 27	69.8	51.9	33.4	8.4	39.4	36.6	20.9	49.3	46.3	53.6	83.6	83.5	72.7
Year 28	69.8	51.9	33.4	8.4	39.4	36.6	20.9	49.3	46.3	53.6	83.6	83.5	72.7
Year 29	69.8	51.9	33.4	8.4	39.4	36.6	20.9	49.3	46.3	53.6	83.6	83.5	72.7

[a] 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 4.2.3-5: 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.[a]

	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	(3.0)	(20.8)	(50.1)	960.5	(44.1)	(46.9)	1,019.2	(34.2)	(37.2)	581.5
Year 1	(3.0)	(20.8)	(50.1)	(29.3)	(44.1)	(46.9)	(15.1)	(34.2)	(37.2)	(3.8)
Year 2	(3.0)	(20.8)	(50.1)	(29.3)	(44.1)	(46.9)	(15.1)	(34.2)	(37.2)	(3.8)
Year 3	(3.0)	(20.8)	(50.1)	(29.3)	(44.1)	(46.9)	(15.1)	(34.2)	(37.2)	(3.8)
Year 4	(3.0)	(20.8)	(50.1)	(29.3)	(44.1)	(46.9)	(15.1)	(34.2)	(37.2)	(3.8)
Year 5	(3.0)	(20.8)	(50.1)	(29.3)	(44.1)	(46.9)	(15.1)	(34.2)	(37.2)	(3.8)
Year 6	(3.0)	(20.8)	(50.1)	(29.3)	(44.1)	(46.9)	(15.1)	(34.2)	(37.2)	(3.8)
Year 7	(3.0)	(20.8)	(50.1)	(29.3)	(44.1)	(46.9)	(15.1)	(34.2)	(37.2)	(3.8)
Year 8	(3.0)	(20.8)	(50.1)	(29.3)	(44.1)	(46.9)	(15.1)	(34.2)	(37.2)	(3.8)
Year 9	(3.0)	(20.8)	(50.1)	(29.3)	(44.1)	(46.9)	(15.1)	(34.2)	(37.2)	(3.8)
Year 10	(3.0)	(20.8)	(50.1)	(29.3)	(44.1)	(46.9)	(15.1)	(34.2)	(37.2)	(3.8)
Year 11	(3.0)	(20.8)	(50.1)	(29.3)	(44.1)	(46.9)	(15.1)	(34.2)	(37.2)	(3.8)
Year 12	(3.0)	(20.8)	(50.1)	(29.3)	(44.1)	(46.9)	(15.1)	(34.2)	(37.2)	(3.8)
Year 13	(3.0)	(20.8)	(50.1)	(29.3)	(44.1)	(46.9)	(15.1)	(34.2)	(37.2)	(3.8)
Year 14	(3.0)	(20.8)	(50.1)	(29.3)	(44.1)	(46.9)	(15.1)	(34.2)	(37.2)	(3.8)
Year 15	(3.0)	(20.8)	(50.1)	(29.3)	(44.1)	(46.9)	(15.1)	(34.2)	(37.2)	(3.8)
Year 16	(3.0)	(20.8)	(50.1)	(29.3)	(44.1)	(46.9)	(15.1)	(34.2)	(37.2)	(3.8)
Year 17	(3.0)	(20.8)	(50.1)	(29.3)	(44.1)	(46.9)	(15.1)	(34.2)	(37.2)	(3.8)
Year 18	(3.0)	(20.8)	(50.1)	(29.3)	(44.1)	(46.9)	(15.1)	(34.2)	(37.2)	(3.8)
Year 19	(3.0)	(20.8)	(50.1)	(29.3)	(44.1)	(46.9)	(15.1)	(34.2)	(37.2)	(3.8)
Year 20	(3.0)	(20.8)	(50.1)	(75.1)	(44.1)	(46.9)	(62.6)	(34.2)	(37.2)	(30.0)
Year 21	(3.0)	(20.8)	(50.1)	(75.1)	(44.1)	(46.9)	(62.6)	(34.2)	(37.2)	(30.0)
Year 22	(3.0)	(20.8)	(50.1)	(75.1)	(44.1)	(46.9)	(62.6)	(34.2)	(37.2)	(30.0)
Year 23	(3.0)	(20.8)	(50.1)	(75.1)	(44.1)	(46.9)	(62.6)	(34.2)	(37.2)	(30.0)
Year 24	(3.0)	(20.8)	(50.1)	(75.1)	(44.1)	(46.9)	(62.6)	(34.2)	(37.2)	(30.0)
Year 25	(3.0)	(20.8)	(50.1)	(75.1)	(44.1)	(46.9)	(62.6)	(34.2)	(37.2)	(30.0)
Year 26	(3.0)	(20.8)	(50.1)	(75.1)	(44.1)	(46.9)	(62.6)	(34.2)	(37.2)	(30.0)
Year 27	(3.0)	(20.8)	(50.1)	(75.1)	(44.1)	(46.9)	(62.6)	(34.2)	(37.2)	(30.0)
Year 28	(3.0)	(20.8)	(50.1)	(75.1)	(44.1)	(46.9)	(62.6)	(34.2)	(37.2)	(30.0)
Year 29	(3.0)	(20.8)	(50.1)	(75.1)	(44.1)	(46.9)	(62.6)	(34.2)	(37.2)	(30.0)

[a] Parentheses indicate a net reduction in GHG emissions.

Table 4.2.3-6: 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.[a]

	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	(1.8)	(12.5)	-	88.1	1.0	(0.5)	60.9	(1.2)	(1.4)	15.8
2024	(1.8)	(12.5)	-	(16.3)	1.0	(0.5)	(9.5)	(1.2)	(1.4)	(3.2)
2025	(1.8)	(12.5)	-	(16.3)	1.0	(0.5)	(9.5)	(1.2)	(1.4)	(3.2)
2026	(1.8)	(12.5)	-	(16.3)	1.0	(0.5)	(9.5)	(1.2)	(1.4)	(3.2)
2027	(1.8)	(12.5)	-	(16.3)	1.0	(0.5)	(9.5)	(1.2)	(1.4)	(3.2)
2028	(1.8)	(12.5)	-	(16.3)	1.0	(0.5)	(9.5)	(1.2)	(1.4)	(3.2)
2029	(1.8)	(12.5)	-	(16.3)	1.0	(0.5)	(9.5)	(1.2)	(1.4)	(3.2)
2030	(1.8)	(12.5)	-	(16.3)	1.0	(0.5)	(9.5)	(1.2)	(1.4)	(3.2)
2031	(1.8)	(12.5)	-	(16.3)	1.0	(0.5)	(9.5)	(1.2)	(1.4)	(3.2)
2032	(1.8)	(12.5)	-	(16.3)	1.0	(0.5)	(9.5)	(1.2)	(1.4)	(3.2)
2033	(1.8)	(12.5)	-	(16.3)	1.0	(0.5)	(9.5)	(1.2)	(1.4)	(3.2)
2034	(1.8)	(12.5)	-	(16.3)	1.0	(0.5)	(9.5)	(1.2)	(1.4)	(3.2)
2035	(1.8)	(12.5)	-	(16.3)	1.0	(0.5)	(9.5)	(1.2)	(1.4)	(3.2)
2036	(1.8)	(12.5)	-	(16.3)	1.0	(0.5)	(9.5)	(1.2)	(1.4)	(3.2)
2037	(1.8)	(12.5)	-	(16.3)	1.0	(0.5)	(9.5)	(1.2)	(1.4)	(3.2)
2038	(1.8)	(12.5)	-	(16.3)	1.0	(0.5)	(9.5)	(1.2)	(1.4)	(3.2)
2039	(1.8)	(12.5)	-	(16.3)	1.0	(0.5)	(9.5)	(1.2)	(1.4)	(3.2)
2040	(1.8)	(12.5)	-	(16.3)	1.0	(0.5)	(9.5)	(1.2)	(1.4)	(3.2)
2041	(1.8)	(12.5)	-	(16.3)	1.0	(0.5)	(9.5)	(1.2)	(1.4)	(3.2)
2042	(1.8)	(12.5)	-	(16.3)	1.0	(0.5)	(9.5)	(1.2)	(1.4)	(3.2)
2043	(1.8)	(12.5)	-	(12.4)	1.0	(0.5)	(6.8)	(1.2)	(1.4)	(3.4)
2044	(1.8)	(12.5)	-	(12.4)	1.0	(0.5)	(6.8)	(1.2)	(1.4)	(3.4)
2045	(1.8)	(12.5)	-	(12.4)	1.0	(0.5)	(6.8)	(1.2)	(1.4)	(3.4)
2046	(1.8)	(12.5)	-	(12.4)	1.0	(0.5)	(6.8)	(1.2)	(1.4)	(3.4)
2047	(1.8)	(12.5)	-	(12.4)	1.0	(0.5)	(6.8)	(1.2)	(1.4)	(3.4)
2048	(1.8)	(12.5)	-	(12.4)	1.0	(0.5)	(6.8)	(1.2)	(1.4)	(3.4)
2049	(1.8)	(12.5)	-	(12.4)	1.0	(0.5)	(6.8)	(1.2)	(1.4)	(3.4)
2050	(1.8)	(12.5)	-	(12.4)	1.0	(0.5)	(6.8)	(1.2)	(1.4)	(3.4)
2051	(1.8)	(12.5)	-	(12.4)	1.0	(0.5)	(6.8)	(1.2)	(1.4)	(3.4)
2052	(1.8)	(12.5)	-	(12.4)	1.0	(0.5)	(6.8)	(1.2)	(1.4)	(3.4)
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. Parentheses indicate a net reduction in GHG emissions.

Table 4.2.3-7: 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.[a]

	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	(0.7)	(4.9)	-	(5.3)	(0.1)	(0.2)	16.3	0.1	2.2	1.7
2025	(0.7)	(4.9)	-	1.0	(0.1)	(0.2)	(2.5)	0.1	2.2	(0.3)
2026	(0.7)	(4.9)	-	1.0	(0.1)	(0.2)	(2.5)	0.1	2.2	(0.3)
2027	(0.7)	(4.9)	-	1.0	(0.1)	(0.2)	(2.5)	0.1	2.2	(0.3)
2028	(0.7)	(4.9)	-	1.0	(0.1)	(0.2)	(2.5)	0.1	2.2	(0.3)
2029	(0.7)	(4.9)	-	1.0	(0.1)	(0.2)	(2.5)	0.1	2.2	(0.3)
2030	(0.7)	(4.9)	-	1.0	(0.1)	(0.2)	(2.5)	0.1	2.2	(0.3)
2031	(0.7)	(4.9)	-	1.0	(0.1)	(0.2)	(2.5)	0.1	2.2	(0.3)
2032	(0.7)	(4.9)	-	1.0	(0.1)	(0.2)	(2.5)	0.1	2.2	(0.3)
2033	(0.7)	(4.9)	-	1.0	(0.1)	(0.2)	(2.5)	0.1	2.2	(0.3)
2034	(0.7)	(4.9)	-	1.0	(0.1)	(0.2)	(2.5)	0.1	2.2	(0.3)
2035	(0.7)	(4.9)	-	1.0	(0.1)	(0.2)	(2.5)	0.1	2.2	(0.3)
2036	(0.7)	(4.9)	-	1.0	(0.1)	(0.2)	(2.5)	0.1	2.2	(0.3)
2037	(0.7)	(4.9)	-	1.0	(0.1)	(0.2)	(2.5)	0.1	2.2	(0.3)
2038	(0.7)	(4.9)	-	1.0	(0.1)	(0.2)	(2.5)	0.1	2.2	(0.3)
2039	(0.7)	(4.9)	-	1.0	(0.1)	(0.2)	(2.5)	0.1	2.2	(0.3)
2040	(0.7)	(4.9)	-	1.0	(0.1)	(0.2)	(2.5)	0.1	2.2	(0.3)
2041	(0.7)	(4.9)	-	1.0	(0.1)	(0.2)	(2.5)	0.1	2.2	(0.3)
2042	(0.7)	(4.9)	-	1.0	(0.1)	(0.2)	(2.5)	0.1	2.2	(0.3)
2043	(0.7)	(4.9)	-	1.0	(0.1)	(0.2)	(2.5)	0.1	2.2	(0.3)
2044	(0.7)	(4.9)	-	0.7	(0.1)	(0.2)	(1.8)	0.1	2.2	(0.4)
2045	(0.7)	(4.9)	-	0.7	(0.1)	(0.2)	(1.8)	0.1	2.2	(0.4)
2046	(0.7)	(4.9)	-	0.7	(0.1)	(0.2)	(1.8)	0.1	2.2	(0.4)
2047	(0.7)	(4.9)	-	0.7	(0.1)	(0.2)	(1.8)	0.1	2.2	(0.4)
2048	(0.7)	(4.9)	-	0.7	(0.1)	(0.2)	(1.8)	0.1	2.2	(0.4)
2049	(0.7)	(4.9)	-	0.7	(0.1)	(0.2)	(1.8)	0.1	2.2	(0.4)
2050	(0.7)	(4.9)	-	0.7	(0.1)	(0.2)	(1.8)	0.1	2.2	(0.4)
2051	(0.7)	(4.9)	-	0.7	(0.1)	(0.2)	(1.8)	0.1	2.2	(0.4)
2052	(0.7)	(4.9)	-	0.7	(0.1)	(0.2)	(1.8)	0.1	2.2	(0.4)
2053	(0.7)	(4.9)	-	0.7	(0.1)	(0.2)	(1.8)	0.1	2.2	(0.4)
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. Parentheses indicate a net reduction in GHG emissions.

Table 4.2.3-8: 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.[a]

	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	(0.9)	(6.2)	-	1.0	0.2	0.4	14.2	(0.2)	(0.5)	1.3
2026	(0.9)	(6.2)	-	(0.2)	0.2	0.4	(2.2)	(0.2)	(0.5)	(0.3)
2027	(0.9)	(6.2)	-	(0.2)	0.2	0.4	(2.2)	(0.2)	(0.5)	(0.3)
2028	(0.9)	(6.2)	-	(0.2)	0.2	0.4	(2.2)	(0.2)	(0.5)	(0.3)
2029	(0.9)	(6.2)	-	(0.2)	0.2	0.4	(2.2)	(0.2)	(0.5)	(0.3)
2030	(0.9)	(6.2)	-	(0.2)	0.2	0.4	(2.2)	(0.2)	(0.5)	(0.3)
2031	(0.9)	(6.2)	-	(0.2)	0.2	0.4	(2.2)	(0.2)	(0.5)	(0.3)
2032	(0.9)	(6.2)	-	(0.2)	0.2	0.4	(2.2)	(0.2)	(0.5)	(0.3)
2033	(0.9)	(6.2)	-	(0.2)	0.2	0.4	(2.2)	(0.2)	(0.5)	(0.3)
2034	(0.9)	(6.2)	-	(0.2)	0.2	0.4	(2.2)	(0.2)	(0.5)	(0.3)
2035	(0.9)	(6.2)	-	(0.2)	0.2	0.4	(2.2)	(0.2)	(0.5)	(0.3)
2036	(0.9)	(6.2)	-	(0.2)	0.2	0.4	(2.2)	(0.2)	(0.5)	(0.3)
2037	(0.9)	(6.2)	-	(0.2)	0.2	0.4	(2.2)	(0.2)	(0.5)	(0.3)
2038	(0.9)	(6.2)	-	(0.2)	0.2	0.4	(2.2)	(0.2)	(0.5)	(0.3)
2039	(0.9)	(6.2)	-	(0.2)	0.2	0.4	(2.2)	(0.2)	(0.5)	(0.3)
2040	(0.9)	(6.2)	-	(0.2)	0.2	0.4	(2.2)	(0.2)	(0.5)	(0.3)
2041	(0.9)	(6.2)	-	(0.2)	0.2	0.4	(2.2)	(0.2)	(0.5)	(0.3)
2042	(0.9)	(6.2)	-	(0.2)	0.2	0.4	(2.2)	(0.2)	(0.5)	(0.3)
2043	(0.9)	(6.2)	-	(0.2)	0.2	0.4	(2.2)	(0.2)	(0.5)	(0.3)
2044	(0.9)	(6.2)	-	(0.2)	0.2	0.4	(2.2)	(0.2)	(0.5)	(0.3)
2045	(0.9)	(6.2)	-	(0.1)	0.2	0.4	(1.6)	(0.2)	(0.5)	(0.3)
2046	(0.9)	(6.2)	-	(0.1)	0.2	0.4	(1.6)	(0.2)	(0.5)	(0.3)
2047	(0.9)	(6.2)	-	(0.1)	0.2	0.4	(1.6)	(0.2)	(0.5)	(0.3)
2048	(0.9)	(6.2)	-	(0.1)	0.2	0.4	(1.6)	(0.2)	(0.5)	(0.3)
2049	(0.9)	(6.2)	-	(0.1)	0.2	0.4	(1.6)	(0.2)	(0.5)	(0.3)
2050	(0.9)	(6.2)	-	(0.1)	0.2	0.4	(1.6)	(0.2)	(0.5)	(0.3)
2051	(0.9)	(6.2)	-	(0.1)	0.2	0.4	(1.6)	(0.2)	(0.5)	(0.3)
2052	(0.9)	(6.2)	-	(0.1)	0.2	0.4	(1.6)	(0.2)	(0.5)	(0.3)
2053	(0.9)	(6.2)	-	(0.1)	0.2	0.4	(1.6)	(0.2)	(0.5)	(0.3)
2054	(0.9)	(6.2)	-	(0.1)	0.2	0.4	(1.6)	(0.2)	(0.5)	(0.3)

[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. Parentheses indicate a net reduction in GHG emissions.

Table 4.2.3-9: 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.[a]

	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	(1.8)	(12.5)	-	88.1	1.0	(0.5)	60.9	(1.2)	(1.4)	15.8
2024	(2.5)	(17.4)	-	(21.6)	0.9	(0.6)	6.9	(1.1)	0.7	(1.5)
2025	(3.3)	(23.6)	-	(14.3)	1.2	(0.2)	2.2	(1.3)	0.2	(2.1)
2026	(3.3)	(23.6)	-	(15.5)	1.2	(0.2)	(14.2)	(1.3)	0.2	(3.8)
2027	(3.3)	(23.6)	-	(15.5)	1.2	(0.2)	(14.2)	(1.3)	0.2	(3.8)
2028	(3.3)	(23.6)	-	(15.5)	1.2	(0.2)	(14.2)	(1.3)	0.2	(3.8)
2029	(3.3)	(23.6)	-	(15.5)	1.2	(0.2)	(14.2)	(1.3)	0.2	(3.8)
2030	(3.3)	(23.6)	-	(15.5)	1.2	(0.2)	(14.2)	(1.3)	0.2	(3.8)
2031	(3.3)	(23.6)	-	(15.5)	1.2	(0.2)	(14.2)	(1.3)	0.2	(3.8)
2032	(3.3)	(23.6)	-	(15.5)	1.2	(0.2)	(14.2)	(1.3)	0.2	(3.8)
2033	(3.3)	(23.6)	-	(15.5)	1.2	(0.2)	(14.2)	(1.3)	0.2	(3.8)
2034	(3.3)	(23.6)	-	(15.5)	1.2	(0.2)	(14.2)	(1.3)	0.2	(3.8)
2035	(3.3)	(23.6)	-	(15.5)	1.2	(0.2)	(14.2)	(1.3)	0.2	(3.8)
2036	(3.3)	(23.6)	-	(15.5)	1.2	(0.2)	(14.2)	(1.3)	0.2	(3.8)
2037	(3.3)	(23.6)	-	(15.5)	1.2	(0.2)	(14.2)	(1.3)	0.2	(3.8)
2038	(3.3)	(23.6)	-	(15.5)	1.2	(0.2)	(14.2)	(1.3)	0.2	(3.8)
2039	(3.3)	(23.6)	-	(15.5)	1.2	(0.2)	(14.2)	(1.3)	0.2	(3.8)
2040	(3.3)	(23.6)	-	(15.5)	1.2	(0.2)	(14.2)	(1.3)	0.2	(3.8)
2041	(3.3)	(23.6)	-	(15.5)	1.2	(0.2)	(14.2)	(1.3)	0.2	(3.8)
2042	(3.3)	(23.6)	-	(15.5)	1.2	(0.2)	(14.2)	(1.3)	0.2	(3.8)
2043	(3.3)	(23.6)	-	(11.6)	1.2	(0.2)	(11.6)	(1.3)	0.2	(4.0)
2044	(3.3)	(23.6)	-	(11.8)	1.2	(0.2)	(10.9)	(1.3)	0.2	(4.0)
2045	(3.3)	(23.6)	-	(11.8)	1.2	(0.2)	(10.3)	(1.3)	0.2	(4.0)
2046	(3.3)	(23.6)	-	(11.8)	1.2	(0.2)	(10.3)	(1.3)	0.2	(4.0)
2047	(3.3)	(23.6)	-	(11.8)	1.2	(0.2)	(10.3)	(1.3)	0.2	(4.0)
2048	(3.3)	(23.6)	-	(11.8)	1.2	(0.2)	(10.3)	(1.3)	0.2	(4.0)
2049	(3.3)	(23.6)	-	(11.8)	1.2	(0.2)	(10.3)	(1.3)	0.2	(4.0)
2050	(3.3)	(23.6)	-	(11.8)	1.2	(0.2)	(10.3)	(1.3)	0.2	(4.0)
2051	(3.3)	(23.6)	-	(11.8)	1.2	(0.2)	(10.3)	(1.3)	0.2	(4.0)
2052	(3.3)	(23.6)	-	(11.8)	1.2	(0.2)	(10.3)	(1.3)	0.2	(4.0)
2053	(1.6)	(11.1)	-	0.6	0.1	0.3	(3.4)	(0.1)	1.7	(0.7)
2054	(0.9)	(6.2)	-	(0.1)	0.2	0.4	(1.6)	(0.2)	(0.5)	(0.3)

[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. Parentheses indicate a net reduction in GHG emissions.

Table 4.2.3-10: 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.[a]

	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	(0.1)	(0.4)	-	137.3	0.6	(0.3)	93.9	(0.5)	(0.7)	31.0
2024	(0.1)	(0.4)	-	(4.2)	0.6	(0.3)	(1.4)	(0.5)	(0.7)	(0.2)
2025	(0.1)	(0.4)	-	(4.2)	0.6	(0.3)	(1.4)	(0.5)	(0.7)	(0.2)
2026	(0.1)	(0.4)	-	(4.2)	0.6	(0.3)	(1.4)	(0.5)	(0.7)	(0.2)
2027	(0.1)	(0.4)	-	(4.2)	0.6	(0.3)	(1.4)	(0.5)	(0.7)	(0.2)
2028	(0.1)	(0.4)	-	(4.2)	0.6	(0.3)	(1.4)	(0.5)	(0.7)	(0.2)
2029	(0.1)	(0.4)	-	(4.2)	0.6	(0.3)	(1.4)	(0.5)	(0.7)	(0.2)
2030	(0.1)	(0.4)	-	(4.2)	0.6	(0.3)	(1.4)	(0.5)	(0.7)	(0.2)
2031	(0.1)	(0.4)	-	(4.2)	0.6	(0.3)	(1.4)	(0.5)	(0.7)	(0.2)
2032	(0.1)	(0.4)	-	(4.2)	0.6	(0.3)	(1.4)	(0.5)	(0.7)	(0.2)
2033	(0.1)	(0.4)	-	(4.2)	0.6	(0.3)	(1.4)	(0.5)	(0.7)	(0.2)
2034	(0.1)	(0.4)	-	(4.2)	0.6	(0.3)	(1.4)	(0.5)	(0.7)	(0.2)
2035	(0.1)	(0.4)	-	(4.2)	0.6	(0.3)	(1.4)	(0.5)	(0.7)	(0.2)
2036	(0.1)	(0.4)	-	(4.2)	0.6	(0.3)	(1.4)	(0.5)	(0.7)	(0.2)
2037	(0.1)	(0.4)	-	(4.2)	0.6	(0.3)	(1.4)	(0.5)	(0.7)	(0.2)
2038	(0.1)	(0.4)	-	(4.2)	0.6	(0.3)	(1.4)	(0.5)	(0.7)	(0.2)
2039	(0.1)	(0.4)	-	(4.2)	0.6	(0.3)	(1.4)	(0.5)	(0.7)	(0.2)
2040	(0.1)	(0.4)	-	(4.2)	0.6	(0.3)	(1.4)	(0.5)	(0.7)	(0.2)
2041	(0.1)	(0.4)	-	(4.2)	0.6	(0.3)	(1.4)	(0.5)	(0.7)	(0.2)
2042	(0.1)	(0.4)	-	(4.2)	0.6	(0.3)	(1.4)	(0.5)	(0.7)	(0.2)
2043	(0.1)	(0.4)	-	(10.7)	0.6	(0.3)	(5.8)	(0.5)	(0.7)	(1.6)
2044	(0.1)	(0.4)	-	(10.7)	0.6	(0.3)	(5.8)	(0.5)	(0.7)	(1.6)
2045	(0.1)	(0.4)	-	(10.7)	0.6	(0.3)	(5.8)	(0.5)	(0.7)	(1.6)
2046	(0.1)	(0.4)	-	(10.7)	0.6	(0.3)	(5.8)	(0.5)	(0.7)	(1.6)
2047	(0.1)	(0.4)	-	(10.7)	0.6	(0.3)	(5.8)	(0.5)	(0.7)	(1.6)
2048	(0.1)	(0.4)	-	(10.7)	0.6	(0.3)	(5.8)	(0.5)	(0.7)	(1.6)
2049	(0.1)	(0.4)	-	(10.7)	0.6	(0.3)	(5.8)	(0.5)	(0.7)	(1.6)
2050	(0.1)	(0.4)	-	(10.7)	0.6	(0.3)	(5.8)	(0.5)	(0.7)	(1.6)
2051	(0.1)	(0.4)	-	(10.7)	0.6	(0.3)	(5.8)	(0.5)	(0.7)	(1.6)
2052	(0.1)	(0.4)	-	(10.7)	0.6	(0.3)	(5.8)	(0.5)	(0.7)	(1.6)
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. Parentheses indicate a net reduction in GHG emissions.

Table 4.2.3-11: 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.[a]

	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)	(0.2)	-	(8.3)	(0.1)	(0.1)	25.2	0.0	1.0	3.3
2025	(0.0)	(0.2)	-	0.3	(0.1)	(0.1)	(0.4)	0.0	1.0	(0.0)
2026	(0.0)	(0.2)	-	0.3	(0.1)	(0.1)	(0.4)	0.0	1.0	(0.0)
2027	(0.0)	(0.2)	-	0.3	(0.1)	(0.1)	(0.4)	0.0	1.0	(0.0)
2028	(0.0)	(0.2)	-	0.3	(0.1)	(0.1)	(0.4)	0.0	1.0	(0.0)
2029	(0.0)	(0.2)	-	0.3	(0.1)	(0.1)	(0.4)	0.0	1.0	(0.0)
2030	(0.0)	(0.2)	-	0.3	(0.1)	(0.1)	(0.4)	0.0	1.0	(0.0)
2031	(0.0)	(0.2)	-	0.3	(0.1)	(0.1)	(0.4)	0.0	1.0	(0.0)
2032	(0.0)	(0.2)	-	0.3	(0.1)	(0.1)	(0.4)	0.0	1.0	(0.0)
2033	(0.0)	(0.2)	-	0.3	(0.1)	(0.1)	(0.4)	0.0	1.0	(0.0)
2034	(0.0)	(0.2)	-	0.3	(0.1)	(0.1)	(0.4)	0.0	1.0	(0.0)
2035	(0.0)	(0.2)	-	0.3	(0.1)	(0.1)	(0.4)	0.0	1.0	(0.0)
2036	(0.0)	(0.2)	-	0.3	(0.1)	(0.1)	(0.4)	0.0	1.0	(0.0)
2037	(0.0)	(0.2)	-	0.3	(0.1)	(0.1)	(0.4)	0.0	1.0	(0.0)
2038	(0.0)	(0.2)	-	0.3	(0.1)	(0.1)	(0.4)	0.0	1.0	(0.0)
2039	(0.0)	(0.2)	-	0.3	(0.1)	(0.1)	(0.4)	0.0	1.0	(0.0)
2040	(0.0)	(0.2)	-	0.3	(0.1)	(0.1)	(0.4)	0.0	1.0	(0.0)
2041	(0.0)	(0.2)	-	0.3	(0.1)	(0.1)	(0.4)	0.0	1.0	(0.0)
2042	(0.0)	(0.2)	-	0.3	(0.1)	(0.1)	(0.4)	0.0	1.0	(0.0)
2043	(0.0)	(0.2)	-	0.3	(0.1)	(0.1)	(0.4)	0.0	1.0	(0.0)
2044	(0.0)	(0.2)	-	0.6	(0.1)	(0.1)	(1.5)	0.0	1.0	(0.2)
2045	(0.0)	(0.2)	-	0.6	(0.1)	(0.1)	(1.5)	0.0	1.0	(0.2)
2046	(0.0)	(0.2)	-	0.6	(0.1)	(0.1)	(1.5)	0.0	1.0	(0.2)
2047	(0.0)	(0.2)	-	0.6	(0.1)	(0.1)	(1.5)	0.0	1.0	(0.2)
2048	(0.0)	(0.2)	-	0.6	(0.1)	(0.1)	(1.5)	0.0	1.0	(0.2)
2049	(0.0)	(0.2)	-	0.6	(0.1)	(0.1)	(1.5)	0.0	1.0	(0.2)
2050	(0.0)	(0.2)	-	0.6	(0.1)	(0.1)	(1.5)	0.0	1.0	(0.2)
2051	(0.0)	(0.2)	-	0.6	(0.1)	(0.1)	(1.5)	0.0	1.0	(0.2)
2052	(0.0)	(0.2)	-	0.6	(0.1)	(0.1)	(1.5)	0.0	1.0	(0.2)
2053	(0.0)	(0.2)	-	0.6	(0.1)	(0.1)	(1.5)	0.0	1.0	(0.2)
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. Parentheses indicate a net reduction in GHG emissions.

Table 4.2.3-12: 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.[a]

	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)	(0.2)	-	1.6	0.1	0.3	21.8	(0.1)	(0.2)	2.6
2026	(0.0)	(0.2)	-	(0.0)	0.1	0.3	(0.3)	(0.1)	(0.2)	(0.0)
2027	(0.0)	(0.2)	-	(0.0)	0.1	0.3	(0.3)	(0.1)	(0.2)	(0.0)
2028	(0.0)	(0.2)	-	(0.0)	0.1	0.3	(0.3)	(0.1)	(0.2)	(0.0)
2029	(0.0)	(0.2)	-	(0.0)	0.1	0.3	(0.3)	(0.1)	(0.2)	(0.0)
2030	(0.0)	(0.2)	-	(0.0)	0.1	0.3	(0.3)	(0.1)	(0.2)	(0.0)
2031	(0.0)	(0.2)	-	(0.0)	0.1	0.3	(0.3)	(0.1)	(0.2)	(0.0)
2032	(0.0)	(0.2)	-	(0.0)	0.1	0.3	(0.3)	(0.1)	(0.2)	(0.0)
2033	(0.0)	(0.2)	-	(0.0)	0.1	0.3	(0.3)	(0.1)	(0.2)	(0.0)
2034	(0.0)	(0.2)	-	(0.0)	0.1	0.3	(0.3)	(0.1)	(0.2)	(0.0)
2035	(0.0)	(0.2)	-	(0.0)	0.1	0.3	(0.3)	(0.1)	(0.2)	(0.0)
2036	(0.0)	(0.2)	-	(0.0)	0.1	0.3	(0.3)	(0.1)	(0.2)	(0.0)
2037	(0.0)	(0.2)	-	(0.0)	0.1	0.3	(0.3)	(0.1)	(0.2)	(0.0)
2038	(0.0)	(0.2)	-	(0.0)	0.1	0.3	(0.3)	(0.1)	(0.2)	(0.0)
2039	(0.0)	(0.2)	-	(0.0)	0.1	0.3	(0.3)	(0.1)	(0.2)	(0.0)
2040	(0.0)	(0.2)	-	(0.0)	0.1	0.3	(0.3)	(0.1)	(0.2)	(0.0)
2041	(0.0)	(0.2)	-	(0.0)	0.1	0.3	(0.3)	(0.1)	(0.2)	(0.0)
2042	(0.0)	(0.2)	-	(0.0)	0.1	0.3	(0.3)	(0.1)	(0.2)	(0.0)
2043	(0.0)	(0.2)	-	(0.0)	0.1	0.3	(0.3)	(0.1)	(0.2)	(0.0)
2044	(0.0)	(0.2)	-	(0.0)	0.1	0.3	(0.3)	(0.1)	(0.2)	(0.0)
2045	(0.0)	(0.2)	-	(0.1)	0.1	0.3	(1.3)	(0.1)	(0.2)	(0.1)
2046	(0.0)	(0.2)	-	(0.1)	0.1	0.3	(1.3)	(0.1)	(0.2)	(0.1)
2047	(0.0)	(0.2)	-	(0.1)	0.1	0.3	(1.3)	(0.1)	(0.2)	(0.1)
2048	(0.0)	(0.2)	-	(0.1)	0.1	0.3	(1.3)	(0.1)	(0.2)	(0.1)
2049	(0.0)	(0.2)	-	(0.1)	0.1	0.3	(1.3)	(0.1)	(0.2)	(0.1)
2050	(0.0)	(0.2)	-	(0.1)	0.1	0.3	(1.3)	(0.1)	(0.2)	(0.1)
2051	(0.0)	(0.2)	-	(0.1)	0.1	0.3	(1.3)	(0.1)	(0.2)	(0.1)
2052	(0.0)	(0.2)	-	(0.1)	0.1	0.3	(1.3)	(0.1)	(0.2)	(0.1)
2053	(0.0)	(0.2)	-	(0.1)	0.1	0.3	(1.3)	(0.1)	(0.2)	(0.1)
2054	(0.0)	(0.2)	-	(0.1)	0.1	0.3	(1.3)	(0.1)	(0.2)	(0.1)

[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. Parentheses indicate a net reduction in GHG emissions.

Table 4.2.3-13: 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.[a]

	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	(0.1)	(0.4)	-	137.3	0.6	(0.3)	93.9	(0.5)	(0.7)	31.0
2024	(0.1)	(0.6)	-	(12.5)	0.5	(0.4)	23.8	(0.5)	0.3	3.1
2025	(0.1)	(0.8)	-	(2.3)	0.6	(0.1)	20.0	(0.6)	0.1	2.4
2026	(0.1)	(0.8)	-	(4.0)	0.6	(0.1)	(2.1)	(0.6)	0.1	(0.2)
2027	(0.1)	(0.8)	-	(4.0)	0.6	(0.1)	(2.1)	(0.6)	0.1	(0.2)
2028	(0.1)	(0.8)	-	(4.0)	0.6	(0.1)	(2.1)	(0.6)	0.1	(0.2)
2029	(0.1)	(0.8)	-	(4.0)	0.6	(0.1)	(2.1)	(0.6)	0.1	(0.2)
2030	(0.1)	(0.8)	-	(4.0)	0.6	(0.1)	(2.1)	(0.6)	0.1	(0.2)
2031	(0.1)	(0.8)	-	(4.0)	0.6	(0.1)	(2.1)	(0.6)	0.1	(0.2)
2032	(0.1)	(0.8)	-	(4.0)	0.6	(0.1)	(2.1)	(0.6)	0.1	(0.2)
2033	(0.1)	(0.8)	-	(4.0)	0.6	(0.1)	(2.1)	(0.6)	0.1	(0.2)
2034	(0.1)	(0.8)	-	(4.0)	0.6	(0.1)	(2.1)	(0.6)	0.1	(0.2)
2035	(0.1)	(0.8)	-	(4.0)	0.6	(0.1)	(2.1)	(0.6)	0.1	(0.2)
2036	(0.1)	(0.8)	-	(4.0)	0.6	(0.1)	(2.1)	(0.6)	0.1	(0.2)
2037	(0.1)	(0.8)	-	(4.0)	0.6	(0.1)	(2.1)	(0.6)	0.1	(0.2)
2038	(0.1)	(0.8)	-	(4.0)	0.6	(0.1)	(2.1)	(0.6)	0.1	(0.2)
2039	(0.1)	(0.8)	-	(4.0)	0.6	(0.1)	(2.1)	(0.6)	0.1	(0.2)
2040	(0.1)	(0.8)	-	(4.0)	0.6	(0.1)	(2.1)	(0.6)	0.1	(0.2)
2041	(0.1)	(0.8)	-	(4.0)	0.6	(0.1)	(2.1)	(0.6)	0.1	(0.2)
2042	(0.1)	(0.8)	-	(4.0)	0.6	(0.1)	(2.1)	(0.6)	0.1	(0.2)
2043	(0.1)	(0.8)	-	(10.5)	0.6	(0.1)	(6.5)	(0.6)	0.1	(1.6)
2044	(0.1)	(0.8)	-	(10.1)	0.6	(0.1)	(7.6)	(0.6)	0.1	(1.8)
2045	(0.1)	(0.8)	-	(10.2)	0.6	(0.1)	(8.7)	(0.6)	0.1	(1.9)
2046	(0.1)	(0.8)	-	(10.2)	0.6	(0.1)	(8.7)	(0.6)	0.1	(1.9)
2047	(0.1)	(0.8)	-	(10.2)	0.6	(0.1)	(8.7)	(0.6)	0.1	(1.9)
2048	(0.1)	(0.8)	-	(10.2)	0.6	(0.1)	(8.7)	(0.6)	0.1	(1.9)
2049	(0.1)	(0.8)	-	(10.2)	0.6	(0.1)	(8.7)	(0.6)	0.1	(1.9)
2050	(0.1)	(0.8)	-	(10.2)	0.6	(0.1)	(8.7)	(0.6)	0.1	(1.9)
2051	(0.1)	(0.8)	-	(10.2)	0.6	(0.1)	(8.7)	(0.6)	0.1	(1.9)
2052	(0.1)	(0.8)	-	(10.2)	0.6	(0.1)	(8.7)	(0.6)	0.1	(1.9)
2053	(0.1)	(0.4)	-	0.5	0.1	0.2	(2.9)	(0.0)	0.8	(0.3)
2054	(0.0)	(0.2)	-	(0.1)	0.1	0.3	(1.3)	(0.1)	(0.2)	(0.1)

[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. Parentheses indicate a net reduction in GHG emissions.

Table 4.2.3-14: 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.[a]

	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	-	-

[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. Parentheses indicate a net reduction in GHG emissions.

4.2.4 Monetized GHG Impacts

4.2.4.1 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.[263] We estimate the social benefits of GHG reductions in this illustrative scenario using estimates of the social cost of greenhouse gases (SC-GHG), specifically using the social cost of carbon (SC-CO_2). 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 and 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. EPA and other Federal agencies began regularly incorporating SC-GHG estimates in their benefit-cost analyses conducted under Executive Order (E.O.) 12866[264] since 2008, following a Ninth Circuit Court of Appeals remand of a rule for failing to monetize the benefits of reducing CO_2 emissions in that rulemaking process.

In 2017, the National Academies of Sciences, Engineering, and Medicine published a report that provides a roadmap for how to update SC-GHG estimates used in Federal analyses going forward to ensure that they reflect advances in the scientific literature.[265] The National Academies' report recommended specific criteria for future SC-GHG updates, 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. The research community has made considerable progress in developing new data and methods that help to advance various components of the SC-GHG estimation process in response to the National Academies' recommendations.

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[263] It would be preferable to use estimates for each gas (e.g., CO_2, CH_4, N_2O), but we use CO_2e estimates for this illustrative scenario as they are the most readily available biofuel carbon intensity estimates.

[264] Presidents since the 1970s have issued executive orders requiring agencies to conduct analysis of the economic consequences of regulations as part of the rulemaking development process. E.O. 12866, released in 1993 and still in effect today, requires that for all economically significant regulatory actions, an agency provide an assessment of the potential costs and benefits of the regulatory action, and that this assessment include a quantification of benefits and costs to the extent feasible. Many statutes also require agencies to conduct at least some of the same analyses required under E.O. 12866, such as the Energy Policy and Conservation Act, which mandates the setting of fuel economy regulations. For purposes of this action, monetized climate benefits are presented for purposes of providing a complete benefit-cost analysis under E.O. 12866 and other relevant executive orders. The estimates of change in GHG emissions and the monetized benefits associated with those changes play no part in the record basis for this action.

[265] National Academies. (2017). Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide. Washington, DC: The National Academies Press.

In a first-day executive order (E.O. 13990), Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis, President Biden called for a renewed focus on updating estimates of the social cost of greenhouse gases (SC-GHG) to reflect the latest science, noting that "it is essential that agencies capture the full benefits of reducing greenhouse gas emissions as accurately as possible." Important steps have been taken to begin to fulfill this directive of E.O. 13990. In February 2021, the Interagency Working Group on the SC-GHG (IWG) released a technical support document (hereinafter the "February 2021 TSD") that provided a set of IWG recommended SC-GHG estimates while work on a more comprehensive update is underway to reflect recent scientific advances relevant to SC-GHG estimation.[266] In addition, as discussed further below, EPA has developed a draft updated SC-GHG methodology within a sensitivity analysis in the regulatory impact analysis of EPA's November 2022 supplemental proposal for oil and gas standards that is currently undergoing external peer review and a public comment process.[267]

EPA has applied the IWG's recommended interim SC-GHG estimates in the Agency's regulatory benefit-cost analyses published since the release of the February 2021 TSD and is likewise using them in this document. 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 until revised estimates have been developed reflecting the latest, peer-reviewed science. The SC-GHG estimates presented in the February 2021 SC-GHG TSD and used in this document 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 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.[268,269,270] 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

[266] IWG. (2021). Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990. Retrieved from Washington, DC: https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf
[267] See https://www.epa.gov/environmental-economics/scghg
[268] Dynamic Integrated Climate and Economy (DICE) 2010 (Nordhaus 2010).
[269] Climate Framework for Uncertainty, Negotiation, and Distribution (FUND) 3.8 (Anthoff and Tol 2013a, 2013b)
[270] Dynamic Integrated Climate and Economy (DICE), Climate Framework for Uncertainty, Negotiation, and Distribution (FUND), and Policy Analysis of the Greenhouse Gas Effect (PAGE) 2009 (Hope 2013).

consistent with the methodology underlying the $SC\text{-}CO_2$ estimates. The modeling approach that extends the IWG $SC\text{-}CO_2$ methodology to non-CO_2 GHGs has undergone multiple stages of peer review. The $SC\text{-}CH_4$ and $SC\text{-}N_2O$ estimates were developed by Marten, Kopits, Griffiths, Newbold, and Wolverton (2015) and underwent a standard double-blind peer review process prior to journal publication. These estimates were applied in regulatory impact analyses of EPA proposed rulemakings with CH_4 and N_2O emissions impacts. EPA also sought additional external peer review of technical issues associated with its application to regulatory analysis. Following the completion of the independent external peer review of the application of the Marten et al. (2015) estimates[271], EPA began using the estimates in the primary benefit-cost analysis calculations and tables for a number of proposed rulemakings in 2015.[272] EPA considered and responded to public comments received for the proposed rulemakings before using the estimates in final regulatory analyses in 2016.[273] In 2015, as part of the response to public comments received to a 2013 solicitation for comments on the $SC\text{-}CO_2$ estimates, the IWG announced a National Academies of Sciences, Engineering, and Medicine review of the $SC\text{-}CO_2$ 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-GHG 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.[274] 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-GHG 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-GHG estimates that attempted to focus on the specific share of climate change damages in the U.S. as captured by the models (which did not reflect many pathways by which climate impacts affect the welfare of U.S. citizens and residents) and were calculated using two discount rates recommended by Circular A-4, 3 percent and 7 percent.[275] All other methodological decisions and model versions used in SC-GHG calculations remained the same as those used by the IWG in 2010 and 2013, respectively.

[271] Alex L. Marten, Elizabeth A. Kopits, Charles W. Griffiths, Stephen C. Newbold & Ann Wolverton (2015) Incremental CH4 and N2O mitigation benefits consistent with the US Government's SC-CO2 estimates, Climate Policy, 15:2, 272-298, DOI: 10.1080/14693062.2014.912981

[272] U.S. Environmental Protection Agency (EPA), 2015b. Regulatory Impact Analysis for the Proposed Revisions to the Emission Guidelines for Existing Sources and Supplemental Proposed New Source Performance Standards in the Municipal Solid Waste Landfills Sector. https://www.regulations.gov/document?D=EPA-HQ-OAR-2014-0451-0086.

[273] The $SC\text{-}CH_4$ and $SC\text{-}N_2O$ estimates were first used in sensitivity analysis for the Proposed Rulemaking for Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles–Phase 2 (U.S. EPA, 2015a).

[274] 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.

[275] EPA regulatory analyses under E.O. 13783 included sensitivity analyses based on global SC-GHG values and using a lower discount rate of 2.5%. OMB Circular A-4 (OMB, 2003) recognizes that special considerations arise when applying discount rates if intergenerational effects are important. In the IWG's 2015 Response to Comments, OMB—as a co-chair of the IWG—made clear that "Circular A-4 is a living document," that "the use of 7 percent is

On January 20, 2021, President Biden issued Executive Order 13990, which re-established an IWG and directed it to develop an update of the social cost of carbon and other greenhouse gas estimates that reflect the best available science and the recommendations of the National Academies. In February 2021, the IWG recommended the interim use of the most recent SC-GHG estimates developed by the IWG prior to the group being disbanded in 2017, adjusted for inflation.[276] As discussed in the February 2021 TSD, the IWG's selection of these interim estimates reflected the immediate need to have SC-GHG estimates available for agencies to use in regulatory benefit-cost analyses and other applications that were developed using a transparent process, peer reviewed methodologies, and the science available at the time of that process. As noted above, EPA participated in the IWG but has also independently evaluated the interim SC-GHG estimates published in the February 2021 TSD and determined they are appropriate to use here to estimate climate benefits 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. 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.

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not considered appropriate for intergenerational discounting," and that "[t]here is wide support for this view in the academic literature, and it is recognized in Circular A-4 itself." OMB, as part of the IWG, similarly repeatedly confirmed that "a focus on global SCC estimates in [regulatory impact analyses] is appropriate" (IWG, 2015).

[276] IWG. (2021). Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990. Retrieved from Washington, DC: https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

As a member of the IWG involved in the development of the February 2021 SC-GHG TSD, EPA agrees with this assessment and, therefore, in this document 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 (2017) 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.[277,278,279,280] 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

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[277] IWG. (2010). Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866. Retrieved from Washington, DC: https://www.epa.gov/sites/default/files/2016-12/documents/scc_tsd_2010.pdf 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.

[278] IWG. (2013). Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866. Retrieved from Washington, DC: https://obamawhitehouse.archives.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf 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.

[279] IWG. (2016a). 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. Retrieved from Washington, DC: https://www.epa.gov/sites/default/files/2016-12/documents/addendum_to_sc-ghg_tsd_august_2016.pdf Greenhouse Gases (IWG). 2016a.August.

[280] IWG. (2016b). Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866. Retrieved from Washington, DC: https://www.epa.gov/sites/default/files/2016-12/documents/sc_co2_tsd_august_2016.pdf. 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.

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 percent and 7 percent 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 percent discount rate is not appropriate to apply to value the social cost of greenhouse gases in the analysis presented in this final rule. 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 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 represent the extensive evidence in the scientific and economic literature of the potential for lower-probability, higher-impact outcomes from climate change, which would be particularly harmful to society and thus relevant to the public and policymakers. Absent formal inclusion of risk aversion in the modeling, considering values above the mean in a right skewed distribution with long tails acknowledges society’s preference for avoiding risk when high consequence outcomes are possible. 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. Those estimates were subject to public comment in the context of dozens of proposed rulemakings as well as in a dedicated public comment period in 2013.

Table 4.2.4.1-1 summarizes the interim SC-CO_2 estimates for the years 2023–2054. 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.[281] 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.

[281] IWG. (2021). Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990. Retrieved from Washington, DC: https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.

Table 4.2.4.1-1: Interim Social Cost of Carbon Values, 2023-2054 (2022$/Metric Ton CO_2)[282]

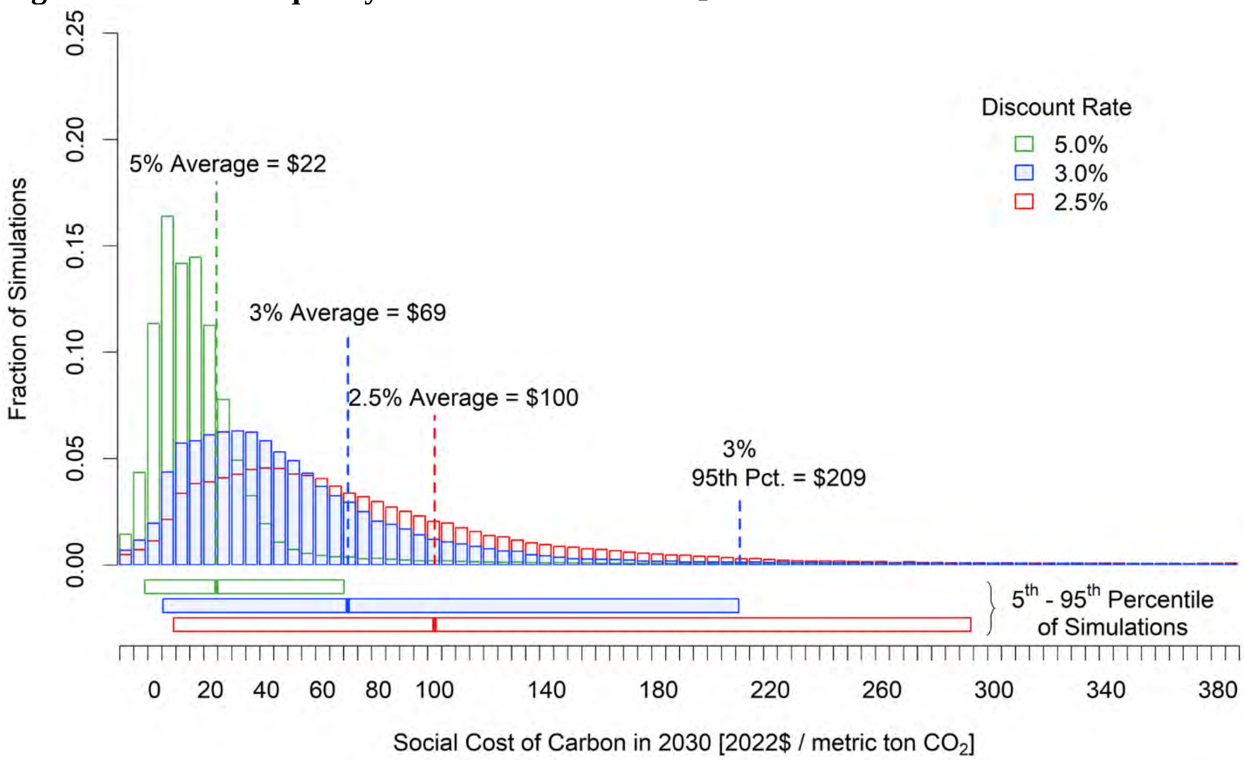
Emissions Year	Discount Rate and Statistic			
	5% Average	3% Average	2.5% Average	3% 95th Percentile
2023	$18	$61	$90	$182
2024	$18	$62	$91	$185
2025	$19	$63	$93	$189
2026	$19	$64	$94	$193
2027	$20	$66	$96	$197
2028	$21	$67	$97	$201
2029	$21	$68	$99	$205
2030	$22	$69	$100	$209
2031	$22	$70	$102	$213
2032	$23	$72	$103	$218
2033	$24	$73	$105	$222
2034	$24	$74	$106	$226
2035	$25	$76	$108	$230
2036	$26	$77	$109	$235
2037	$26	$78	$111	$239
2038	$27	$79	$112	$243
2039	$28	$81	$114	$248
2040	$28	$82	$115	$252
2041	$29	$83	$117	$256
2042	$30	$85	$118	$260
2043	$30	$86	$120	$264
2044	$31	$87	$121	$267
2045	$32	$88	$123	$271
2046	$33	$90	$124	$275
2047	$33	$91	$126	$279
2048	$34	$92	$127	$283
2049	$35	$93	$129	$287
2050	$35	$95	$130	$291
2051	$36	$95	$132	$292
2052	$37	$96	$133	$293
2053	$38	$97	$135	$294
2054	$38	$99	$136	$295

[282] The 2023-2050 SC-CO2 values are identical to those reported in the February 2021 TSD (IWG 2021) adjusted to 2022 dollars using the annual GDP Implicit Price Deflator values in the U.S. Bureau of Economic Analysis' (BEA) NIPA Table 1.1.9 (U.S. BEA 2022). 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 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. The annual unrounded 2051-2054 values used in the calculations in this document are available in the docket for this action, and the replication code is available upon request.

There are a number of limitations and uncertainties associated with the SC-CO_2 estimates presented in Table 4.2.4.1-1. 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 4.2.4.1-1 presents the quantified sources of uncertainty in the form of frequency distributions for the SC-CO_2 estimates for emissions in 2030 (in 2022$). 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 4.2.4.1-1: Frequency Distribution of $SC-CO_2$ Estimates for 2030[283]



The interim $SC-CO_2$ estimates presented in Table 4.2.4.1-1 have a number of other limitations. First, the current scientific and economic understanding of discounting 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.[284] 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.

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[283] 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 0.584 to 0.96 percent of the estimates falling below the lowest bin displayed and 0.38 to 3.9 percent of the estimates falling above the highest bin displayed, depending on the discount rate and GHG.

[284] IWG. (2021). Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990. Retrieved from Washington, DC: https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

The modeling limitations do not all work in the same direction in terms of their influence on the SC-GHG estimates. However, as discussed in the February 2021 TSD, the IWG has recommended that, taken together, the limitations suggest that the SC-GHG estimates used in this final rule likely underestimate the damages from GHG emissions. EPA concurs that the values used in this rulemaking conservatively underestimate the climate benefits associated with GHG emission reductions. 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.[285] 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 assessments.[286,287,288,289,290,291,292,293] 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

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[285] 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.

[286] 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.

[287] 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.)].

[288] 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.)].

[289] 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.)].

[290] 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.

[291] 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.

[292] 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.

[293] 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.

2000, while not ruling out even more extreme outcomes.[294] EPA has reviewed and considered the limitations of the models used to estimate the interim SC-GHG estimates and concurs with the February 2021 SC-GHG TSD's assessment that, taken together, the limitations suggest that the interim SC-GHG estimates likely underestimate the damages from GHG emissions.

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. The IWG 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, public comments received on the February 2021 TSD, and other input from experts and diverse stakeholder groups (National Academies, 2017). While that process continues EPA is continuously reviewing developments in the scientific literature on the SC-GHG, including more robust methodologies for estimating damages from emissions, and looking for opportunities to further improve SC-GHG estimation going forward. Most recently, EPA presented a draft set of updated SC-GHG estimates within a sensitivity analysis in the regulatory impact analysis of EPA's November 2022 supplemental proposal for oil and gas standards that that aims to incorporate recent advances in the climate science and economics literature. Specifically, the draft updated methodology incorporates new literature and research consistent with the National Academies near-term recommendations on socioeconomic and emissions inputs, climate modeling components, discounting approaches, and treatment of uncertainty, and an enhanced representation of how physical impacts of climate change translate to economic damages in the modeling framework based on the best and readily adaptable damage functions available in the peer reviewed literature. EPA solicited public comment on the sensitivity analysis and the accompanying draft technical report, which explains the methodology underlying the new set of estimates, in the docket for the proposed oil and gas rule. EPA is also conducting an external peer review of this technical report. More information about this process and public comment opportunities is available on EPA's website.[295] EPA's draft technical report will be among the many technical inputs available to the IWG as it continues its work. Tables 4.2.3-6 through Tables 4.2.3-13 show the estimated changes in CO_2e for the volume changes analyzed in each year, 2023-2025. 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 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 4.2.4.1-1, 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.[296]

[294] 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.
[295] See https://www.epa.gov/environmental-economics/scghg.
[296] According to OMB's Circular A-4 (OMB, 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, but separately. Circular A-4 also reminds analysts that "[d]ifferent regulations may call for different emphases in the analysis, depending on the

4.2.4.2 Results

For this illustrative scenario, the interim estimates for carbon dioxide from the February 2021 TSD, presented in Table 4.2.4.1-1, were used to estimate the social benefits of the estimated 30-year stream of GHG impacts presented in Chapter 4.2.3. For each year, the total of emissions changes presented in Tables 4.2.3-6 through 4.2.3-13 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 4.2.4.2-1 through 4.2.4.2-8. 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 2023 supplemental volume requirement as described in Chapter 3.3. We present the results for these supplemental volumes in Tables 4.2.4.2-9 and 4.2.4.2-10. All calculations are available in a spreadsheet in the docket for this rule.[297]

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 EO 13783 were a limited approximation of some of the U.S. specific climate damages from GHG emissions. These estimates range from $8 per metric ton CO_2 for emissions occurring in 2023 to $13 per metric ton CO_2 for emissions occurring in 2054. However, as discussed at length in the IWG's February 2021 SC-GHG TSD, these estimates are an underestimate of the benefits of GHG 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 SC-GHG 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" p.29 (U.S. GAO, 2020). 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" p.26 (U.S. GAO, 2020). 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.

[297] See "GHG Scenario for 2023-25 Set Rule (FRM).xlsx," available in the docket for this rule.

Table 4.2.4.2-1: 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 ($SC\text{-}CO_2$) (millions of 2022$)[a]

Year	Rate: 5%	Rate: 3%	Rate: 2.5%	Rate: 3% 95th percentile
2023	$(2,649)	$(9,021)	$(13,350)	$(26,943)
2024	$794	$2,726	$4,040	$8,156
2025	$778	$2,697	$4,004	$8,086
2026	$763	$2,668	$3,968	$8,014
2027	$747	$2,639	$3,931	$7,939
2028	$731	$2,609	$3,894	$7,861
2029	$714	$2,578	$3,856	$7,781
2030	$698	$2,547	$3,818	$7,699
2031	$685	$2,518	$3,781	$7,628
2032	$671	$2,490	$3,744	$7,554
2033	$657	$2,460	$3,707	$7,479
2034	$643	$2,431	$3,669	$7,401
2035	$629	$2,400	$3,631	$7,321
2036	$615	$2,370	$3,593	$7,240
2037	$601	$2,339	$3,554	$7,158
2038	$586	$2,308	$3,515	$7,074
2039	$572	$2,277	$3,476	$6,988
2040	$558	$2,246	$3,437	$6,902
2041	$545	$2,215	$3,396	$6,805
2042	$532	$2,183	$3,356	$6,708
2043	$446	$1,852	$2,853	$5,689
2044	$435	$1,825	$2,818	$5,605
2045	$424	$1,798	$2,783	$5,522
2046	$413	$1,771	$2,748	$5,438
2047	$402	$1,744	$2,714	$5,355
2048	$391	$1,717	$2,679	$5,272
2049	$381	$1,690	$2,644	$5,190
2050	$370	$1,663	$2,610	$5,107
2051	$362	$1,625	$2,582	$4,975
2052	$351	$1,595	$2,542	$4,846
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 4.2.4.2-2: 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-CO_2) (millions of 2022$)[a]

Year	Rate: 5%	Rate: 3%	Rate: 2.5%	Rate: 3% 95th percentile
2023	$-	$-	$-	$-
2024	$(161)	$(551)	$(817)	$(1,650)
2025	$94	$325	$483	$975
2026	$92	$322	$478	$966
2027	$90	$318	$474	$957
2028	$88	$314	$469	$947
2029	$86	$311	$465	$938
2030	$84	$307	$460	$928
2031	$83	$304	$456	$919
2032	$81	$300	$451	$910
2033	$79	$296	$447	$901
2034	$78	$293	$442	$892
2035	$76	$289	$438	$882
2036	$74	$286	$433	$873
2037	$72	$282	$428	$863
2038	$71	$278	$424	$852
2039	$69	$274	$419	$842
2040	$67	$271	$414	$832
2041	$66	$267	$409	$820
2042	$64	$263	$404	$808
2043	$63	$259	$400	$797
2044	$56	$235	$363	$721
2045	$55	$231	$358	$711
2046	$53	$228	$354	$700
2047	$52	$224	$349	$689
2048	$50	$221	$345	$678
2049	$49	$217	$340	$668
2050	$48	$214	$336	$657
2051	$47	$209	$332	$640
2052	$45	$205	$327	$624
2053	$44	$201	$322	$608
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 4.2.4.2-3: 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 ($SC\text{-}CO_2$) (millions of 2022$)[a]

Year	Rate: 5%	Rate: 3%	Rate: 2.5%	Rate: 3% 95th percentile
2023	$-	$-	$-	$-
2024	$-	$-	$-	$-
2025	$(162)	$(561)	$(833)	$(1,683)
2026	$164	$575	$855	$1,727
2027	$161	$569	$847	$1,711
2028	$157	$562	$839	$1,694
2029	$154	$556	$831	$1,677
2030	$150	$549	$823	$1,659
2031	$148	$543	$815	$1,644
2032	$145	$537	$807	$1,628
2033	$142	$530	$799	$1,612
2034	$139	$524	$791	$1,595
2035	$136	$517	$783	$1,578
2036	$133	$511	$774	$1,561
2037	$129	$504	$766	$1,543
2038	$126	$498	$758	$1,525
2039	$123	$491	$749	$1,506
2040	$120	$484	$741	$1,488
2041	$117	$477	$732	$1,467
2042	$115	$471	$723	$1,446
2043	$112	$464	$715	$1,425
2044	$109	$457	$706	$1,404
2045	$99	$421	$652	$1,293
2046	$97	$415	$643	$1,273
2047	$94	$408	$635	$1,254
2048	$92	$402	$627	$1,234
2049	$89	$396	$619	$1,215
2050	$87	$389	$611	$1,196
2051	$85	$380	$604	$1,165
2052	$82	$373	$595	$1,135
2053	$80	$367	$586	$1,105
2054	$77	$360	$577	$1,077

[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 4.2.4.2-4: 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 ($SC\text{-}CO_2$) (millions of 2022$)[a]

Year	Rate: 5%	Rate: 3%	Rate: 2.5%	Rate: 3% 95th percentile
2023	$(2,649)	$(9,021)	$(13,350)	$(26,943)
2024	$633	$2,174	$3,222	$6,506
2025	$710	$2,461	$3,653	$7,378
2026	$1,019	$3,565	$5,301	$10,707
2027	$998	$3,525	$5,252	$10,606
2028	$976	$3,485	$5,202	$10,503
2029	$954	$3,444	$5,152	$10,396
2030	$932	$3,403	$5,101	$10,286
2031	$915	$3,365	$5,052	$10,191
2032	$897	$3,326	$5,003	$10,093
2033	$878	$3,287	$4,953	$9,992
2034	$860	$3,247	$4,902	$9,888
2035	$841	$3,207	$4,852	$9,782
2036	$822	$3,166	$4,800	$9,673
2037	$802	$3,126	$4,749	$9,563
2038	$783	$3,084	$4,697	$9,451
2039	$764	$3,043	$4,644	$9,337
2040	$745	$3,001	$4,592	$9,222
2041	$728	$2,959	$4,538	$9,092
2042	$710	$2,917	$4,484	$8,963
2043	$621	$2,575	$3,967	$7,911
2044	$600	$2,517	$3,887	$7,731
2045	$578	$2,450	$3,793	$7,525
2046	$563	$2,413	$3,745	$7,412
2047	$548	$2,376	$3,698	$7,298
2048	$533	$2,340	$3,651	$7,185
2049	$519	$2,303	$3,603	$7,072
2050	$504	$2,267	$3,556	$6,960
2051	$494	$2,214	$3,518	$6,780
2052	$479	$2,174	$3,464	$6,605
2053	$124	$568	$908	$1,713
2054[b]	$77	$360	$577	$1,077

[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 4.2.4.2-4 are the sum of the three thirty-year streams of impacts for the 2023 through 2025 standards presented in Tables 4.2.4.2-1, 4.2.4.2-2, and 4.2.4.2-3. Because we assess thirty years of impacts for each year standards, the period of analysis for the 2023 standards extends to 2052.

Table 4.2.4.2-5: 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-CO_2) (millions of 2022$)[a]

Year	Rate: 5%	Rate: 3%	Rate: 2.5%	Rate: 3% 95th percentile
2023	$(4,653)	$(15,845)	$(23,449)	$(47,324)
2024	$125	$430	$637	$1,286
2025	$123	$425	$631	$1,275
2026	$120	$421	$625	$1,263
2027	$118	$416	$620	$1,251
2028	$115	$411	$614	$1,239
2029	$113	$406	$608	$1,226
2030	$110	$401	$602	$1,213
2031	$108	$397	$596	$1,202
2032	$106	$392	$590	$1,191
2033	$104	$388	$584	$1,179
2034	$101	$383	$578	$1,167
2035	$99	$378	$572	$1,154
2036	$97	$374	$566	$1,141
2037	$95	$369	$560	$1,128
2038	$92	$364	$554	$1,115
2039	$90	$359	$548	$1,101
2040	$88	$354	$542	$1,088
2041	$86	$349	$535	$1,073
2042	$84	$344	$529	$1,057
2043	$223	$924	$1,423	$2,838
2044	$217	$910	$1,406	$2,797
2045	$212	$897	$1,389	$2,755
2046	$206	$883	$1,371	$2,713
2047	$201	$870	$1,354	$2,672
2048	$195	$857	$1,336	$2,630
2049	$190	$843	$1,319	$2,589
2050	$185	$830	$1,302	$2,548
2051	$181	$811	$1,288	$2,482
2052	$175	$796	$1,268	$2,418
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 4.2.4.2-6: 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 2022$)[a]

Year	Rate: 5%	Rate: 3%	Rate: 2.5%	Rate: 3% 95th percentile
2023	$-	$-	$-	$-
2024	$(366)	$(1,258)	$(1,865)	$(3,765)
2025	$(9)	$(33)	$(49)	$(98)
2026	$(9)	$(32)	$(48)	$(97)
2027	$(9)	$(32)	$(48)	$(97)
2028	$(9)	$(32)	$(47)	$(96)
2029	$(9)	$(31)	$(47)	$(95)
2030	$(8)	$(31)	$(46)	$(94)
2031	$(8)	$(31)	$(46)	$(93)
2032	$(8)	$(30)	$(46)	$(92)
2033	$(8)	$(30)	$(45)	$(91)
2034	$(8)	$(30)	$(45)	$(90)
2035	$(8)	$(29)	$(44)	$(89)
2036	$(7)	$(29)	$(44)	$(88)
2037	$(7)	$(28)	$(43)	$(87)
2038	$(7)	$(28)	$(43)	$(86)
2039	$(7)	$(28)	$(42)	$(85)
2040	$(7)	$(27)	$(42)	$(84)
2041	$(7)	$(27)	$(41)	$(83)
2042	$(6)	$(27)	$(41)	$(82)
2043	$(6)	$(26)	$(40)	$(80)
2044	$4	$18	$27	$54
2045	$4	$17	$27	$54
2046	$4	$17	$27	$53
2047	$4	$17	$26	$52
2048	$4	$17	$26	$51
2049	$4	$16	$26	$50
2050	$4	$16	$25	$50
2051	$4	$16	$25	$48
2052	$3	$15	$25	$47
2053	$3	$15	$24	$46
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 4.2.4.2-7: 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 2022$)[a]

Year	Rate: 5%	Rate: 3%	Rate: 2.5%	Rate: 3% 95th percentile
2023	$-	$-	$-	$-
2024	$-	$-	$-	$-
2025	$(444)	$(1,540)	$(2,286)	$(4,617)
2026	$10	$34	$50	$101
2027	$9	$33	$50	$100
2028	$9	$33	$49	$99
2029	$9	$32	$49	$98
2030	$9	$32	$48	$97
2031	$9	$32	$48	$96
2032	$8	$31	$47	$95
2033	$8	$31	$47	$94
2034	$8	$31	$46	$93
2035	$8	$30	$46	$92
2036	$8	$30	$45	$91
2037	$8	$29	$45	$90
2038	$7	$29	$44	$89
2039	$7	$29	$44	$88
2040	$7	$28	$43	$87
2041	$7	$28	$43	$86
2042	$7	$28	$42	$85
2043	$7	$27	$42	$83
2044	$6	$27	$41	$82
2045	$19	$82	$127	$253
2046	$19	$81	$126	$249
2047	$18	$80	$124	$245
2048	$18	$79	$123	$241
2049	$17	$77	$121	$237
2050	$17	$76	$119	$234
2051	$17	$74	$118	$228
2052	$16	$73	$116	$222
2053	$16	$72	$114	$216
2054	$15	$70	$113	$210

[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 4.2.4.2-8: 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 2022$)[a]

Year	Rate: 5%	Rate: 3%	Rate: 2.5%	Rate: 3% 95th percentile
2023	$(4,653)	$(15,845)	$(23,449)	$(47,324)
2024	$(241)	$(829)	$(1,228)	$(2,479)
2025	$(331)	$(1,148)	$(1,704)	$(3,440)
2026	$121	$422	$627	$1,267
2027	$118	$417	$621	$1,255
2028	$115	$412	$615	$1,242
2029	$113	$407	$609	$1,230
2030	$110	$402	$603	$1,217
2031	$108	$398	$598	$1,205
2032	$106	$393	$592	$1,194
2033	$104	$389	$586	$1,182
2034	$102	$384	$580	$1,170
2035	$99	$379	$574	$1,157
2036	$97	$375	$568	$1,144
2037	$95	$370	$562	$1,131
2038	$93	$365	$556	$1,118
2039	$90	$360	$549	$1,105
2040	$88	$355	$543	$1,091
2041	$86	$350	$537	$1,076
2042	$84	$345	$530	$1,060
2043	$223	$925	$1,425	$2,841
2044	$228	$955	$1,475	$2,933
2045	$235	$997	$1,543	$3,061
2046	$229	$982	$1,524	$3,015
2047	$223	$967	$1,504	$2,969
2048	$217	$952	$1,485	$2,923
2049	$211	$937	$1,466	$2,877
2050	$205	$922	$1,447	$2,831
2051	$201	$901	$1,431	$2,758
2052	$195	$884	$1,409	$2,687
2053	$19	$87	$139	$262
2054[b]	$15	$70	$113	$210

[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 4.2.4.2-8 are the sum of the three thirty-year streams of impacts for the 2023 through 2025 standards presented in Tables 4.2.4.2-5, 4.2.4.2-6, and 4.2.4.2-7. Because we assess thirty years of impacts for each year standards, the period of analysis for the 2023 standards extends to 2052.

Table 4.2.4.2-9: 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 ($SC\text{-}CO_2$) (millions of 2022$)[a]

Year	Rate: 5%	Rate: 3%	Rate: 2.5%	Rate: 3% 95th percentile
2023	$(225)	$(767)	$(1,135)	$(2,290)
2024	$34	$118	$175	$353
2025	$34	$117	$173	$350
2026	$33	$115	$172	$347
2027	$32	$114	$170	$343
2028	$32	$113	$168	$340
2029	$31	$112	$167	$337
2030	$30	$110	$165	$333
2031	$30	$109	$164	$330
2032	$29	$108	$162	$327
2033	$28	$106	$160	$324
2034	$28	$105	$159	$320
2035	$27	$104	$157	$317
2036	$27	$103	$155	$313
2037	$26	$101	$154	$310
2038	$25	$100	$152	$306
2039	$25	$99	$150	$302
2040	$24	$97	$149	$299
2041	$24	$96	$147	$294
2042	$23	$94	$145	$290
2043	$16	$67	$104	$207
2044	$16	$66	$102	$204
2045	$15	$65	$101	$200
2046	$15	$64	$100	$197
2047	$15	$63	$99	$194
2048	$14	$62	$97	$191
2049	$14	$61	$96	$188
2050	$13	$60	$95	$185
2051	$13	$59	$94	$181
2052	$13	$58	$92	$176
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 4.2.4.2-10: 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 2022$)[a]

Year	Rate: 5%	Rate: 3%	Rate: 2.5%	Rate: 3% 95th percentile
2023	$(347)	$(1,181)	$(1,748)	$(3,527)
2024	$5	$17	$26	$52
2025	$5	$17	$25	$51
2026	$5	$17	$25	$51
2027	$5	$17	$25	$50
2028	$5	$17	$25	$50
2029	$5	$16	$24	$49
2030	$4	$16	$24	$49
2031	$4	$16	$24	$48
2032	$4	$16	$24	$48
2033	$4	$16	$24	$48
2034	$4	$15	$23	$47
2035	$4	$15	$23	$47
2036	$4	$15	$23	$46
2037	$4	$15	$23	$45
2038	$4	$15	$22	$45
2039	$4	$14	$22	$44
2040	$4	$14	$22	$44
2041	$3	$14	$22	$43
2042	$3	$14	$21	$43
2043	$14	$57	$87	$174
2044	$13	$56	$86	$172
2045	$13	$55	$85	$169
2046	$13	$54	$84	$167
2047	$12	$53	$83	$164
2048	$12	$53	$82	$162
2049	$12	$52	$81	$159
2050	$11	$51	$80	$156
2051	$11	$50	$79	$152
2052	$11	$49	$78	$148
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 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.[298] 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[299] 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. A more in-depth evaluation of cropland conversion and its impacts to the environment can be found in the May 19, 2023 biological evaluation that EPA submitted to the U.S. Fish and Wildlife Service and the National Marine Fisheries Service (together, "the Services") on May 20, 2023, and the May 31, 2023 addendum that EPA provided to NMFS in response to a follow-up request (together, "the May 19 BE").[300] Although the discussion which follows is not as detailed as in the May 19 BE, some aspects of it are discussed. As can be seen in DRIA Chapter 4.2.2, there is a wide range of estimates for the area and types of land use change depending on feedstock, model choice, scenario design and input assumptions.[301] This section focuses on impacts related to the domestic production of renewable

[298] 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 (87 FR 3801). 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.
[299] 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.
[300] "Biological Evaluation of the Renewable Fuel Standard (RFS) Set Rule," May 19, 2023 & Email from T. Phillips, EPA, to D. Baldwin, NOAA (May 31, 2023) are both available in the docket for this action.
[301] The DRIA for the proposed rule includes a discussion of available models and land use change estimates that is not part of this RIA for the final rule. The review of studies and land use change estimates in the DRIA remains relevant, but we determined it did not bear repeating in this document as it does not factor directly into our analysis of the climate impacts of the candidate volumes.

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 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, or biogas. The impacts of the candidate volumes in many of these sections is compared to the 2022 baseline as a substitute to the No RFS baseline as land use change for crop-based feedstocks would not be drastically affected by the removal of the RFS program as referenced in Chapter 2. We note that to the extent the RFS standards in this action 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 fossil fuels.[302]

[302] 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,[303] including the U.S. Fish and Wildlife Service (USFWS) Status and Trends of Wetlands in the Conterminous United States,[304] the USFWS and NOAA Status and Trends of Wetlands in the Coastal Watersheds of the Coterminous United States,[305] the USFWS Status and Trends of Prairie Wetlands in the United States,[306] EPA's National Wetland Condition Assessment[307] (NWCA), and USDA's Natural Resources Inventory (NRI).[308] The USGS NWALT (National Water-Quality Assessment (NAWQA) Program's Wall-to-Wall Anthropogenic Land Use Trends) series does not model changes in wetlands.[309] 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.[310] 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

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[303] Summarized and listed here: https://www.epa.gov/wetlands/how-does-epa-keep-track-status-and-trends-wetlands-us.

[304] 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.

[305] 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.)

[306] 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).

[307] 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

[308] 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.

[309] Falcone JA (2015). U.S. conterminous wall-to-wall anthropogenic land use trends (NWALT), 1974–2012. U.S. Geological Survey: 33 pp. Washington, DC.

[310] *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.

developed and water areas.[311] 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[312] and estuarine[313] wetlands on different land use/cover types between 2007, 2012, and 2017[314]

	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.[315] 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 significant portion of U.S. ethanol production is exported and therefore cannot be attributed to the RFS program.

[311] "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."

[312] 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*, https://www.nrcs.usda.gov/sites/default/files/2022-10/NRI_glossary.pdf.

[313] 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*, https://www.nrcs.usda.gov/sites/default/files/2022-10/NRI_glossary.pdf.

[314] 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.

[315] 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.

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,[316] 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 established in this action. As discussed in further detail in Chapter 2, much of the biofuel projected to be used in 2023–2025 is 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 action.

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.[317] The bulk of the wetland losses were in the Prairie Pothole region, as reported elsewhere,[318] 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. The volume increases for 2023-2025 compared to the No RFS baseline that are described in Chapter 3 and the Biological Evaluation, 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 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 found in the May 19 BE. (In addition to corn ethanol, and especially soy BBD, the main volume changes in this rule are from soy biodiesel and biogas derived CNG/LNG which is not expected to have associated impacts on land-use change and

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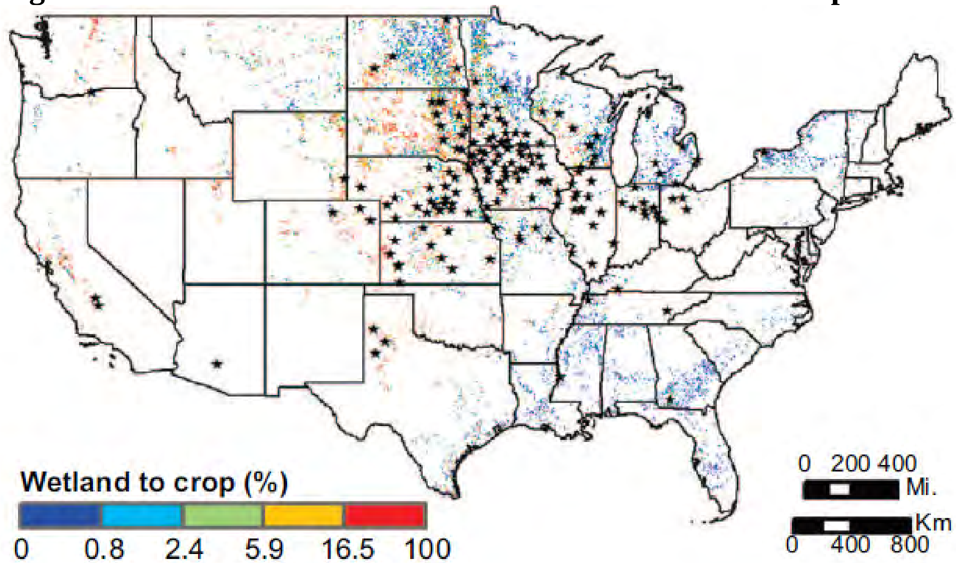
[316] Agricultural extensification is the expansion of agricultural land onto previously uncultivated land. U.S. EPA (2018). Biofuels and the Environment: Second Triennial Report to Congress. U.S. Environmental Protection Agency, EPA/600/R-18/195: 159 pp. Washington, DC, June.

[317] 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. *See also* USDA, 2017 National Resources Inventory. 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.

[318] 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.

therefore wetlands). Additionally, we used a probabilistic approach in the Biological Evaluation to estimate potential overlap between cropland changes and species critical habitats or ranges. The study began with the area of potential land use change and overlayed that with critical habitat and species range data. Of the estimated acreage impacts about 8% was projected to be "idle lands". According to the National Land Cover Dataset, idle lands include emergent herbaceous wetlands in addition to pasture/hay. With this evaluation, little change would be anticipated on wetlands as candidate volumes would be met from alternative means.

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 [319]). 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 and the Biological Evaluation.

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.[320] 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).[321]

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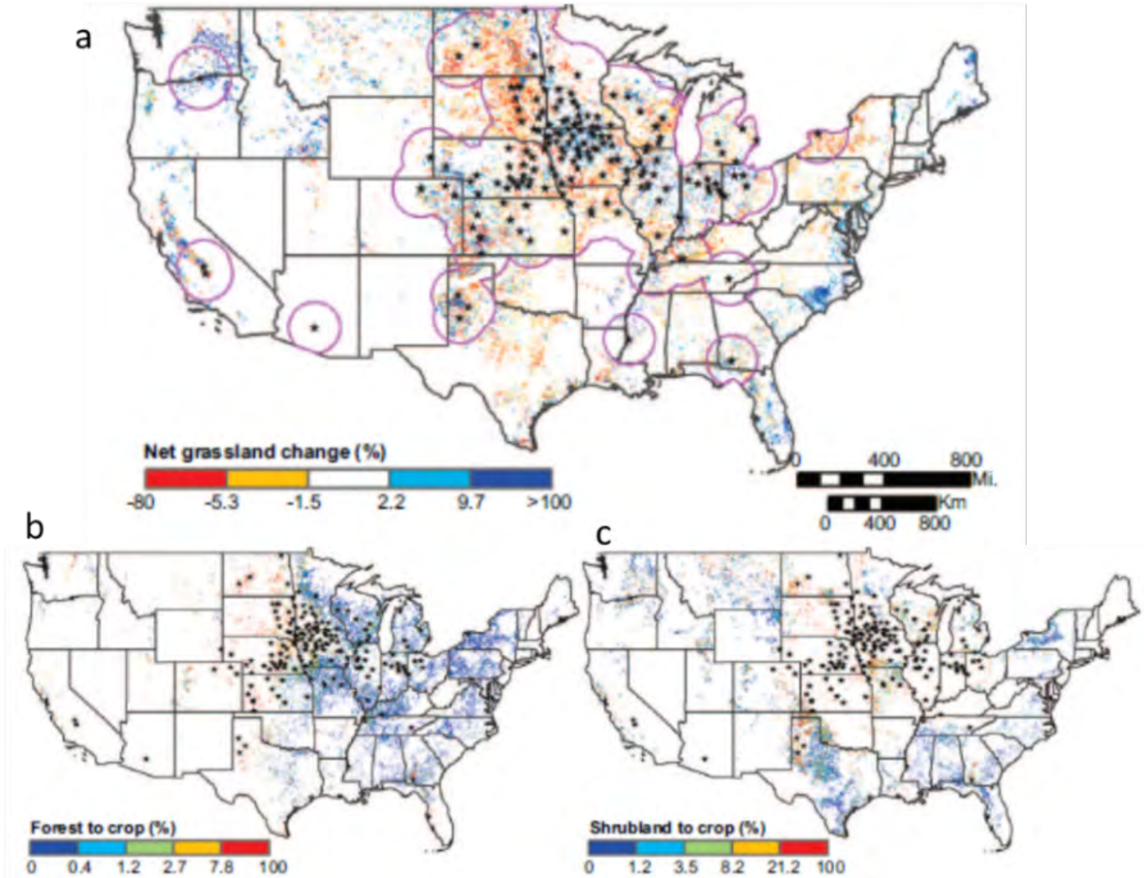
[319] Wright, C. K., et al. (2017). "Recent grassland losses are concentrated around US ethanol refineries." Environmental Research Letters 12(4).
[320] Id.
[321] Id.

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 [322]). 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.[323] The NRI defines rangeland as a land use/land cover that is more lightly managed than pastureland,[324] 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

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[322] Id.

[323] 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.

[324] 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."

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).[325]

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.[326] 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.[327] Despite the rental payment incentive to farmers, enrollment in the CRP has been shrinking since 2007.[328] 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.[329] 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%).[330] 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., corn, soybean, winter wheat, spring wheat, and sorghum), with the majority of that to corn and soybean.[331] 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.

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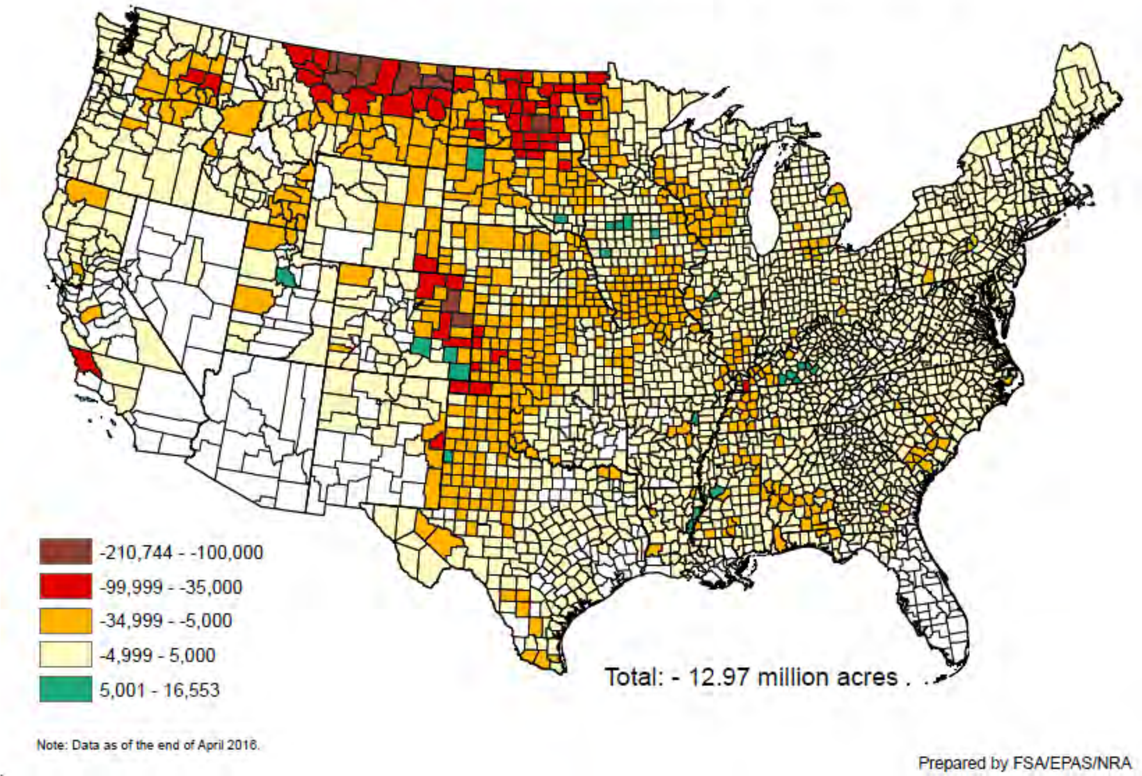
[325] U.S. Department of Agriculture. 2020. *Summary Report: 2017 National Resources Inventory*, Natural Resources Conservation Service, Washington, DC, and Center for Survey Statistics and Methodology, Iowa State University, Ames, Iowa. https://www.nrcs.usda.gov/sites/default/files/2022-10/2017NRISummary_Final.pdf.
[326] 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.
[327] 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.
[328] Data from the USDA Farm Service Agency (FSA), https://www.fsa.usda.gov/programs-and-services/conservation-programs/reports-and-statistics/conservation-reserve-program-statistics/index.
[329] USDA FSA, FY 2020 Annual Summary. Data from the USDA Farm Service Agency (FSA), https://www.fsa.usda.gov/programs-and-services/conservation-programs/reports-and-statistics/conservation-reserve-program-statistics/index.
[330] 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/sites/default/files/2022-10/2017NRISummary_Final.pdf.
[331] 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.

Figure 4.3.2-2: Change in CRP enrollment between 2007 and 2016.[332]



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.[333] Thus, even though some forest land did convert to cropland according to the NRI,[334] 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 will rise. Thus the 2023-2025 volumes will have a potential to adversely impact grassland and other non-wetland ecosystems. In the Biological Evaluation, land conversion for crop production is analyzed in more detail.

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[332] 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).

[333] 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.

[334] The 2020 NRI reports that 292,200, and 265,600 acres of forest land converted to cropland between 2007-2012, and 2012-2017, respectively.

A process was created in the Biological Evaluation to determine how species and their habitats would be affected by the RFS Set Rule. This process starts with the estimation of land use change associated with an increase in production due to the rule. It then identifies potential locations where affected increases in biofuel production could cause land use change. We analyzed these first two steps of the process in two different ways.

Corn and canola potential land use changes were analyzed using a probabilistic methodology as a land selection model was unable to be developed. More information on this can be found in the May 19 BE. This method analyzed available land in the action area with a greater likelihood of being affected by this rule. This included four different land cover classes, three of which were non-wetland. Corn was analyzed using ArcGIS and R5. 500,000 acres were randomly selected from the available land within the action area. This process was repeated hundreds of times to estimate the probability of an acre converted to crop production for renewable fuel use. A similar process was done with canola but with a constrained analysis to the state of North Dakota as this state is shown to be the primary affected area for this crop.

Soy potential cropland expansion was evaluated separately by contracting firm ICF. They developed a land selection model using weighted factors deemed important in determining where additional soy acres might be planted. This provided an estimate of which land parcels would be most likely to be converted to additional cropland. The example given in the Biological Evaluation shows that land near soybean fields would be weighted higher than elsewhere.

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 Biological Evaluation. 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).[335] 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 and in the May 19 BE.

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.[336] However, studies of the effects of bioenergy feedstock production suggest that grassland bird species of conservation concern are more likely to be

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[335] Listed here: https://www.fsa.usda.gov/programs-and-services/conservation-programs/crp-practices-library/index.

[336] 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.

affected by increased corn production than are more common species of birds.[337] 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 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.[338] 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.[339] 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.[340] 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.[341] 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.[342]

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.[343] Roughly 20%

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[337] 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.

[338] 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.

[339] 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.

[340] Primary crops were defined as corn, soybeans, and wheat.

[341] 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.

[342] Id.

[343] 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.

of these pollination services are estimated from wild populations which depend on local habitat for food and nesting sites.[344] A 2016 modeling study suggests that wild bee populations decreased by 23% across the U.S. between 2008 and 2013.[345] The causes of these reductions are complex, but include land use change, pesticides, and disease.[346] Subsequent effects from reductions in local bee populations are possible, including reductions in pollinator-dependent crops grown in the area,[347] 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.[348] 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.[349] 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.[350] For soybeans, risks were considered uncertain at the time and are currently undergoing re-evaluation by EPA. Neonicotinoids, like all pesticides, are approved for

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[344] Losey, J.E., Vaughan, M. (2006). "The economic value of ecological services provided by insects." *Bioscience* 56(4):311–323.

[345] 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.

[346] 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.

[347] 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.

[348] 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.

[349] 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.

[350] 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.

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.[351] 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.

In the associated Biological Evaluation, wildlife habitats are evaluated for many species listed within the action area for this rule. 704 unique species are located in the potential area for crop land expansion. These species are associated with designated habitats by the US Fish and Wildlife Service (FWS) and National Marine Fisheries Service (NMFS). EPA evaluated critical habitat and range of these potential affected species for each crop. Additional information on these estimates and impacts can be found in the May 19 BE.[352,353]

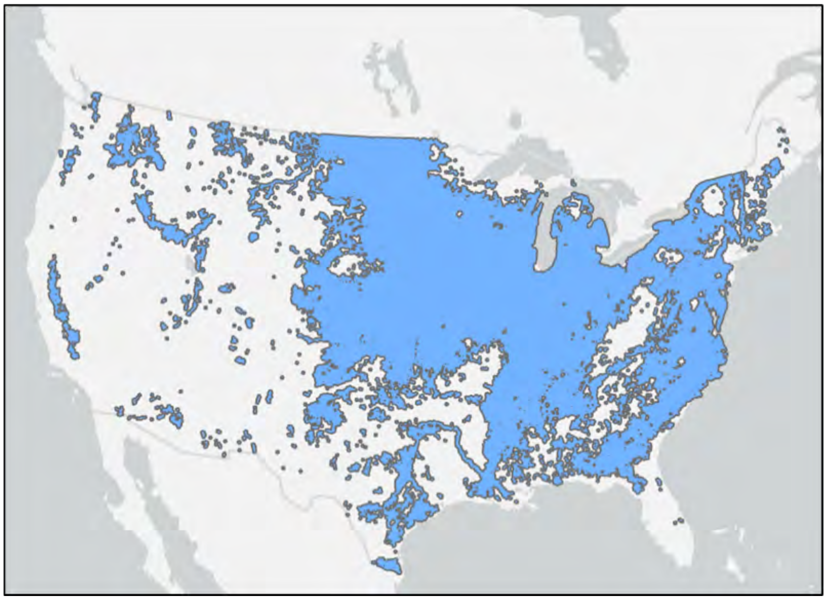
4.3.4 Potential Future Impacts of Annual Volume Requirements

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. Modeling and discussion on the estimates for land use change are further discussed in Chapter 4.2 and in the May 19 BE.

In the Biological Evaluation, a more fulsome estimate of potential land conversion for each of the main crops for renewable fuel was projected. Corn, soybean and canola expansion was estimated using ArcGIS Pro as a tool with data from the United States Department of Agriculture (USDA)'s Cropland Data Layer (CDL). Mapping was conducted with this data and an additional buffer was included to conservatively account for indirect land use change effects. The resulting area is shown in Figure 4.3.4-1.

[351] U.S. EPA (2018), "How We Assess Risks to Pollinators." https://www.epa.gov/pollinator-protection/how-we-assess-risks-pollinators.
[352] 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.
[353] U.S. EPA (2018), "How We Assess Risks to Pollinators." https://www.epa.gov/pollinator-protection/how-we-assess-risks-pollinators.

Figure 4.3.4-1: Geographical region where additional corn, soybean, and canola might be grown to meet biofuel volumes as established by the RFS actions covering the years 2023-2025.[354]



Because the size of this analysis was so large, a number of assumptions had to be made creating some uncertainty in the final results. However, even with uncertain results, EPA found that overlaps occurred with 712 total species and their habitats. From this information, a further evaluation was done on the species and potential impact from a cropland expansion.

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.[355] It can be affected by biofuel feedstock production through changes in soil erosion, soil organic matter (SOM),[356] and soil nutrients, among other

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[354] This region was identified by extracting corn, soybean, and canola croplands from the 2020 USDA Cropland Data Layer, applying a 15-acre minimum mapping unit filter, and applying a five-mile buffer. ICF (2022, September). "Potential Impacts of Expanded Soybean Production on Endangered Species and Critical Habitats – Addendum." EPA Contract No. 68HERC21D0016. Work Assignment No. 68HERC22F0305. Modification P00002.

[355] Soil quality is defined by the Soil Science Society of America's Ad Hoc Committee on Soil Quality (S-581) 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." Karlen et al., (1997). "Soil Quality: A Concept, Definition, and Framework for Evaluation." *Soil Science Society of America Journal*, 61: 4-10: https://doi.org/10.2136/sssaj1997.03615995006100010001x. 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.

[356] 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,

characteristics. Soil erosion can negatively impact soil quality by disproportionately removing 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.[357] Crop-based biofuel feedstock production can affect water quality through associated changes in nutrients, dissolved oxygen, sediment, and chemical loadings.[358] 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).[359] Water quality impacts are evaluated as either proximal (i.e., geographically close) or downstream, although effects can span both. We discuss in the Biological Evaluation, 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. Additionally, water quality impacts due to increased crop production are discussed in the May 19 BE, with data from the Soil and Water Assessment Tool (SWAT) used in the draft Third Triennial Biofuels Report to Congress (RtC3).

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 BBD. 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 from biogas are not anticipated to

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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).

[357] 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.

[358] The USDA NRCS Environmental Technical Note No. MT-1 (2011) defines these water quality parameters and their significance.

[359] 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).

have any land affecting production changes. Canola oil is also used for BBD 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.

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.[360] 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.[361] 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.[362] In a meta-analysis, Qin et al. (2016) found that replacing grasslands with corn decreased soil carbon by approximately 20% on average.[363] 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

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[360] 81 FR 89746 (December 12, 2016).

[361] 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.

[362] 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.

[363] 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.

soybeans, when both crops are managed using the same tillage practice (tillage practices are discussed in greater detail later in this section).[364] Increased erosion from conversion, in turn, can negatively impact water quality through increased sediment and nutrient loadings to waterways.[365]

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[366] 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.[367] For planted soybean acres, 99% were treated with herbicides, 16% with insecticides, and 15% with fungicides.[368] Glyphosate isopropylamine salt and glyphosate potassium salt were the top active ingredients among herbicides applied to planted soybean acres.[369] 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.[370]

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[364] 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.
[365] 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.
[366] 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.
[367] USDA NASS (2019). 2018 Agricultural Chemical Use Survey: Corn. https://www.nass.usda.gov/Surveys/Guide_to_NASS_Surveys/Chemical_Use/2018_Peanuts_Soybeans_Corn/ChemUseHighlights_Corn_2018.pdf.
[368] USDA NASS (2019). 2018 Agricultural Chemical Use Survey: Soybeans. https://www.nass.usda.gov/Surveys/Guide_to_NASS_Surveys/Chemical_Use/2018_Peanuts_Soybeans_Corn/ChemUseHighlights_Soybeans_2018.pdf.
[369] Id.
[370] 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[371,372,373]

	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)[374]	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) [375]	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.[376] 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

[371] USDA NASS (2019). 2018 Agricultural Chemical Use Survey: Corn. https://www.nass.usda.gov/Surveys/Guide_to_NASS_Surveys/Chemical_Use/2018_Peanuts_Soybeans_Corn/ChemUseHighlights_Corn_2018.pdf.
[372] USDA NASS (2019). 2018 Agricultural Chemical Use Survey: Soybeans. https://www.nass.usda.gov/Surveys/Guide_to_NASS_Surveys/Chemical_Use/2018_Peanuts_Soybeans_Corn/ChemUseHighlights_Soybeans_2018.pdf.
[373] USDA NASS (2020). 2019 Agricultural Chemical Use Survey: Wheat. https://www.nass.usda.gov/Surveys/Guide_to_NASS_Surveys/Chemical_Use/2019_Field_Crops/chem-highlights-wheat-2019.pdf.
[374] This is expressed in acid equivalent.
[375] This is expressed in acid equivalent.
[376] 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.[377,378] Conservation tillage, including no-till, reduces soil erosion and increases SOM content relative to conventional tillage.[379,380] (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.[381] 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.[382] From this evidence, Zuber et 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.[383] Notably, the percent increase in soil organic carbon of other cropland moving to

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[377] 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.

[378] 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). 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. NRCS. USDA. https://www.nrcs.usda.gov/publications/ceap-crop-2010-Upper-MRB-full.pdf.
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.

[379] 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.

[380] 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.

[381] 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.

[382] 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.

[383]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.

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.[384] 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.[385] In a modeling study, Secchi et al. (2011) concluded that this intensification[386] of corn would likely lead to higher nitrogen and phosphorus loads in the Upper Mississippi River Basin.[387]

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.[388] 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.[389] Yet too much stover removal can increase soil erosion, decrease SOM and soil nutrients, and ultimately decrease corn yields.[390] 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 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.[391] Additional research is needed to understand effects on soil and water quality if soil conservation methods are employed while harvesting corn stover.

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[384] 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.

[385] 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.

[386] 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.

[387] 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.

[388] 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.

[389] 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*. https://doi.org/10.1016/j.biombioe.2017.09.016.

[390] 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.

[391] 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.

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.[392] 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.[393] Notably, however, the effects of these perennial feedstocks can depend upon the plant species grown and the type of land converted.[394] Additionally, the literature definitions of what constitutes marginal land and estimates of its extent vary widely.[395] 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.[396] Alternative feedstock production (e.g., switchgrass) requires less fertilizer than corn, thereby reducing nutrient runoff.[397] 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.[398] 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).[399]

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).[400] Fertilizer runoff,

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[392] 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.
[393] 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.
[394] 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.
[395] 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.
[396] 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.
[397] 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.
[398] 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.
[399] 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.
[400] 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-

in addition to other factors (e.g., temperature and precipitation) and conservation practices, influence downstream eutrophication,[401] 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.[402] 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.[403]

In coastal systems, nutrient loadings affect hypoxic zone size, which is also a function of climate, weather (e.g., storms), basin[404] morphology, circulation patterns, water retention time, freshwater inflows, stratification, and mixing, as seen in the Gulf of Mexico.[405] Hypoxia is caused by excess nutrients, particularly phosphorus and nitrogen, which enter the water stream from agricultural runoff. As discussed in the Biological Evaluation, this runoff can lead to growth of algae which leads to additional oxygen consumption in water. Lack of oxygenated water can lead to fish die-offs and can harm other aquatic life. 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 grasses such as switchgrass and Miscanthus, even with manure application, could significantly reduce phosphorus runoff into water bodies.[406]

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.

[401] 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, https://sor.epa.gov/sor_internet/registry/termreg/searchandretrieve/glossariesandkeywordlists/search.do?details=&glossaryName=Acid%20Rain%20Glossary.

[402] 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.

[403] 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.

[404] 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, https://sor.epa.gov/sor_internet/registry/termreg/searchandretrieve/glossariesandkeywordlists/search.do?details=&glossaryName=Chesapeake%20Bay%20Glossary.

[405] 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.

[406] 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.

4.4.2.3 Aquatic Life Effects

Impacts of biofuel crop production on aquatic ecosystems is understudied compared to the impacts on terrestrial ecosystems. [407] 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.[408] The May 19 BE has made steps to elaborate on the study of aquatic ecosystems and the affects they experience from cropland expansion near waterways. 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.[409] 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[410] and fish.[411] 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 in poor condition and 26% were in good condition based on fish species indicators.[412] The leading problems contributing to poor biological condition were excess nutrients (especially phosphorus), loss of shoreline vegetation, and excess sediments.[413] For rivers and streams, sites with a condition rating of poor because of excess nutrients were most prevalent in the mid-

[407] 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] Id.
[409] Id
[410] Benthic macroinvertebrate taxa are small, bottom-dwelling, aquatic animals and the aquatic larval stages of insects. EPA, National Aquatic Resource Survey: Indicators: Benthic Macroinvertebrates, https://www.epa.gov/national-aquatic-resource-surveys/indicators-benthic-macroinvertebrates#:~:text=What%20are%20benthic%20macroinvertebrates%3F,snails%2C%20worms%2C%20and%20beetles.
[411] USEPA (2020). National Rivers and Streams Assessment 2013-2014: A collaborative Survey. EPA 841-R-19-001. Washington, DC. https://www.epa.gov/national-aquatic-resource-surveys/nrsa.
[412] Id.
[413] Id.

continent ecoregions[414] of the nation compared to the eastern and western regions.[415] 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.[416] 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).[417] 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.[418]

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[414] 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. https://www.epa.gov/national-aquatic-resource-surveys/nrsa.

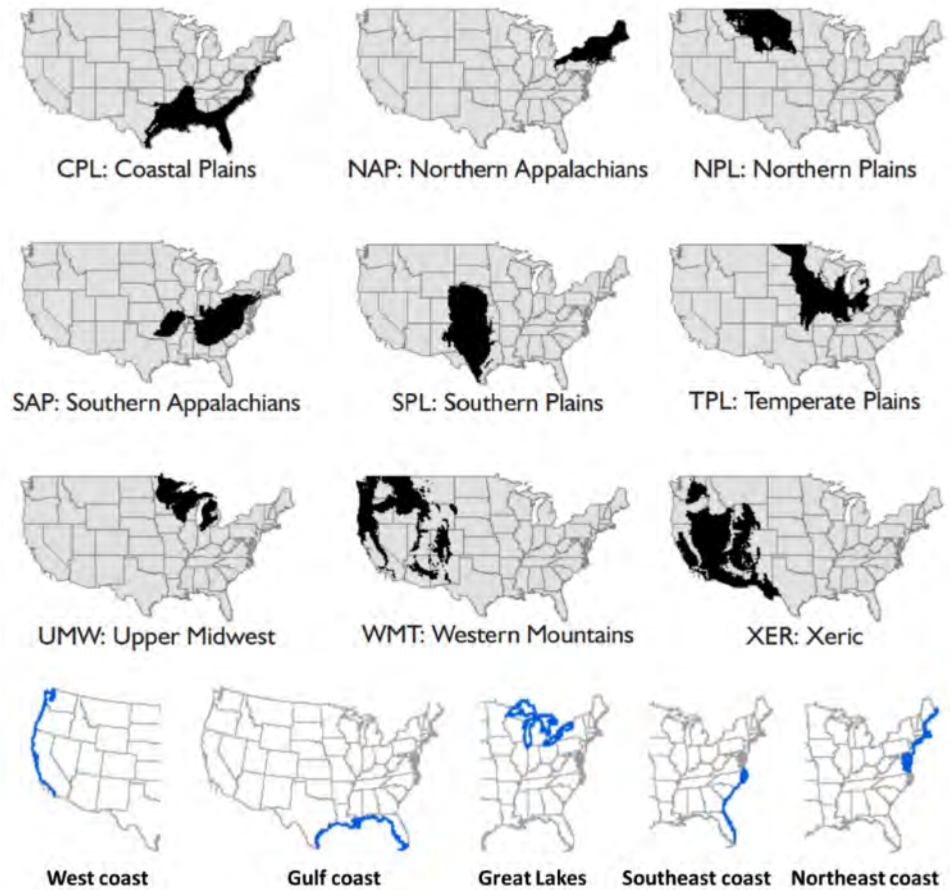
[415] USEPA (2020). National Rivers and Streams Assessment 2013-2014: A collaborative Survey. EPA 841-R-19-001. Washington, DC. https://www.epa.gov/national-aquatic-resource-surveys/nrsa.

[416] 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. https://www.epa.gov/sites/default/files/2016-12/documents/nla_report_dec_2016.pdf.

[417] 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. https://www.epa.gov/sites/default/files/2016-01/documents/ncca_2010_report.pdf.

[418] 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.[419]



Excess nutrients (both nitrogen and phosphorus)[420] 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

[419] 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.

[420] 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.[421] 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.[422] 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[423] of some waterbodies also include internal nutrient recycling of legacy inputs.[424]

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[425] in organ tissues and altered muscle and brain function.[426] Some bacteria can use glyphosate for growth, enhancing microbial proliferation.[427] There are cyanobacteria with natural tolerance to glyphosate[428] and certain concentrations of glyphosate can stimulate photosynthesis in a common bloom-forming taxon, *Microcystis aeruginosa*.[429] 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.[430] In 2014, 58% of U.S. rivers and streams were given a rating of poor for the

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[421] 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. https://www.noaa.gov/media-release/large-dead-zone-measured-in-gulf-of-mexico.

[422] 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.

[423] “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. https://edis.ifas.ufl.edu/pdffiles/SS/SS56200.pdf.

[424] 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.

[425] 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.

[426] 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.

[427] 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.

[428] Harris TD and Smith VH. 2016. Do persistent organic pollutants stimulate cyanobacterial blooms? Inland Waters 6: 124–30.

[429] 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.

[430] 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.[431] 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).[432] 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.[433] 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.[434] 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

[431] USEPA (2020). National Rivers and Streams Assessment 2013-2014: A collaborative Survey. EPA 841-R-19-001. Washington, DC. https://www.epa.gov/national-aquatic-resource-surveys/nrsa.
[432] 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.
[433] USEPA (2016). Refined Ecological Risk Assessment for Atrazine. EPA-HQ-OPP-2013-0266. U.S. Environmental Protection Agency, Washington, DC.
[434] 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.[435,436] 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.[437] 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.[438] 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 Final 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

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[435] USEPA (2021). Frequent questions about underground storage tanks. https://www.epa.gov/ust/frequent-questions-about-underground-storage-tanks.
[436] "UST Confirmed Releases National data 2016-2021," available in the docket.
[437] 40 CFR Part 280.
[438] 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.[439] 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.[440,441] 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. 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 however; in the May 19 BE, we further evaluate these based on models and assessments. 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.

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 future effects of the candidate volumes as increases in feedstock production such as soybeans may lead to water impacts.

[439] 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.
[440] 2010 – US Climate Action Report: Fifth National Communication of the United States of America Under the United Nations Framework Convention on Climate Change.
[441] 2011 Annual Report: ENERGY STAR and Other Climate Protection Partnerships.

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.[442] 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)[443] "where groundwater levels have declined at unsustainable rates."[444]

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 Draft Third Triennial Report to Congress on Biofuels, the water quantity impacts of biofuels were assessed.[445] 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."[446] These early studies characterized this issue as biofuel's water intensity,[447] embodied water,[448] and water

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[442] 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.

[443] The High Plains Aquifer is often referred to as the Ogallala Aquifer, which is the largest formation within the High Plains Aquifer.

[444] 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.

[445] 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.

[446] 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.

[447] King, C. W., & Webber, M. E. (2008). Water intensity of transportation. *Environmental Science & Technology*, 42(21), 7866.

[448] Chiu, Y. W., Walseth, B., & Suh, S. W. (2009). Water embodied in bioethanol in the United States. *Environmental Science & Technology*, 43(8), 2688-2692.

footprint.[449] 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).[450] 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.[451] 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.[452]

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."[453] 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).[454] 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 per liter of ethanol-equivalent biodiesel (based on energy equivalence).[455] These values all represent an upper end estimate of water demands, if fuels are made from irrigated crops.

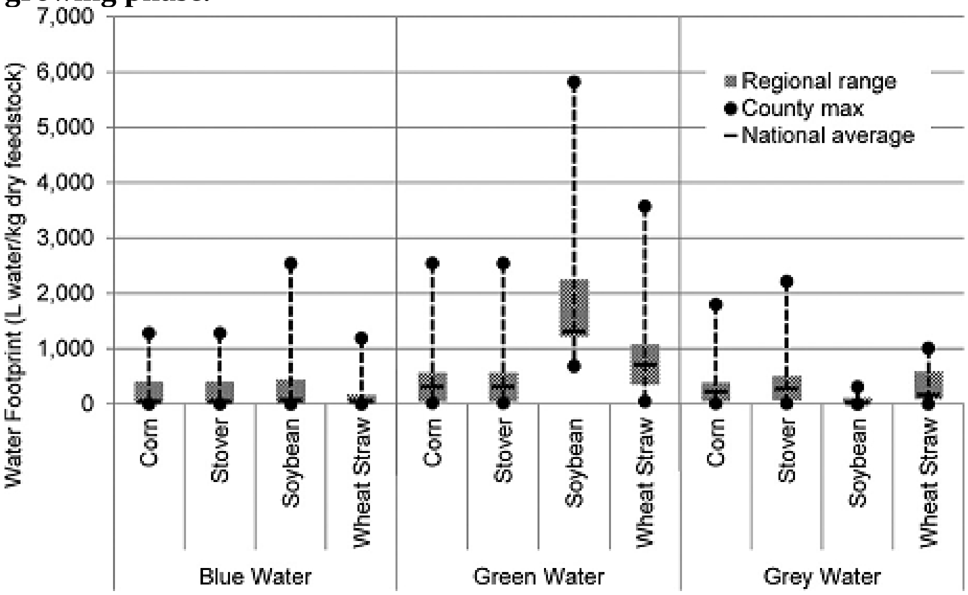
However, where and how crops are grown also matter because irrigation rates for the same crops can vary enormously based on where they are cultivated: from no irrigation in rain-

[449] 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.
[450] 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.
[451] 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.
[452] 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.
[453] 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.
[454] 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.
[455] 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.

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.[456] 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.[457] 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.[458] 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.[459] 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."[460] 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).[461]

[456] 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.
[457] 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.
[458] Gerbens-Leenes, W., & Hoekstra, A. Y. (2012). The water footprint of sweeteners and bio-ethanol. *Environment international*, 40, 202-211.
[459] EIA (2018). "Six states account for more than 70% of U.S. fuel ethanol production." https://www.eia.gov/todayinenergy/detail.php?id=36892. *See also* EIA. (2017, February 16). "Nebraska State Profile and Energy Estimates: Profile Analysis." https://www.eia.gov/state/analysis.php?sid=NE.
[460] NAS (2011). Renewable Fuel Standard: Potential Economic and Environmental Effects of U.S. Biofuel Policy. National Academy of Sciences. Washington, DC.
[461] 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.[462] 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.[463] These values are typical of a dry mill facility. Wet mill facilities require closer to 4 gallons per gallon of ethanol.[464] 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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[462] 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.
[463] 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.
[464] 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.[465] 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.[466] 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).[467]

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.[468] 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,[469] 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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[465] 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. http://www.ethanolproducer.com/articles/8860/dropping-water-use.

[466] 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.

[467] 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.

[468] Sun, Pinping; Estimation of U.S. refinery water consumption and allocation to refinery products; Fuel; Volume 221; June 18, 2018.

[469] 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.[470] 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.[471] [472] 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.[473] 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.[474] 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.[475] 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. Of these fuels, soy biodiesel and renewable diesel is the volume expected to expand the most as a result of the final standards. However, the increase is expected to derive mostly from increases in soybean crushing in the U.S., not from increase plantings of soybeans.

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

[470] 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.
[471] Id.
[472] Sun, Pinping; Estimation of U.S. refinery water consumption and allocation to refinery products; Fuel; Volume 221; June 18, 2018.
[473] 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.
[474] Haas, M.J, A process model to estimate biodiesel production costs, Bioresource Technology 97 (2006) 671-678.
[475] Sun, Pinping; Estimation of U.S. refinery water consumption and allocation to refinery products; Fuel; Volume 221; June 18, 2018.

supplies attributed specifically to the increased production of corn grain-based ethanol and 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.[476] These are areas unlikely to have sufficient precipitation to support corn or soybean cultivation.[477] 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.[478] From 2013 to 2018, there was an increase in total irrigated acres of nearly 0.6 million acres in the U.S.[479] 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.[480] 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.[481] Figure 4.5.3-1 shows acres of irrigated land in 2012, the most recent year of data for which this figure is available.

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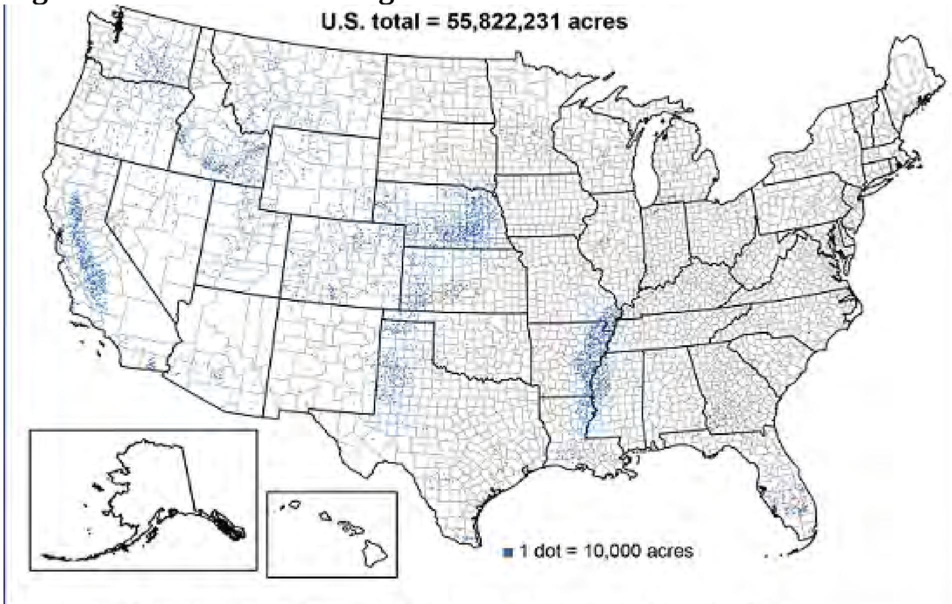
[476] U.S. EPA (2018). Biofuels and the Environment: Second Triennial Report to Congress. U.S. Environmental Protection Agency, EPA/600/R-18/195: 159 pp. Washington, DC, June.
[477] Lark TJ, Salmon JM, and Gibbs HK (2015). Cropland expansion outpaces agricultural and biofuel policies in the United States. 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).
[478] USDA NASS (2018). 2018 Irrigation and Water Management Survey. https://www.nass.usda.gov/Publications/AgCensus/2017/Online_Resources/Farm_and_Ranch_Irrigation_Survey/fris.pdf.
[479] Id.
[480] Id.
[481] Id.

Figure 4.5.3-1: Acres of irrigated land in 2012

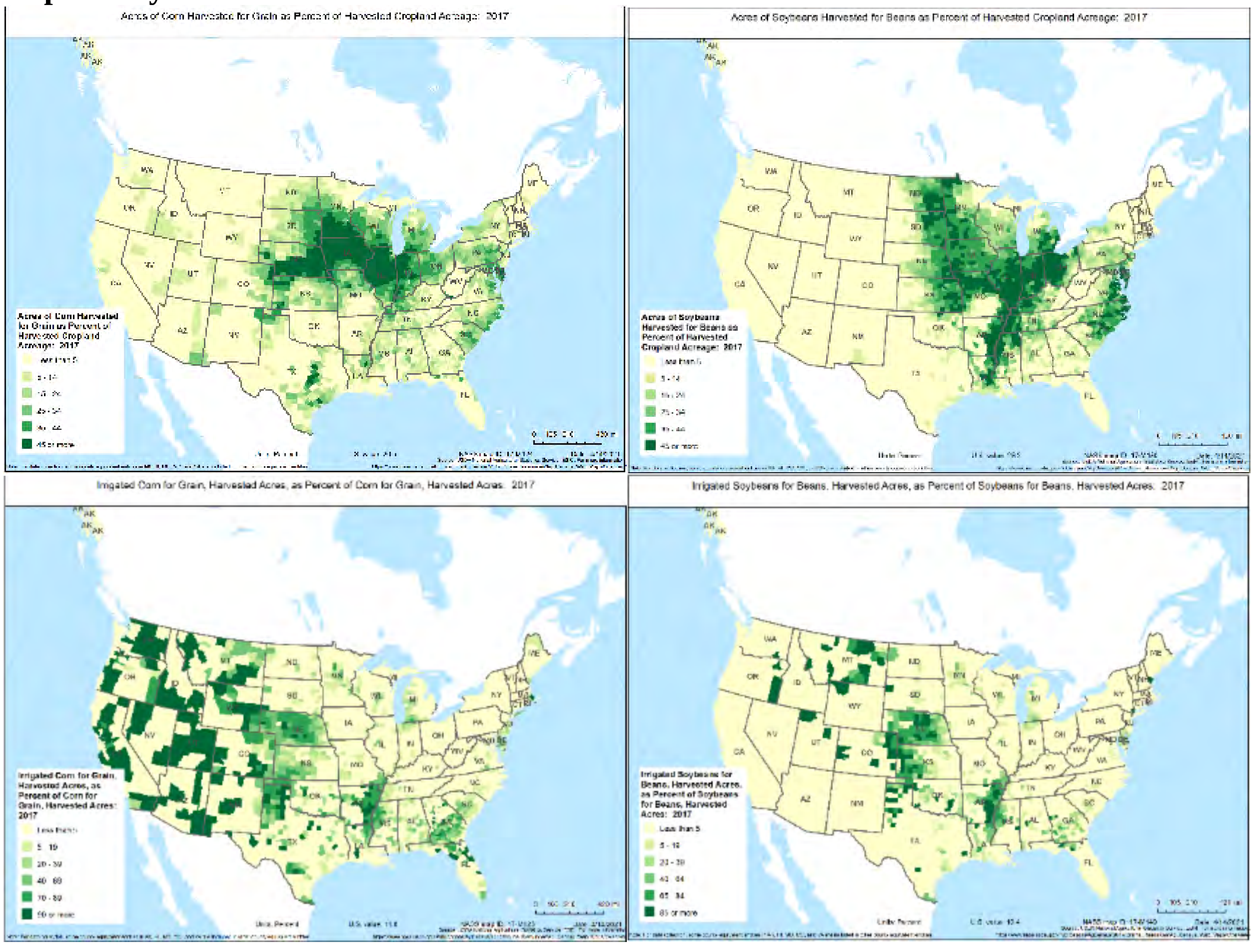


Source: USDA, National Agricultural Statistics Service, Map Atlases for the 2012 Census of Agriculture.

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



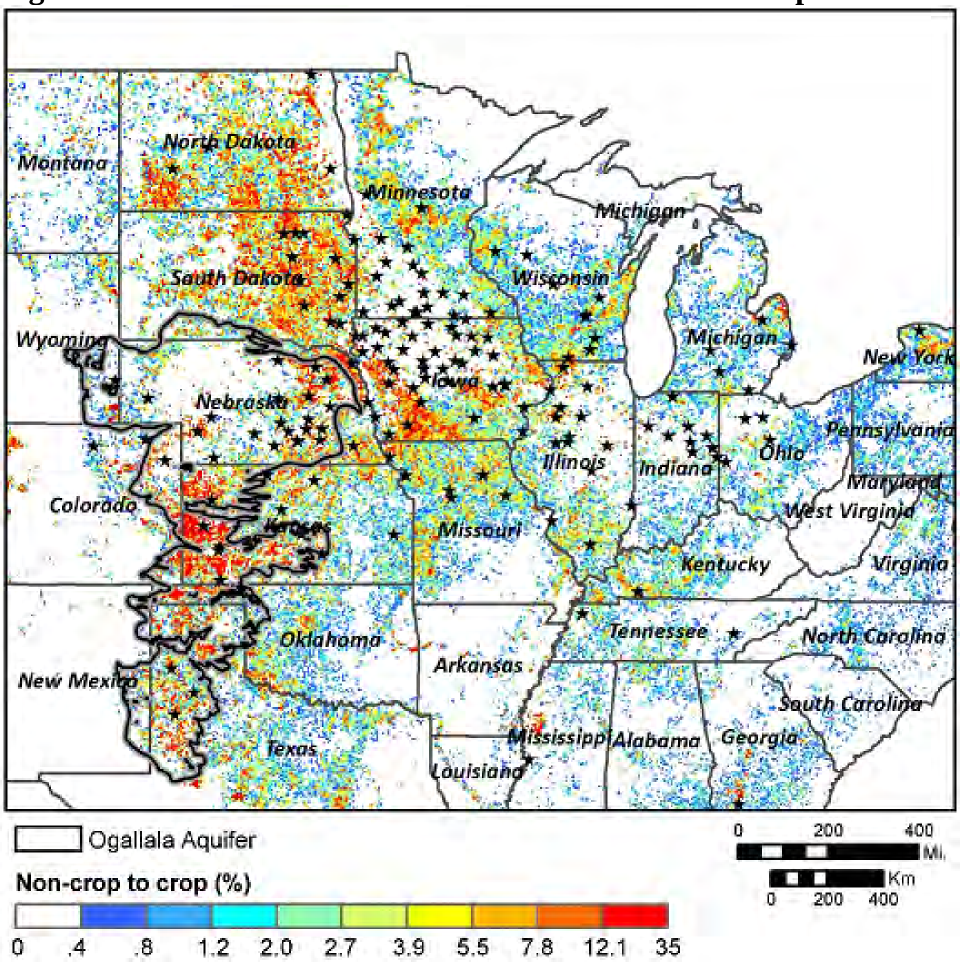
Top left: Acres of Corn Harvested as a Percent of Harvested Cropland Acreage.
Top right: Acres of Soybean Harvested as a Percent of Harvested Cropland Acreage.
Bottom left: Irrigated Corn as a Percent of Total Corn (Harvested Acres).
Bottom right: Irrigated Soybeans as a Percent of Total Soybeans (Harvested Acres).
Source: USDA Agricultural Census Web Maps.
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."[482] 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.

[482] 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)

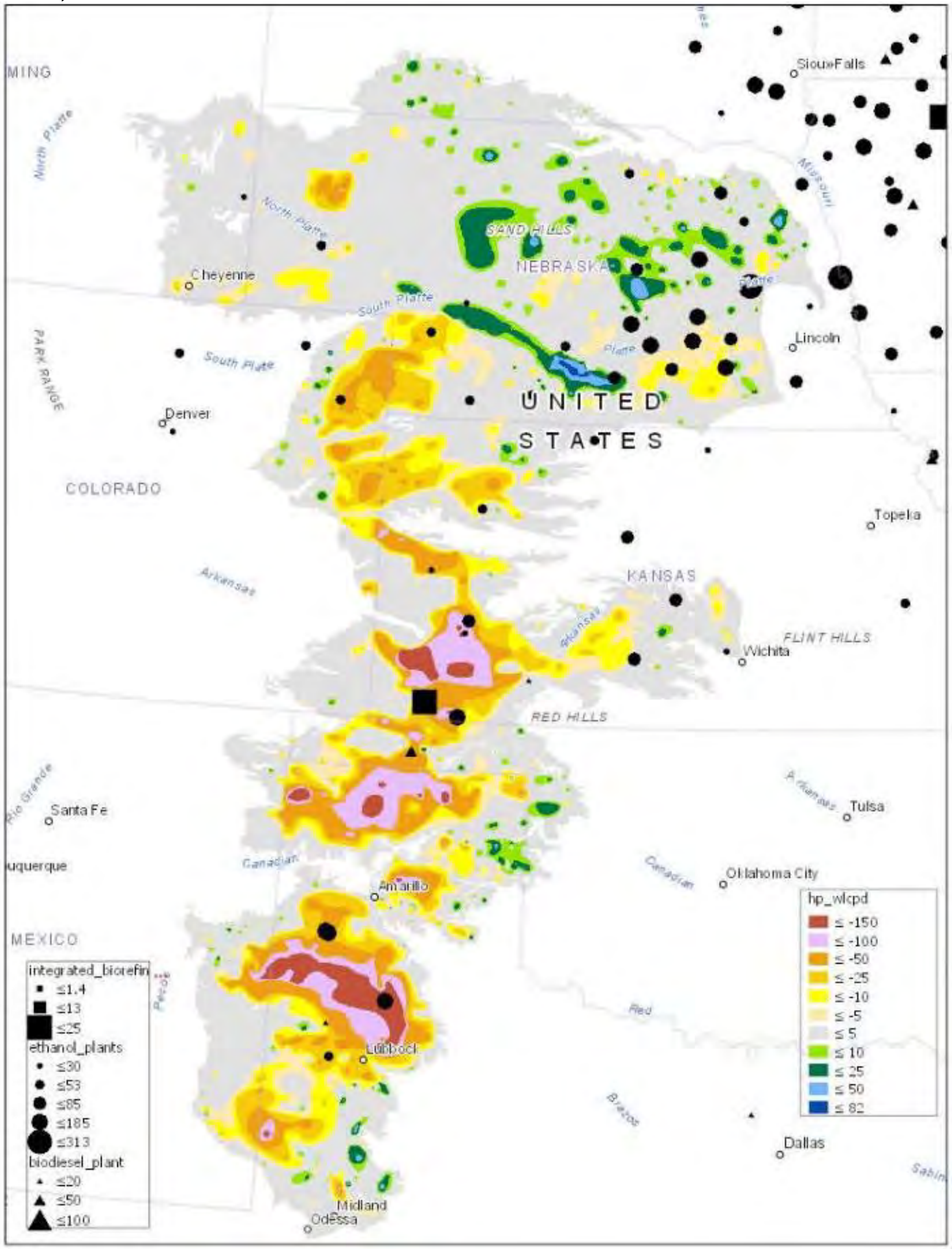
As stated above, there have been no comprehensive studies of the changes in irrigated acres, rates of irrigation, or changes in surface and groundwater supplies attributed specifically to the increased production of corn grain-based ethanol and soybean-based biodiesel. In the absence of analyses that 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."[483] 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.[484] 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[485]) 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.

[483] 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.

[484] 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.

[485] 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.[486] 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.[487] 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.[488] 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."[489]

4.5.3.2 Non-Cropland Biofuels and Non-U.S. Crops

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.[490] 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

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[486] 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.
[487] 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).
[488] 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.
[489] 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.
[490] 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[491] or focus on future cellulosic feedstocks while soy renewable diesel is the fuel with the more significant increases expected under this final rule.[492] 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.[493] 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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[491] 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.

[492] 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.

[493] 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. 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 with is discussed in the May 19 BE as well. 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.[494] The United Nations Millennium Ecosystem Assessment[495] categorized four different types of ecosystem services, including:

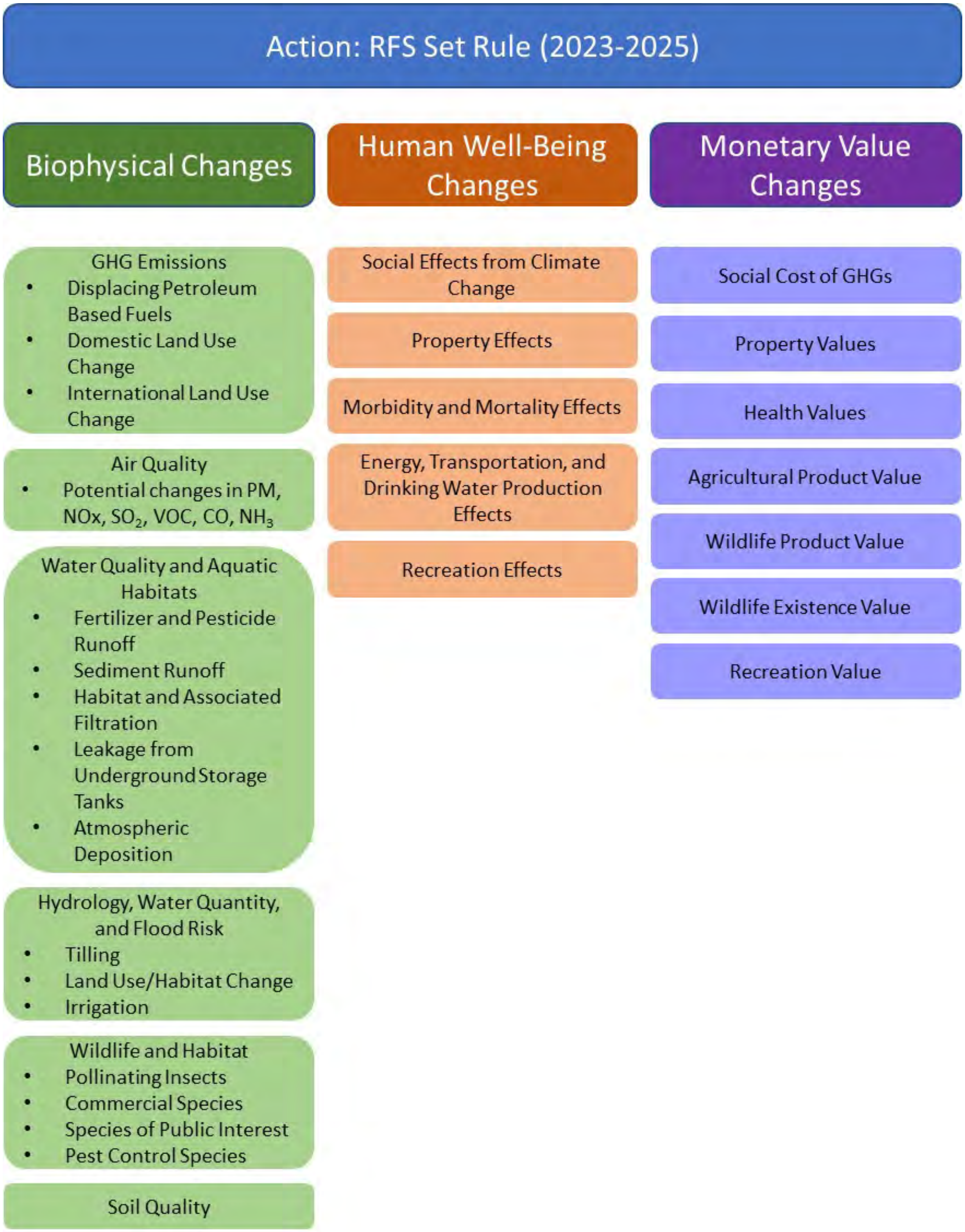
- Provisioning Services; the provision of food, fresh water, fuel, fiber, and other goods
- Regulating Services; climate, water, and disease regulation as well as pollination
- Supporting Services; soil fermentation and nutrient cycling
- Cultural services; education, aesthetic, and cultural heritage 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.

[494] US EPA website on Ecosystem Services. https://www.epa.gov/eco-research/ecosystem-services.
[495] 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 uninterrupted availability of energy sources at an acceptable price.[496] Most discussions of U.S. energy security revolve around the topic of the economic costs of U.S. dependence on oil imports.[497] 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, or more broadly, as reducing the sensitivity of the U.S. economy to energy imports and foreign energy markets.[498] 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.[499] 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.[500]

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.[501] U.S. oil consumption rebounded to roughly pre-COVID-19 levels in 2022 and is anticipated to modestly decline in the 2023–2025 timeframe of this rule.[502,503] The U.S. has increased its

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[496] IEA. Energy Security: Reliable, affordable access to all fuels and energy sources. 2019. December.

[497] 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.

[498] Greene, D. 2010. Measuring energy security: Can the United States achieve oil independence? *Energy Policy* 38, pp. 1614–1621.

[499] 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).

[500] Greene, D. 2010. Measuring energy security: Can the United States achieve oil independence? *Energy Policy* 38, pp. 1614–1621.

[501] EIA. Total Energy. *Monthly Energy Review*. Table 3.1. Petroleum Overview. December 2021.

[502] EIA. Total Energy. *Monthly Energy Review*. Table 3.1. Petroleum Overview. March 2023.

[503] EIA. AEO 2023. Reference Case. Table A11. Petroleum and Other Liquids Supply and Disposition.

production of oil, particularly "tight" (i.e., shale) oil over the last decade.[504] 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 petroleum products in 2023–2025.[505] 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.[506]

Oil is a commodity that is globally traded and, as a result, an oil price shock is transmitted globally. 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 which could be subject to supply disruptions. 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 the 2023–2025 time frame of this rule.

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.[507] 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**.**[508] 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.[509]

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.

[504] EIA (2021). *Tight oil production estimates by play*.
[505] EIA. AEO 2023. Reference Case. Table A11. Petroleum and Other Liquids Supply and Disposition.
[506] EIA. "Oil and petroleum products explained – Oil imports and exports." April 21st, 2022.
[507] Bordoff, J. 2019. The Myth of US Energy Independence has Gone Up in Smoke. *Foreign Policy*. September 18th.
[508] 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.
[509] Foreman, D. 2018. Why the US must Import and Export Oil: American Petroleum Institute. June 14th.

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)).[510] 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.[511] Bohi and Montgomery (1982) detailed the theoretical foundations of the oil import premium and established many of the critical analytic relationships.[512] 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.[513] 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).[514,515]

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.[516] 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.[517] 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.

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

[510] 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.
[511] Plummer, J. (Ed.). 1982. Energy Vulnerability, "Basic Concepts, Assumptions and Numerical Results," pp. 13–36, Cambridge MA: Ballinger Publishing Co.
[512] Bohi, D. and Montgomery, D. 1982. Social Cost of Imported and U.S. Import Policy, *Annual Review of Energy*, 7:37-60.
[513] 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.
[514] 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.
[515] 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.
[516] National Research Council. 2009. Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use. National Academy of Science, Washington, DC.
[517] 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.

(2010)), while other work continues to find evidence regarding the economic importance of oil shocks.[518] 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."[519] 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)).[520,521] 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."[522]

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)).[523] 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.[524] 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)."[525]

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.[526] They state: "The results indicate that the economic consequences of a supply-driven oil-price

[518] Rasmussen, T. and Roitman, A. 2011. Oil Shocks in a Global Perspective: Are We Really That Bad. IMF Working Paper Series.
[519] 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*.
[520] Kim, D. 2012. What is an oil shock? Panel data evidence. *Empirical Economics*, Volume 43, pp. 121-143.
[521] 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.
[522] 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).
[523] 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.
[524] 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.
[525] 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.
[526] 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).

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.

Considering all of the recent energy security literature, EPA's assessment concludes that there are benefits to the U.S. from reductions of its oil imports. There is some debate as to the magnitude, and even the existence, of energy security benefits from U.S. oil import reductions. However, differences in economic impacts from oil demand and oil supply shocks have been distinguished, with oil supply shocks resulting in economic losses in oil importing countries. 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 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.[527] In a follow-on study, Brown summarized the RFF study results as well.[528] 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.

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

[527] 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.
[528] Brown, S. 2018. New estimates of the security costs of U.S. oil consumption", *Energy Policy*, 113 pp. 171-192.

developed by Balke and Brown.[529] The second set of modeling frameworks use alternative structural vector autoregressive models of the global crude oil market.[530] The last of the models utilized is the National Energy Modeling System (NEMS).[531]

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 14th, 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 oil processing and stabilization plant in the world, with a capacity of roughly 7 MMBD or about 7% of global crude oil production capacity.[532] On September 16th, the first full day of

[529] Balke, N. and Brown, S. 2018. "Oil Supply Shocks and the U.S. Economy: An Estimated DSGE Model." *Energy Policy*, 116, pp. 357-372.
[530] 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*; 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.
[531] 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.
[532] EIA. "Saudi Arabia crude oil production outage affects global crude oil and gasoline prices." *Today in Energy*. September 23, 2019.

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 17th, 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.[533] Tanker loading estimates from third-party data sources indicated that loadings at two Saudi Arabian export facilities were restored to the pre-attack levels.[534] As a result, both Brent and WTI crude oil prices fell on September 17th, 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 first half of 2022. For example, on January 3rd, 2022, the WTI crude oil price was roughly $76/bbl.[535] The WTI oil price increased to roughly $124/bbl on March 8th, 2022, a 63% increase.[536] Crude oil prices increased in the first half of 2022 because of oil supply concerns. Russia's invasion of Ukraine came during eight consecutive quarters (from the third quarter of 2020 to the second quarter of 2022) of global crude oil inventory decreases.[537] The lower inventory of crude oil was the result of withdrawals from storage to meet the demand that resulted from rising economic activity after pandemic-related restrictions eased.[538] Oil prices have drifted downwards throughout the second half of 2022 and early 2023. As of March 13th, 2023, the WTI crude oil price was roughly $75/barrel.[539]

Geopolitical disruptions that occurred in 2022 are likely to continue to affect global trade of crude oil and petroleum products in 2023 and beyond. In response to Russia's invasion of Ukraine in late February 2022, the U.S. and many of its allies, particularly in Europe, announced various sanctions against Russia's petroleum industry.[540] For the European Union (EU), petroleum from Russia had accounted for a large share of all energy imports, but the EU banned imports of crude oil from Russia starting in December 2022 and imports of petroleum products starting in February 2023.[541] Given oil market trends in 2022, the U.S. set a new record for petroleum product exports, up 7% from 2021.[542] Since both significant demand and supply factors are influencing world oil prices in 2022 and the early part of 2023, it is not clear how to evaluate unfolding oil market price trends from an energy security standpoint. Thus, the attack of

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533 Id.
534 Id.
535 U.S. Energy Information Administration. 2022. *Petroleum and Other Liquids: Spot Prices*. https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm.
536 Id.
537 U.S. Energy Information Administration. 2023. Today in Energy. Crude oil prices increased in the first half of 2022 and declined in the second half of 2022. January.
538 Id.
539 EIA. *Petroleum and Other Liquids Spot Prices*. https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm.
540 U.S. Energy Information Administration. 2023. Today in Energy. U.S. petroleum product exports set a record high in 2022. March.
541 Id.
542 Id.

the Abqaiq oil processing facility in Saudi Arabia and the events in the world oil market in 2022 and 2023 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.[543]

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.[544] 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 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.[545] 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.[546] 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. In December 2015, the 40-year ban on the export of domestically produced crude oil was lifted as part of the Consolidated Appropriations Act, 2016. Pub. L. 114-113 (Dec. 18, 2015).[547] According to the GAO, the ban was lifted in part due to increases in tight (i.e., shale) oil.[548] Second, due to

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[543] 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.

[544] Uría-Martínez, R., Leiby, P., Oladosu, G., Bowman, D., Johnson, M. 2018. Using Meta-Analysis to Estimate World Oil Demand Elasticity, ORNL Working Paper.

[545] 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.

[546] 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.

[547] https://uscode.house.gov/statutes/pl/114/113.pdf (see 129 stat. 2987).

[548] 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

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.[549]

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.[550] 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.[551] Growth in U.S. tight oil production during this period was only interrupted in 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.[552] 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.[553] 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.[554]

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".

[549] Kemp, J. 2021. U.S. shale restraint pushes oil prices to multi-year high. Reuters. June 4, 2021.

[550] EIA (2021). *Crude Oil Production*. https://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_m.htm.

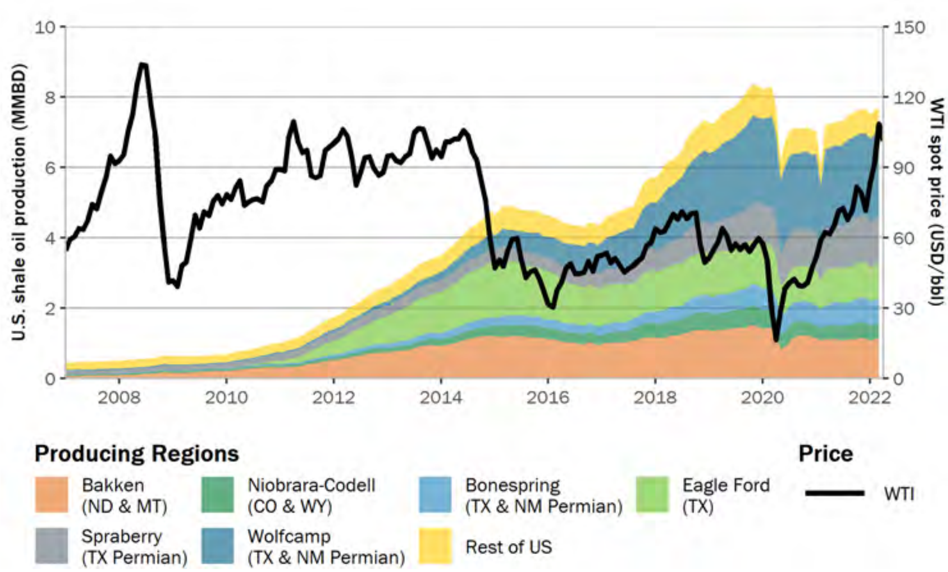
[551] EIA (2021). *Tight oil production estimates by play*. https://www.eia.gov/petroleum/data.php.

[552] 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.

[553] 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.

[554] Bjørnland, H., Nordvik, F. and Rohrer, M. 2021. "Supply flexibility in the shale patch: Evidence from North Dakota," *Journal of Applied Economics*.

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[555,556]

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 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?[557] 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.[558] For both conventional oil wells and shale oil wells (i.e., unconventional oil wells),

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[555] EIA. *Tight oil production estimates by play*. https://www.eia.gov/petroleum/data.php.
[556] EIA. *Petroleum and Other Liquids Spot Prices*. https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm.
[557] 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."
[558] Newell, R. and Prest, B. 2019. The Unconventional Oil Supply Boom: Aggregate Price Response from Microdata, *The Energy Journal*, Volume 40, Issue Number 3.

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.[559] 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.

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.[560] 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.[561] Most U.S.

[559] Bjørnland, H., Nordvik, F. and Rohrer, M. 2021. "Supply flexibility in the shale patch: Evidence from North Dakota," *Journal of Applied Economics*.
[560] Walls, W. D., & Zheng, X. 2022. Fracking and Structural Shifts in Oil Supply. *The Energy Journal*, *43*(3).
[561] McLean, B. *The Next Financial Crisis Lurks Underground*. New York Times, September 1st, 2018.

tight oil producers did not generate positive cashflow.[562] As of 2021, U.S. shale oil producers have pledged to repay their debt and reward shareholders through dividends and stock buybacks.[563] 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 government regulations.[564] 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.

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

[562] Id.
[563] Crowley, K. and Wethe, D. *Shale Bets on Dividends to Match Supermajors, Revive Sector*. Bloomberg. August 2nd, 2021.
[564] Federal Reserve Bank of Dallas. Dallas Fed Energy Survey. March 23rd, 2022.

response option should a disruption in commercial oil supplies threaten the U.S. economy.[565] Emergency SPR drawdowns have taken place in 1991 (Operation Desert Storm), 2005 (Hurricane Katrina), 2011 (Libyan Civil War), and 2022 (War in Ukraine). 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.[566] 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.[567] For 2023, the DOE has announced plans to sell 26 million barrels of oil between April and June.[568] 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.

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 action.

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

[565] Energy Policy and Conservation Act, 42 U.S. Code § 6241(d) (1975).
[566] DOE. DOE Announces Emergency Notice of Sale of Crude Oil from the Strategic Petroleum Reserve to Address Oil Supply Disruptions. 2022. March.
[567] DOE. DOE Announces Second Emergency Notice of Sale of Crude Oil From The Strategic Petroleum Reserve to Address Putin's Energy Price Hike. 2022. April.
[568] DOE. DOE Issues Notice of Congressionally Mandated Sale to Purchase Crude Oil from the Strategic Petroleum Reserve. 2023. February.

accounts rather than by mission, the allocation to particular missions is not always clear.[569] 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).[570]

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).[571] 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.[572] 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 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.[573] 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

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[569] 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.
[570] Koplow, D. and Martin, A. 1998. Fueling Global Warming: Federal Subsidies to Oil in the United States. Greenpeace, Washington, D.C.
[571] 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.
[572] Stern, R. 2010. "United States cost of military force projection in the Persian Gulf, 1976–2007." *Energy Policy* 38, no. 6. June: 2816-2825.
[573] 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.

global oil supplies.[574] 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.[575]

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.[576] 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.

5.4 Energy Security Impacts

5.4.1 U.S. Oil Import Reductions

From 2023–2025, the AEO 2023 Reference Case projects that the U.S. will be both an exporter and an importer of crude oil.[577] 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 fairly stable at 3.3 MMBD in 2023 and 3.2 MMBD from 2024–2025. U.S. crude oil imports, meanwhile, are projected to range between 6.8 MMBD and 7.0 MMBD over the 2023–2025 time period. AEO 2023 also projects that net U.S. exports of refined petroleum products will increase from 4.2 MMBD in 2023 to 5.5 MMBD in 2025. Given the pattern of stable net U.S. crude oil imports, and the projected growth in the U.S.'s net petroleum product exports, the U.S. is projected to increase its net crude oil and refined petroleum products exports from 0.8 MMBD in 2023 to 1.9 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.[578] U.S. oil consumption is projected to decrease modestly from 19.2 MMBD in 2023 to 18.6 MMBD in 2025.[579] It is not just U.S. crude oil imports alone, but both imports and consumption of petroleum from all

[574] Securing America's Future Energy. 2018. Issue Brief. The Military Cost of Defending the Global Oil Supply.
[575] Id.
[576] 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.
[577] EIA. AEO 2023. Reference Case. Table A11. Petroleum and Other Liquids Supply and Disposition.
[578] EIA. Monthly Energy Review, March 2023. Calculated using series "Petroleum Consumption (Excluding Biofuels) Annual" (Table 1.3) and "Petroleum Consumption Total Heat Content Annual" (Table A3).
[579] EIA. AEO 2023. Reference Case. Table A11. Petroleum and Other Liquids Supply and Disposition.

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 how increased consumption of renewable fuels caused by this rule reduces U.S. refined product consumption (i.e., gasoline and diesel fuel). For this energy security analysis, we undertake a detailed analysis of how the reduction in U.S. refined product fuel consumption impacts U.S. imports/exports of crude oil and petroleum products in the 2023–2025 timeframe. The impact of lower refined product demand on imports/exports is estimated by comparing the AEO 2023 Low Economic Growth to the AEO 2023 Reference Case. The Low Economic Growth Case is used since refined product demand decreases in comparison to the Reference Case, and we assume that this reduction would be similar to the reduction caused by increased consumption of renewable fuels.[580] An 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. refined product consumption in the two different AEO cases considered. Based on this analysis, we project that approximately 100% of the change in refined product consumption resulting from this rule is likely to be reflected in reduced aggregate net U.S. crude oil imports/petroleum product imports in 2023–2025. Thus, on balance, each gallon of petroleum product reduced as a result of this rule is anticipated to reduce total net U.S. imports of crude oil/petroleum refined products by one, energy-equivalent gallon.

Based on the changes in oil consumption estimated by EPA and the 100% 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 2023 Reference Case.[581]

[580] We analyze how U.S. crude oil imports/exports and net petroleum products in Table 11. Petroleum and Other Liquids Supply and Disposition of the AEO 2023, the Low Economic Growth Case, changes in comparison to that in the Reference Case. See the spreadsheet in the Docket, “Change of product demand on imports AEO 2023.xlsx”.

[581] EIA. AEO 2023. Reference Case. Table A11. Petroleum and Other Liquids Supply and Disposition.

Table 5.4.1-1: Projected Trends in U.S. Oil Exports/Imports, Net Oil Refined Product Exports, Net Crude Oil and Refined Petroleum Product Exports, U.S. Oil Consumption and Reductions in U.S. Oil imports Resulting From the Candidate Volumes (2023-2025) (MMBD)

	2023	2024	2025
U.S. Crude Oil Exports	3.3	3.2	3.2
U.S. Crude Oil Imports	6.8	7.0	6.9
U.S. Net Petroleum Refined Product Exports[a]	4.2	5.4	5.5
U.S. Net Crude Oil and Refined Petroleum Product Exports[b]	0.8	1.7	1.9
U.S. Oil Consumption[c]	19.2	18.7	18.6
Reduction in U.S. Oil Imports from the Candidate Volumes			
Excluding 2023 Supplemental Standard	0.13	0.13	0.14
Including 2023 Supplemental Standard	0.14	0.13	0.14

[a] Calculated from AEO 2023 Table A11 as Net Product Exports minus Ethanol, Biodiesel, Renewable Diesel, and Other Biomass-derived Liquid Net Exports.
[b] Calculated from AEO 2023 Table A11 as Total Net Exports minus Ethanol, Biodiesel, Renewable Diesel, and Other Biomass-derived Liquid Net Exports.
[c] Calculated from AEO 2023 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.[582] 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.[583] This same approach was used to estimate energy security benefits for the RFS2 final rule.[584] 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. For this rule, EPA updated the ORNL methodology using the AEO 2023.

The ORNL methodology is used to compute the oil import premium per barrel of imported oil.[585] The values of U.S. oil import premium components (macroeconomic 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

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[582] 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.
[583] 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.
[584] 75 FR 14839-42, March 26, 2010.
[585] The oil import premium concept is defined in Chapter 5.1.

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 2023 into its model.[586] 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.[587]

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 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.

[586] The oil market projection data used for the calculation of the oil import premiums came from AEO 2023, supplemented by the latest complete EIA international projections from the *Annual Energy Outlook (AEO)/International Energy Outlook (IEO) 2021*. Projections for global oil prices, U.S. GDP 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 2023. Global and OECD Europe supply/demand projections as well as OPEC oil production share are from IEO 2021. The need to combine AEO 2023 and IEO 2021 data arises due to two reasons: (a) EIA stopped including Table 21 "International Petroleum and Other Liquids Supply, Disposition, and Prices" (international oil market balances) in the U.S.-focused *Annual Energy Outlook* after 2019, (b) EIA does not publish complete updates of the IEO every year and IEO 2023 is not due out until later in 2023.

[587] 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.

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.[588] 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, particularly in the 2023–2025 time frame of this final rule. According to IEA, the share of global oil consumption attributed to the transportation sector grew from 60% in 2000 to 66% in 2019.[589] 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 also, 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 2020–2022 annual rule, we are increasing the short-run price elasticity of demand for oil from –0.045

[588] See 75 FR 26049 (May 10, 2010).
[589] IEA, Data and Statistics, https://www.iea.org/data-and-statistics?country=WORLD&fuel=Oil&indicator=OilProductsConsBySector

to –0.07, a 56% increase.[590] 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.[591] 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).[592] 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.[593] 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 prem for 2023–2025, showing that they are relatively steady over this time period.

Table 5.4.2-1: Estimated Macroeconomic Oil Security Premiums (2022$/bbl)[a]

Year	Avoided Macroeconomic Disruption/Adjustment Costs (Range)
2023	$3.75 ($0.86–$6.81)
2024	$3.70 ($0.69–$6.87)
2025	$3.67 ($0.65–$6.87)

[a] Top values in each cell are mean values. Values in parentheses are 95% 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 security benefits are far smaller than the quantified costs. In all cases, we would reach the same

[590] 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.
[591] See 75 FR 26049 (May 10, 2010).
[592] 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.
[593] 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.

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 2023. 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 Oil Import Reductions[a] (millions of gallons)	Benefits (millions of 2022$)
2023		
Excluding Supplemental Standard	2,012	$180
Including Supplemental Standard	2,151	$192
2024	1,960	$173
2025	2,141	$187

[a] U.S. oil import reductions used for the energy security analysis in this section are a combination of reduced U.S. imports of gasoline, diesel fuel, and crude oil from Tables 10.4.2.1-3 and 10.4.2.1-4 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.[594]

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 document. 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), imported 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).

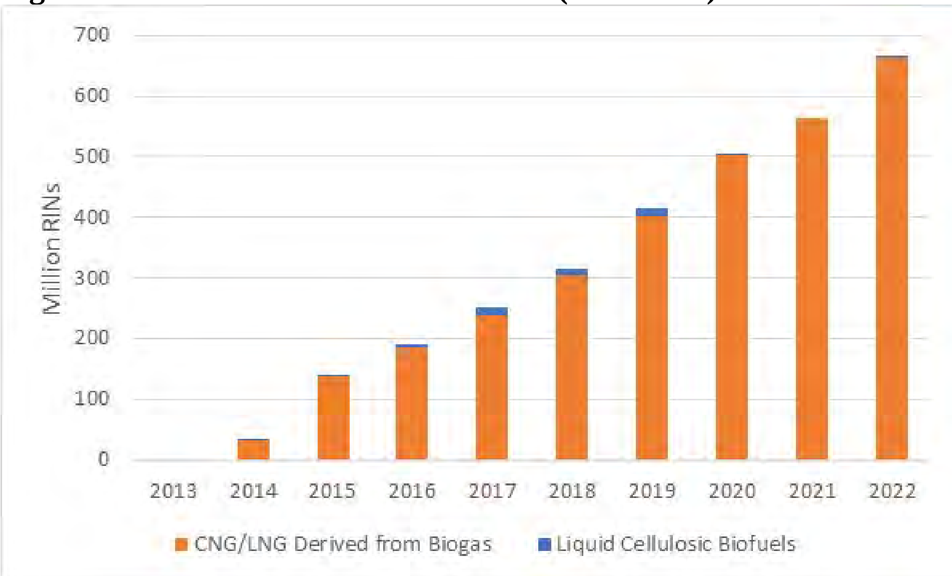
6.1 Cellulosic Biofuel

In the past several years, production of cellulosic biofuel has continued to increase. Cellulosic biofuel production reached record levels in 2022, driven by CNG and LNG derived from biogas.[595] 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. 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).

[594] This is what we generally mean when we use the term biofuel "production" in this section and do not specify whether we are discussing domestic production or imports.

[595] 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 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 considered the same factors as in previous RFS rules. Based on the available information we project that ethanol produced from corn kernel fiber will be the only type of liquid cellulosic biofuel produced in 2023 – 2025. To project the production of cellulosic biofuel RINs for RNG used as CNG/LNG, we used the same marketwide year-over-year growth rate methodology as in the 2018–2022 final rules, with updated RIN generation data through March 2023. 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. However, the rate of growth used to project the production of RNG used as CNG/LNG is based on data from 2015 – 2022 rather than data from the previous 24 months. Given the many years of steady growth with the primary exception of the 2020 when all markets were impacts significantly by Covid-19, this longer time period was believed to provide a more accurate estimate of potential growth in 2023-2025.

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 and 6.1.3 discuss the methodologies used by EPA to project cellulosic biofuel production for liquid cellulosic biofuels and RNG used as CNG/LNG. Chapter 6.1.4 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 comments received. As discussed in greater detail in Chapter 6.1.2 through 6.1.3, 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 RNG used as CNG/LNG is 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 2015-2022[596] 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, 2018, and 2022[597] and higher than the actual number of RINs made available in 2016, 2017, 2019, and 2020.[598] 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

[596] 2022 is the last year for which complete data is available at the time of this action.
[597] 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.
[598] 2021 values were set at the actuals after the fact, see 87 FR 39600 (July 1, 2022).

biofuel production. It also emphasizes the importance of continuing to consider refinements to our projection methodology in order to make our projections more accurate.

Table 6.1.1.1-1: Projected and Actual Cellulosic Biofuel Production (2015-2022) (million gallons)

	Projected Volume[a]			Actual Production Volume[b]		
Year	**Liquid Cellulosic Biofuel**	**RNG used as CNG/LNG**	**Total Cellulosic Biofuel[c]**	**Liquid Cellulosic Biofuel**	**RNG used as CNG/LNG**	**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
2022	0	632	632	1.6	665.1	666.7

[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); projected volumes for 2022 can be found in the 2020 – 2022 Final Rule (87 FR 39600, July 1, 2022).
[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 RNG used as CNG/LNG 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).[599] 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. For the first time since 2015 EPA under-projected liquid cellulosic biofuel volumes in 2022 using the methodology first adopted in the 2018 final rule.

We next turn to the projection of RNG used as CNG/LNG. 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 RNG used as CNG/LNG. EPA used a facility-by-facility approach to project the production of CNG/LNG derived from biogas from 2015-2017. Notably the facility-by-facility methodology resulted in significant over-estimates of CNG/LNG

[599] 82 FR 58486 (December 12, 2017).

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 RNG used as CNG/LNG. 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 RNG used as CNG/LNG in 2018, 2019, and 2022 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 RNG used as CNG/LNG 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 2022 to estimate the production of RNG used as CNG/LNG in 2023–2025.[600] In comments on the proposed rule, some parties claimed that the production of RNG used as CNG/LNG was negatively impacted by the COVID-19 pandemic in 2020–2022, 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. As discussed in further detail below, the growth rate we are using to project the production of RNG used as CNG/LNG for 2023 – 2025 is based on data from 2015 – 2022, which we believe is more reflective of the potential for growth in the production and use of these fuels in 2023 – 2025.

We applied the growth rate to the number of available 2022 RINs generated for RNG used as CNG/LNG 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 RNG used as CNG/LNG 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 RNG used as CNG/LNG relative to the technologies used to produce liquid cellulosic biofuel, the relatively low production cost of RNG used as CNG/LNG (see Chapter 10), and the comparatively high value of the cellulosic RIN. These factors are unlikely to change in 2023–2025. While we project production volumes of liquid cellulosic biofuel and RNG used as CNG/LNG separately, ultimately it is overall accuracy of the combined cellulosic biofuel volume projection that is relevant to obligated parties.

[600] To project the volume of CNG/LNG derived from biogas in 2023 – 2025, we multiply (1) the number of 2022 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 2023. We then multiply the projected volume of CNG/LNG derived from biogas for 2023 by the growth rate again to project the volume of these fuels for 2024, and repeat this process for 2025.

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,[601] 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.[602] 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.[603] 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) 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.

Compressed Natural Gas (CNG) and Liquefied Natural Gas (LNG) Producers

In July 2014 EPA approved, as part of the "Pathways II" rule,[604] 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 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

[601] 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).
[602] 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).
[603] 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.
[604] 79 FR 42128, July 18, 2014.

gas for injection into a pipeline, and to build a stub line to connect to the natural gas pipeline system.

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. In this final rule we are projecting production of cellulosic ethanol from CKF using both the simultaneous conversion and sequential conversion technologies. Our projections of ethanol produce from CKF is discussed in Chapter 6.1.2.

Fulcrum BioEnergy

Fulcrum BioEnergy has developed a technology to convert separated MSW into a synthetic crude oil using a gasification and Fischer-Tropsch process.[605] 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.[606] In December 2022 Fulcrum announced that this facility had begun producing synthetic crude oil from landfill waste.[607] At this time, however, this facility has not registered as a cellulosic biofuel producer under the RFS program.

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.

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[605] Unless otherwise noted, all information in this paragraph from Fulcrum BioEnergy website: Sierra Biofuels Plant: https://fulcrum-bioenergy.com/facilities.
[606] Fulcrum BioEnergy Completes Construction of the Sierra Biofuels Plant: https://www.fulcrum-bioenergy.com/news-resources/fulcrum-bioenergy-completes-construction-of-the-sierra-biofuels-plant.
[607] Fulcrum BioEnergy Successfully Produces First Ever Low-Carbon Fuel from Landfill Waste at its Sierra BioFuels Plant. Press Release. December 20, 2022.

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[608]) 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.

Cellulosic biofuel produced at three foreign facilities (GranBio's and Raizen's Brazilian facilities, Kerry) 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.[609] 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.[610] Enerkem's facility in Edmonton is designed to produce up to 13 million gallons of cellulosic ethanol per year.[611] This facility began production of methanol in 2015, with production switching from methanol to ethanol in 2017.

608 Tuttle, Robert. *Canada Releases California-Style Fuel Rules to Cut Emissions*. Bloomberg, June 29, 2022.
609 "Technology," Enerkem Website. https://enerkem.com/about-us/technology.
610 Id.
611 "Enerkem Alberta Biofuels," Enerkem Website. https://enerkem.com/facilities/enerkem-alberta-biofuels.

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,[612] Brazil,[613] and the United States[614] with the intention of selling heating oil and/or biocrude into the U.S. market. In November 2022 CastleRock Green Energy announced plans to build two biofuel production facilities in Washington using Ensyn's production technology.[615]

GranBio

GranBio uses a group of technologies to convert cellulosic biomass into ethanol.[616] Construction of their first cellulosic ethanol production facility was announced in mid-2012, and financing was completed in May 2013.[617] In September 2014, GranBio announced that its first cellulosic ethanol facility became operational.[618] 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.[619] 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.

Kerry Inc.

Kerry Inc. purchased Ensyn's Renfrew, Ontario facility in December 2019.[620] This facility is designed to produce biocrude from wood residues, and is capable of producing approximately 4 million gallons of biocrude per year. The biocrude produced from this facility is primarily used in food ingredients but can also be used as heating oil.

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612 "Cote Nord," Ensyn Website. http://www.ensyn.com/quebec.html.
613 "Aracruz Project," Ensyn Website. http://www.ensyn.com/brazil.html.
614 "Ensyn Maine Project," Ensyn Website. http://www.ensyn.com/maine.html.
615 "CastleRock Green Energy to build biofuel facilities in Washington," Biomass Magazine. November 10, 2022.
616 "AVAP," GranBio Website. https://www.granbio.com.br/en/our-technology/avap.
617 Schill, Susanne R. "Financing Complete on Brazil's first commercial 2G Ethanol Plant," Ethanol Producer Magazine. May 17, 2013.
618 "Our Trajectory," GranBio Website. https://www.granbio.com.br/en/about-us/our-trajectory.
619 Id.
620 Mulvihill, Jonathon. "Fifth Liquid Smoke Plant: International Food Group Purchases Renfrew's Ensyn Facility." Inside Ottawa Valley. December 19, 2019. Available Online.

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.[621] 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.[622] 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 RNG used as CNG/LNG, 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. 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.

[621] "Raizen Project," Iogen Website. https://www.iogen.ca/raizen-project.
[622] Id.

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)[623]	Construction Start Date	First Production[624]
CNG/LNG Producers	Various	Biogas	CNG/ LNG	Various	Various	Various
Enerkem	Edmonton, AL, Canada	Separated MSW	Ethanol	10[625]	2012	September 2017[626]
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
Fulcrum/ Marathon	Storey County, NV	Separated MSW	Diesel, Jet Fuel	11	May 2018	December 2022
GranBio	São Miguel dos Campos, Brazil	Sugarcane bagasse	Ethanol	21	Mid 2012	September 2014
Raizen	Piracicaba City, Brazil	Sugarcane bagasse	Ethanol	11	January 2014	July 2015

623 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.

624 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.

625 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 "May 2023 Liquid Cellulosic Biofuel Projections for 2023 – 2025 CBI").

626 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. After gathering updated information on potential liquid cellulosic biofuel producers, we determined that the only facilities likely to produce commercial scale volumes of liquid cellulosic biofuel in 2023 – 2025 were facilities intending to produce ethanol from CKF. In the proposed rule we had also identified a few facilities that we projected could produce gasoline, jet fuel, and diesel fuel from cellulosic biomass by 2025. Since the time of our proposal, two of these facilities have announced project delays and/or significant revisions to their project plans. The nature of these delays and changed plans are such that we no longer anticipate these facilities will be able to produce commercial scale volumes of liquid cellulosic biofuel by 2025.[627] One facility considered in our proposed rule announced that they have successfully began producing biocrude, however this facility has not registered as a cellulosic biofuel producer in the RFS program at this time.[628] We therefore believe there is significant uncertainty as to whether fuel produced from the biocrude at this facility will generate cellulosic biofuel RINs and we have not included production from this facility in our projections of liquid cellulosic biofuel production.

In the proposed rule we also identified ethanol produced from CKF as another potential source of liquid cellulosic biofuel in 2023 – 2025. We noted that 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.[629] EPA has continued to have substantive discussions with technology providers intending to use analytical methods consistent with the guidance document and owners of facilities intending to register as cellulosic biofuel producers using these analytical methods. We now project that many of these facilities will register as cellulosic biofuel producers in 2023 – 2025 and will produce commercial scale volumes of cellulosic biofuel during these years.

To project the volume of ethanol produced from CKF each year from 2023 – 2025 we have developed a projection methodology that considers the size of the ethanol facilities expected to register to produce cellulosic ethanol from CKF, the amount of cellulosic ethanol (vs. starch ethanol) expected to be produced at each facility, and the number of facilities expected to produce cellulosic ethanol each year. We recognize this is a different projection methodology than what EPA has historically used to project the production of liquid cellulosic biofuels. We believe this new projection methodology is appropriate due to the significant differences between the production of a small volume of cellulosic ethanol at an existing corn ethanol production facility and the production of liquid cellulosic biofuel using novel

[627] May 2023 Liquid Cellulosic Biofuel Projections for 2023 – 2025 CBI.
[628] May 2023 Liquid Cellulosic Biofuel Projections for 2023 – 2025 CBI.
[629] Guidance on Qualifying an Analytical Method for Determining the Cellulosic Converted Fraction of Corn Kernel Fiber Co-Processed with Starch. Compliance Division, Office of Transportation and Air Quality, U.S. EPA. September 2022 (EPA-420-B-22-041).

technologies at facilities that are not yet producing fuel. To produce cellulosic ethanol from corn kernel fiber requires very few operational changes at existing ethanol production facilities, and in some cases ethanol producers claim they are already producing ethanol from CKF. In these cases, we would not expect a long ramp-up period to full production of cellulosic biofuel, nor would we expect the type of construction delays or challenges related to the readiness of the production technology that has often hindered the production of other liquid cellulosic biofuels.

The first step in projecting the volumes of cellulosic ethanol produced from CKF in 2023 – 2025 is projecting the size of the ethanol production facilities that will produce this fuel. At this time, we do not have sufficient data that would allow us to identify precisely which ethanol production facilities will produce ethanol from CKF. In the absence of this information, we have projected that the total ethanol production capacity (for both ethanol from corn starch and ethanol from CKF) will be equal to the industry average. As of January 2022 (the most data that were available at the time of the final rule EIA reported that there were 192 ethanol production facilities in the U.S. with a total ethanol production capacity of 17.38 billion gallons, with an average production capacity of approximately 90 million gallons.[630]

The next step in projecting the production of ethanol from CKF is determining the portion of total ethanol production from an ethanol facility is from corn starch versus CKF. Conversations with technology providers intending to use analytical methods consistent with the guidance document suggest that approximately 1.5% of all ethanol produced at these facilities is from CKF.[631] Taken together, these numbers indicate that an average ethanol production facility could be capable of producing approximately 1.35 million gallons of ethanol from CKF per year.

Finally, we projected the number of ethanol facilities that would register as CKF producers each year. To inform these projections we referenced public data from California's LCFS program. This data lists the facilities registered as producers of ethanol from CKF under California's LCFS program, and in nearly all cases also lists the technology the facility is using to produce ethanol from CKF. EPA used this data, together with projections of when various technology providers may be in a position to register facilities as cellulosic biofuel producers under the RFS program to project the number of facilities that would register each year.[632] We projected that the facilities that register in 2023 would produce at 25% of their potential capacity in 2023 (representative of a facility completing the registration process on October 1, 2023, with some facilities registering earlier and other facilities registering later) since we do not expect any facilities will register as cellulosic biofuel producers in the first half of 2023. We projected that the facilities that register in 2024 would produce at 50% of their potential capacity in 2024 (representative of a facility completing the registration process on July 1, 2024, with some facilities registering earlier and other facilities registering later). Our projections of cellulosic ethanol production from CKF from new facilities is summarized in Table 6.1.2-1.

[630] U.S. Fuel Ethanol Plant Production Capacity. EIA. August 2022.
[631] May 2023 Liquid Cellulosic Biofuel Projections for 2023 – 2025 CBI.
[632] For more information on how EPA projected the number of facilities that would register as CKF producers each year see May 2023 Liquid Cellulosic Biofuel Projections for 2023 – 2025 CBI.

Table 6.1.2-1: Projected Production of Ethanol from CKF from New Facilities (million RINs)

New vs. Existing	Number of Facilities	Total Ethanol Production	Potential Cellulosic Ethanol Production	Percent of Potential Production	Total Cellulosic Ethanol Production
2023					
New	16	1,440	21.6	25%	5
2024					
New	39	3,510	52.7	50%	26
Existing	16	1,440	21.6	100%	22
2025					
Existing	55	4,950	74.3	100%	74

In addition to the facilities that we project will produce ethanol from CKF simultaneously with the production of ethanol from corn starch, there are also two facilities that are currently registered to produce ethanol from CKF after first converting the starch to ethanol (sequential production). At this time, we are not aware of any other ethanol facilities that intend to produce ethanol from CKF using this technology. We have projected cellulosic ethanol production from these facilities based on the previous production rates achieved at these facilities and production to date in 2023.[633] Projected production from facilities producing ethanol from CKF sequentially are shown in Table 6.1.2-2. Total projected production of ethanol from CKF each year from 2023 to 2025 are shown in Table 6.1.2-3. We are not projecting the production of any liquid cellulosic biofuel other than ethanol from CKF through 2025.

Table 6.1.2-2: Projected Production from Facilities Producing Ethanol from CKF Sequentially (million RINs)

2023	2024	2025
2	3	3

Table 6.1.2-3: Projected Production of Ethanol from CKF (Million RINs)

	2023	2024	2025
Simultaneous Conversion	5	48	74
Sequential Conversion	2	3	3
Total	7	51	77

6.1.3 Projected Production of RNG used as CNG/LNG

The incentive created by the cellulosic biofuel RIN has led to rapid growth in renewable natural gas use as CNG/LNG since 2014 (See Table 6.1.3-1). In light of this incentive, we believe that renewable natural gas (RNG) used as CNG/LNG can continue to grow under the influence of the RFS standards through 2025. At the same time, there are several market factors that we expect could limit the rate of growth in the production of CNG/LNG from biogas in

[633] More detail on our projections from these facilities can be found in May 2023 Liquid Cellulosic Biofuel Projections for 2023 – 2025 CBI.

future years that must be taken into consideration when projecting volumes. These market factors are discussed in the following paragraphs. Several of these factors, however, are related not to the production of CNG/LNG from biogas, but rather to the consumption of CNG/LNG from biogas.

Table 6.1.3-1: Cellulosic RIN Generation (Million RINs) and Annual Growth Rate for RNG used as CNG/LNG

	2015	2016	2017	2018	2019	2020	2021	2022
D3 RIN Generation	139.9	188.6	240.6	304.2	404.3	503.8	567.8	666.1
Annual Growth Rate	N/A	34.8%	27.6%	26.4%	32.9%	24.6%	12.7%	17.3%

Currently, a significant volume of biogas is produced at landfills and wastewater treatment plants across the U.S.[634] Some of this biogas is currently being flared or used to produce electricity onsite. There are also significant opportunities for increasing the production of biogas from manure and other agricultural residues. Raw biogas from landfills, wastewater treatment facilities, or agricultural digesters must be upgraded before it can be used as transportation fuel in CNG/LNG vehicles, either at on-site fueling stations or transported to fueling stations via the natural gas pipeline network. Biogas that has been upgraded and distributed via a closed, private distribution system is called "treated biogas" while biogas that has been upgraded and distributed via the natural gas commercial pipeline system it is referred to as RNG. Collecting and treating the raw biogas to produce RNG requires a significant capital investment. While the quantity of biogas produced from potentially qualifying sources exceeds the quantity of CNG/LNG used as transportation fuel, much of this biogas is not currently being upgraded to RNG, which is a necessary step to using this biogas in CNG/LNG vehicles.[635]

Along with the incentives provided by the RFS program for the use of biogas as CNG/LNG in the transportation sector, state programs can also provide significant incentives. Since its inception in 2011 California's LCFS program has provided credits for RNG used as CNG/LNG that is used as transportation fuel in California. Since 2014 when RNG used as CNG/LNG was determined to qualify as cellulosic biofuel under the RFS program, the quantity of this fuel used with the incentives of both programs (RFS and California's LCFS) has increased dramatically. It is likely that this rapid expansion was aided by the ability for RNG used as CNG/LNG to generate lucrative credits under both programs and displace the fossil CNG/LNG otherwise being used. As of 2022, however, the LCFS data indicates that the quantity of fossil CNG/LNG generating credits under the LCFS program had decreased to only approximately 13 million diesel gallon equivalents.[636] This suggests that there is little remaining ability for new sources of RNG used as CNG/LNG to displace CNG/LNG derived from fossil-based natural gas in California, however the greater incentives offered for CNG/LNG from sources with a lower carbon intensity could continue to incentivize the production and collection

[634] EPA Landfill Methane Outreach Program Landfill and Project Database, available at https://www.epa.gov/lmop/lmop-landfill-and-project-database.
[635] According to the American Biogas Council, there are currently over 2,200 sites producing biogas in the U.S. (see Biogas Industry Market Snapshot - American Biogas Council, available in the docket). Approximately 860 of these sites use the biogas they produce, and of this total 138 facilities generated RINs for CNG/LNG derived from biogas used as transportation fuel in 2021.
[636] LCFS Data Dashboard, https://www.arb.ca.gov/fuels/lcfs/dashboard/dashboard.htm. For context, in 2021, approximately 190 million diesel gallon equivalents of bio-CNG/LNG generated credits in the LCFS program.

of biogas from these sources. Currently Oregon and Washington have also adopted clean fuels programs, and there are opportunities for RNG used as CNG/LNG to generate financial incentives in these state programs, though the size of the CNG/LNG fleets in these states are much smaller than in California. If additional states adopt programs similar to California's LCFS or Oregon and Washington's Clean Fuels programs, these other state programs could provide additional incentives for the increased production and use of RNG used as CNG/LNG.

Growth of RNG used as CNG/LNG could also potentially be limited by the cost associated with establishing a pipeline interconnect to transport RNG to CNG/LNG fueling stations. Not all CNG/LNG vehicles will be situated such that they can refuel at the location where the biogas is produced and upgraded to RNG. Therefore, getting the RNG to CNG/LNG vehicles requires that it be put into common carrier pipelines. If there are no such pipelines near the source of the biogas, then it can become cost prohibitive and/or require considerable time to put in place a stub pipeline to connect to the common carrier pipeline. While constructing pipelines in such cases is technically possible, the costs of doing so may result in the use of RNG in applications other than CNG/LNG in the transportation sector.

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 RNG used as CNG/LNG used as transportation fuel.[637] However, unlike in the proposed rule and previous annual rules the rate of growth used to project the production of RNG used as CNG/LNG is based on data from 2015 – 2022 (See Table 6.1.3-1) rather than data from the previous 24 months. While the nature of the incentives provided by state programs may be changing and incremental volumes of CNG/LNG will likely be produced at marginally higher costs, we believe the incentives provided by the RFS program, existing and potentially newly adopted state programs, and the extension of the investment tax credit to qualified biogas facilities in the IRA[638] are sufficient to support growth in the production and use of CNG/LNG derived from biogas as the rates observed in previous years. Given the many years of steady growth with the primary exception of 2020 and 2021 when all markets were still being impacted by the economic turmoil brought on by the COVID pandemic, we believe projecting volumes using a growth rate calculated from a longer time period provides a more accurate estimate of potential growth in 2023-2025. The growth rate calculated using this data is 25.0%. The number of RINs generated for CNG/LNG derived from biogas in 2015 and 2022 from which this growth rate is calculated are shown in Table 6.1.3-1.

[637] 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.

[638] Inflation Reduction Act Gives a Boost to Biogas Sector. The National Law Review. Volume XII, Number 279. October 6, 2022.

Table 6.1.3-1: Generation of Cellulosic Biofuel RINs for RNG used as CNG/LNG (million ethanol-equivalent gallons)

RIN Generation (2015)	RIN Generation (2022)	Year-Over-Year Increase
139.9	666.1	25.0%

EPA then applied this 25.0% year-over-year growth rate to the total number of 2022 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 2022), taking into account actual RIN generation as well as RINs retired for reasons other than compliance with the annual volume obligations. Since we are establishing 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 RNG used as CNG/LNG in 2023–2025.

Table 6.1.3-2: 2023–2025 Projection of RNG used as CNG/LNG (million ethanol-equivalent gallons)

D3 RINs generated for CNG/LGN derived from biogas in 2022	666
RINs retired for reasons other than compliance with annual obligations	1
Net RINs generated in 2022	665
Growth rate	25.0%
Projected production of RNG used as CNG/LNG in 2023	831
Projected production of RNG used as CNG/LNG in 2024	1,039
Projected production of RNG used as CNG/LNG in 2025	1,299

In the proposal, EPA had followed the precedent from previous rules and projected the rate of growth of RNG used as CNG/LNG based on the prior 24 months of data. This method of projection had proven fairly reliable. However, in discussions with EPA a number of cellulosic biogas producers highlighted 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.

In considering the appropriate growth rate to use for projecting the production of RNG used as CNG/LNG we considered the annual growth rates each year from 2015 to 2022 (see Table 6.1.3-1). In reviewing these data, it is apparent that the observed rate of growth in RIN generation for RNG used as CNG/LNG was notably lower from 2020 to 2021 than in other years. While 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, it is also likely that the COVID pandemic was a significant factor in the lower observed growth rates observed in 2021 and 2022. At this time we are unable to determine how much of the decrease in the rate of growth of RNG used as CNG/LNG was due to the COVID pandemic vs. the maturation of the industry and limitations on the quantity of these fuels used as transportation fuel (discussed further below). However, given that the rate of increase in 2022 appears to have recovered somewhat, it would appear that the COVID pandemic likely had a significant impact. Given the steady rate of growth over a long period of time and the apparent anomaly in 2021, for this final rule we believe using the full period from 2015 through 2022 likely provides a more accurate projection for 2023-2025.

We then compared the resulting 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).[639] A paper prepared by Bates White for the Coalition for Renewable Natural Gas presented an independent assessment of 1.53, 1.55, and 1.58 billion ethanol-equivalent gallons used in 2023–2025.[640]

Separately, EPA estimated 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 RNG used as CNG/LNG projected to be used in 2023–2025. Thus, the volume of CNG/LNG used as transportation fuel

[639] 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.
[640] *Renewable Natural Gas: Transportation Demand*. Bates White Economic Consulting. February 2, 2022; Updated April 29, 2022.

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 of the production of RNG used as CNG/LNG could exceed these estimates. Even if the production of RNG in 2023–2025 can grow at a higher rate, RIN generation in these years may could still be limited to the quantity of CNG/LNG used as transportation fuel. This may become a more significant constraint in years after 2025 as the volume of RNG used as CNG/LNG approaches the total volume of CNG/LNG used as transportation fuel.

We believe that projecting the production of RNG used as CNG/LNG using the same industry-wide methodology as in recent years but using the data over the full period from 2015-2022 to calculate the growth rate appropriately takes into consideration the significant incentive created by the RFS standards as well as the real world constraints on growth. We believe that applying the resulting 25% year-on-year growth rate takes into both the potential for future growth and the challenges associated with increasing RIN generation from these fuels for 2023-2025. This methodology may not be appropriate to use in the future as the projected volume of RNG used as CNG/LNG 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 RNG used as CNG/LNG is still below the total volume of CNG/LNG that is currently used as transportation fuel.

6.1.4 Projected Rate of Cellulosic Biofuel Production for 2023–2025

After projecting production of cellulosic biofuel from liquid cellulosic biofuels and CNG/LNG derived from biogas, 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 0.84 billion ethanol-equivalent gallons of qualifying cellulosic biofuel will be produced in 2023, 1.09 billion ethanol-equivalent gallons will be produced in 2024, and 1.38 billion ethanol-equivalent gallons will be produced in 2025.

Table 6.1.4-1: Projected Volume of Cellulosic Biofuel in 2023–2025

Projected Volume in 2023 (million ethanol-equivalent gallons)	Projected Volume
Liquid Cellulosic Biofuel	7
CNG/LNG Derived from Biogas	831
Total[a]	840
Projected Volume in 2024 (million ethanol-equivalent gallons)	**Projected Volume[a]**
Liquid Cellulosic Biofuel	51
CNG/LNG Derived from Biogas	1,039
Total[a]	1,090
Projected Volume in 2025 (million ethanol-equivalent gallons)	**Projected Volume[a]**
Liquid Cellulosic Biofuel	77
CNG/LNG Derived from Biogas	1,299
Total[a]	1,380

[a] Rounded to the nearest 10 million gallons.

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 information on a number of factors we consider in projecting the domestic production and net imports of BBD in 2023 – 2025. First, we present the available data on biodiesel and renewable diesel production, import, and use in previous years (Chapter 6.2.1). Next, we assess the current and projected future production capacity for biodiesel and renewable diesel (Chapter 6.2.2), followed by the availability of qualifying feedstocks for biodiesel and renewable diesel production (Chapter 6.2.3). Potential imports and exports of BBD (Chapter 6.2.4), and an analysis of the available data on BBD production, imports, and exports in 2023 (Chapter 6.2.5) are in the following sections. Finally, we describe our assessment of the rate of production and use of qualifying biomass-based diesel biofuel in 2023–2025 based on this information (Chapter 6.2.6), and discuss 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,[641] the extension of the biodiesel tax credit, tariffs on imported biodiesel, biofuel policies in other countries, 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.

[641] Throughout this section 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 2022[642] (million gallons)[a]

	2014[b]	2015[b]	2016	2017	2018	2019	2020	2021	2022
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)	1,701 (-101)	1,616 (-85)
Imported Biodiesel (Annual Change)	130 (–23)	261 (+131)	562 (+301)	462 (–100)	175 (–287)	185 (+10)	209 (+24)	208 (-1)	240 (+32)
Exported Biodiesel (Annual Change)	72 (–5)	73 (+1)	89 (+16)	129 (+40)	74 (–55)	76 (+2)	88 (+12)	91 (+3)	113 (+22)
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)	1,818 (-106)	1,743 (-75)
Domestic Renewable Diesel (Annual Change)	149 (+79)	169 (+20)	231 (+62)	252 (+21)	282 (+30)	454 (+172)	472 (+18)	778 (+306)	1,371 (+593)
Imported Renewable Diesel (Annual Change)	130 (–15)	120 (–10)	165 (+45)	191 (+26)	176 (–15)	267 (+91)	280 (+13)	362 (+82)	320 (-42)
Exported Renewable Diesel (Annual Change)	15 (+10)	21 (+6)	40 (+19)	37 (–3)	80 (+43)	145 (+65)	223 (+78)	241 (+18)	324 (+101)
Total Renewable Diesel (Annual Change)[c]	264 (+154)	268 (+4)	356 (+88)	406 (+50)	378 (–28)	576 (+198)	529 (–47)	899 (+370)	1,367 (+468)
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)	2,720 (+263)	3,123 (+403)

[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 (<20 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,

642 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 6 years all of the net growth has been in renewable diesel volume. By 2022 production and imports of renewable diesel had increased not only in absolute terms (from 264 million gallons in 2014 to 1.36 billion gallons in 2022), but also as a percentage of the BBD pool. In 2022 approximately 44% of all BBD was renewable diesel, while the remaining 56% 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, 2021, and 2022) 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, 64 million gallons,[643] 263 million gallons, and 403 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.

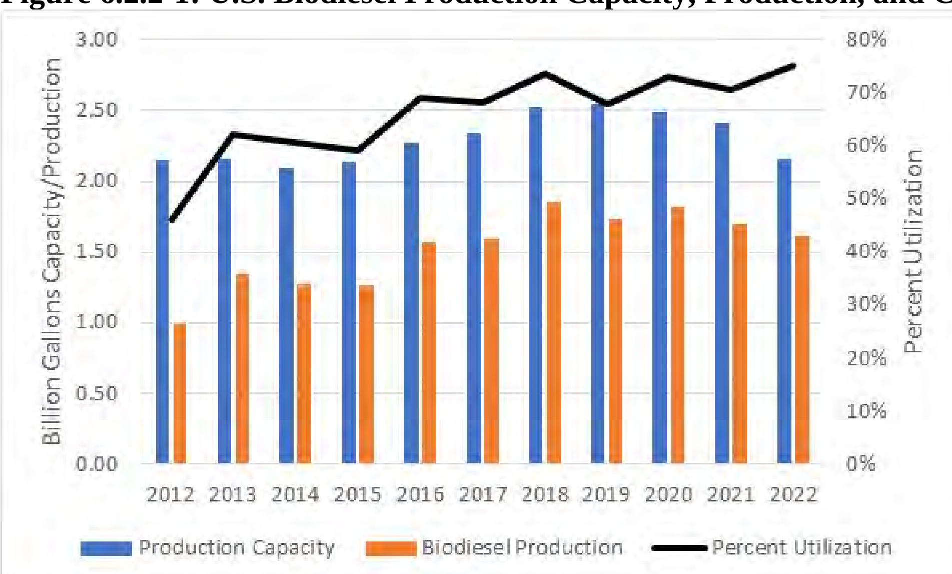
Another important factor highlighted by the historic data is the tariffs imposed by the U.S. on biodiesel imported from Argentina and Indonesia. In December 2017 the U.S. International Trade Commission adopted tariffs on biodiesel imported from Argentina and Indonesia.[644] According to data from EIA,[645] 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.

[643] This is the volume increase in 2020, which was impacted by the COVID pandemic.
[644] "Biodiesel from Argentina and Indonesia Injures U.S. Industry, says USITC," https://www.usitc.gov/press_room/news_release/2017/er1205ll876.htm.
[645] See "EIA Biodiesel Imports".

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.[646] As of December 2022, active biodiesel production capacity has decreased slightly since then, to approximately 2.1 billion gallons.[647] While production of biodiesel has generally increased during this time period, significant excess production capacity remains, with facility utilization remaining at or below 75% through 2022. 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 limit domestic biodiesel production.

Figure 6.2.2-1: U.S. Biodiesel Production Capacity, Production, and Capacity Utilization

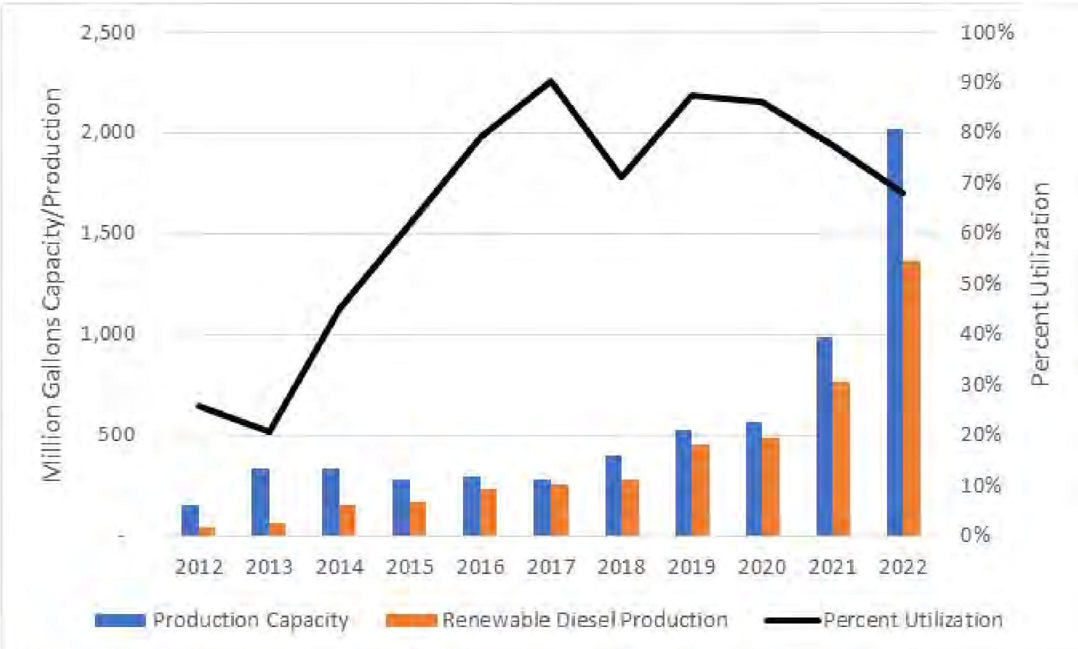


Unlike domestic biodiesel production capacity, domestic renewable diesel production capacity has increased significantly in recent years, from approximately 280 million gallons in 2017 to approximately 2.85 billion gallons in December 2022 (Figure 6.2.2-2).[648] Domestic

[646] Biodiesel production capacity from EIA Monthly Biodiesel Production reports and the EIA Monthly Biofuels Capacity and Feedstock Update. February 2023.
[647] See EIA Monthly Biofuels Capacity and Feedstock Update.
[648] Renewable diesel capacity is based on RFS facility registration data and EIA Monthly Biofuels Capacity and Feedstock Update.

renewable diesel production has increased along with production capacity in recent years, and capacity utilization at domestic renewable diesel production facilities has been high, approximately 80% from 2017-2022. 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 volumes are from EMTS data. Production capacity is from EMTS from 2012–2020 and EIA Monthly Biofuels Capacity and Feedstock Update for 2021 and 2022 when EIA first reported renewable diesel production capacity. Production capacity shown for 2021 and 2022 is the average of the monthly reported production capacities. 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 2025

Facility Name	Location	Capacity (MGY)	Start Date (Actual or Expected)
Bakersfield Renewables[649]	Bakersfield, CA	230	Q2 2023
Marathon Martinez Expansion[650]	Martinez, CA	470	End 2023
Phillips 66 Rodeo Phase 2[651]	Rodeo, CA	680	Q1 2024
Next Renewable Fuels[652]	Port Westward, OR	575	2024
REG Geismar Expansion[653]	Geismar, LA	250	2024
World Energy[654]	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 approximately 2.5 billion gallons per year, increasing total domestic renewable diesel capacity to over 5.5 billion gallons by the end of 2025. This production capacity projection is similar to recent projections of domestic renewable diesel capacity by 2025 from EIA (5.9 billion gallons per year by the end of 2025).[655] However, feedstock limitations (discussed in Chapter 6.2.3) are not expected to support all of these facilities. It is also possible that some of these projects may be delayed or cancelled. Thus, it is unlikely that the domestic renewable diesel production will reach the approximately 5.5 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.

6.2.3 Availability of Biomass-Based Diesel Feedstocks

As EPA considered the rate of production of BBD through 2025, a central and critical factor influencing final volume requirements was our assessment of 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 such feedstocks in future years. A summary of the feedstocks used to produce BBD from 2012 through 2022 is shown in Figure 6.2.3-1.

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649 Cox, John. *Refinery owner hunts for capital to complete past-due conversion project on Rosedale*. Bakerfield.com. November 14, 2022.

650 Id.

651 *Phillips 66 Makes Final Investment Decision to Convert San Francisco Refinery to a Renewable Fuels Facility*. Phillips 66 News Release. May 11, 2022.

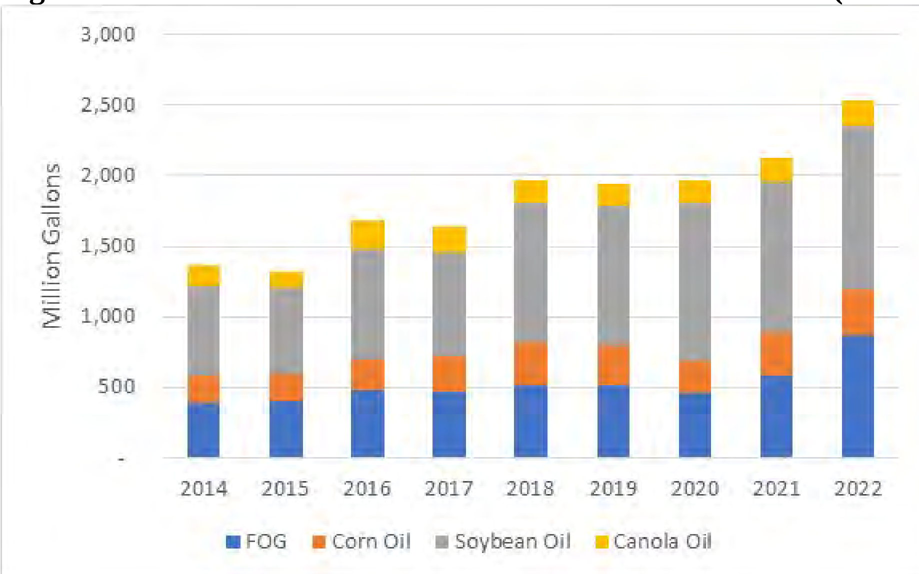
652 Kotrba, Ron. *Oregon approves key permit for $2 billion renewable diesel project*. Biobased Diesel Daily. March 25, 2022.

653 *Renewable Energy Group Breaks Ground on Geismar, Louisiana Renewable Diesel Expansion and Improvement Project*. Renewable Energy Group Website. https://www.regi.com/resources/press-releases/renewable-energy-group-breaks-ground-on-geismar-louisiana-renewable-diesel-expansion-and-improvement-project.

654 *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. https://www.airproducts.com/news-center/2022/04/0422-air-products-and-world-energy-sustainable-aviation-fuel-facility-in-california.

655 Domestic Renewable Diesel Capacity Could More Than Double Through 2025. U.S. Energy Information Administration. Today in Energy. February 2, 2023.

Figure 6.2.3-1: Feedstocks Used To Produce BBD in the U.S. (2014-2022)[656]



Domestic BBD production from fats, oils, and greases (FOG) in the U.S. has generally increased from 2014 through 2022 at an average annual rate of approximately 50 million gallons per year. These feedstocks are generally by-products of other industries. Assessments submitted by commenters rule generally agree that the domestic supply of these feedstocks will increase only slightly in future years.[657] 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 2022. The most significant increases in the volume of BBD produced from distillers corn occurred 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 – 350 million gallons per year since 2017. Total production of distillers corn oil in the U.S. in 2021 was approximately 2 million tons,[658] or enough corn oil to produce about 530 million gallons 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.[659] It is also possible that domestic production of distillers corn oil could increase in

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[656] Based on EMTS data

[657] For example, see "The Outlook for Increased Availability & Supply of Sustainable Lipid Feedstocks in the U.S. to 2025," LMC International. Submitted by Clean Fuels Alliance America (EPA-HQ-OAR-2021-2021-0427-0805).

[658] USDA Grain Crushings and Co-Products Production 2021 Summary. March 2022. https://www.nass.usda.gov/Publications/Todays_Reports/reports/cagcan22.pdf.

[659] For a discussion of backfilling when oil is removed from dried distillers grains, see 83 FR 37735 (August 2, 2018).

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 in 2016 to a low of approximately 120 million gallons in 2015. Production of BBD from canola oil averaged approximately 160 million gallons each year from 2018 to 2022. 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.[660] Canola oil production has ranged between 1.5 and 2.0 billion pounds from 2013/2014 and 2021/2022.[661] 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, was imported in 2020/2021. A pathway that allows for the generation of RINs for renewable diesel produced from canola oil was also finalized in December 2022. This new pathway could increase demand for canola oil for biofuel production.

In comments on the proposed rule, several commenters noted recent announcements of new or expanding canola crush capacity in Canada. These commenters stated that this new crush capacity would result in additional canola oil production that could be available to U.S. biofuel producers. According to the Canola Council of Canada, since 2021 companies have announced five major investments in expanded canola crushing capacity, together which would increase total canola crushing capacity in Canada by approximately 6.7 million metric tons by 2025.[662] One of these facilities has since canceled their plans, however the remaining capacity expansions appear to be on track to complete construction by 2025. While it is unlikely that the entire increase in canola oil production from this additional crushing capacity will be available to U.S. biofuel producers due to demand from other markets (including Canadian biofuel producers) we expect that increasing quantities of canola oil from Canada will be available for U.S. domestic biodiesel and renewable diesel production in 2023 – 2025 (see Chapter 6.2.6 for more details on our projection of the availability of imported canola oil to domestic biofuel producers).

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 2013/2014 agricultural marketing year to approximately 10.3 billion pounds in the 2021/2022 agricultural marketing year.[663] 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 40% in 2021/2022. As a point of reference, if all the soybean oil produced in the

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[660] U.S. Canola oil production data sourced from USDA's Oil Crops Yearbook. https://www.ers.usda.gov/data-products/oil-crops-yearbook.
[661] Id.
[662] "The Oilseed Processing Industry." Canola Council of Canada.
[663] U.S. Soybean oil production and use data sourced from USDA's March 2023 Oil Crops Yearbook. https://www.ers.usda.gov/data-products/oil-crops-yearbook. The agricultural marketing year for soybeans runs from September to August.

U.S. in 2021/2022 (25 billion pounds) were used to produce BBD, this quantity of feedstock could be used to produce approximately 3.4 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.

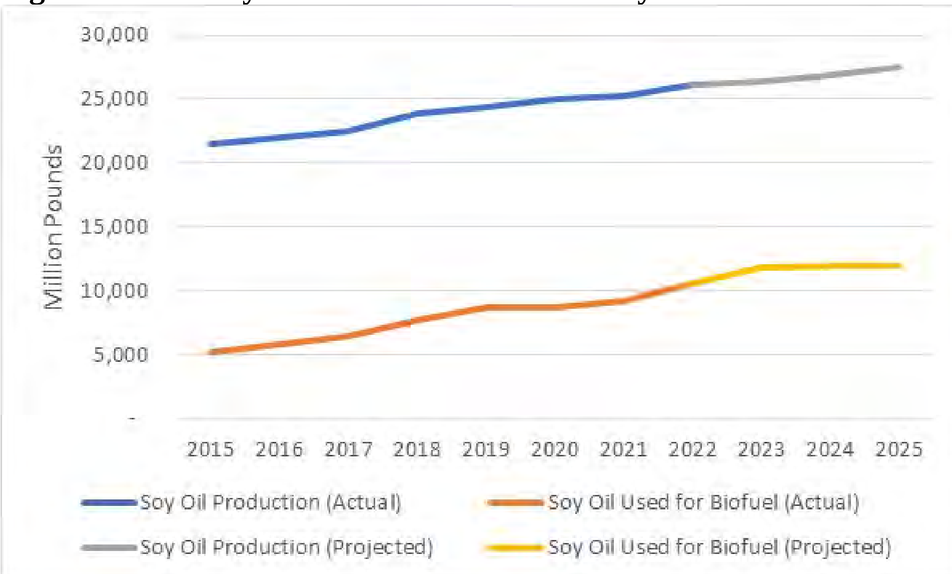
Additional soybean oil production in future years could come from several sources. The first potential source of additional soybean oil is increased crushing of soybeans in the U.S. Soybean crushing is the process by which whole soybeans are converted into soybean oil and soybean meal. The percentage 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.[664] Most of the rest of the whole soybeans are exported to foreign countries, where the beans are then crushed to produce soybean meal and soy oil for their own markets.

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 of 65.9 million tons (approximately 2.2 billion bushels) in the 2021/2022 agricultural marketing year.[665] There have also been numerous announcements of investments to increase domestic soybean crush capacity, both through the construction of new facilities as well as the expansion of existing facilities. Increasing the domestic soybean crushing capacity is expected to result in increased soybean oil production in the U.S. If the increased domestic crushing capacity results in reduced exports of whole soybeans (rather than increased soybean production) this increased soybean oil production could be achieved with little impact on overall U.S. soybean production.

The USDA Agricultural Projections to 2032 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 1.3 billion pounds from 2022 (26.2 billion pounds) to 2025 (27.5 billion pounds).[666] If this entire increase in soybean oil production were used to produce biodiesel or renewable diesel, it would result in an increase of approximately 170 million gallons of biofuel from 2022 to 2025, or an increase of approximately 60 million gallons per year. These projections, however, assume that the RFS volume requirements stay constant at 2022 levels in all future years. Absent increased demand for soybean oil for biofuel production domestic, soybean crush, and by extension domestic soybean oil production, is primarily driven by increasing demand for soybean meal from the livestock industry. These projections are therefore not likely representative of potential domestic soybean oil production with incentives for increasing biodiesel and renewable diesel in place through 2025. Perhaps most importantly, these projections do not appear to account for the significant investments that have been made to increase domestic soybean oil production through 2025.

[664] U.S. Soybean crushing data sourced from USDA's Oil Crops Yearbook. https://www.ers.usda.gov/data-products/oil-crops-yearbook.
[665] USDA's Oil Crops Yearbook (March 2023).
[666] USDA Agricultural Projections to 2032. February 2023. 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 0.75 and production in the second agricultural marketing year (e.g., 2023/2024 for the 2023 price) by 0.25.

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 comments on the proposed rule, many stakeholders stated that EPA had significantly under-projected the potential for domestic soybean oil production in 2023 – 2025. These commenters generally cited the large number of announcements of investment in increasing soybean crush capacity. The National Farmers Union identified over 24 major expansions or new soybean crushing facilities that are announced or underway.[667] The American Soybean Association projected that the increase in domestic soybean oil production from 2023 – 2025 would be sufficient to produce approximately 700 million gallons of biodiesel and renewable diesel.[668] The Clean Fuels Alliance America submitted a study conducted by LMC international that found that the projected growth in soybean oil production in the U.S. from 2021 – 2025 would be sufficient to produce approximately 750 – 800 million gallons of biodiesel and renewable diesel.[669] While there are some slight variations in these estimates, the data submitted by commenters demonstrates that domestic soybean oil production is likely to increase significantly through 2025.

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 2021/2022 agricultural marketing year approximately 10% of the soybean oil produced in the U.S. was exported.[670] Soybean oil exports in 2021/2022 are estimated at approximately 1.7 billion pounds, or enough soybean oil to produce approximately 225 million gallons of biodiesel or renewable diesel.[671] Soybean oil imports have been relatively small (300–400 million pounds)[672] in recent years,

[667] EPA-HQ-OAR-2021-0427-0595.
[668] EPA-HQ-OAR-2021-0427-0579.
[669] EPA-HQ-OAR-2021-0427-0805.
[670] USDA Economic Research Service. *Oil Crops Data: Yearbook Tables*. March 2023.
[671] Id.
[672] Id

likely due to the tariff on soybean oil imports.[673] 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 February 2023 WASDE report from USDA project that global production of vegetable oils will be approximately 204 million metric tons in the 2022/2023 agricultural marketing year.[674] This quantity of vegetable oil, if converted to fuel, would result in approximately 59 billion gallons of biodiesel and/or renewable diesel. The vast majority of this is used for food and other purposes around the world and could not be readily used to supply advanced biodiesel and renewable diesel to the U.S.[675] 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. In comments on the proposed rule, stakeholders representing the food and pet food manufacturing industries opposed increasing the volume requirements for biodiesel and renewable diesel due to concerns that increased demand for biofuel production would negatively impact the supply of animal fats and vegetable oils to other markets. Some of these commenters cited recent high prices for vegetable oils as evidence of increasing competition for these feedstocks. 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.[676] In 2021/2022 soybean oil prices increased to $0.73 per pound.[677] Soybean oil prices reached a high of approximately $0.87 per pound in April 2022, before falling to approximately $0.62 per pound in March 2023.[678] Soybean oil prices are projected by USDA to decrease from 2022/2023 ($0.69 per pound) through 2025/2026 ($0.47 per pound).[679]

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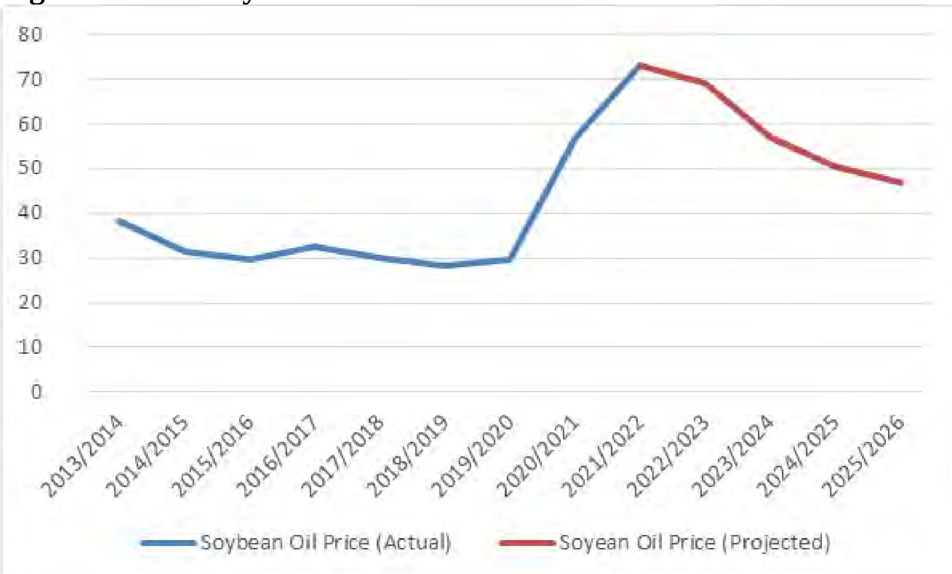
[673] Harmonized Tariff Schedule of the United States (2020) Revision 19.
[674] United States Department of Agriculture World Agricultural Supply and Demand Estimates. February 8, 2023.
[675] These reasons include the demand for vegetable oil in the food, feed, and industrial markets both domestically 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.
[676] USDA Economic Research Service. *Oil Crops Data: Yearbook Tables*. March 2023.
[677] Id.
[678] Nasdaq Soybean Oil Price. July 14, 2022. https://www.nasdaq.com/market-activity/commodities/zl.
[679] USDA Agricultural Projections to 2032. February 2023.

Figure 6.3.2-3: Soybean Oil Price



Actual data from USDA Oil Crops Yearbook; Projected data from USDA Agricultural Projections to 2032

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 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).[680] At the same time, palm oil production in Malaysia was impacted by flooding caused by a typhoon.[681] Recently Argentina is experienced its worst drought in decades, with soybean production expected to fall well below historical levels.[682]

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 increases in the availability of FOG and distillers corn oil, consistent with historical trends. We expect increasing volumes of canola oil imported from Canada will be available to U.S. biofuel producers as canola crushing capacity expands through 2025. Finally, we expect significant increases in domestic soybean oil production from increased soybean crushing capacity in the U.S. from 2023 – 2025. Taken together, these projected increases in feedstock production are expected to enable significant growth in renewable diesel production through 2025.

6.2.4 Imports and Exports of Biomass-Based Diesel

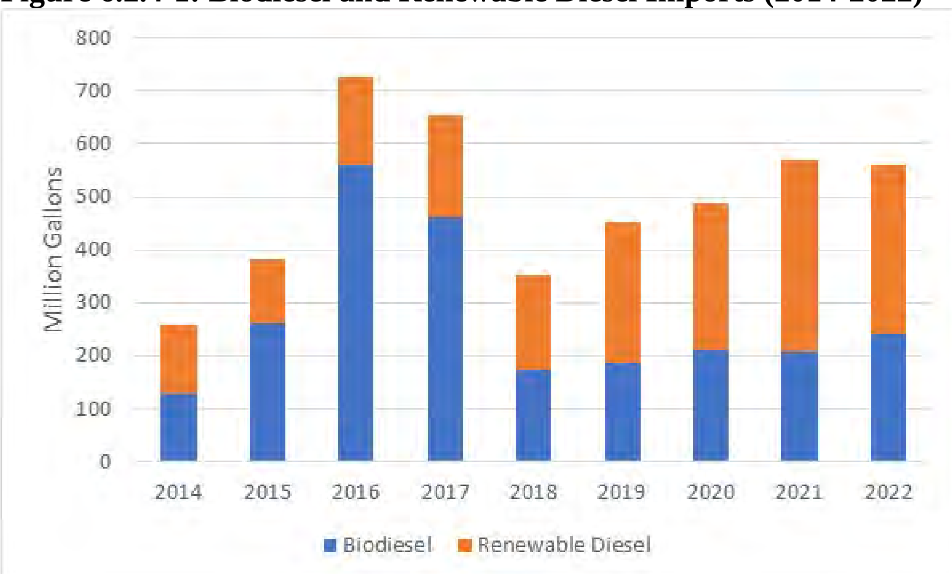
In evaluating the likely rate of production of BBD through 2025 we also examined BBD imports and exports in previous years. While imports and exports of BBD may not directly impact the rate of production of BBD in the U.S., they do impact the volume of these fuels

[680] Wilson, Nick. *Oil Prices Surge – Vegetable Oil That Is*. Marketplace.org. February 17, 2022.
[681] Id.
[682] Sigal, L. and Raszewski, E. *Argentina's 'unprecedented' drought pummels farmers and economy*. Reuters. March 9, 2023.

available to obligated parties. We therefore think that the volume of these fuels that may be 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.[683] These tariffs were subsequently confirmed in April 2018.[684] Since the time the preliminary tariffs were announced, EIA has not reported any biodiesel imported from these countries.[685] 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 2018-2022.

Figure 6.2.4-1: Biodiesel and Renewable Diesel Imports (2014-2022)



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.[686] We expect that, as the carbon intensity

683 82 FR 40748 (August 28, 2017).
684 83 FR 18278 (April 26, 2018).
685 See EIA data on biodiesel imports by country, https://www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_EPOORDB_im0_mbbl_a.htm.
686 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

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.

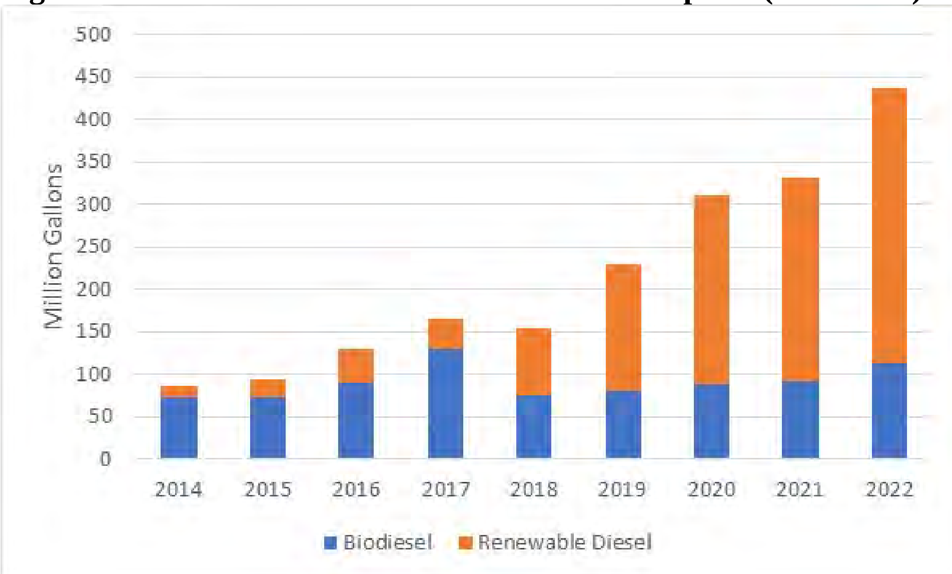
Exports of RIN generating biodiesel, based on EMTS data, have been fairly consistent since 2014, generally ranging between 70 and 130 million gallons per year. According to EMTS data, renewable diesel exports increased with domestic renewable diesel production, reaching over 300 million gallons in 2022. 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.[687] 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. The U.S. tax credit for biodiesel and renewable diesel applies to fuel either used or produced in the U.S. Thus, 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.

renewable diesel were consumed in the U.S. in 2021, including both renewable diesel that generated BBD RINs and advanced RINs.

[687] Tuttle, Robert. *Canada Releases California-Style Fuel Rules to Cut Emissions*. Bloomberg, June 29, 2022.

Figure 6.2.4-2: Biodiesel and Renewable Diesel Exports (2014-2022)



Biodiesel and renewable diesel exports based on data from EMTS

6.2.5 Biomass-Based Diesel Supply in 2023

In considering the projected rate of production and use of BBD in 2023 – 2025 it is also relevant to consider the available BBD production and import data for BBD to date for 2023. At the time the analyses for this rulemaking were completed EPA had RIN generation data for the first three months of 2023 (January – March). These data are summarized in Table 6.2.5-1.

Table 6.2.5-1: BBD Production, Import, and Export Data (January – March 2023) (Million RINs)

	January	February	March	Total
Domestic BBD	422.3	408.1	489.1	1,319.6
Importer/Foreign Generator BBD	100.3	106.2	129.8	336.3
Exports	N/A	N/A	N/A	134.1
Total RIN Supply	N/A	N/A	N/A	1,521.8

While RIN generation and retirement data for the first three months of 2023 are not determinative of RIN generation and retirement though the remainder of the year, we can use this data to inform the supply of BBD in 2023. The simplest way to project BBD RIN supply in 2023 using this data is to multiply the total RIN supply from the first quarter of the year by 4. This would indicate that the expected supply of BBD in 2023 would be approximately 6.1 billion RINs. This projection methodology, however, ignores the observed seasonality in BBD RIN generation. An alternative methodology to use the available data to project the BBD RIN supply in 2023 that takes this seasonality into account is to compare RIN generation in the first 3 months of 2023 to RIN generation during the first 3 months of 2022. From this data we can calculate a percentage increase (or decrease) that can be applied to the total BBD RIN supply in 2022 to project the total BBD RIN supply in 2023. These calculations, and the resulting projecting of BBD RIN supply in 2023 are shown in Table 6.2.5-2.

Table 6.2.5-2: Projected BBD Supply for 2023 Based on Q1 20233 Data (Million RINs)

<table>
<tr><td colspan="20">Extrapolating Q1 Production</td></tr>
<tr><td colspan="5">RIN Generation (Jan. – Mar. 2023)</td><td colspan="5">RINs Retired for Exports (Jan. – Mar. 2023)</td><td colspan="5">RIN Generation (Jan. – Mar. 2023)</td><td colspan="5">BBD RIN Supply (2023) - Projected</td></tr>
<tr><td colspan="5">1,656</td><td colspan="5">134</td><td colspan="5">1,522</td><td colspan="5">6,088</td></tr>
<tr><td colspan="20">Projection based on Growth from Q1 2022 to Q1 2023</td></tr>
<tr><td colspan="4">RIN Generation (Jan. – Mar. 2022)</td><td colspan="4">RIN Generation (Jan. – Mar. 2023)</td><td colspan="4">Percent Change</td><td colspan="4">BBD RIN Supply (2022)</td><td colspan="4">BBD RIN Supply (2023) - Projected</td></tr>
<tr><td colspan="4">1,241</td><td colspan="4">1,656</td><td colspan="4">+33.4%</td><td colspan="4">4,956</td><td colspan="4">6,613</td></tr>
</table>

In our analyses for this final rule we projected that the market would supply approximately 6.2 billion BBD RINs to meet the implied volumes for non-cellulosic advanced biofuel (5.1 billion RINs) and the volume of BBD needed to make up for the shortfall in the supply of conventional renewable fuel (approximately 1.4 billion gallons, including the supplemental volume requirement) from the proposed rule, after accounting for the projected supply of other non-cellulosic advanced biofuels (290 ethanol-equivalent gallons).[688] Data from the first three months of 2023 indicate that the market is on track to supply this volume of BBD in 2023. These data also indicate that both domestic production and imports have increased in the first three months of 2023 relative to the same time period in 2022. On a percentage basis imports have increased at a slightly higher rate (36%) than domestic production of BBD (33%). Further, while we do not have data on the quantity of BBD produced domestically from imported feedstocks, available data and news reports indicate that imports of soybean oil,[689] canola oil,[690] and FOG[691] have all increased in 2023 relative to previous years. These observed increases in imported BBD and imported feedstocks that can be used to produce BBD are consistent with our analysis of available BBD feedstocks presented in Chapters 6.2.3 and 6.2.6, which indicated that opportunities for increased production of BBD from *domestic* feedstocks in 2023 are limited.

6.2.6 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.

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688 See Chapter 3 for more information on our projection of the candidate volumes for this rule.
689 USDA FAS Soybean Oil Import Data.
690 USDA FAS Canola Oil Import Data.
691 Xu, C., and Chipman, K. *China's Used Cooking Oil is Starting to Clean Up Dirty US Diesel.* Bloomberg. February 28, 2023.

We projected the domestic production and net imports of BBD separately by fuel type (biodiesel and renewable diesel) and feedstock. Our projections of biodiesel production from all feedstocks and renewable diesel production from FOG and distillers corn oil are based on linear regressions of the quantities of these fuels supplied in previous years. We expect that changes in the supply of these fuels will generally follow the trends observed in previous years. Our projections of the production and net import of these fuels are presented in Chapter 6.2.6.1.

For two types of BBD, renewable diesel produced from soybean oil and canola oil, we do not believe that the historical data provides a good indication of the future production and net import of these fuels. Rather, we anticipate that the production and net imports of these fuels will increase beyond what would be expected based solely on the historical data due to projected increases in the availability of domestic soybean oil and imported canola from Canada available for biofuel production. Our projections of the production and net imports of these fuels are based on our projections of the increases in the quantity of North American soybean oil and canola oil available to U.S. biofuel producers in 2023 – 2025. These projections are described in Chapter 6.2.6.2.

After projecting the production and net imports of BBD as described above, we next compared the projected volumes to the volume of BBD we estimate would be needed to meet the proposed RFS volumes for 2023 – 2025. The resulting projected volumes are significantly less than the volume of BBD we project would be needed to meet the proposed RFS volumes for 2023, slightly less than the proposed volumes for 2024, and significantly higher than the proposed volumes for 2025. This implies that in 2023 and to a lesser extent in 2024 the market would likely need to increase BBD production by diverting feedstocks from existing uses or rely on additional volumes of imported BBD and/or feedstocks to produce BBD to meet the proposed RFS volumes. Available data from January – March 2023 indicates that the market is on track to supply the volume of BBD we project would be needed to satisfy the proposed RFS volume requirements in 2023. This data is discussed in Chapter 6.2.6.3.

Finally, Chapter 6.2.6.4 presents our projections of BBD production and net imports in 2023 – 2025. These volumes include the BBD we project would be supplied in these years based on the historical data and projections of increased soybean oil and canola oil production in North America and the additional volumes of BBD from imports and/or imported feedstocks that are being supplied to U.S. markets based on data from January – March 2023.

6.2.6.1 Projected Supply of Biodiesel and Renewable Diesel Based on Historical Data

To project the production and net imports of biodiesel from all feedstocks and renewable diesel from distillers corn oil and FOG, we used a linear regression based on the quantities of these fuels supplied from 2018–2022. As discussed in Chapter 6.2.3, we expect limited increases in the availability of corn oil and FOG for biofuel production in future years, as these feedstocks are primarily by-products of other industries. While we do project significant increases in the production of soybean oil and canola oil in North America from 2023 – 2025, most of the increases in the quantity of these feedstocks available for biofuel production will be used to produce renewable diesel rather than biodiesel. We therefore believe that regressions based on past data are appropriate to use to project the future production and net imports of these fuels.

The domestic production and net imports of these fuels from 2018–2022, 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 6.2.6-1. The projected volumes of these fuels, using the equations from Table 6.2.6-1, are shown in Table 6.2.6-2.

Table 6.2.6-1: Domestic Production and Net Imports of BBD (2016–2022; million gallons)

Fuel	Feedstock	2018	2019	2020	2021	2022	Equation
Biodiesel	Canola Oil	214	223	264	269	267	15.2X – 30,419
Biodiesel	DCO	255	210	181	196	130	-26.2X + 53,108
Biodiesel	FOG	433	375	345	368	346	-18.0X + 36,690
Biodiesel	Soybean Oil	1,041	1,006	1,113	954	995	-14.5X + 30,354
Renewable Diesel	DCO	59	78	61	115	209	19.7X – 39,610
Renewable Diesel	FOG	304	443	421	605	859	85.0X – 171,160

Table 6.2.6-2: Projected Domestic Production and Net Imports of BBD (2023-2025; million gallons)

Fuel	Feedstock	2023	2024	2025
Biodiesel	Canola Oil	292	307	323
Biodiesel	DCO	116	89	63
Biodiesel	FOG	321	202	285
Biodiesel	Soybean Oil	982	968	953
Renewable Diesel	DCO	205	239	272
Renewable Diesel	FOG	905	1,032	1,160

6.2.6.2 Projected Supply of Renewable Diesel Based on North American Feedstock Growth

To project domestic production and net imports of renewable diesel produced from soybean oil and canola oil we used a different methodology. This is partially due to the fact that there has been no discernable trend in the use of soybean oil and canola oil for renewable diesel production from 2018–2022. More importantly, however, we expect that the production of these fuels in future years will primarily be dependent on the availability of feedstock, and the projected increases in soybean and canola oil in the U.S. and Canada (discussed in Chapter 6.2.3) indicate that the availability of these feedstocks in future years will increase significantly through 2025 due to investments in soybean and canola crush capacity, and therefore is unlikely to follow historic trends.

Our projections of renewable diesel produced from soybean oil and canola oil are primarily based on our projections of increased soybean oil and canola oil production in the U.S. and Canada. To project increases in soybean oil available for renewable diesel production we started with projections of the increase in soybean oil crush capacity from the American Soybean

Association.[692] In their comments on the proposed rule, the American Soybean Association suggested a methodology for estimating the annual increase in soybean crush based on the projected increase in crush capacity. They suggested that because new crush capacity may come online part way through the year that the practical crush capacity in any given year could be estimated by averaging the available crush capacity at the end of the year with the available crush capacity in the previous year.[693] They further suggested that the practical crush capacity be estimated at 92% of the listed nameplate capacity, and assuming each facility operates 350 days per year.[694] We used these recommended methodologies to project the increase in soybean crush each year from 2023 – 2025 over the total soybean crush in 2022.

After projecting the increase in soybean crush each year over 2022 levels, we next projected how the increase in crush capacity would affect the availability of soybean oil to renewable diesel producers. We first calculated the total increase in soybean oil production associated with the increase in soybean crush using the average yield of soybean oil per bushel of soybeans according to data from USDA (11.7 lbs soybean oil per bushel soybeans crushed).[695] We next projected that 80% of the increase in soybean oil production would be available to renewable diesel producers, while 20% of the increased soybean oil production would be used in other non-biofuel markets. Finally, we projected the quantity of renewable diesel that could be produced from the increase in soybean oil production. These calculations, and the resulting projections in the volume of renewable diesel that could be produced in 2023 – 2025 (relative to the volume produced in 2022) are shown in Table 6.2.6-3.

Table 6.2.6-3: Projected Renewable Diesel Growth Based on Increased Soybean Oil Production

	2022	2023	2024	2025
Additional Soybean Crush Capacity (million bushels)	59.1	94.1	276.9	142.4
Practical Crush Capacity Increase (million bushels)	N/A	76.6	185.5	209.6
Soybean Oil Production Increase (million lbs)	N/A	896	2,170	2,453
Soybean Oil Available to RD Producers (million lbs)	N/A	717	1,736	1,962
Projected Increase in RD Production from Soybean Oil – Annual (million gallons)	N/A	94	228	258
Projected Increase in RD Production from Soybean Oil – Cumulative (million gallons)	N/A	94	323	581

To project increases in the volume of renewable diesel from canola oil imported from Canada we used a similar methodology. We first projected increases in nameplate crush capacity each year based on public announcements of facility expansions and new canola crush facilities. We next estimated a practical crush capacity increase using the average of the current year and

[692] American Soybean Association projections of soybean crush capacity in 2023 – 2025 were provided to EPA by USDA.
[693] See comments from the American Soybean Association (EPA-HQ-OAR-2021-0427-0579).
[694] Id.
[695] USDA Economic Research Service. *Oil Crops Data: Yearbook Tables*. March 2023.

previous year crush capacity and the factors for production based on nameplate capacity (92%) and operational days (350 per year) described in our assessment of soybean oil production. We then projected the increase in canola oil production based on the average yield of canola oil per ton of canola crushed (0.43 metric tons of oil per metric ton of canola seeds crushed). Due to the high demand for canola oil in non-biofuel markets and demand for canola oil from Canadian biofuel producers we estimated that 50% of the increase in canola oil production in Canada would be available to U.S. renewable diesel producers. Finally, we estimated the quantity of renewable diesel that could be produced from the increases in canola oil production. These calculations, and the resulting projections in the volume of renewable diesel that could be produced in 2023 – 2025 (relative to the volume produced in 2022) are shown in Table 6.2.6-4.

Table 6.2.6-4: Projected Renewable Diesel Growth Based on Increased Canola Oil Production

	2022	2023	2024	2025
Additional Canola Crush Capacity (million metric tons)	0	0	4.6	1.1
Practical Crush Capacity Increase (million metric tons)	N/A	0	2.0	2.5
Canola Oil Production Increase (million metric tons)	N/A	0	0.87	1.08
Canola Oil Available to RD Producers (million metric tons)	N/A	0	0.44	0.54
Projected Increase in RD Production from Canola Oil – Annual (million gallons)	N/A	0	126	156
Projected Increase in RD Production from Canola Oil – Cumulative (million gallons)	N/A	0	126	283

After projecting increases in renewable diesel production from domestic soybean oil production and imported canola oil from Canada we added these volumes to the volume of these fuels produced or imported in 2022. These numbers, shown in Table 6.2.6-5, reflect our projections of potential renewable diesel production and net imports in 2023 – 2025 from growth in available quantities of domestic soybean oil and canola oil imported from Canada.

Table 6.2.6-5: Renewable Diesel Production and Net Imports from Soybean Oil and Canola Oil Based on North American Feedstock Production Growth (million gallons)

	2022	**2023**	**2024**	**2025**
Renewable Diesel from Domestic Soybean Oil	293	387	616	874
Renewable Diesel from Canadian Canola Oil	0	0	126	283

6.2.6.3 Additional Supply of BBD Imports and Imported Feedstocks

The volumes shown in Tables 6.2.6-2 and 6.2.6-5 show our projections of domestic production and net imports of biodiesel and renewable diesel based on the historic trends (for all biodiesel and renewable diesel from corn oil and FOG) and expected increases in the production of soybean oil and canola oil in North America (for renewable diesel from soybean oil and canola oil). As a point of comparison, we next considered how the total volume of BBD that results from these projections compares to the volume of BBD that we projected would be needed to satisfy the implied non-cellulosic advanced biofuel and conventional renewable fuel volumes from the proposed rule. This comparison is shown in Table 6.2.6-6. Because proposed RFS volumes for 2023 – 2025 are in RINs (rather than physical gallons) we show the number of RINs we project would be generated for these fuels, rather than the number of physical gallons, in this comparison.

Table 6.2.6-6: Projected Production and Net Imports of BBD from North American Feedstock Growth (million RINs)

	2023	2024	2025
Biodiesel from Canola Oil	438	461	484
Biodiesel from DCO	173	134	95
Biodiesel from FOG	481	454	427
Biodiesel from Soybean Oil	1,473	1,451	1,430
Renewable Diesel from Canola Oil	0	215	481
Renewable Diesel from DCO	348	406	484
Renewable Diesel from FOG	1,539	1,755	1,972
Renewable Diesel from Soybean Oil	659	1,047	1,486
Total BBD Supply	5,111	5,923	6,836
Volume Need to Meet Proposed Volumes	6,215	6,205	6,481
Difference	-1,104	-282	+355

This data demonstrates that with the projected growth in these fuels from 2023 – 2025 based on the historical data and projected growth in North American canola and soybean oil production, the projected BBD supply would be significantly less than what we project will be needed to meet the proposed volumes for 2023 and 2024, but significantly greater than what would be need in 2025.

However, as discussed in Chapter 6.2.5, data from January – March 2023 indicates that the market is nevertheless on track to supply the volumes of BBD necessary to meet the proposed RFS volumes for 2023. This is a strong indication that the market is capable of supplying additional volumes of BBD to the U.S. beyond those projected in Chapters 6.2.6.1 and 6.2.6.2. As the volumes presented in Table 6.2.6-6 represent all of the projected increases relative to 2022 based on historic trends (for all biodiesel and renewable diesel produced from DCO and FOG) and the projected increase in North American canola oil and soybean oil (for renewable diesel produced from canola oil and soybean oil).The data from January – March 2023 also indicates that the most likely source of this additional volume currently being used in 2023 is imported BBD and imported feedstocks (beyond canola oil imported from Canada from expanded crush capacity) that can be used to produce BBD.

To reflect the data on BBD supply from the first quarter of 2023 in our projections of the production and net imports of BBD, we have increased our projections of the production and net imports of renewable diesel in 2023 and 2024 such that the total volume of biodiesel and renewable diesel is equal to the volumes projected to be needed to meet the proposed RFS volumes for these years. We projected that any additional imports of BBD and/or feedstocks used to produce BBD will result in greater volumes of renewable diesel available to the U.S.

market, both because of the rapidly expanding renewable diesel production capacity (discussed in Chapter 6.2.2) and the ease of access of renewable diesel to the California, Oregon, and Washington fuels markets where LCFS credits provide an added incentive. While we do not yet have sufficient data to determine precisely which feedstocks are being used to produce the BBD and/or its feedstocks imported to the U.S. in 2023, available data and news reports suggest that imports of soybean oil, canola oil, and FOG have all increased in 2023. Therefore, for the purposes of the analyses in this document projected that the feedstocks used to produce this renewable diesel would be equally divided between soybean oil, canola oil, and FOG. Because, as discussed in Preamble Sections 3 and 6, we believe that fuels produced from North American feedstocks likely have greater benefits and fewer negative environmental impacts that fuels produced from foreign feedstocks. We therefore did not project additional renewable diesel imports or renewable diesel produced from imported feedstocks for 2025.

The additional volumes of imported renewable diesel and renewable diesel produced from imported feedstocks projected for 2023 – 2025 are shown in Table 6.2.6-7. The decreasing volumes of renewable diesel produced from foreign feedstocks from 2023 – 2025 reflect the projected increases in BBD feedstocks produced in North America and our desire to focus the future growth of biodiesel and renewable diesel production on these feedstocks.

Table 6.2.6-7: Additional Supply of Renewable Diesel from Foreign Feedstocks (million RINs/gallons)

	2023		**2024**		**2025**	
	RINs	Volume	RINs	Volume	RINs	Volume
Total Renewable Diesel	1,103	649	282	166	0	0
Renewable Diesel from Soybean Oil	368	216	94	55	0	0
Renewable Diesel from Canola Oil	368	216	94	55	0	0
Renewable Diesel from FOG Oil	368	216	94	55	0	0

6.2.6.4 Projected BBD Production and Net Imports

A summary of all of the projected volumes of BBD from 2023–2025 is shown in Tables 6.2.6-8 (in million gallons) and 6.2.6-9 (in million RINs), along with the volumes of these fuels supplied in 2022 for context. This table includes both volumes of biodiesel and renewable diesel projected to be produced from North American feedstocks, and feedstocks from other foreign countries.

Table 6.2.6-8: Projected Domestic Production and Net Imports of Renewable Diesel Produced from Soybean Oil (million gallons)

Year	2022	2023	2024	2025
Biodiesel				
Canola Oil	267	292	307	323
DCO	130	116	89	63
FOG	346	321	303	285
Soybean Oil	995	982	968	953
Renewable Diesel				
Canola Oil	0	216	182	283
DCO	209	205	239	272
FOG [a]	859	1,122	1,088	1,160
Soybean Oil	293	604	671	874
BBD Total				
All Feedstocks [a]	3,099	3,857	3,846	4,212

[a] Includes 14 million gallons of Jet Fuel projected to be supplied each year from 2023–2025

Table 6.2.6-8: Projected Domestic Production and Net Imports of Renewable Diesel Produced from Soybean Oil (million RINs)

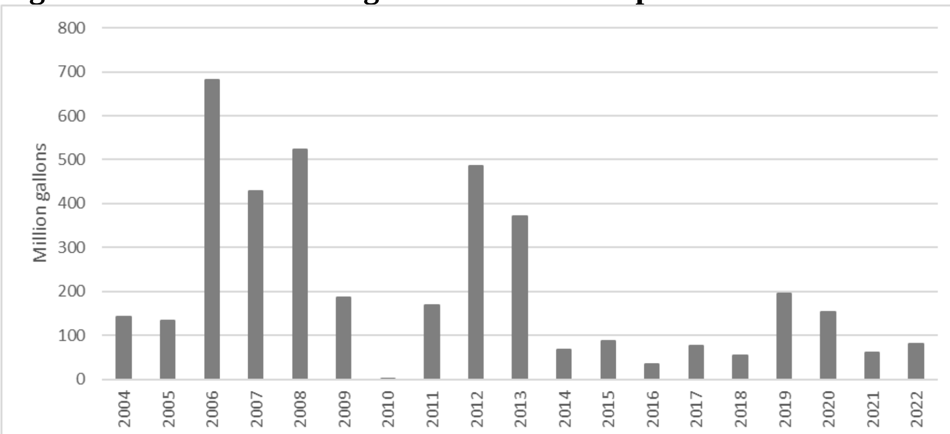
Year	2022	2023	2024	2025
Biodiesel				
Canola Oil	400	438	461	484
DCO	195	173	134	95
FOG	519	481	454	427
Soybean Oil	1,492	1,473	1,451	1,430
Renewable Diesel				
Canola Oil	0	368	309	481
DCO	356	348	406	463
FOG [a]	1,460	1,907	1,849	1,972
Soybean Oil	498	1,026	1,141	1,486
BBD Total				
All Feedstocks [a]	4,921	6,215	6,205	6,836

[a] Includes 24 million RINs of Jet Fuel projected to be supplied each year from 2023–2025

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 2022 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 2023." 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, as did the majority of ethanol imports in 2022. 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.[696] 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.[697] 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 action 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 95 million gallons. As we are projecting volumes for 2023-2025 in this action, and this is the latest data available, the same projection applies for all three years.

[696] See, e.g., 85 FR 7032-33 (February 6, 2020) and 87 FR 39600 (July 1, 2022).
[697] 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
2015	89	0.0078125
2016	34	0.015625
2017	74	0.03125
2018	78	0.0625
2019	196	0.125
2020	185	0.25
2021	60	0.5
2022	81	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 95 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
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	85	149
2021	7	26	2	33	105	173
2022	6	29	3	76	124	238

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 195 million RINs. This volume of other advanced biofuel is composed of 27 million RINs of domestic advanced ethanol, 104 million RINs of co-processed renewable diesel, and 63 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 action. 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 D5 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).

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.[698] 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 pool-wide ethanol concentration derived from EIA data with the number of stations that have offered E15 and E85.

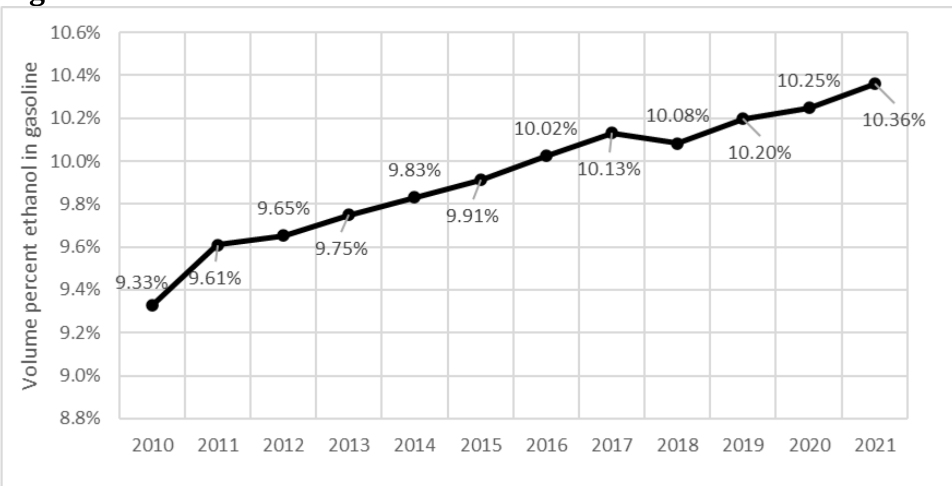
For the purposes of estimating the costs of renewable fuel, however, it is helpful to account for the different distribution practices required for different gasoline-ethanol blends. Thus, for cost purposes only, we have projected volumes of E15 and E85 for 2023–2025 using aggregate consumption data 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 results from the use of the EIA forecasts used in setting the percentage standards. 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 document.

[698] 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[699]



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.

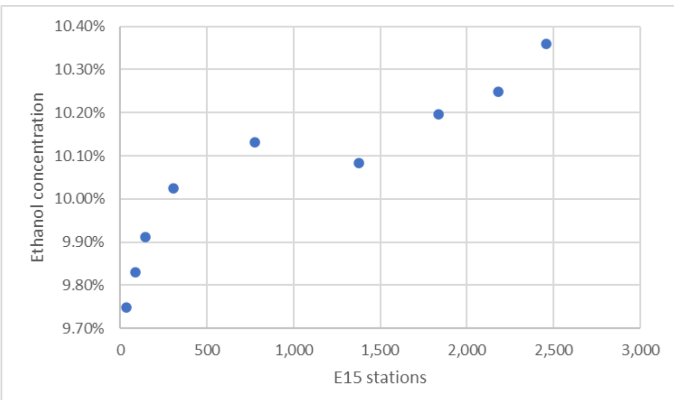
[699] U.S. Energy Information Administration. https://www.eia.gov/totalenergy/data/monthly/archive/00352303.pdf. See, e.g., US Energy Information Administration – March 2023 Monthly Energy Review.

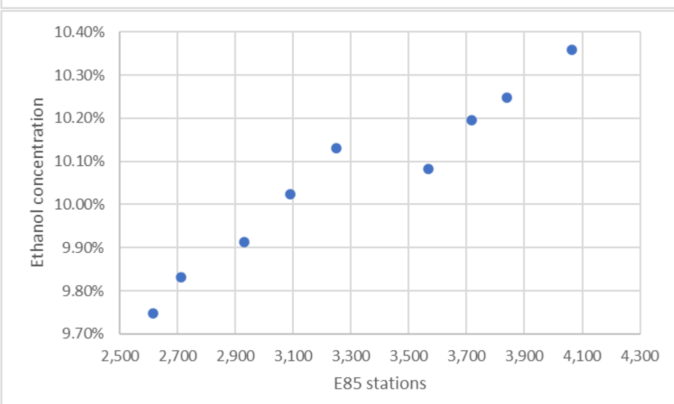
Table 6.5.1-1: Annual Average Number of Stations Offering Higher Level Ethanol Blends

	E15 stations	E85 stations
2013	36	2,616
2014	88	2,713
2015	145	2,932
2016	308	3,091
2017	776	3,251
2018	1,376	3,567
2019	1,838	3,717
2020	2,180	3,841
2021	2,461	4,063
2022	2,724	4,418

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:

$$\text{Ethanol concentration (\%)} = (5.721\times10^{-4}) \times \ln(\text{E15 station count}) + (2.028\times10^{-6}) \times (\text{E85 station count}) + 0.09031$$

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 7.4.3 and 7.4.2, 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	3,586	4,499	10.41%
2024	4,197	4,696	10.46%
2025	4,713	4,892	10.51%

The projected ethanol concentration can then be combined with total projected gasoline energy demand from EIA's AEO 2023 to estimate total ethanol consumption. We use this projection method due to a discrepancy found between EIA domestic gasoline consumption and net gasoline exports. A further discussion of our investigation is found in Chapter 1.11.

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	10.41%	16.1357	13,974
2024	10.46%	16.2350	14,128
2025	10.51%	15.9890	13,978

[a] See AEO2023 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 AEO2023 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.[700] 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)[701,702] while

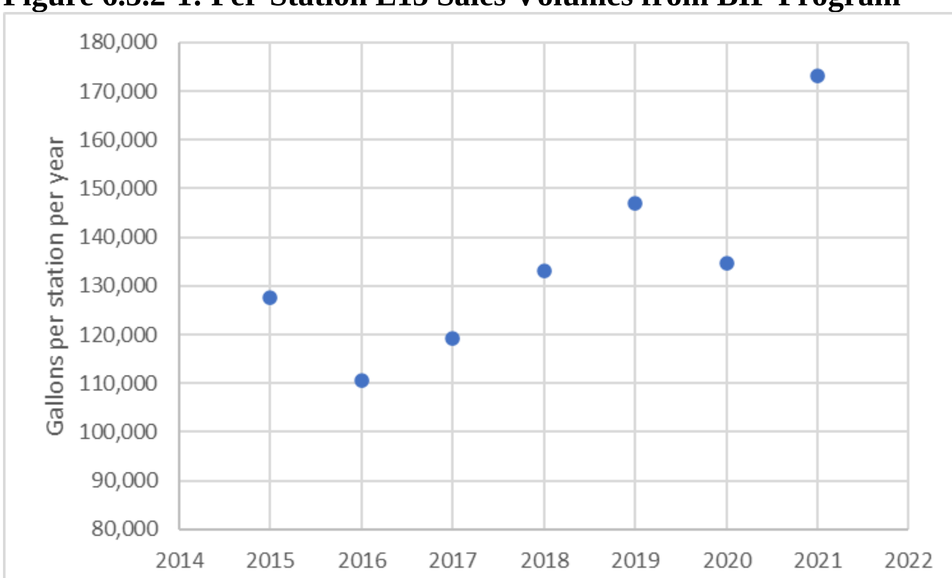
[700] "Communication with USDA on the BIP program 1-19-22," available in the docket.
[701] Iowa Department of Revenue. https://tax.iowa.gov/report-category/retailers-annual-gallons. See, e.g., "Iowa Department of Revenue - 2021 Retailers Fuel Gallons Annual Report."
[702] Minnesota Commerce Department. https://mn.gov/commerce/business/weights-measures/fuel/biodiesel/ethanol.jsp. See, e.g., "Minnesota Commerce Department - 2022 Minnesota E85 & Mid-Blends Station Report."

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).[703]

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. In the proposal, 2019 was used as a more representative value over 2020. Since then, 2021 data has become available and presents values which are more accurate for estimating future values to the program.

We recognize that in 2021 the 1 psi waiver applied nationwide to E15, but that it may not apply nationwide in 2023–2025.[704,705] The 1 psi waiver could have resulted in higher sales volumes in 2021 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 may not apply nationwide.[706] However, there are reasons to believe that the use of data from 2021 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.

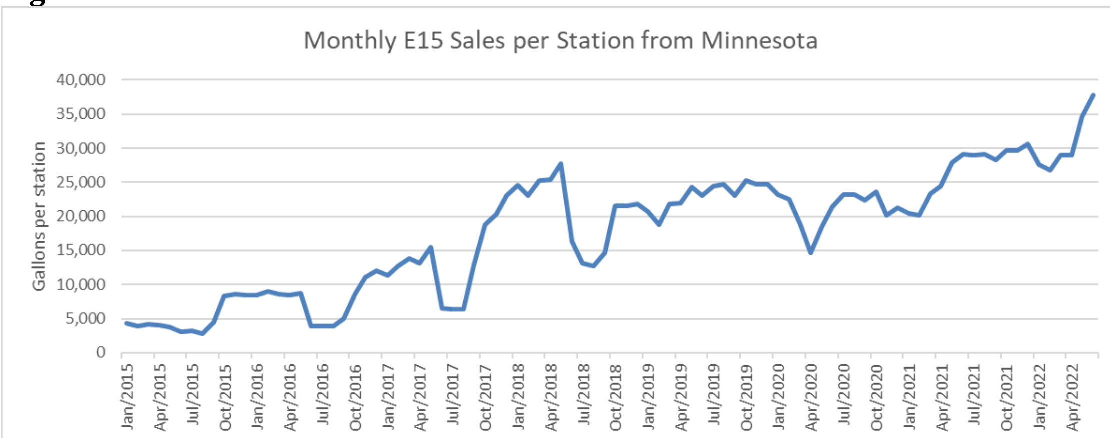
Figure 6.5.2-1: Per-Station E15 Sales Volumes from BIP Program



[703] See discussion of data sources in "Estimate of E85 consumption in 2020," available in the docket.
[704] 84 FR 26980, June 10, 2019.
[705] "Court decision on 1 psi waiver for E15," available in the docket.
706 "Request from States for Removal of Gasoline Volatility Waiver" available in the docket

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. Additional BIP program data was accessed recently showing an increase in E15 sales to pre-pandemic era trends. Given this rebound and that of gasoline demand in 2021 and 2022, we can forgo using 2019 data for more accurate 2021 data. Moreover, a similar upward trend is evident in per-station E15 sales volumes in Minnesota.

Figure 6.5.2-2: Per-Station E15 Sales Volumes in Minnesota



Source: Minnesota Commerce Department. 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, sustained high D6 RIN prices, 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 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 and Ethanol as E15

	E15 stations	E15 sales volumes per year per station	Annual E15 sales volumes (mill gal)	Ethanol in Excess of E10 (mill gal)
2023	3,586	172,988	535	28
2024	4,197	180,593	619	31
2025	4,713	188,198	708	35

Table 6.5.2-2: Projected Volume of E85 and Ethanol as E85

	E85 stations	E85 sales volumes per year per station	Annual E85 sales volumes (mill gal)	Ethanol in Excess of E10 (mill gal)
2023	4,499	54,716	352	233
2024	4,696	47,097	368	243
2025	4,892	39,477	383	253

These are the volumes used to estimate distribution costs associated with E15 and E85 for 2023–2025 as discussed in Chapter 10.1.4.

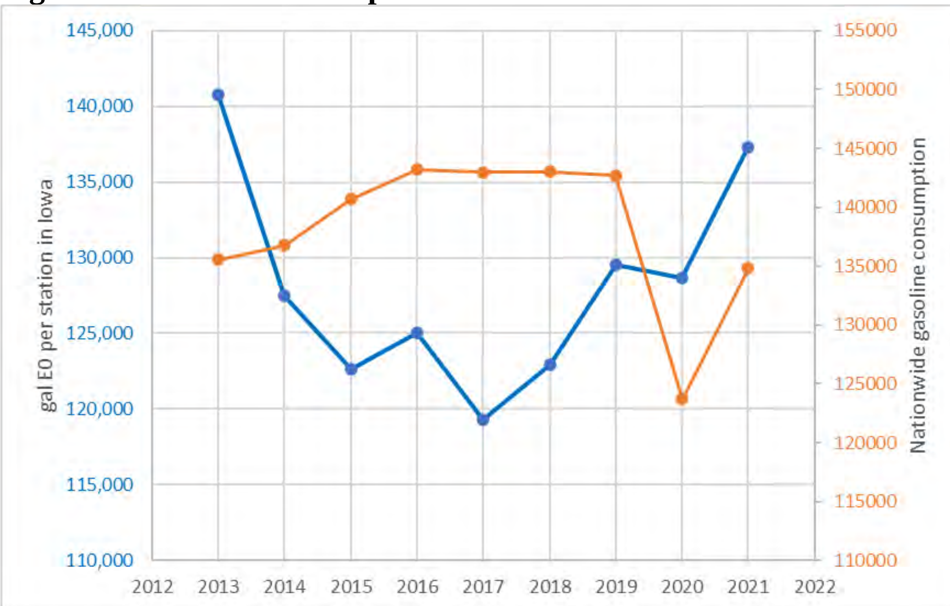
As we noted above, we do not use these E15 and E85 estimates to assess total ethanol volumes or for any purpose other than estimating costs.[707] We note, however, that the E15 and E85 volume projections shown in Tables 6.5.2-1 and 2 correspond to lower total ethanol consumption than the volumes shown 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 2, and why we nonetheless believe it is reasonable to use these E15 and E85 estimates for purposes of our costs analyses. See Chapter 1.11 for our investigation into the EIA forecast/projection of gasoline demand and our adjustment to those forecasts.

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 significantly 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. 2021 data may be the exception to this pattern with both gasoline consumption and E0 raising from 2020 points.

[707] Our 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 2023 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.[708] Given that total ethanol consumption was 12.7 billion gallons in 2020[709], 18.6 billion gallons of E0 would have required that 37.9 billion gallons of E15 be consumed.[710] 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.[711] 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 2,209 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

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[708] According to Table 3.5 of EIA's Monthly Energy Review, total gasoline consumption in 2020 was 123.73 billion gallons.
[709] Table 10.3 of EIA's Monthly Energy Review
[710] 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).
[711] "2020 Retailers Fuel Gallons Annual Report," available in the docket.

in 2021 was E0.[712] 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.[713] Since 1,940 million gallons is very similar to 2,128 million gallons, we had confidence that 2,209 million gallons is a reasonable estimate of E0 consumption.

Estimates of E0, E15, and E85 consumption, combined with total gasoline energy demand from AEO2023, 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	2,209	535	352	16.1357	131,015
2024	2,209	619	368	16.2350	131,744
2025	2,209	708	383	15.9590	129,601

[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	535	80	352	260	131,015	13,232	13,573
2024	619	93	368	272	131,744	13,306	13,671
2025	708	106	383	283	129,601	13,089	13,479

[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 pool-wide ethanol concentration (Table 6.5.1-3). The results are shown in Table 6.5.2-5.

[712] "National Fuels Survey Program Ethanol Data for the 2021 Compliance Period," available in the docket.
[713] "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	13,974	13,573	-401 (1.8%)
2024	14,128	13,671	-501 (3.5%)
2025	13,978	13,479	-498 (3.5%)

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. It could be due to errors in estimates of E0 or that the data collected through the BIP program may not be representative of the nation as a whole. However, the magnitude of the difference suggests that it may also be due to underestimates of the total gasoline demand. 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.

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.[714,715] 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.[716]

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

[714] "2021 Ethanol Industry Outlook - RFA," available in docket EPA-HQ-OAR-2021-0324.
[715] "Ethanol production capacity - EIA April 2021," available in docket EPA-HQ-OAR-2021-0324.
[716] "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	13,974	14,128	13,978
Imported sugarcane ethanol	95	95	95
Domestic advanced ethanol	27	927	27
Corn ethanol	13,845	13,955	13,779

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.[717]

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 2014–2022 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	2022
Domestic D6 Biodiesel	1	0	0	0	0	0	0	0	0
Domestic D6 Renewable Diesel	0	0	0	0	0	0	0	0	0
Imported D6 Biodiesel	52	74	113	0	0	0	0	0	0
Imported D6 Renewable Diesel	2	86	45	2	0	0	0	0	0
All D6 Biodiesel and Renewable Diesel	55	160	158	2	0	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 2018-2022. Nearly all of

[717] "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 2022 the volumes of renewable diesel for which conventional biofuel RINs were generated each year (in million gallons) were 107, 116, 76, 135, and 75 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 1.6 billion gallons in the U.S., with an additional 0.9 billion gallons internationally. While domestic feedstock availability may be limited, worldwide feedstock availability does also not appear to be a limiting factor, as USDA estimates that approximately 218 million metric tons of vegetable oil will be produced globally in the 2022/2023 agricultural marketing year.[718] If all of it were to be used to produce biodiesel and renewable diesel, this quantity of vegetable oil could be used to produce approximately 63 billion gallons.[719] While the majority of this vegetable oil is used for food and other non-biofuel purposes, 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,[720] 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.

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[718] USDA World Agricultural Supply and Demand Estimates. February 8, 2023.

[719] This calculation assumes one gallon of biodiesel or renewable diesel can be produced from 7.6 pounds of vegetable oil.

[720] 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 describes the analysis of 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.[721] 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.[722] 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

[721] 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.
[722] 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.[723]

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.[724] 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 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.[725] 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 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

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[723] 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.

[724] 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.

[725] See Chapter 1.2.2 of the RFS2 Regulatory Impact Analysis (EPA-420-R-10-006).

could be resolved.[726] 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 1.7–2 billion gallons per year from 2017–2022, often exceeding the 1.82 billion gallons that we projected would be used in 2022.[727] 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.

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.[728] 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.[729] 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.[730] 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.[731]

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 volume of biodiesel used in 2022. 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.[732] A review of monthly biodiesel imports suggests that import

[726] 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.
[727] Biodiesel consumption numbers based on EMTS data.
[728] 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.
[729] 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.
[730] See Pilot Flying J Fuel Offerings, Memorandum to EPA Docket EPA-HQ-OAR-2021-0427.
[731] See Average Biodiesel Blend Level By State Based on EIA Data, Memorandum to EPA Docket EPA-HQ-OAR-2021-0427.
[732] See Chapter 6.2.

infrastructure can support significantly higher volumes of imports.[733] For example, over 700 million gallons of biodiesel was imported in 2016.[734] 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.[735]

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.[736]

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.[737] 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.[738] 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.[739] Therefore, a substantial increase in the use of biodiesel, especially biodiesel produced from palm oil, during the winter may be a challenge.

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[733] EIA, U.S. Imports of Biodiesel 2009 thorough 2021.

[734] Id.

[735] 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.

[736] 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.

[737] B5 blend levels can typically be maintained.

[738] Biodiesel Cold Flow Basics, National Biodiesel Board, 2014.

[739] 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.

7.3 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.[740] 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.[741] 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.[742]

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.[743] 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.

[740] See Chapter 1.2.2 of the RFS2 Regulatory Impact Analysis (EPA-420-R-10-006).
[741] Such drop-in fuels are typically blended with petroleum-based diesel prior to use.
[742] See Chapter 1.6 of the RFS2 Regulatory Impact Analysis (EPA-420-R-10-006).
[743] See Chapter 6.2.

7.4 Ethanol

We are projecting that the candidate volumes for 2023–2025 would result in increased use of higher-level ethanol blends such as E15 and E85; E10 is economical to be blended in the absence of the RFS program.

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 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.[744]

7.4.1 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.[745] 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 affected rail corridors without undue difficulty, and that therefore the

[744] A nationwide average ethanol concentration above 10.00% can only occur insofar as there is consumption of E15 and/or E85.
[745] "Analysis of Fuel Ethanol Transportation Activity and Potential Distribution Constraints," ORNL, March 2009.

infrastructure system to the blending terminal could accommodate the projected increased volume of ethanol in a timely fashion.[746]

To update and expand upon the analysis of distribution infrastructure upstream of retail that was conducted for the 2010 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.[747] 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 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 2010 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.

7.4.2 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.[748] 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.

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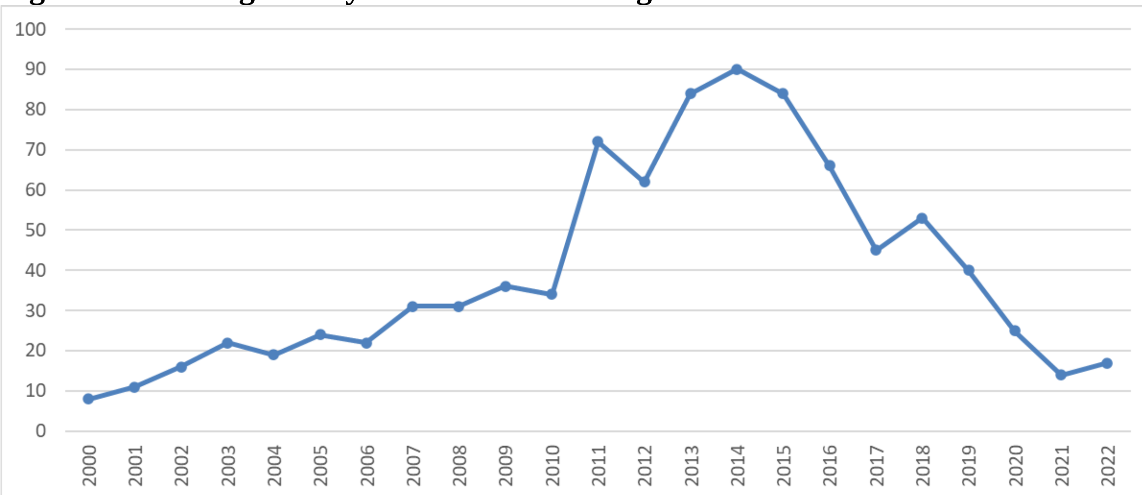
[746] See Chapter 1.6 of the RFS2 Regulatory Impact Analysis (EPA-420-R-10-006).
[747] Impact of Biofuels on Infrastructure, Report for EPA by ICF International Inc., January 2018.
[748] "FFV registrations from AFDC December 2021" and "DOT National Transportation Statistics Table 1-11," available in the docket.

Figure 7.4.2-1: Light-Duty FFV Model Offerings



Source: Alternative Fuels Data Center. See "Light-Duty AFV HEV and Diesel Model Offerings by Technology-Fuel March 2023," 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 7.4.2-1. If FFV offerings remain at their 2022 levels or continue to decrease, we would expect the number of FFVs in the in-use fleet to begin decreasing after 2022.

Table 7.4.2-1: Change in Light-Duty FFV Registration Counts

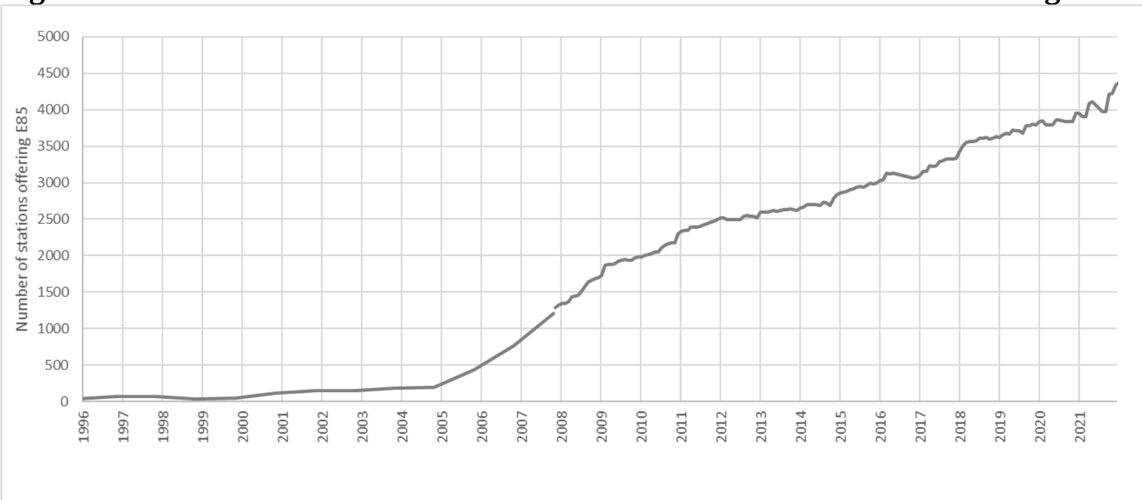
Year	% change in FFV counts compared to previous year
2017	+10.0%
2018	+6.4%
2019	+4.5%
2020	+1.6%

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.[749] As shown in Figure 7.4.2-2, stations offering E85 have increased steadily since about 2005. By June 2022, the total number of stations offering E85 had reached 4,476.

[749] "UST System Compatibility with Biofuels," EPA 510-K-20-001, July 2020.

Figure 7.4.2-2: Number of Public and Private Retail Service Stations Offering E85[a]

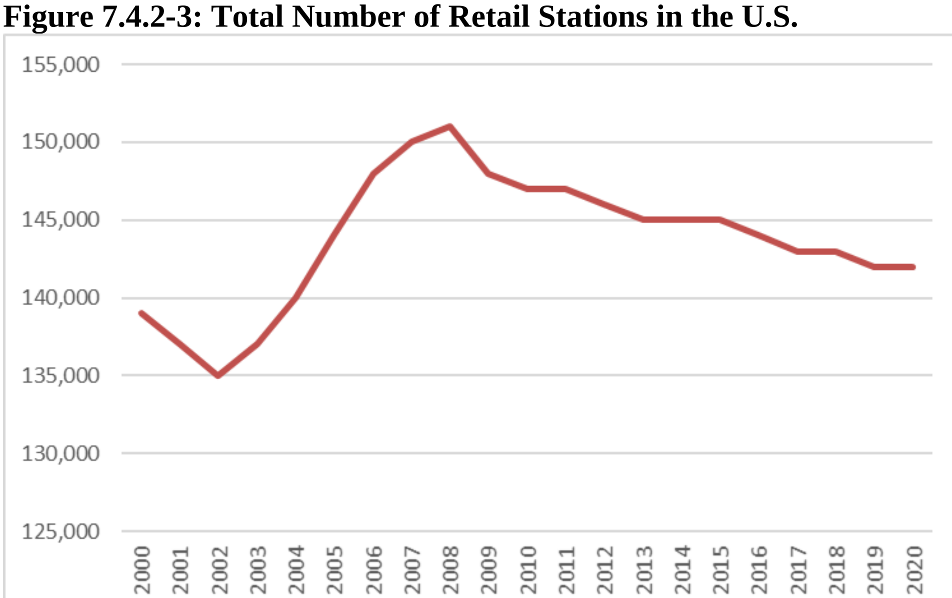


[a] Data through 2007 is annual, whereas data for 2008 and later is monthly.
Source: Department of Energy's Alternative Fuels Data Center (AFDC). https://afdc.energy.gov/stations/states. See, e.g., "AFDC - Alternative Fueling Station Counts by State 10-13-22," available in the docket.

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.

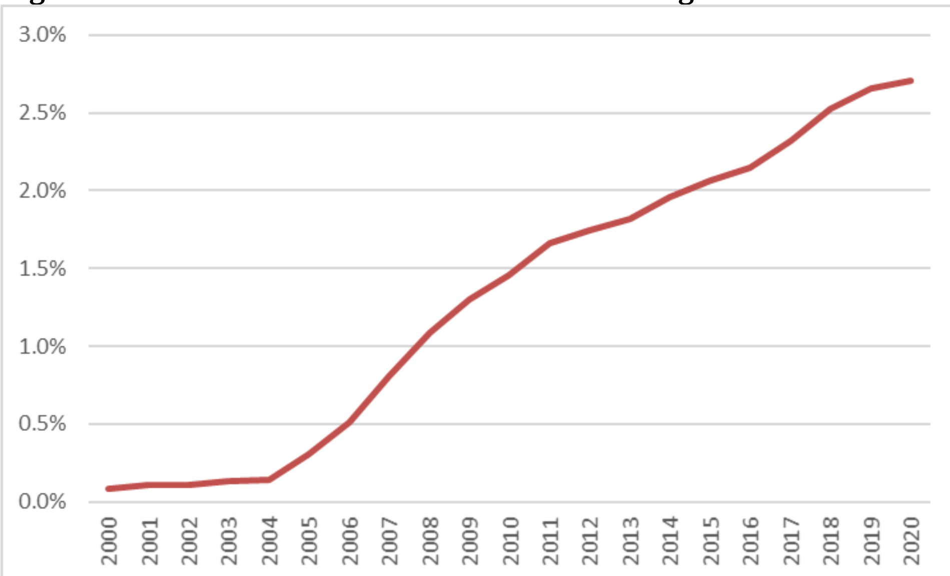
Although the total number of retail stations in the U.S. has varied, as shown in Figure 7.4.2-3, the fraction of those stations offering E85 has steadily increased. By the end of 2020, the fraction of retail stations offering E85 had reached 2.7%, as seen in Figure 7.4.2-4.

Figure 7.4.2-3: Total Number of Retail Stations in the U.S.



Source: Table 4.24, Transportation Energy Data Book, Edition 40.

Figure 7.4.2-4: 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 7.4.2-2.

Table 7.4.2-2: Projected Average Number of Stations Offering E85[a]

Year	Stations
2023	4,499
2024	4,696
2025	4,892

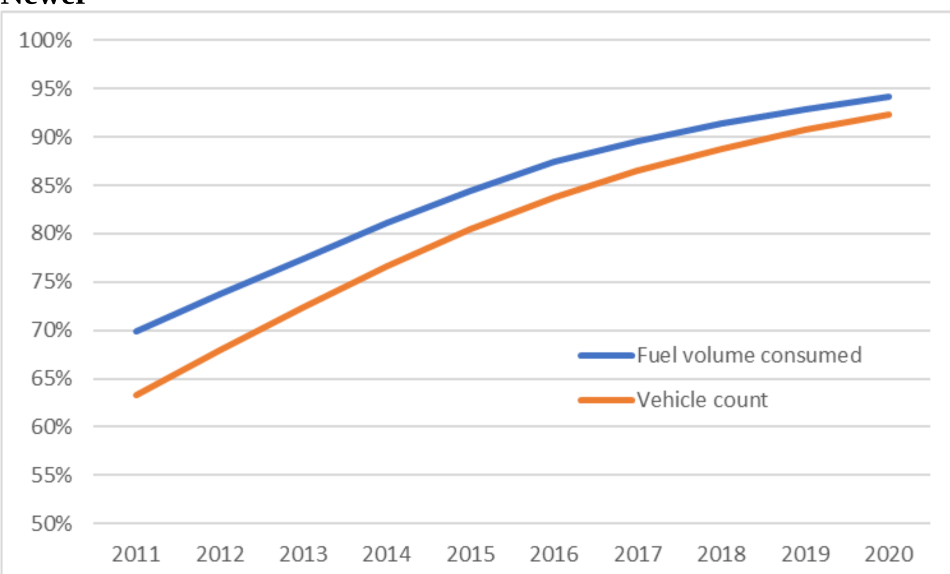
[a] Annual average, not year-end.

7.4.3 Infrastructure for E15

E15 is permitted to be used only in MY2001 and newer light-duty motor vehicles.[750] 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[751]—the number of terminals offering preblended E15 directly to service stations has been increasing.[752] 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.[753,754]

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 7.4.3-1: 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

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[750] 76 FR 4662 (January 26, 2011).

[751] According to Prime the Pump, 1,771 out of 2,302 stations offering E15 at the end of 2020 used blender pumps.

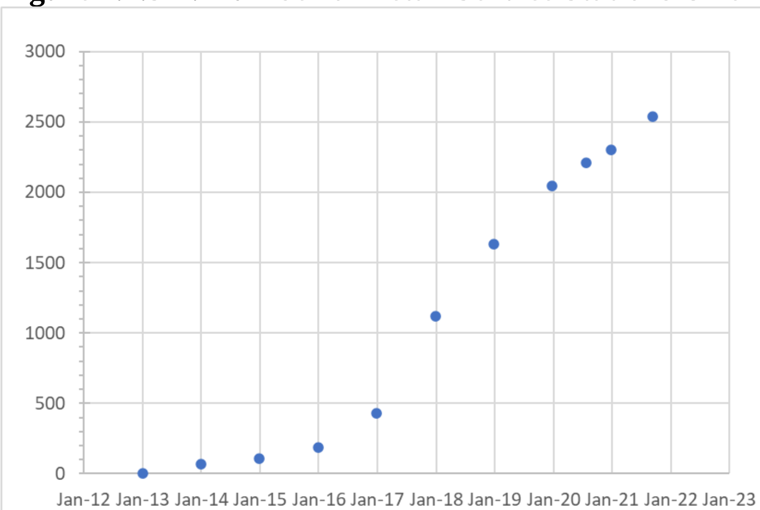
[752] "Terminal Availability of E15 Grows as EPA Prepares to Remove RVP Barrier," available in the docket.

[753] https://growthenergy.org/resources/retailer-hub. See also "Retailer Hub Growth Energy 92421," available in the docket.

[754] 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 7.4.3-2: Number of Retail Service Stations Offering E15



Source: "Prime the Pump Infrastructure Update – Jan 2023 ," 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. HBIIP is composed of HBIIP 1.0 and HBIIP 2.0 which are the original and renewal of the program. 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.[755] 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)[756] and Stillwater

[755] See, e.g., "SIGMA NATSO NACS comments on the proposed Set rule 2-10-23," available in the docket.
[756] K. Moriarty and J. Yanowitz, "E15 and Infrastructure," National Renewable Energy Laboratory, May 2015. Attachment 3 of comments submitted by the Renewable Fuels Association.

Associates,[757] 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 required to demonstrate compatibility of their tanks with the fuel through one of the following methods:[758]

- 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.[759] 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

[757] 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.
[758] "UST System Compatibility with Biofuels," available in the docket.
[759] See, e.g., 40 CFR 1090.1420 and 1090.1510.

program was responsible for the conversion of 841 retail stations from 2016–2018.[760] 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 7.4.3-2. 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 efforts. The HBIIP program effectively began in 2021.[761] Given its similarity to the BIP program in terms of funding levels and intended outcomes, 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 7.4.3-1: Historical Breakdown of E15 Stations

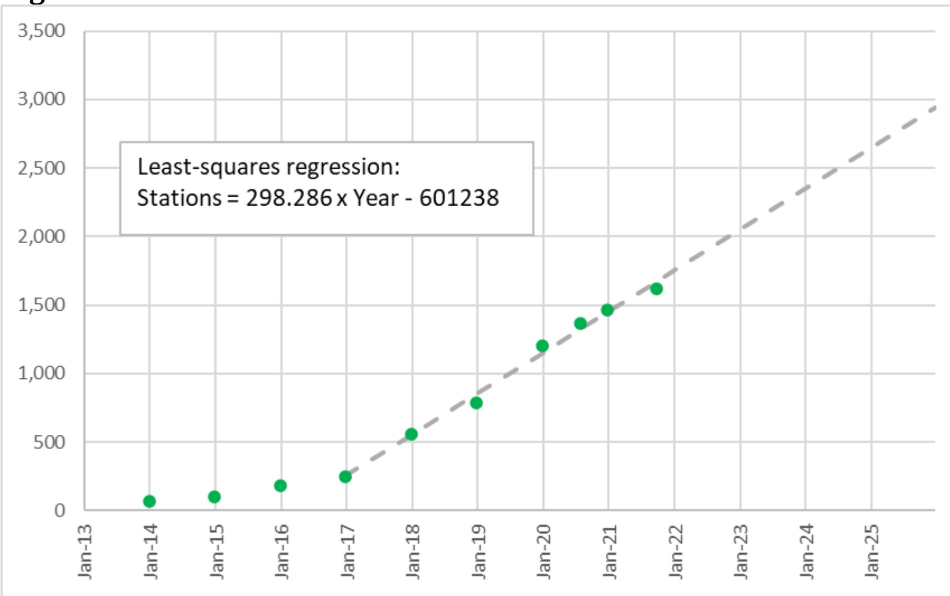
	Total[a]	**BIP[b]**	**HBIIP[c]**	**PTP + private efforts**
December 2012	2	0	0	2
December 2013	70	0	0	70
December 2014	105	0	0	105
December 2015	184	0	0	184
December 2016	431	183	0	248
December 2017	1,122	563	0	559
December 2018	1,630	841	0	789
December 2019	2,045	841	0	1,204
July 2020	2,208	841	0	1,367
December 2020	2,302	841	0	1,461
September 2021	2,536	841	210	1,485
April 2022	2,667	841	372	1,454
November 2022	2,923	841	523	1,515

[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 7.4.3-3.

[760] "Biofuel Infrastructure Partnership - original grants & projections" and "Communication with USDA on the BIP program 11-15-21," available in the docket.
[761] 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 7.4.3-3: Growth in E15 Stations Due to Private Initiatives



Using the available information on the BIP and HBIIP programs and the projection shown in Figure 7.4.3-3, we were able to estimate the breakdown of E15 stations for 2023–2025, as shown in Figure 7.4.3-4. The projected total number of E15 stations for 2023–2025 is shown in Table 7.4.3-2.

Figure 7.4.3-4: Projected Breakdown of E15 Stations

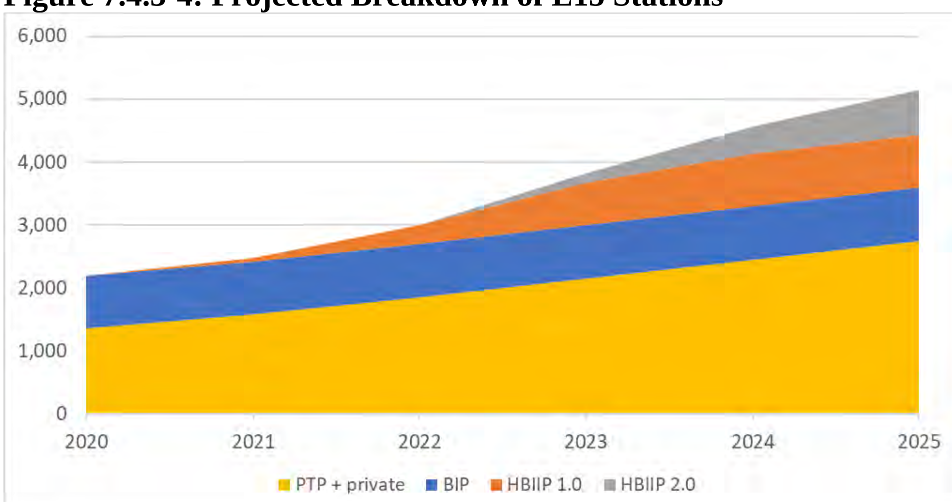


Table 7.4.3-2: Projected Average Number of Stations Offering E15[a]

Year	Stations
2023	3,552
2024	4,197
2025	4,713

[a] Annual average, not year-end.

7.5 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 2010 RFS2 rule concluded that there would be minimal additional stress on most U.S. transportation networks overall due to increased biofuel volumes.[762] 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.[763] 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.[764] Since that biogas will be displacing natural gas used in

[762] "Analysis of Fuel Ethanol Transportation Activity and Potential Distribution Constraints," ORNL, March 2009.
[763] Impact of Biofuels on Infrastructure, Report for EPA by ICF International Inc., January 2018.
[764] See Chapter 7.1.

CNG/LNG vehicles, we do not expect a net increase in total volume of biogas + natural gas delivered.

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 13.8 – 14.0 billion gallons, which is less than the volume of corn ethanol consumed in 2018.[765] 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.

We estimate that the use of FOG for the production of biofuel will remain at approximately 1.4 billion gallons from 2023 to 2025 (see Table 3.1-3). The projected use of FOG for biofuel production is consistent with the trend observed from 2018–2022. 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 increase from approximately 1.1 billion gallons in 2022 to approximately 1.8 billion gallons in 2025. This projected increase is based on the expected expansion of soybean crushing over this time period in the U.S.

[765] "RIN Supply as of 2-17-22," available in the docket.

Chapter 8: Other Factors

The CAA directs EPA to consider the impact of the use of renewable fuels on "other factors" that have a more indirect relationship to volume standards, including job creation, the price and supply of agricultural commodities, rural economic development, and food prices.[766] 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.[767]

8.1 Job Creation

This section 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 prepared by John Urbanchuk for the Renewable Fuels Association (RFA).[768] Urbanchuk estimates that the total number of direct, full-time-equivalent jobs for domestic corn ethanol production in 2022 was 11,635 across the 199 plants that RFA found to be operating that year. The total nameplate capacity of those plants is reported at 17.9 billion gallons, suggesting an average plant size of 90 million gallons per year and an average employee concentration of 0.65 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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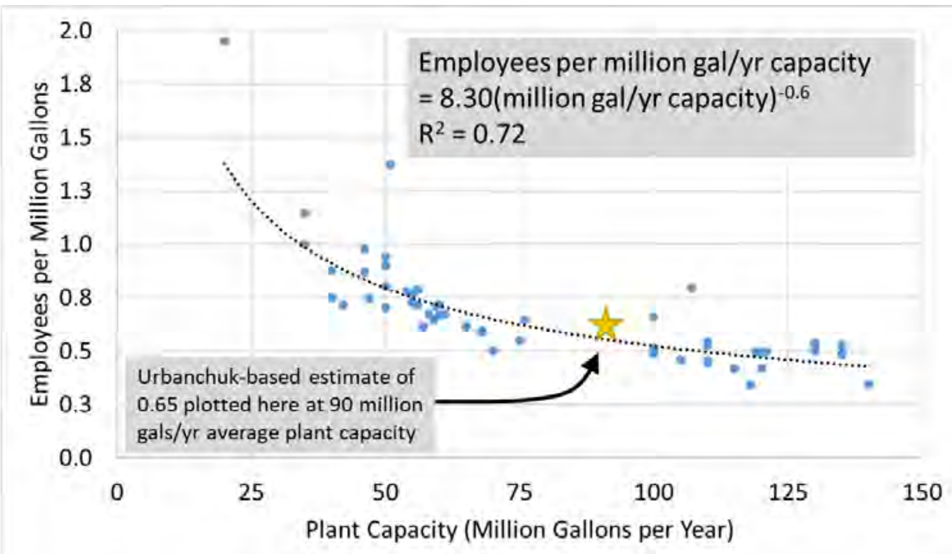
[766] As we explain in Preamble Section II, we also consider several other factors besides those enumerated in the statute.
[767] The impacts evaluated in this chapter are for volume increases for 2023–2025 compared to the No RFS baseline, as shown in Table 3.2.-2.
[768] Urbanchuk, J. ABF Economics. "Contribution of the Ethanol Industry to the Economy of the United States in 2022," February 14, 2023.

themselves as operational.[769] The average plant size using these figures is 91 million gallons per year, and using Urbanchuk's total direct employment suggests an average employee concentration of 0.67 jobs per million gallons capacity.

In 2018, Ethanol Producer Magazine made available data on the capacity and number of employees at each of 65 corn ethanol facilities.[770] 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 0.65 plotted at the national average facility size of 90 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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[769] EIA. U.S. Fuel Ethanol Plant Production Capacity as of January 1, 2022. https://www.eia.gov/petroleum/ethanolcapacity/archive/2022/index.php.

[770] Ethanol plant employment data obtained via Ethanol Producer Magazine website in 2018 (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 2022. 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 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 2022 study by LMC International on the economic impact of the biodiesel and renewable diesel industry prepared for the Clean Fuels Alliance America.[771] The report presents economic and employment impacts of several steps in the biofuel value chain using a methodology that combines direct, indirect, and induced jobs based on multipliers taken from the U.S. Department of Commerce Bureau of Economic Analysis. In Table 6, LMC presents a figure of 17,120 jobs involved in feedstock collection and biofuel processing for production of 2.5 billion gallons in 2021. This equates to 6.8 jobs per million gallons, a figure that represents a volume-weighted average of the biodiesel and renewable diesel in 2021. Using these figures and the volumes in Table 3.2-2, we project an impact of 6700–7300 long-term jobs in biodiesel production for the years 2023–2025 relative to the No RFS Baseline. Minimal new construction is expected for biodiesel given the currently-available capacity and the projection of flat growth relative to 2022.

8.1.1.3 Renewable Diesel Production

As described in Chapters 3 and 6, renewable diesel production has grown significantly in recent years, and is projected to continue as shown in Table 3.3-1. The additional volume is expected to come from expansion of existing facilities, construction of new facilities, and conversion of process trains at petroleum refineries. These differing scenarios will result in a wide range of employment impacts, from minimal growth for existing facility conversions to significantly more at new sites. The 2022 LMC analysis referenced above did not break out impact figures for renewable diesel specifically, and therefore we will use the same estimate of 6.8 operations jobs per million gallons to project an impact of 6000–7600 long-term jobs related to renewable diesel production over the years 2023–2025 relative to the No RFS Baseline. LMC also estimated temporary construction jobs related to volume growth. Those figures show 25 jobs lasting up to two years per million gallons of added capacity. Considering the projected renewable diesel growth relative to 2022, this would suggest up to 35,000 construction jobs by 2025.

[771] LMC International. "Economic Impact of Biodiesel on the United States Economy." November 2022.

8.1.1.4 RNG Production

As described in Chapters 3 and 6, we project continued growth of RNG used as CNG/LNG 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 gas cleanup and pipeline interconnect equipment.[772] 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 2022 data showed 10,600 jobs across 255 operating facilities with total production of 91 million MMBtu.[773] Converting to ethanol-equivalent gallons (EGEs) gives 9 operations jobs per million EGE, and approximately 42 workers per facility. Additional data is provided for plants under construction in 2022, which indicates there are 67 construction jobs per million EGE. These factors were applied to the projected volume increases of RNG used as CNG/LNG in 2022–2025, resulting in the employment impacts shown in Table 8.1.1.4-1. These employment estimates implicitly assume that the average employment at facilities in 2023–2025 occur at the same ratio to EGEs as in 2022. The construction employment figures also 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 (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	33,165	4,455	37,620
2024	46,096	6,192	52,288
2025	62,444	8,388	70,832

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 RNG used as CNG/LNG is produced from waste or byproduct materials (e.g., separated MSW, wastewater, and agricultural residue), we expect the projected increases in the production of RNG used as CNG/LNG to have very little impact on employment related to feedstock production. As noted above, we are projecting higher volumes of ethanol,

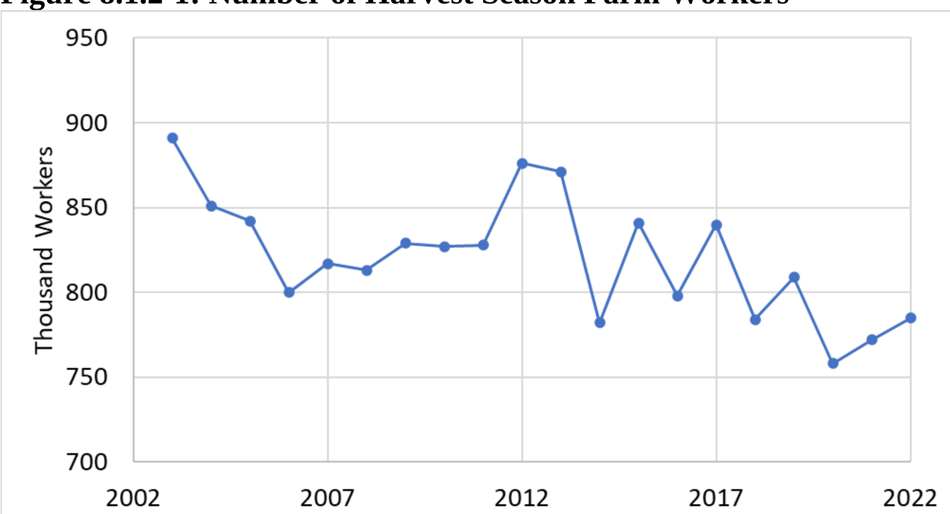
[772] Jaramillo and Matthews, Environmental Science & Technology 2005 39 (19), 7365-7373.
[773] Coalition for Renewable Natural Gas. Economic Analysis of the U.S. Renewable Natural Gas Industry. December 2022.

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.[774]

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 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).[775] 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.

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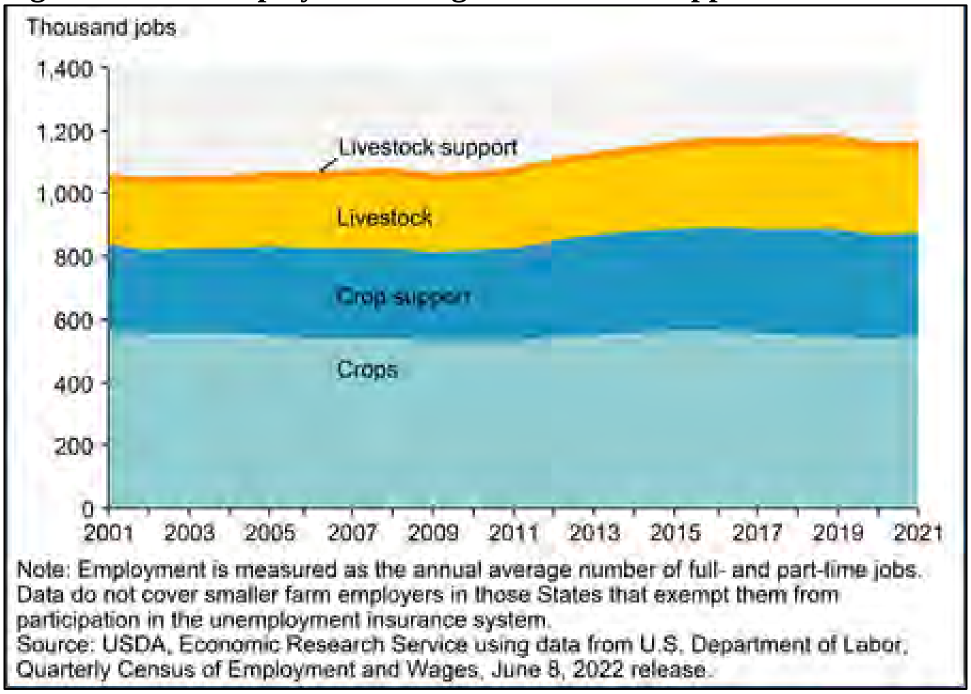
[774] We are also projecting that lesser quantities of FOG and corn oil would be used to produce biodiesel and renewable diesel in 2023–2025, but since these feedstocks are wastes or co-products of other industries, we do not expect their increased use to impact agricultural employment.

[775] USDA NASS Agricultural Statistics and Farm Labor data, https://usda.library.cornell.edu/concern/publications/x920fw89s and https://usda.library.cornell.edu/concern/publications/j3860694x?locale=en.

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 2001–2021.[776]

Figure 8.1.2-2: Employment in Agriculture and Support Activities



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 2008–2010 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 RNG used as CNG/LNG in 2023–2025 relative to the No RFS baseline. As discussed in Chapter 8.1.1.1, the impact of the RFS volumes for 2023–2025 on domestic ethanol production are uncertain. In their absence, domestic ethanol production could continue at a level at or near current production volumes with increasing

[776] USDA ERS Farm Labor, March 2023. https://www.ers.usda.gov/topics/farm-economy/farm-labor.

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 will be related to the production of feedstocks for these fuels. We project that almost all of the increase in biodiesel and renewable diesel production in 2023–2025 will be produced from soybean 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 RNG used as CNG/LNG is expected to result in additional rural economic activity. Using factors derived from a 2022 analysis by CRNG, we estimated that each additional million RINs of CNG/LNG from agricultural digesters is associated with $0.76 million in economic activity related to gas capture, upgrading, and facility administration activities.[777] This figure suggests that the candidate volumes would result in $375 million, $522 million, and $707 million in economic activity in 2023, 2024, and 2025, respectively, relative to the No RFS baseline. That analysis also indicated that 68% of facilities under construction in 2022 were agricultural waste digesters, which were likely to be located in rural areas, and that total capital expenditure on these facilities was $1.1 billion. While the overall share of this economic impact occurring in rural areas is unknown, the fact that the majority of CNG/LNG facilities under construction in 2022 were agricultural waste digesters suggests that much of this economic activity is occuring 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 higher volumes of ethanol, biodiesel, renewable diesel, and RNG used as CNG/LNG 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 1995–2022.[778] 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.

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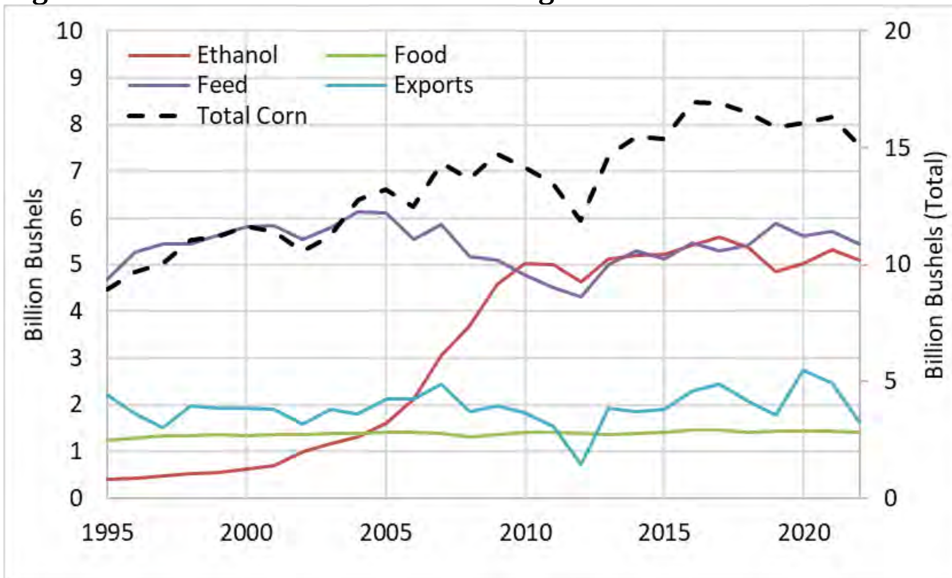
[777] Coalition for Renewable Natural Gas. Economic Analysis of the U.S. Renewable Natural Gas Industry, December 2022. See slides 35 (MMBtu/yr for agricultural digesters) and 37 (dollars per year for capture and upgrade).
[778] USDA ERS Bioenergy Statistics, April 2023 (Table 5). 2022 values are estimates. https://www.ers.usda.gov/data-products/u-s-bioenergy-statistics.

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 showed modest but consistent growth at historical rates during this period, despite increased consumption as ethanol feedstock. Exports also remained relatively steady, except for a drop corresponding to weather-related supply disruptions and elevated prices in 2011–2012. Animal feed use began to rebound after 2014 when growth in ethanol use 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 relatively modest changes in ethanol volumes associated with this rule are likely to have minimal 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.[779] Roughly 80% of this growth since 2005 has been associated with rising exports of soybeans, which have nearly doubled over that period. Domestic crushing of beans has grown by about 25% since 2005, which is mirrored in growth of the crush products, soy meal and oil. This data 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. (Worldwide, over 95% of beans are eventually crushed for meal and oil.)

[779] USDA ERS Oilcrops Data Yearbook, Soy Tables, March 2023.

Figure 8.3-2: Soybean Production and Usage

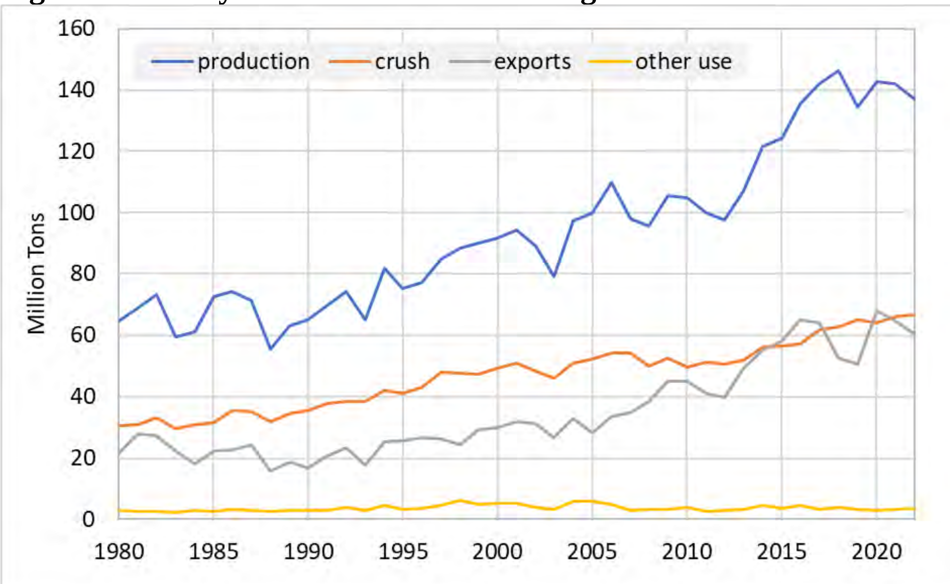
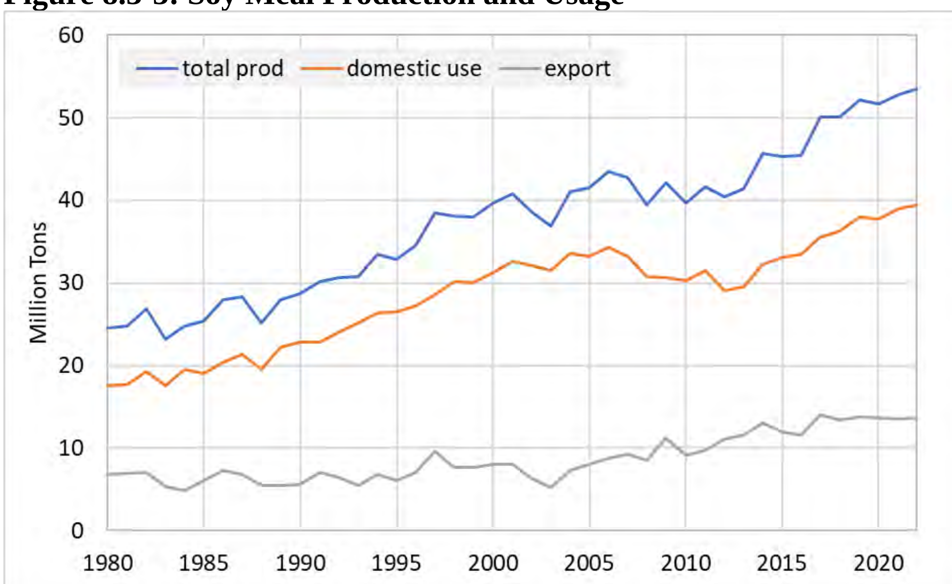


Figure 8.3-3: Soy Meal Production and Usage



Growth in soybean oil production and its uses are shown in Figure 8.4-2.[779] The steepened upward production trend over the past decade has been enabled by both increasing crush capacity and increasing yields of oil per bushel of soybean input. The use of soybean oil for biofuel production has also increased steeply since about 2014, with a further uptick since 2020. This continued expansion of biofuel demand has begun to shift the relative value relationship between the oil and meal crush products, as discussed further in 8.4 below.

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 section reviews historical trends and presents key observations from the literature.

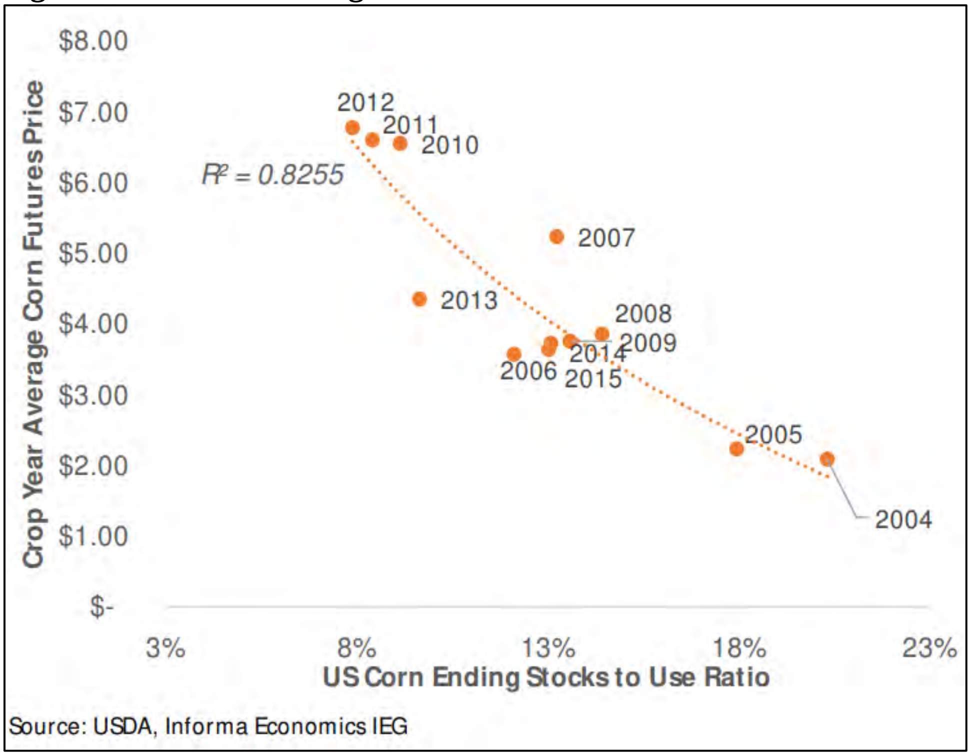
In the U.S., corn and soybeans are generally only harvested once per year, and therefore storage is a critical factor in the supply chain. After harvest, grain stores are replenished and then drawn down throughout the year. In recent years, 10-15% of the previous year's overall corn production is typically still in storage at the time of the new harvest.[780] 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.[781] 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.

[780] USDA ERS Feed Grains Data Yearbook, April 2023 (Table 4).

[781] 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.[782] 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.[783] 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 660–787 million gallons per year) 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 production for these years.[784] This

[782] 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.
[783] Food and Agricultural Policy Research Institute. Literature Review of Estimated Market Effects of U.S. Corn Starch Ethanol, 2016. FAPRI-MU Report #01-16.
[784] USDA Agricultural Projections to 2032. February 2023.

history of significant export volumes makes it difficult to assess the impact of the projected volumes.

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]	$6.80	$5.70	$4.90
Corn Price Increase per Billion Gallons of Ethanol; $/bushel	$0.20	$0.17	$0.15
Corn Ethanol Increase; billion gallons	0.706	0.776	0.840
Corn Price Increase; $/bushel	$0.14	$0.13	$0.12
Corn Price (No RFS Baseline); $/bushel	$6.66	$5.57	$4.78

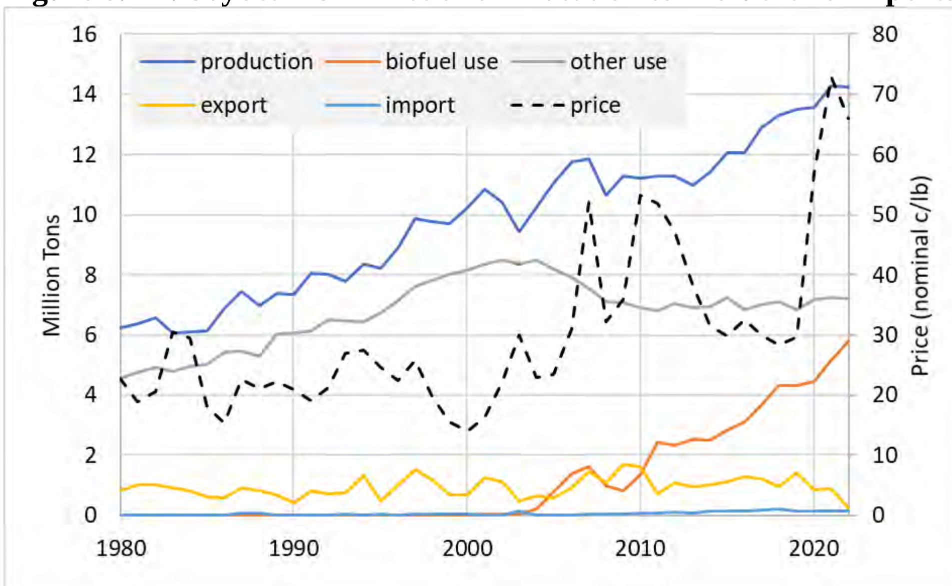
[a] Corn prices are from the USDA Agricultural Projections to 2032 report. Prices represent the average price for a calendar year. For corn, the price is calculated using 1/3 of the price for the first agricultural marketing year (e.g., 2022/2023 for 2023) and 2/3 of the price for the second agricultural 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 soybean 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.[785] Use in domestic biofuel rose from 0.8 million tons in 2005 to 5.8 million tons in 2022. Other domestic uses also increased steadily through 2005, decreased slightly from 2005–2010, and have remained relatively consistent since 2010. Exports of soybean oil are a relatively minor outlet and had remained fairly consistent for many years until dropping toward zero following the steep price increase since 2020. Noting the lack of correlation between soybean oil price and its use in

[785] USDA ERS Oilcrops Data Yearbook, Soy Tables, March 2023.

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.[786]

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%.[787,788,789]

In our proposal, 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

[786] Wilson, Nick. "Oil Prices Surge – Vegetable Oil That Is." Marketplace.org. February 17, 2022.
[787] Babcock, B. A. 2012. The impact of US biofuel policies on agricultural price levels and volatility. China Agricultural Economic Review 4:407-426.
[788] 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.
[789] Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis. EPA-420-R-10-006. February 2010.

from modeling work published by Babcock, *et al.*, and is the same figure used for other cost estimates in this rule.[790] 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 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 at the time of proposal are shown in Table 8.4-2.1.

Table 8.4-2.1: Projected Impact on Soybean Oil Prices Relative to the No RFS Baseline Babcock Methodology

	2023	**2024**	**2025**
Soybean Oil Price (Candidate Volumes); $/pound[a]	$0.69	$0.57	$0.505
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	$0.37	$0.25	$0.20

[a] Soybean oil prices are from the USDA Agricultural Projections to 2032 report. 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).

However, in the time between proposal and final, research on this topic has evolved and we have adapted our analysis to reflect this. We largely base this on Lusk, *et al.*, which uses a shock of 20% of current biofuel volumes (equivalent to approximately 243 million gallons of soy-derived biodiesel) to project a price impact on soybean oil prices and other commodities.[791]

[790] 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.
[791] Lusk, Jayson L. (2022) Prepared for United Soybean Board, *Food and Fuel: Modeling Food System Wide Impacts of Increase in Demand for Soybean Oil*.

Table 8.4-2.2: Projected Impact on Soybean Oil Prices Relative to the No RFS Baseline Lusk Methodology

	2023	2024	2025
Soybean Oil Price (Candidate Volumes); $/pound[a]	$0.69	$0.57	$0.505
Soybean Oil Price Response, per Billion Gallons of Biofuel[b]	35.7%	35.7%	35.7%
Soybean Oil Price Increase per Billion Gallons of Biofuel; $/pound	$0.25	$0.20	$0.18
Soybean Oil Biofuel Increase; billion gallons	2,017	1,983	1,955
Soybean Oil Price Increase; $/pound	$0.50	$0.40	$0.35
Soybean Oil Price (No RFS Baseline); $/pound	$0.19	$0.17	$0.15
Soybean Meal Price, $/ton	$390	$380	$352
Soybean Meal Price Response, %[b]	-7.94%	-7.94%	-7.94%
Soybean Meal Price (No RFS Baseline); $/ton	$421	$410	$380

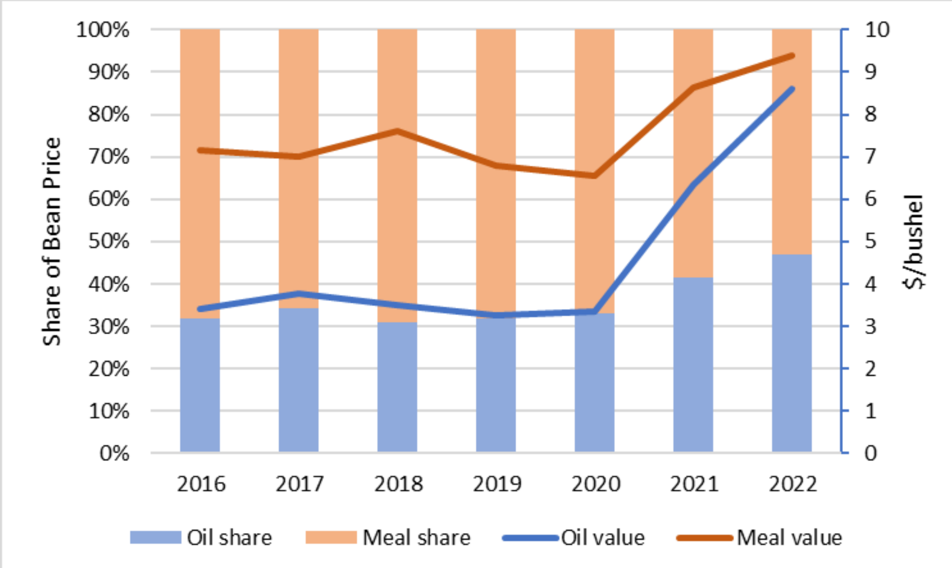
[a] Soybean oil prices are from the USDA Agricultural Projections to 2032 report. Prices represent the average price for a calendar year. For soybean oil, the price is calculated using 1/4 of the price for the first agricultural marketing year (e.g., 2022/2023 for 2023) and 3/4 of the price for the second agricultural marketing year (e.g., 2023/2024 for 2023).
[b] This number is based on a modified shock from Lusk equivalent to 1 billion gallons (as opposed to approximately 240 million gallons in the Lusk paper)

The data in Table 8.4-2.2 reflects an updated methodology to soybean oil and meal price responses based on a more recent study than Babcock, *et.al*. While EPA is confident of this methodology moving forward, the price impact projections from Lusk may not be representative of the true nature of biofuels' future effect on soybean oil, particularly for 2023-24. Vegetable oil prices have been well above historical norms for the past couple years due to a variety of supply and demand impacts around the world. The price impact may be more in line with numbers shown for 2025 in Table 8.4-2.2 assuming the market begins to renormalize.

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.[792] In recent years soybean oil prices appear to have increased significantly relative to soybean meal prices, as shown in Figure 8.4-3.

[792] 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 Values of Soybean Oil and Soybean Meal



From 2016 through the end of 2020, the value of soybean oil relative to soybean meal was relatively stable, with soybean oil representing around 33% of the value of a soybean on average.[793] Starting in 2021, the relative value of the soybean oil has increased significantly, averaging 47% in the 21/22 crop year. Examining the $/bushel value contribution of the components, we see that the oil value has more than doubled while the meal has increased by around 30%. Thus the value of the soybean is shifting more toward the oil than the meal in recent years. This suggests that the supply of soybean oil may tightening relative to soybean meal, with rising soybean oil prices exerting some downward pressure on soybean meal prices.

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.

[793] USDA ERS Oilcrops Data Yearbook, Soy Tables, March 2023.

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	$0.13	$0.12	$0.11
Barley; $/bushel	$0.12	$0.11	$0.11
Oats; $/bushel	$0.10	$0.09	$0.06
Distillers Grains; $/ton	$4.26	$4.64	$4.29

[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).[794]

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.[795] 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

[794] 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.

[795] 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.[796]

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.[797] 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.

[796] 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.
[797] 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	$0.14 per bushel	6,725 million bushels	$942 million
Grain Sorghum	$0.13 per bushel	90 million bushels	$12 million
Barley	$0.12 per bushel	160 million bushels	$19 million
Oats	$0.10 per bushel	141 million bushels	$14 million
Soybean Oil	$0.50 per pound	13.7 billion pounds	$6,850 million
Distillers Grains	$4.26 per short ton	41.5 million short tons	$177 million
Soybean Meal	-$31 per ton	39,450 thousand short tons	-$1223 million
Total	N/A	N/A	$6,790 million
Changes in Food Expenditures in 2024			
Corn	$0.13 per bushel	7,150 million bushels	$930 million
Grain Sorghum	$0.12 per bushel	120 million bushels	$14 million
Barley	$0.11 per bushel	160 million bushels	$18 million
Oats	$0.09 per bushel	141 million bushels	$13 million
Soybean Oil	$0.40 per pound	13.9 billion pounds	$5,560 million
Distillers Grains	$4.64 per short ton	43.5 million short tons	$202 million
Soybean Meal	-$30 per ton	40,225 thousand short tons	-$1,207 million
Total	N/A	N/A	$5,530 million
Changes in Food Expenditures in 2025			
Corn	$0.12 per bushel	7,425 million bushels	$869 million
Grain Sorghum	$0.11 per bushel	120 million bushels	$13 million
Barley	$0.11 per bushel	165 million bushels	$18 million
Oats	$0.06 per bushel	142 million bushels	$9 million
Soybean Oil	$0.35 per pound	14.1 billion pounds	$4,935 million
Distillers Grains	$4.29 per short ton	44.5 million short tons	$191 million
Soybean Meal	-$28 per ton	41,025 thousand short tons	-$1149 million
Total	N/A	N/A	$4,886 million

[a] Quantity used for food and feed calculated based on the USDA Agricultural Projections to 2032 (February 2023). 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 2021 survey.[798] We used

[798] Bureau of Labor and Statistics - Consumer Expenditures in 2021: Table 1, Quintiles of income before taxes: Annual expenditure means, shares, standard errors, and coefficients of variation. 2021.

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 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)	133,595	133,595	133,595
Food Expenditures per Consumer Unit	$8,289	$8,289	$8,289
Total Food Expenditures	$1,107 billion	$1,107billion	$1,107 billion
Change in Food Expenditures	$6,790 million	$5,530 million	$4,886 million
Percent Change in Food Expenditures	0.61%	0.50%	0.44%

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	$8,289	$8,289	$8,289
Percent Impact on Food Expenditures	0.61%	0.50%	0.44%
Projected Food Expenditure Increase	$50.56	$41.45	$36.59
Lowest Quintile Income Consumer Units			
Food Expenditures	$4,875	$4,875	$4,875
Percent Impact on Food Expenditures	0.61%	0.50%	0.44%
Projected Food Expenditure Increase	$29.74	$24.38	$21.52
Second-Lowest Quintile Income Consumer Units			
Food Expenditures	$5,808	$5,808	$5,808
Percent Impact on Food Expenditures	0.61%	0.50%	0.44%
Projected Food Expenditure Increase	$35.43	$29.04	$25.63

Chapter 9: Environmental Justice

Executive Orders 12898 (Federal Actions to Address Environmental Justice in Minority Populations, and Low-Income Populations) and 14096 (Revitalizing Our Nation's Commitment to Environmental Justice for All) 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 communities with EJ concerns 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[799] (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 communities with EJ concerns, 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

[799] https://www.epa.gov/sites/default/files/2016-06/documents/ejtg_5_6_16_v5.1.pdf.

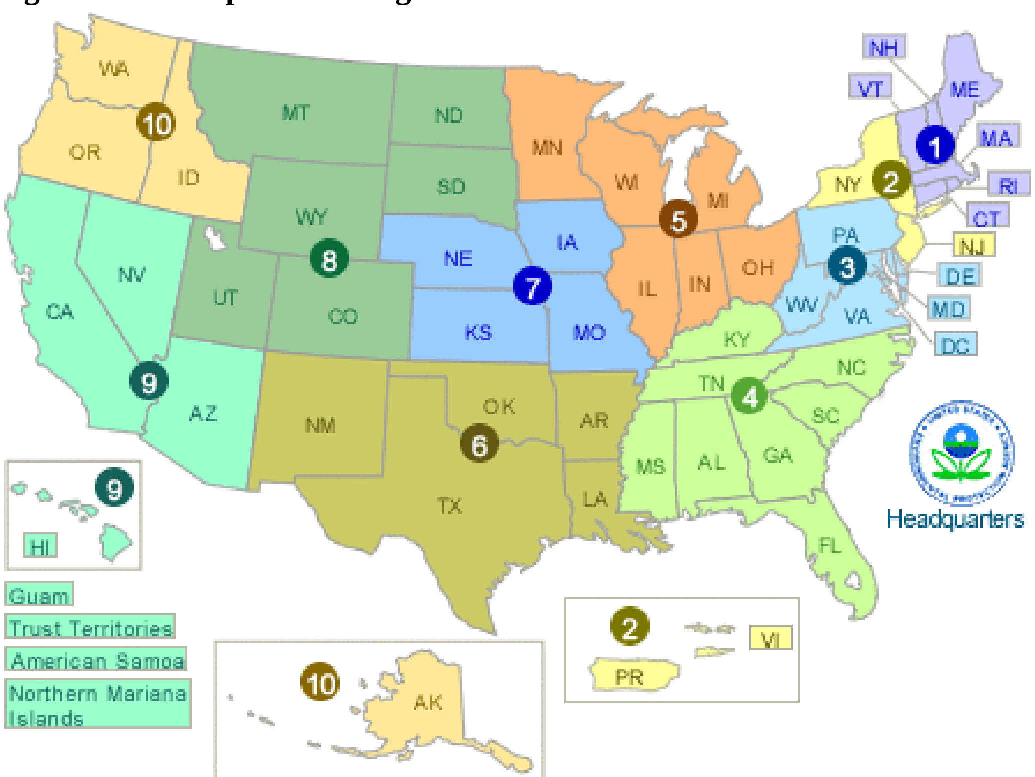
on a framework similar to what is outlined in EPA's Technical Guidance, in addition to investigating ways to further weave EJ into the fabric of the rulemaking process.

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.

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: Demographics Near RIN-generating Facilities 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: Demographics Near Rural RIN-generating 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 RIN-generating 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 RIN-generating 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 RIN-generating 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 RIN-generating 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 RIN-generating 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 RIN-generating 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 RIN-generating 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 RIN-generating 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 RIN-generating 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.[800,801,802,803] 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.[804]

Emissions of non-GHG pollutants such as PM, NO_x, 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.[805] 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. [806,807,808] 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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800 Mohai, P.; Pellow, D.; Roberts Timmons, J. (2009) Environmental justice. Annual Reviews 34: 405-430. https://doi.org/10.1146/annurev-environ-082508-094348.

801 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.

802 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.

803 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.

804 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.

805 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.

806 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.

807 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.

808 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,[809] 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.[810] 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 produce RNG, as they are making use of waste streams of processes driven by other phenomena.[811,812,813,814] 97% of all RINs generated via biogas-related pathways came from wastewater treatment plants, agricultural digesters, or landfill methane capture. The RFS program does not affect human, animal, or solid waste production, and in fact

[809] CAA section 211(o)(2)(B)(ii).
[810] See Chapter 4.3.2.
[811] 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.
[812] 81 FR 59332 (August 29, 2016).
[813] https://www.epa.gov/agstar/benefits-anaerobic-digestion.
[814] https://www.resourcerecoverydata.org/Potential_Power_of_Renewable_Energy_Generation_From_Wastewater_and_Biosolids_Fact_Sheet.pdf.

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 on communities with environmental justice concerns. However, going forward, we would like to better understand the relationship between the RFS volume standards and land use/land management decisions that impact those concerns.

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.[815] 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.[816] 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.[817] American Indian tribes also rely on recreational fisheries for income, as explained by the U.S. Department of the Interior.[818] 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

[815] 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.

[816] Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards. EPA-452/R-11-011. December 2011.

[817] Id.

[818] U.S. Department of the Interior, Working with Native American Tribes (https://web.archive.org/web/20210719071659/https://www.fws.gov/southeast/our-services/native-american-tribes). See also, U.S. Department of the Interior, Native American Trust Responsibilities (https://web.archive.org/web/20220207145305/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 (https://www.bia.gov/bia/ots/division-natural-resources/branch-fish-wildlife-recreation).

populations that rely on them. Additionally, any increased use of nitrogen rich fertilizers, as are 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[819,820] 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 2.4¢/gal in 2023, 3.2¢/gal in 2024, and 4.3¢/gal in 2025. Diesel prices would rise by 10.1¢/gal in 2023 and 2024, and 11.1¢/gal in 2025. Food prices would rise from these volumes by 0.61% in 2023, 0.55% in 2024, and 0.44% 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

[819] 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.
[820] 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.

greater portion of their total expenditures on food and fuel (see Table 9.4-1). Thus, even though 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[821]

	All Consumer Units[822]	Lowest 20% Consumer Unit Income	Second-lowest 20% Consumer Unit Income
Total expenditures	$66,928	$30,869	$43,918
Food expenditures	$8,289	$4,875	$5,808
% of total expenditures on food	12.4%	15.8%	13.2%
Fuel expenditures	$2,148	$1,111	$1,702
% of total expenditures on fuel	3.2%	3.6%	3.9%
% Women	53%	62%	56%
% Black	13%	19%	15%
% With a High School Degree or Less	28%	45%	37%

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 $4,950.64, or 16%% of their income on food (versus 15.8% currently) by 2025, while the second lowest quintile of consumer units would spend $5,898.10, or 13.4% of their income on food (versus 13.2% currently), by 2025. This is shown in year by year increments below in Table 9.4-2. These consumer units would also see increases in their fuel expenditures. The lowest and second-lowest quintile income consumer units would see cumulative increases to their fuel expenditures of $41.66 and $63.83, respectively, by 2025. These increases would result in these groups spending 3.7% and 4% of their total expenditures on fuel, compared to 3.3% for all consumer units. This can be seen in Table 9.4-3

[821] 2021 Consumer Expenditure Survey, Bureau of Labor Statistics, published September 2022.
[822] Consumer units consist of families, single persons living alone or sharing a household with others but who are financially independent, or two or more persons living together who share major expenses. This represents an average value.

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	$8,289	$8,289	$8,289
Percent Impact on Food Expenditures	0.61%	0.50%	0.44%
Projected Food Expenditure Increase	$50.56	$41.45	$36.59
Lowest Quintile Income Consumer Units			
Food Expenditures	$4,875	$4,875	$4,875
Percent Impact on Food Expenditures	0.61%	0.50%	0.44%
Projected Food Expenditure Increase	$29.74	$24.38	$21.52
Second-Lowest Quintile Income Consumer Units			
Food Expenditures	$5,808	$5,808	$5,808
Percent Impact on Food Expenditures	0.61%	0.50%	0.44%
Projected Food Expenditure Increase	$35.43	$29.04	$25.63

Table 9.4-3: Year By Year Change in Fuel Expenditures per Consumer Unit Relative to the No RFS Baseline

	2023	2024	2025
All Consumer Units			
Fuel Expenditures	$2,148	$2,148	$2,148
Percent Impact on Fuel Expenditures	0.79%	1.23%	1.73%
Projected Fuel Expenditure Increase	$16.97	$26.42	$37.24
Lowest Quintile Income Consumer Units			
Fuel Expenditures	$1,111	$1,111	$1,111
Percent Impact on Fuel Expenditures	0.79%	1.23%	1.73%
Projected Fuel Expenditure Increase	$8.78	$13.67	$19.22
Second-Lowest Quintile Income Consumer Units			
Fuel Expenditures	$1,702	$1,702	$1,702
Percent Impact on Fuel Expenditures	0.79%	1.23%	1.73%
Projected Fuel Expenditure Increase	$13.45	$20.93	$29.44

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),[823,824] the Intergovernmental Panel on Climate Change (IPCC),[825,826,827,828] and the National Academies of Science, Engineering, and Medicine[829,830] 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

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[823] 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.

[824] 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.

[825] 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.

[826] 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.

[827] 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.

[828] 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

[829] National Research Council. 2011. America's Climate Choices. Washington, DC: The National Academies Press. https://doi.org/10.17226/12781.

[830] 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.

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 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."[831] 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

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[831] 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

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 emergency services operations.[832] 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.[833] 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.[834] 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

[832] 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.
[833] 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.
[834] Porter et al., 2014: Food security and food production systems.

economies.[835] 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 Northwest have identified climate risks to salmon, elk, deer, roots, and huckleberry habitat.[836] 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, such as disorientation and other effects, 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.

[835] 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.

[836] 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 set 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 renewable fuel volumes in 2023 through 2025 relative to a No RFS baseline. Costs are also calculated for the incremental increase in renewable fuel volumes relative to the year 2022 renewable fuel volumes established in the recent 2020-2022 final rule.[837] In both cases, costs are reported in 2022 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.[838]

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.[839] 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 2022 dollars.[840]

[837] 87 FR 39600 (July 1, 2022).
[838] 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: "Estimated Fuel Costs for the Set Final Rule".
[839] USDA Agricultural Projections to 2032; Long Term Projections Report; February 2023
[840] 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.

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 number in Table 10.1.1.1-1.

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).[841] 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 2022 dollars used across this cost analysis (row #2). [842]

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).[843] 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 2022 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 2022 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:[844]

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 2022 dollars (row #2) to derive the final adjusted corn prices (row #9) subsequently used as an input value for estimating corn ethanol costs as shown in Table 10.1.1.1-1.

[841] USDA Agricultural Projections to 2032; Long Term Projections Report; February 2023.
[842] USDA reports estimated future inflation rates which are used for the nominal dollar to 2021$ adjustment.
[843] 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.
[844] 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.

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	6.80	5.70	4.90
	USDA 2022$	2	6.78	5.65	4.76
Crude Oil Prices	USDA Nominal $	3	75.7	72.7	71.8
	USDA 2022$	4	75.5	72.1	69.8
	EIA 2022$	5	83.18	89.12	83.70
Regressed Corn Prices	Based on USDA 2022	6	3.98	3.89	3.82
	Based on EIA 2022	7	4.86	5.08	4.88
Corn Prices	Difference in Regressed Corn Prices EIA - USDA	8	0.87	1.19	1.06
Corn Prices	Adjusted USDA 2022$	9	7.65	6.84	5.82

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).[845] The FAPRI DDGS projected prices are reported in nominal dollars, so we adjusted the price projections to 2022 dollars. Table 10.1.1.1-2 summarizes DDGS prices used in the cost analysis.

Table 10.1.1.1-2: DDGS Prices (2022 dollars)

Year	DDGS Prices ($/dry ton)
2023	175.5
2024	232.4
2025	183.4

10.1.1.2 Soybean Oil, Corn Oil and Fats, Oil and Grease Prices

Soybean oil, waste fats, oils, and greases (FOG), corn oil, and canola oil were identified in Chapter 2 as the feedstocks for producing biodiesel and renewable diesel fuel. For the cost analysis, canola oil volumes are combined with the soybean oil volume to estimate a single soybean oil volume. We believe it is a reasonable cost assumption to combine canola oil with soybean oil because they are both virgin vegetable oils and would likely have similar production costs. Soybean oil price projections made by USDA are used as a starting point for this cost analysis.[846]

[845] U.S. Agricultural Market Outlook, Food and Agricultural Policy Research Institute (FAPRI); FAPRI-MU Report #02-22; March 2023.
[846] USDA Agricultural Projections to 2032; Long Term Projections Report; February 2023.

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 2022 dollars (row #2), and then adjusting for the differences in crude oil prices (row #4 for USDA in 2022 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:[847]

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	69	57	50.5
	USDA 2022$	2	68.8	56.5	49.1
Crude Oil Prices	USDA Nominal $	3	75.7	72.7	71.8
	USDA 2022$	4	75.5	72.1	69.8
	EIA 2022$	5	83.18	89.12	83.70
Regressed Soy Oil Prices	Based on USDA 2022$	6	34.44	33.75	33.28
	Based on EIA 2022$	7	40.62	42.16	40.75
Soy Oil Prices	Difference in Regressed Soy Oil Prices EIA - USDA	8	6.18	8.40	7.47
Soy Oil Prices	Adjusted USDA 2022$	9	75.0	64.9	56.6

Neither USDA nor FAPRI project future corn oil or FOG prices. Instead, future prices for these oils were estimated based on the historical differences between them and soybean oil's spot prices.[848] Corn oil and FOG spot prices were compared to soybean oil spot prices between January 2016 and December 2022. Over that time period, soybean oil averaged about 40 cents per pound (ranged from 29 to 68 cents per pound. Corn oil and FOG prices were compared to soy oil prices, and these were priced at 82.7 percent and 75.4 percent of soybean oil, respectively.

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

[847] 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.
[848] USDA Yearbook Tables by the Economic Research Service, downloaded March 2023.

soybean oil price by 0.032 dollars per pound.[849] 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 action. Similar adjustments are made for FOG and corn oil, the markets of which are around 20 percent the size of the soy oil market. The projected soy 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, along with the projected prices for FOG and corn oil.

Table 10.1.1.2-2: Projected Vegetable Oil Production Costs (2022 dollars/pound)

	Base Prices	Projected Vegetable Oil Prices		
	Soybean Oil	**Soybean Oil**	**FOG**	**Corn Oil**
2023	75	82.1	75.8	60.7
2024	65	79.1	61.2	53.1
2025	57	80.0	58.7	46.8

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.

Detailed cost summaries presented for each renewable fuel in this section are based on 2023 cost inputs.[850] All the costs summarized in this section for all years are calculated in a spreadsheet which is available in the docket for this rulemaking.[851]

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

[849] Shelby, Michael; Cost Impacts of the Final 2019 Annual Renewable Fuel Standards; Memorandum to EPA Air and Radiation Docket EPA-HQ-OAR-2018-0167.
[850] 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.
[851] Estimated Fuel Costs for SET Final Rule.xlsx.

used in the following section for converting the one-time, total capital cost to an equivalent per-gallon cost.[852] 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.[853,854,855,856,857]

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 2022 dollars for this analysis. The Chemical Engineering Plant Index (CEPI) capital cost index was used to adjust capital costs to 2022 dollars. Consistent with the increased inflation observed over the past year, the CEPI capital cost index for 2022 represents a large increase in capital costs when adjusting capital costs to the year 2022.

Fixed operating costs include the maintenance costs, insurance costs, rent, laboratory charges and miscellaneous chemical supplies.[858] Maintenance costs can range from 1% to 8% for industrial processes.[859] 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

Utility and Fuel inputs are variable operating 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

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852 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).

853 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.

854 Cost Estimates of Long-Term Options for Addressing Boutique Fuels; Memorandum from Lester Wyborny to the Docket; October 22, 2001.

855 Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements; EPA420-R-00-028; December 2000.

856 Final Regulatory Analysis: Control of Emissions from Nonroad Diesel Engines; EPA420-R-04-007; May 2004.

857 Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis; EPA-420-R-10-006; February 2010.

858 Peters, Max S., Timmerhaus, Klaus, D.; Plant Design and Economics for Chemical Engineers 3rd Edition; McGraw Hill; 1980.

859 McNair, Sam Budgeting for Maintenance: A Behavior-Based Approach, Life Cycle Engineering, 2011.

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) 2023 Annual Energy Outlook.[860] 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.[861,862]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 (2022 dollars)[a]

Year	Natural Gas ($/1000 cf)	Electricity (c/kWhr)	Water ($/1000 gals)
2023	6.76	8.18	3.0
2024	5.56	7.56	3.0
2025	4.95	7.15	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.

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.[863,864] 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.[865] 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. 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.[866] Of the corn ethanol plants in the 2012 survey, 74% were separating and selling corn oil , however, we believe that by now all corn ethanol plants are separating and selling corn oil.

The quantity of dried distillers grain with solubles (DDGS) produced by corn ethanol plants was estimated from USDA DDGS production data from February to October, 2022. USDA reports DDGS production for four different categories of DDGS: dried distillers grain (DDG), dried distillers grain with solubles (DDGS), distillers wet grain (DWG) with 65 or more

[860] Annual Energy Outlook 2023, Energy Information Administration, March 2023.
[861] Haas, M.J, A process model to estimate biodiesel production costs, Bioresource Technology 97 (2006) 671-678.
[862] 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.
[863] Lee, Uisung; Retrospective analysis of the U.S. corn ethanol industry for 2005 – 2019; implications for greenhouse gas emission reductions;: Biofpr; May 4, 2021.
[864] Mueller, Steffen; 2012 Corn Ethanol: Emerging Plant Energy and Environmental Technologies; April 29, 2013.
[865] Irwin, Scott; Weekly Output: Ethanol Plants Remain Barely Profitable; 3/16/2018.
[866] Edwards, William; Grain Truck Transportation Cost Calculator (a3-29graintransportation.xlsx version 1.4_82017); Iowa State University.

percent moisture, and distillers wet grain (DWG) with 40 to 64 percent moisture. The production quantity of DWG is adjusted to an equivalent of dried DDG. The DWG with 65 or more percent moisture is assumed to have 75 percent moisture, while the DWG with 40 to 65 percent moisture is assumed to have 52 percent moisture. Both wet distiller grain categories are adjusted to dry distiller grain quantities assuming that dried distiller grains contains 11 percent moisture.[867] Table 10.1.2.2-1 summarizes and averages the quantity of distiller grains by category, reporting the quantity of wet distiller grains both before and after adjusting them to equivalent dry grains amounts.

Table 10.1.2.2-1: USDA-reported DDG (tons) and Corn Ethanol (million gallons) Production for a portion of 2022

	February	March	April	May	June	July	August	September	October	Average
DWG 65%+ Wet	1,293,312	1,382,790	1,321,275	1,328,402	1,283,359	1,279,210	1,322,744	1,249,996	1,397,867	-
DWG 40-65 Wet	492,839	562,599	517,270	468,772	494,792	495,386	544,168	498,142	490,060	-
DWG 65%+ Dry	363,290	388,424	371,145	373,147	360,494	359,329	371,557	351,122	392,659	370,130
DWG 40-65 Dry	287,951	328,710	302,225	273,889	289,092	289,439	317,941	291,049	286,327	296,291
DDG	303,788	372,813	328,691	322,855	346,591	334,122	335,885	281,984	388,993	335,080
DDGS	1,693,253	1,877,338	1,704,698	1,896,665	1,918,611	1,934, 355	1,867,735	1,613,088	1,745,419	1,805,685
Total DDG/DDGS	2,626,132	2,626,132	2,626,132	2,626,132	2,626,132	2,626,132	2,626,132	2,626,132	2,626,132	2,626,132
Ethanol Volume	1,189	1,327	1,217	1,315	1,314	1,322	1,280	1,139	1,321	1,269
Pounds DDGS/gal ethanol	4.42	4.43	4.41	4.33	4.40	4.38	4.48	4.42	4.23	4.39

After averaging the production volume of each grain type over the 9 months, they are totaled and divided by the average ethanol production volume. This analysis estimates DDGS production to be 4.4 pounds per gallon of ethanol produced (12.5 pounds per bushel of corn).

Corn oil production from ethanol plants was estimated using a similar analysis as that conducted for DDGS. The corn oil production by month is summarized and averaged in Table 10.1.2.2.-2.

Table 10.1.2.2-2: USDA-reported Corn Oil Production for a portion of 2022 (tons)

	February	March	April	May	June	July	August	September	October	Average
Corn Oil	154,933	174,657	163,024	177,158	184,350	187,853	180,062	159,873	186,770	174,298

To estimate the corn oil production from corn ethanol plants, the average corn oil production is divided by the average corn ethanol production volume summarized in Table 10.1.2.2-1. Based on this analysis, corn oil production from corn ethanol plants is estimated to be 0.27 lbs per gallon of ethanol (0.79 pounds per bushel of corn).

Table 10.1.2.2-3 contains the plant demand and outputs and capital costs for corn ethanol plants and provides an estimate of the estimated corn ethanol production cost for year 2023.

867 Shurson, Jerry; DDGS present handling and storage considerations; National Hog Farmer; May 29, 2019.

Table 10.1.2.2-3: Corn Ethanol Plant Demands, Production Levels, and Capital Costs for 2023 (2022 dollars)

Category of Plant Input/Output	Plant Inputs/Outputs	Cost per Input	Cost (MM$)	Cost ($/gal)
Ethanol Yield	2.86 Gal/Bushel	7.71 $/bushel	206	2.70
DDG Yield	4.4 Lbs/Gal	175 $/ton	–29	–0.38
Corn Oil Yield	0.27 Lbs/gal	60 cents/lb	–12.5	–0.16
CO2 Yield	1 lb/Gal	$12/ton		
Thermal Demand	22,480 BTU/Gal	6.76 $/1000 cf	11.2	0.15
Electricity Demand	0.63 kWh/Gal	8.18 c/kwh	3.9	0.05
Water Use	2.7 Gal/Gal	$3/1000 gals	0.6	0.01
Labor Cost	0.07 $/Gal	-	5.3	0.07
Capital Cost (2022 dollars, 76 million Gals/Yr)	3.27 $/Gal Plant Capital cost		32.5	0.43
Annual Fixed Cost	5.5% of Total Capital Cost		16.3	0.21
Denaturant	2 volume percent		-1.2	-0.02
Total Cost			231	3.02

The projected corn ethanol social production cost for an 85 million gallon capacity ethanol plant producing 76 million gallons per year of ethanol is $3.02 per gallon of denatured ethanol for 2023, $2.61 for 2024, and $2.37 for 2025. The downward trend in estimated per-gallon production costs reflect the expected downward trend in corn prices.

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.[868,869] 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

[868] Haas, M.J, A process model to estimate biodiesel production costs, Bioresource Technology 97 (2006) 671-678.
[869] 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.

3. Glycerol recovery.[870]

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 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 2022 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,[871] sodium methoxide,[872] hydrochloric acid,[873] sodium hydroxide,[874] and glycerine.[875] [876] The value of methanol is from a Methanex report plus 15

[870] Haas, M.J, A process model to estimate biodiesel production costs, Bioresource Technology 97 (2006) 671-678.
[871] Methanex; current North America prices plus 15 c/gal for shipping; https://www.methanex.com/our-business/pricing; January 31 2023.
[872] Alibaba; https://www.alibaba.com/product-detail/Food-Grade-Purity-28-31-Colorless_1600468349215.html; February 2023.
[873] Chemanalyst; https://www.chemanalyst.com/Pricing-data/hydrochloric-acid-61; February 2023.
[874] eBioChem; http://www.ebiochem.com/product/caustic-soda-sodium-hydroxide-16515; February 2023.
[875].Alibaba https://www.alibaba.com/product-detail/Competitive-Price-80-99-7-Refined_1600713799582.html?spm=a2700.7724857.0.0.4b943a616FYg3J&s=p; February 2023.
[876] Irwin, Scott; 2021 Was a Devastating Year for Biodiesel Production Profits; Farmdoc Daily, February 16, 2022.

cents per gallon distribution costs.[877] Prices for sodium methoxide, hydrochloric acid, and sodium hydroxide are all bulk prices from a chemicals supplier.[878]

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.[879] 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 25 cents per pound for glycerine.

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.

Table 10.1.2.3-1: Biodiesel Production Cost for 2023 (year 2022 dollars)

	Unit Demands	**Cost per Unit**	**Thousand Dollars**	**$/gal**
Soybean Oil Feed	76,875 (1000 lb)	82 cents/lb	63,109	6.31
Methanol	7422 (1000 lb)	1.88 $/gal	2,170	0.22
Sodium Methoxide	927 (1000 lb)	$800/ton	371	0.037
Hydrochloric Acid	529 (1000 lb)	$150/MT	36.1	0.004
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)	24 cents/lb	(2160)	(0.22)
Natural Gas	66.9 million cf	$6.76/1000cf	452	0.045
Electricity	1008 kW	8.18 cents/kWh	722	0.072
Labor				0.05
Capital Cost 2006$	11.35 ($million)	-	-	-
Capital Cost 2022$	18.54 ($million)		2,039	0.20
Fixed Cost		5.5%	1,019	0.10
Total Cost			67,838	6.83

As shown in Table 10.1.2.3-1, biodiesel produced from soybean oil is estimated to cost 6.83 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.

[877] Methanex Methanol Price Sheet; US Gulf Coast; January 31,2022
[878] https://www.alibaba.com.
[879] Yang, Fangxia; Value-added uses for crude glycerol – a byproduct of biodiesel production; Biotechnology for Fuels; March 14, 2012.

Table 10.1.2.3-2: Summary of Estimated Biodiesel Production Costs ($/gal)

Year	Soy Oil	Corn Oil	FOG
2023	6.83	5.19	6.35
2024	6.59	4.59	5.21
2025	6.65	4.10	5.01

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.[880] 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.[881] Hydrogen costs are estimated based on a 50 million standard cubic feet per day steam methane reforming hydrogen plant, adjusted to represent a 32 million cubic feet per day plant which would be the volume required for a typical sized 220 million gallon per year renewable diesel plant.[882]

[880] 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.
[881] Conversation with Mike Ackerson, Duke Biofuels, May 2020.
[882] Meyers, Robert A; Handbook of Petroleum Refining Processes; 4ed., 2016; McGraw Hill.

Table 10.1.2.4-1: Hydrogen Plant Costs

	Unit Demands for a 50 mm cf/day plant	Cost per Unit	Cost for a 32 mmcf/day plant	
			Million Dollars	$/thousand FT3
Feed Natural Gas	730 mmBTU/hr	6.76 $/mmBTU	27.6	2.37
Fuel Gas for Heat	150 mmBTU/hr	6.76 $/mmBTU	5.7	0.49
Power	1200 KW	8.18 c/KWh	0.6	0.05
Boiler feed water	160,000 lb/hr	$3/thousand gallons	0.3	0.03
Cooling water	900 gal/min	$3/thousand gallons	0.9	0.08
Export Steam	120,000 lb/hr 600 psi		-5.9	-0.50
Capital Cost	$70 MM in 2016	For a 50 mm cf/day plant		
	$81 MM in 2022	For a 32 mm cf/day plant	8.9	0.769
Fixed Cost		6.7%	5.47	0.46
Total Cost			43.5	3.70

Based on our cost analysis, hydrogen is estimated to cost $3.70 per thousand standard cubic feet.

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.[883] Despite the age of the reference, the underlying chemistry is unlikely to have changed appreciably.

Table 10.1.2.4-2: Input and Output Streams 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.[884] Finally, the total cost per gallon was estimated at $7.61. 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.

[883] A New Development in Renewable Fuels: Green Diesel, AM-07-10 Annual Meeting NPRA, March 18-20, 2007.
[884] 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.

Table 10.1.2.4-3: Renewable Diesel Production Cost Estimate for a Greenfield 220 Million Gallons/Yr Plant Processing Soy Oil in 2023 (2022 Dollars)

Stream		Estimated value	MM$/yr	$/gal
Soy Oil input	235 MMgals/yr	82c/lb	1483	6.74
Naphtha output	11.8 MMgals/yr	1.81 c/gal	(21.3)	(0.10)
Light fuel gas output	21.2 MMgals/yr	92 c/gal	(19.5)	(0.09)
Hydrogen input	4760 scf/100 gals	$3.73/thousand standard cubic feet	41.8	0.19
Other Operating Costs			15.2	0.07
Capital Costs (2022 dollars)		$1052 million	115.7	0.53
Fixed Costs		5.5%	57.8	0.26
Total Costs			1673	7.61

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.[885] These modifications are estimated to cost about one third the cost of a new renewable diesel hydrotreater, or $315 million, instead of $768 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. [886,887]

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 $7.24/gallon versus $7.61/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.

[885] Chan, Erin; Converting a petroleum diesel refinery for renewable diesel fuel; Hydrocarbon Processing; April 2021.
[886] Chan, E., Converting a petroleum diesel refinery for renewable diesel; Special Focus: Clean Fuels; April 2021.
[887] Lane, Robert; Renewable Diesel Interest Accelerates; August 26, 2020.

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	1483	6.74
Naphtha output	4.0 MMgals/yr	1.45 c/gal	(21.3)	(0.10)
Light fuel gas output	7.2 MMgals/yr	73 c/gal	(19.5)	(0.09)
Hydrogen input	4760 scf/100 gals	$2.80/thousand standard cubic feet	41.8	0.19
Other Operating Costs			15.2	0.07
Capital Costs (2022 dollars)		$315 million	34.7	0.16
Fixed Costs		5.5%	57.8	0.26
Total Costs			1592	7.24

The difference between the low and high production costs is solely due to the difference in capital costs and associated fixed costs. For refineries converting their refineries to produce renewable diesel, the amortized capital cost is estimated to be only $0.16 per gallon, while the greenfield plant's estimated capital cost is $0.53 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 $7.42 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
2023	7.42	5.66	6.91
2024	7.15	5.02	5.68
2025	7.23	4.50	5.47

10.1.2.5 Biogas

Biogas is the result of anaerobic digestion of organic matter, including municipal waste, manure, agricultural waste, and food waste.[888] 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.[889]

The largest source of biogas, which is already being collected to avoid releasing methane into the environment, is from landfills.[890] 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.

[888] Wikipedia. https://en.wikipedia.org/wiki/Biogas.
[889] LeFevers, Daniel; Landfill Gas to Renewable Energy; Hill Briefing; April 26, 2013.
[890] Biomass Explained, Landfill Gas and Biogas; US Energy Information Administration; February 1, 2019; www.eia.gov/energyexplained/index.php?page=bioimass_biogas

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).[891,892] The throughput volume of landfill gas was estimated to be 600 standard cubic feet per minute based on a survey of biogas production facilities.[893] 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.[894] Distribution and retail costs are estimated for biogas in Chapter 10.1.4.3.

Table 10.1.2.5-1: Biogas Cleanup Costs (600 scf/min)

	Cost Factors (2019$)	**million dollars (2022$)**	**$ per thousand cubic feet (2022$)**
Interconnection	$400,000	0.54	0.19
Capital Costs	$6{,}000000 * e^{(0.0003*ft3/min)}$	9.65	3.36
Operating and Maintenance	250 * ft3/min +148,000	0.90/yr	2.85
Electricity Costs	0.009 kWh/ft3	0.33/yr	1.05
Total			7.46

10.1.2.6 Sugar Cane Ethanol

Unlike the starch in corn kernels which first must be depolymerized using enzymes, sugarcane contains free sugar which, after extraction from the sugarcane, can be directly fermented into ethanol. The fibrous portions of the sugarcane plant is typically combusted to produce the energy needed for the process.

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[891] The current version of this model and user's manual dated March 2021 are downloadable from the LMOP website: https://www.epa.gov/lmop.
[892] 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.
[893] Economic Analysis of the US Renewable Natural Gas Industry; The Coalition of Renewable Natural Gas; December 2021.
[894] LFG Energy Project Development Handbook – Project Economics and Financing; Chapter 4.

We estimated the cost to produce sugar cane ethanol two different ways. The first way is based on a simple bottom-up cost estimate using some production cost information. The second is based on price data for sugarcane ethanol received from Brazil available in the EPA Moderated Transaction System (EMTS). Generally, ethanol from sugarcane produced in tropical areas is cheaper to produce than ethanol from cellulose, and is similar to the cost of corn starch ethanol. This is due to favorable growing conditions, relatively low-cost feedstock and energy inputs, and other cost reductions gained from years of experience.

A study by OECD (2008) entitled "Biofuels: Linking Support to Performance," provides a set of assumptions and an estimate of production costs. Our estimate of sugarcane production costs, which is shown in Table 9.1.2.3-1, primarily relies on the analysis made for that study. The original cost estimate reported in the RFS2 rulemaking assumes an ethanol-dedicated mill and is based off an internal rate of return of 12%, a debt/equity ratio of 50% with an 8% interest rate and a selling of surplus power at $57 per MWh. We revised the capital and operating costs higher by 63% to account for the effects of inflation from 2006 to 2022. When we estimated the amortized, per-gallon capital costs we also added a 20% capital cost contingency factor to account for other costs not accounted for in the cost analysis and amortized the capital costs using our capital cost amortization parameters. Table 10.1.2.6-1 provides the updated production cost estimate for sugarcane ethanol.

Table 10.1.2.6-1: Sugar Cane Ethanol Production Cost

<table>
<tr><td rowspan="6">Cost Basis</td><td>Sugarcane Productivity</td><td colspan="2">71.5 tons/hectare</td></tr>
<tr><td>Sugarcane Consumption</td><td colspan="2">2 million tons/year</td></tr>
<tr><td>Harvesting days</td><td colspan="2">167</td></tr>
<tr><td>Ethanol productivity</td><td colspan="2">85 liters/ton feedstock (22.5 gal/ton feedstock)</td></tr>
<tr><td>Ethanol Production</td><td colspan="2">170 million liters/year (45 million gals/yr)</td></tr>
<tr><td>Surplus power produced</td><td colspan="2">40 kWh/ton sugarcane</td></tr>
<tr><td></td><td></td><td>RFS2 Reported Cost ($2006)</td><td>Revised Costs ($2022)</td></tr>
<tr><td rowspan="2">Capital Costs ($ million)</td><td>Investment cost in million$</td><td>97</td><td>158</td></tr>
<tr><td>Investment cost for sugarcane production</td><td>36</td><td>59</td></tr>
<tr><td rowspan="6">Per Gallon Costs ($/gal)</td><td>O & M (Operating & Maintenance) costs</td><td>0.26</td><td>0.42</td></tr>
<tr><td>Variable sugarcane production costs</td><td>0.64</td><td>1.05</td></tr>
<tr><td>Capital costs</td><td>0.49</td><td>0.64</td></tr>
<tr><td>Total production costs</td><td>1.40</td><td>2.11</td></tr>
<tr><td>Shipping Costs to US</td><td></td><td>0.15</td></tr>
<tr><td>Delivered Cost</td><td></td><td>2.26</td></tr>
</table>

We also reviewed recent data on sugar cane ethanol prices which we receive in the EPA Moderated Transaction System (EMTS). These are as-received prices, so they include the cost to ship the ethanol from Brazil to the US. The average of recent sugar cane ethanol prices from EMTS was $2.73 per gallon. Other price data which EPA receives from OPIS showed a similar average price which helps to corroborate the price data from EMTS.

The average FOB ethanol price of $2.73/gallon in Brazil is somewhat higher than the estimated sugar cane ethanol production cost of $2.26/gallon. This cost/price difference can mostly be attributed to the low (0.11) before-tax capital amortization factor that we use which reflects the social cost of capital, and the shipping costs incorporated in the price data. When we use a more typical 0.16 after-tax capital amortization factor used by industry, the per-gallon costs increase to $2.55 per gallon. Normally we would use the bottom-up cost estimate, however, the EMTS price data may capture some inflation effects which the bottom-up cost estimate may not capture regardless of the applied inflation adjustment. For this reason we used the $2.73 per gallon price data from EMTS to represent the production and distribution costs for sugar cane ethanol.

10.1.2.7 Corn Kernel Fiber Ethanol

In addition to converting corn starch to ethanol, some of the fiber contained in the dried distiller grains (DDGS) can also be converted to ethanol. This additional ethanol from corn fiber is considered cellulosic ethanol and earns D3 RINs. Historically, this cellulosic conversion step of the fiber to ethanol was thought of as a separate step than the starch to ethanol conversion, and therefore would require a separate reactor vessel and require additional operating costs. However, one or more companies have found it possible to convert some of the cellulosic fiber to ethanol in the existing starch to ethanol facility, and we project that this single reactor design would likely be producing cellulosic ethanol during the timeframe of this rulemaking.[895] [896] Anticipating that this cellulosic ethanol would be produced in an existing starch to ethanol reactor provides a cost efficiency which would lower the overall production cost. But this also presents a challenge for how to identify the quantity of ethanol produced from cellulose versus that produced from the starch. To remedy this EPA published guidance on how to identify the portion of ethanol being produced from cellulose.[897]

Anticipating that the cellulosic ethanol will be produced along with corn starch in an existing reactor allows us to estimate the cost of producing this cellulosic ethanol. Since we already estimate the capital, fixed and variable operating cost of producing ethanol from corn starch, we simply apply those same cost estimates to the corn fiber ethanol. There are other cost factors to consider, which is the potential cost for the additional enzyme added to convert corn fiber to ethanol, and a cost savings due to increased corn oil production.[898] It appears that the cost of the additional enzyme is approximately equally offset by the cost savings of additional

[895] Kacmar, Jim; Intellulose: An Innovative Approach to your Plant's Profitability; Edeniq presentation to the 2019 Distillers Grains Symposium; May 15, 2019.
[896] Conversion of Corn-Kernel Fiber in Conventional Fuel-Ethanol Plants; National Corn to Ethanol Research Center; Project No. 0340-19-03; November 11, 2018.
[897] Guidance on Quantifying an Analytical Method for Determining the Cellulosic Converted Fraction of Corn Kernel Fiber Co-Processed with Starch; EPA-420-B-22-041; September 2022.
[898] Kacmar, Jim; Intellulose: An Innovative Approach to your Plant's Profitability; Edeniq presentation to the 2019 Distillers Grains Symposium; May 15, 2019

corn oil production. Therefore, we simply use the cost for producing ethanol from corn starch for the cost of producing ethanol from cellulosic ethanol.

It is possible that the DDGS remaining after extracting the corn fiber would have a higher market value than regular DDGS on a mass basis of DDGS due to the higher protein content.[899] However, as a conservative assumption, we do not assume any price increase for residual DDGS due to its higher protein content.

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) when blended into gasoline 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 cost 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

[899] DDGS from which the corn kernel fiber has been extracted have higher protein levels, and can be used in a wider variety of feed markets (e.g., can be fed to poultry and swine in addition to cattle). Therefore, some marketers suggest that this type of DDGS could have a higher value than regular DDGS. Jeremy Javers (ICM), “By-Products to Co-Products to Products,” 2017.

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 based on the output from refinery modeling cases conducted by ICF/Mathpro for a projected 2020 year case assuming that crude oil would be priced at $72/bbl.[900] 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.[901] Due to the options available to refiners to replace ethanol's octane, ICF/Mathpro ran two ethanol replacement cases. In the lower per-gallon cost case, the refinery model principally relied on increased alkylate production. But to be able to replace all of ethanol's octane, the refinery model estimates that refiners would also increase the octane of reformate (through increased reformer severity) and increase production of isomerate, even if the primary octane replacement is alkylate. The refinery model estimates that for this alkylate-centric case over 7.6 million barrels per day of new refinery unit capacity would need to be added by refiners.

ICF/Mathpro modeled a second case. Instead of relying on large butane purchases for producing alkylate, the model increased the throughput to, and turned up the severity of, existing reforming units to increase the octane of reformate, the product stream of the reformer. This case still relied on other octane producing unit additions, including alkylate and isomerate, but increased reformate volume and octane was the principal method. This second reformate-centric refinery modeling case was less capital-intensive, but still added 3.7 million barrels per day of additional refinery unit capacity and was more costly on a per-gallon basis. Increasing the severity of reformers is relatively more expensive because of the cost associated with the production of two by-products of the reforming process which increase as the severity of the reformer is increased. Hydrogen is a by-product of reforming, but reformer-produced hydrogen is much more expensive than hydrogen produced from natural gas because natural gas has been priced much lower than crude oil. Fuel gas is another reformer by-product which is usually used for refinery process heat, but displaces much cheaper purchased natural gas. For short-term octane needs refiners would likely need to rely on increasing reformate severity to avoid or minimize the amount of new refining unit capacity additions, but given the higher cost overall cost, this would not be a preferable long-term solution.

Table 10.1.3.1.1-1 summarizes gasoline's marginal costs for the reference case, and ethanol's marginal costs for two ethanol removal cases, for different gasoline types and refinery regions. For the two ethanol removal cases the refinery modeling 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, low biofuel #1 is the reformate-centric case while biofuel #2 is the alkylate-centric case. The lower marginal values for PADD 1 can be explained because Mathpro forced PADD 3 refineries to satisfy PADD 1's need for replacing ethanol's volume and octane through PADD's 3 exports into the PADD 1

[900] 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.

[901] EPA's contract was with ICF Incorporated, LLC, which in turn retained Mathpro for some aspects of the work.

after initial refinery model runs showed PADD 1's marginal costs for replacing ethanol were exceedingly high.

Table 10.1.3.1.1-1: Gasoline Marginal Values for Reference Case and Ethanol Marginal Values for the No-Biofuel Cases ($/bbl)

PADD of Gasoline Origin			Gasoline Marginal Values					
					Low Biofuel #1		Low Biofuel #2	
	Type	Grade	Summer	Winter	Summer	Winter	Summer	Winter
PADD 1	RFG	Prem	95.74	83.94	108.37	100.88		
		Reg	91.45	81.35	115.98	105.97		
	CG	Prem	92.68	83.89	123.02	100.87		
		Reg	88.93	81.35	136.43	105.88		
PADD 2	RFG	Prem	88.09	81.68	132.42	110.28	113.45	96.62
		Reg	84.80	79.77	145.38	116.02	122.86	101.61
	CG	Prem	85.55	81.25	149.08	110.41	126.74	96.25
		Reg	82.46	79.45	161.21	115.79	135.55	100.93
PADD 3	RFG	Prem	85.42	78.31	121.69	94.72	118.51	89.77
		Reg	81.86	76.39	134.67	98.45	131.29	94.48
	CG	Prem	83.64	78.78	133.95	95.13	129.37	89.91
		Reg	79.97	76.76	146.78	98.46	142.00	94.55
PADD 4	CG	Prem	79.8	77.0	135.5	115.2	150.1	103.1
		Reg	77.4	75.1	149.0	124.0	168.1	110.0
	Low RVP	Prem	94.5		136.5		151.2	
		Reg	98.3		150.1		169.2	
PADD 5	RFG	Prem	96.89	83.68	37.68	96.05		
		Reg	91.61	82.01	62.46	97.37		
	CG	Prem	77.63	83.00	118.14	98.01		
		Reg	73.38	81.12	126.14	97.68		

The gasoline-ethanol difference in marginal values is calculated and summarized on a cents per gallon basis in Table 10.1.3.1.1-2.

Table 10.1.3.1.1-2: Marginal Ethanol Replacement Cost by Gasoline Type and Season (cents/gallon)

PADD of Gasoline Origin	Type	Grade	Low Biofuel #1 Reformate-centric Summer	Low Biofuel #1 Reformate-centric Winter	Low Biofuel #2 Alkylate-centric Summer	Low Biofuel #2 Alkylate-centric Winter
PADD 1	RFG	Prem	30.07	40.35	0	0
		Reg	58.41	58.62	0	0
	CG	Prem	72.23	40.43	0	0
		Reg	113.10	58.42	0	0
PADD 2	RFG	Prem	105.56	68.08	60.39	35.55
		Reg	144.23	86.31	90.61	52.00
	CG	Prem	151.27	69.44	98.08	35.73
		Reg	187.51	86.52	126.41	51.15
PADD 3	RFG	Prem	86.35	39.08	78.77	27.29
		Reg	125.74	52.52	117.69	43.07
	CG	Prem	119.78	38.93	108.86	26.50
		Reg	159.07	51.68	147.69	42.38
PADD 4	CG	Prem	132.70	90.86	167.45	62.16
		Reg	170.67	116.41	216.07	83.19
	Low RVP	Prem	100.19	0.00	135.02	0.00
		Reg	123.27	0.00	168.77	0.00
PADD 5	RFG	Prem	-140.97	29.46	0	0
		Reg	-69.39	36.56	0	0
	CG	Prem	96.44	35.73	0	0
		Reg	125.61	39.43	0	0

The regional ethanol replacement costs are volume-weighted together to develop national-average ethanol replacement costs by gasoline grade and season. These costs are only presented for the conventional gasoline pool since the ethanol was only replaced in the conventional portion of the gasoline pool in the study. Table 10.1.3.1.1-3 summarizes these estimated ethanol-replacement costs.

Table 10.1.3.1.1-3: National Average Ethanol Replacement Cost by Gasoline Grade and Season (c/gal)

	Gasoline Grades	Reformate-centric Summer	Reformate-centric Winter	Alkylate-centric Summer	Alkylate-centric Winter
Conventional	Premium	124.6	50.8	112.0	32.7
	Regular	165.1	66.8	144.2	48.2

To estimate the volatility cost, ethanol's marginal values in Table 10.1.3.1.1-1 for RFG are subtracted from those for CG, although the values are calculated separately for premium and regular grade gasolines. These calculated values are summarized in Table 10.1.3.1.1-4. Although this analysis could have separately analyzed RVP-controlled conventional gasoline without a waiver, it did not since its gasoline volume was less than 2% of the total gasoline pool.

Table 10.1.3.1.1-4 Ethanol's RVP Blending Cost in Reformulated Gasoline in 2020 by PADD ($/gal)[a]

Gasoline PADD	Gasoline Grade	RFG-CG Marginal Values ($/bbl)
PADD 1	Premium	9.74
	Regular	10.53
PADD 2	Premium	9.59
	Regular	9.32
PADD 3	Premium	9.31
	Regular	9.25
PADD 5 (CA)	Premium	58.79
	Regular	62.59

The ethanol RVP blending cost estimated by the refinery model are volume-weighted together to develop national-average values, and ethanol's RVP blending costs are calculated separately for premium and regular grades of summertime RFG, and summarized in Table 10.1.3.1.1-5. The PADD 5 RFG, which is California RFG, is modeled to have a volatility cost which is five time higher than other RFG areas. The cost of complying with California RFG standards may be higher than that for other RFG areas, but a factor of five seemed much too high and was considered an outlier.[902] Therefore, the modeled California RFG ethanol marginal costs, which should reflect ethanol's volatility cost, were omitted from this analysis and the PADD 1 – 3 costs were volume-weighted together and used for all RFG areas, including California.

Table 10.1.3.1.1-5: Calculated RVP Blending Costs by Fuel Grade

	Gasoline Grade	c/gal
Nationwide Aggregated Cost	Premium	22.5
	Regular	22.8

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.[903] However, it is necessary to add in ethanol's volatility cost for RFG, which for ethanol's removal would be a cost savings. The 23 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.

[902] California's relies on ethanol blended at 10 volume percent for compliance with its Low Carbon Fuel Standard, thus, removing E10 ethanol from California gasoline is an unlikely possibility.
[903] Both RFG and CG must meet many of the same gasoline property specifications, including sulfur and benzene, as well as ASTM standards (ASTM D4814).

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 to gasoline refiners 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 congressional 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 and the beginning of summer 2023, EPA granted numerous emergency waivers to allow E15 to continue to be sold with a 1 psi RVP waiver. 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 lower RVP, higher cost gasoline blendstock would be required for both ethanol blends in summertime conventional gasoline in those states. EPA proposed to remove the E10 1 psi waiver for those states in 2024.[904]

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

[904] 88 FR 13758 (March 6, 2023).

lower octane BOB specially designed for producing E15 instead of E10.[905] 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%).[906] 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). The corn ethanol plants add an additional quantity of the NGL, above the quantity needed to denature the ethanol, to produce the E85. 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.[907]

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 and RBOB).[908] Accounting for ethanol's lower energy density adds about $1 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.

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[905] 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.

[906] 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.

[907] 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.

[908] 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.

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.[909,910] 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.[911] 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 27 and 17 cents per gallon to the societal cost of biodiesel and renewable diesel, respectively.

10.1.4 Distribution and Retail Costs

In this section, 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. 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.

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909 Animal Fats for Biodiesel Production; Farm Energy; January 31, 2014.

910 McCormick, Robert; Renewable Diesel Fuel; NREL; July 18, 2016.

911 Modeling a No-RFS Case; ICF Incorporated; Work Assignment 0,1-11, EPA contract EP-C-16-020; July 17, 2018.

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.[912] 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.[913] 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.

[912] Modeling a No-RFS Case; ICF Incorporated; Work Assignment 0,1-11, EPA contract EP-C-16-020; July 17, 2018.
[913] 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 2022 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 2022$		20.1

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.[914,915,916,917] 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 $29,500 when adjusted to 2022 dollars.[918] 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 $132,900.

The E85 stations are also assumed to have an existing underground storage it could use for storing E85, but would require some equipment modification 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 $29,500, for a total cost of $40,500 (assuming only one dispenser at a retail outlet is provided for E85).[919]

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.[920] 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 181 thousand gallons of E15 per year while retail stations offering E85 are estimated to sell 39 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

[914] Moriarity, K.; E15 and Infrastructure; National Renewable Energy Laboratory; May 2015

[915] E15's Compatibility with UST Systems; Office of Underground Storage Tanks, Environmental Protection Agency; January 2020.

[916] UST System Compatibility with Biofuels; Environmental Protection Agency; July 2020.

[917] Conversations with Ryan Haerer, Office of Underground Storage Tanks; Spring 2022

[918] 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.

[919] 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.

[920] "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 19 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 is 1.62 and 22 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.[921] 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 2022 dollars.

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 2022$	19.7

[921] Modeling a No-RFS Case; ICF Incorporated; Work Assignment 0,1-11, EPA contract EP-C-16-020; July 17, 2018.

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 $6.7 million in 2022 dollars for the entire 5 mile pipeline.[922] A typical volume case was modeled of 600 standard cubic feet per minute to estimate the cost for a typical sized landfill.[923] When the pipeline capital costs are amortized over that typical volume of landfill gas, the pipeline capital cost is estimated to cost $1.89 per million BTU.[924]

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 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 $5.53 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 $2.4 per million cubic feet, is assumed to apply to biogas for distribution to the natural gas pipeline.[925]

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[922] Landfill Gas Energy Cost Model (LFGcost-Web); Version 3.5; https://www.epa.gov/lmop.
[923] Economic Analysis of the US Renewable Natural Gas Industry; The Coalition of Renewable Natural Gas; December 2021.
[924] 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 an 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.
[925] 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,

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.[926]

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 $4.61 per million BTU, so this was used for the RNG retail cost.[927] When adjusted to 2022 dollars, the estimated retail cost to dispense RNG is estimated to be $6.53 per million BTU.

10.2 Gasoline, Diesel Fuel and Natural Gas 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.[928] Furthermore, light-

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though, does not represent the true social cost for distributing biogas, and a separate distribution cost is estimated for biogas.

[926] 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.

[927] 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.

[928] 2023 Annual Energy Outlook; Table 12 Petroleum and Other Liquid Prices, and Table 57 Component of Selected Petroleum Product Prices; March 3, 2023.

duty and heavy-duty greenhouse gas standards will continue to phase-in, continuing to reduce transportation fuel demand.[929,930,931,932] Thus, we would not anticipate there to be refined product investment regardless of the 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 2023.[933] 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 ($/bbl)	91.5	92.5	87.0	91.5	92.5	87.0
Wholesale Prices - assumed to be Production Costs ($/gal)	2.81	2.48	2.26	3.44	3.21	2.93

Since the Energy Information Administration models much of the RFS program in its AEO modeling, some price impact of the RFS program is likely represented in these wholesale gasoline and diesel fuel prices. The AEO models the most recent RFS standards, so these wholesale price estimates would be optimal for modeling the final rule RFS standards incremental to the 2022 baseline. The RFS impact on the AEO gasoline and diesel fuel prices will slightly bias the cost analysis conducted for the No RFS Baseline, however, the impact on the estimated costs is expected to be minimal and within the accuracy of the cost analysis.

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 2023, EIA projects the natural gas spot price for Henry Hub to average $5.27 per thousand cubic feet in 2023 and decrease to $3.49 per thousand cubic feet in

929 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.
930 Revised 2023 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions Standards; Environmental Protection Agency, December 30, 2021.
931 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.
932 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.
933 2023 Annual Energy Outlook; Table 4a. U.S. Petroleum and Other Liquids Supply, Consumption and Inventories; March 3, 2023.

2025.[934] The Henry Hub spot price most closely represents the natural gas field price, and thus is a proxy for its production cost.

10.2.2 Gasoline, Diesel Fuel and Natural Gas 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, which also contains the retailing costs. 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 prices) to estimate the distribution costs from the terminal to retail and retail costs. 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 10.2.2.1-1.

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.

[934] 2023 Annual Energy Outlook; Table 13 Natural Gas Supply, Disposition, and Prices; March 3, 2023.

Table 10.2.2.1-2: Projected Gasoline and Diesel Production Costs ($/gal)

		2023	2024	2025
	Brent Crude Oil Prices	91.5	92.5	87.0
Gasoline	Retail Cost minus taxes	3.06	2.64	2.52
	Terminal and Retail Costs	0.20	0.20	0.20
	Terminal Costs	2.86	2.43	2.32
	Distribution Cost	0.05	0.05	0.05
	Production Cost (from Table 10.2.1.1-1)	2.81	2.38	2.26
Diesel Fuel	Retail Cost minus taxes	3.91	3.59	3.40
	Terminal and Retail Costs	0.40	0.40	0.40
	Terminal Costs	3.51	3.19	3.00
	Distribution Cost	0.08	0.08	0.08
	Production Cost (from Table 10.2.1.1-1)	3.44	3.11	2.93

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.[935] 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.[936]

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 2023 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 $6.53 per million BTU for retail costs.[937]

[935] Table 13 Natural Gas Supply, Disposition and Prices; Annual Energy Outlook 2023.
[936] Taxes are not included in social cost estimates because they are not true costs, only transfer payments.
[937] 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.

Table 10.2.2.2-1: Natural Gas Distribution Cost ($/thousand cubic feet)

	2023	2024	2025
Commercial Prices	10.73	9.69	9.19
Henry Hub Prices	5.27	4.07	3.49
Pipeline Distribution Costs	5.65	5.76	5.83
Retail Station Costs	6.53	6.53	6.53
Total Distribution & Retail Station Costs	12.18	12.29	12.36

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.[938]
[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.

[938] Diesel Fuels Technical Review; Chevron Global Marketing; 2007.

For the individual fuel 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.

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.[939] 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.[940] 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 action, and so is not included in this cost analysis.

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[939] Higher Blends Infrastructure Incentive Program; USDA; https://www.rd.usda.gov/hbiip.

[940] 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.

The cost shown for RNG in two different units. The first is RNG dollars per million BTU and dollars per ethanol-equivalent gallon. 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	3.02	2.61	2.37	-0.69	0.40		1.02
	E15 w ½ Retail Costs	3.02	2.61	2.37		0.40	0.81	1.02
	E15 w/Retail Costs	3.02	2.61	2.37		0.40	1.62	1.02
	E85 w/1/2 Retail Costs	3.02	2.61	2.37		0.40	0.11	1.02
	E85 w/Retail Costs	3.02	2.61	2.37		0.40	0.22	1.02
Biodiesel	Soy Oil	6.83	6.59	6.65		0.59		0.27
	Corn Oil	5.19	4.59	4.10		0.59		0.27
	Waste Oil	6.35	5.21	5.01		0.59		0.27
Renewable Diesel	Soy Oil	7.42	7.15	7.23		0.59		0.17
	Corn Oil	5.66	5.02	4.50		0.59		0.17
	Waste Oil	6.91	5.68	5.47		0.59		0.17
Other Advanced	Sugar Cane Ethanol	2.73	2.73	2.73	-0.69	0.40		1.02
Cellulosic Biofuels	RNG ($/gal Ethanol)	0.64	0.64	0.64		0.44	0.50	-
	RNG ($/mmBTU)	8.43	8.43	8.43		5.82	6.53	-
	Corn Kernel Fiber E10 Ethanol	3.02	2.61	2.37	-0.69	0.40		1.02

[a] Fuel economy cost is per fuel being displaced—ethanol displaces gasoline, renewable diesel and biodiesel displaces 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 ($/gallon unless otherwise noted; 2022$)

		Total Cost		
		2023	**2024**	**2025**
Corn Starch Ethanol	E10	3.76	3.35	3.10
	E15 w/1/2 Retail Costs	5.26	4.85	4.60
	E15 w/Retail Costs	6.06	5.65	5.41
	E85 w/1/2 Retail Costs	4.55	4.14	3.90
	E85 w/Retail Costs	4.66	4.25	4.01
Biodiesel	Soy Oil	7.70	7.45	7.51
	Corn Oil	6.05	5.46	4.96
	Waste Oil	7.22	6.08	5.87
Renewable Diesel	Soy Oil	8.18	7.91	7.99
	Corn Oil	6.43	5.78	5.26
	Waste Oil	7.67	6.45	6.24
Other Advanced	Sugar Cane Ethanol	3.46	3.46	3.46
Cellulosic Biofuels	Biogas ($/gal ethanol)	1.59	1.59	1.59
	Biogas ($/mmBTU)	20.78	20.78	20.78
	Corn Kernel Fiber E10 Ethanol	3.76	3.35	3.10

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 3.66 to 3.86 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, and natural gas. For gasoline and diesel, production costs are based on wholesale prices in AEO 2023.[941] Projected natural gas spot prices from the AEO 2023 are used to represent both feedstock and production costs of fossil natural gas.

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

[941] EIA, Annual Energy Outlook 2023, Energy Information Administration, March, 2023.

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 ($/gal)	2.81	2.38	2.26	0.26		3.06	2.64	2.52
Diesel Fuel ($/gal)	3.44	3.11	2.93	0.47		3.91	3.59	3.40
Natural Gas $/gal ethanol	0.51	0.42	0.38	0.51	0.50	1.52	1.43	1.39
Natural Gas ($/million BTU)	6.76	5.56	4.95	6.76	6.53	20.04	18.84	18.23

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 they are assumed to displace.

Table 10.4.1-3: Relative Renewable Fuel Costs for 2023–2025 ($/gal unless otherwise noted, 2022$)

		Total Net Cost		
		2023	2024	2025
Corn Starch Ethanol	E10	0.69	0.61	0.58
	E15 w/1/2 Retail Costs	2.19	2.11	2.08
	E15 w/Retail Costs	3.00	2.92	2.89
	E85 w/1/2 Retail Costs	1.49	1.41	1.38
	E85 w/Retail Costs	1.60	1.52	1.49
Biodiesel	Soy Oil	3.79	3.77	4.12
	Corn Oil	2.14	1.77	1.56
	Waste Oil	3.31	2.39	2.48
Renewable Diesel	Soy Oil	4.27	4.23	4.59
	Corn Oil	2.52	2.10	1.86
	Waste Oil	3.76	2.76	2.84
Other Advanced	Sugar Cane Ethanol	0.68	1.01	1.22
Cellulosic Biofuels	Biogas ($/gal ethanol)	0.06	0.15	0.20
	Biogas ($/mmBTU)	0.74	1.93	2.54
	Corn Kernel Fiber E10 Ethanol	0.69	0.61	0.58

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)	36505	50739	68734	Natural Gas	-36505	-50739	-68734
Corn Kernel Fiber Ethanol	0	0	0	Gasoline	0	0	0
Non-cellulosic adv. - Total							
Biodiesel - Soy	841	757	755	Diesel Fuel	-783	-705	-703
Biodiesel -FOG	-101	-92	-113	Diesel Fuel	94	86	105
Biodiesel - Corn Oil	46	63	20	Diesel Fuel	-43	-59	-19
Biodiesel - Canola	292	307	323	Diesel Fuel	-272	-286	-301
Renewable Diesel - Soy	457	671	729	Diesel Fuel	-437	-642	-697
Renewable Diesel - FOG	110	101	121	Diesel Fuel	-105	-97	-116
Renewable Diesel - Corn	130	-64	-20	Diesel Fuel	-124	61	19
Renewable Diesel - Canola	216	182	291	Diesel Fuel	-207	-174	-278
Sugar Cane Ethanol	0	0	0	Gasoline	0.0	0.0	0.0
Conventional - Total							
Ethanol - E10	-81	-91	-101	Gasoline	55	61	68
Ethanol - E15	80	93	106	Gasoline	-54	-62	-71
Ethanol - E85	260	272	283	Gasoline	-174	-182	-190
Change in Biogas Volume	36505	50739	68734	-	-	-	-
Change in Ethanol Volume	259	274	289	-	-	-	-
Change in Biodiesel Volume	1078	1035	985	-	-	-	-
Change in Renewable Diesel Volume	913	890	1121	-	-	-	-
Change in Gasoline Volume	-	-	-	-	-174	-184	-193
Change in Diesel Fuel Volume	-	-	-	-	-1877	-1815	-1989
Change in Natural Gas Volume	-	-	-	-	-36505	-50739	-68734

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 2023.[942] 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, 92 percent of that gasoline or diesel reduction would be attributed to reduced crude oil imports and imports of refined product would decrease by 8 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 Table 10.4.2.1-4 we also consider the projected change in imported renewable fuels in addition to changes in petroleum products. 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	-14	-15	-16
Change in Imported Diesel Fuel	-151	-146	-160
Total Change in Crude Oil	-1850	-1802	-1968
Change in Domestic Crude Oil	0	0	0
Change in Imported Crude Oil	-1850	-1802	-1968

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 Renewable Fuels imports (million gallons)

	2023	2024	2025
Change in Imported Gasoline	-14	-15	-16
Change in Imported Diesel Fuel	-96	-80	-92
Total Change in Crude Oil	-1978	-1802	-1968
Change in Domestic Crude Oil	0	0	0
Change in Imported Crude Oil	-1978	-1802	-1968

[942] "Change in product demand on imports AEO 2023 for SET final rule", spreadsheet available in the docket.

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.

Table 10.4.2.2-1 Renewable and Petroleum Fuel Costs for 2023 to 2025 (million dollars; year 2022 dollars)

		Renewable Fuel			Petroleum Fuel		
		Production	**Distribution**	**Blending**	**Production**	**Distribution**	**Total**
2023	Cellulosic biofuel						
	CNG - landfill biogas	319	579	0	-247	-631	21
	Corn Kernel Fiber Ethanol	0	0	0	0	0	0
	Non-cellulosic adv.						
	Biodiesel - Soy	5747	499	0	-2691	-370	3185
	Biodiesel -FOG	-642	-60	0	323	44	-334
	Biodiesel - Corn Oil	239	27	0	-147	-20	99
	Biodiesel - Canola	1995	173	0	-934	-129	1106
	Renewable Diesel - Soy	3391	271	0	-1503	-207	1953
	Renewable Diesel - FOG	760	65	0	-362	-50	413
	Renewable Diesel - Corn	675	77	0	-428	-59	265
	Renewable Diesel - Canola	1603	128	0	-710	-98	923
	Sugar Cane Ethanol	0	0	0	0	0	0
	Conventional						
	Ethanol - E10	-246	-33	56	153	14	-56
	Ethanol - E15	243	76	-37	-151	-14	117
	Ethanol - E85	788	155	-24	-490	-45	384
2024	Cellulosic biofuel						
	CNG - landfill biogas	444	805	0	-282	-877	89
	Corn Kernel Fiber Ethanol	0	0	0	0	0	0
	Non-cellulosic adv.						
	Biodiesel - Soy	4987	149	0	-2422	-333	2380
	Biodiesel -FOG	-480	-18	0	294	41	-163
	Biodiesel - Corn Oil	289	12	0	-202	-28	73
	Biodiesel - Canola	2022	60	0	-982	-135	965
	Renewable Diesel - Soy	4797	143	0	-2062	-304	2575
	Renewable Diesel - FOG	574	20	0	-332	-46	216
	Renewable Diesel - Corn	-294	-13	0	210	29	-67
	Renewable Diesel - Canola	1301	57	0	-542	-82	734
	Sugar Cane Ethanol	0	0	0	0	0	0
	Conventional						
	Ethanol - E10	-237	-37	63	151	16	-45
	Ethanol - E15	243	88	-43	-154	-16	118
	Ethanol - E85	712	162	-25	-452	-47	350
2025	Cellulosic biofuel						
	CNG - landfill biogas	601	1091	0	-340	-1188	163
	Corn Kernel Fiber Ethanol	0	0	0	0	0	0
	Non-cellulosic adv.						
	Biodiesel - Soy	5021	149	0	-2416	-333	2421
	Biodiesel -FOG	-566	-22	0	362	50	-177
	Biodiesel - Corn Oil	82	4	0	-64	-9	13
	Biodiesel - Canola	2148	64	0	-1033	-142	1036
	Renewable Diesel - Soy	5267	143	0	-2041	-330	3040
	Renewable Diesel - FOG	662	24	0	-398	-55	233
	Renewable Diesel - Corn	-82	-4	0	66	9	-11
	Renewable Diesel - Canola	2103	57	0	-815	-132	1214
	Sugar Cane Ethanol	0	0	0	0	0	0
	Conventional						
	Ethanol - E10	-239	-41	69	153	17	-40
	Ethanol - E15	252	100	-49	-161	-18	124
	Ethanol - E85	672	168	-26	-430	-10	374

Table 10.4.2.2-2 Renewable Fuel and Petroleum Fuel Costs for the 2023 Supplemental Standard (million dollars; 2022$)

	Renewable Fuel			Fossil Fuel		
	Production	**Distribution**	**Blending**	**Production**	**Distribution**	**Total**
Supplemental Std. RD Soy Oil	1091	87	0	-483.4	-66.6	628.1

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 2023 and summarized in Table 10.4.2.2-3.[943]

Table 10.4.2.2-3: Total Gasoline, Diesel Fuel and Natural Gas Volumes

	2023	**2024**	**2025**	**Units**
Gasoline Volume	134.14	135.06	133.06	Billion gallons
Diesel Volume	56.11	53.35	52.89	Billion gallons
Natural Gas Volume	31.42	30.16	29.82	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 (2022$)

		Total Cost (million $)	**Per-Unit Cost**	**Units**
2023	Gasoline	445	0.33	¢/gal gasoline
	Diesel Fuel	7,610	13.56	¢/gal diesel
	Natural Gas	55	0.1753	$/1000 FT3 natural gas
	Total	8,110	4.26	¢/gal gasoline and diesel
2023 with Suppl. Std.	Gasoline	445	0.33	¢/gal gasoline
	Diesel Fuel	8,238	14.68	¢/gal diesel
	Natural Gas	55	0.1753	$/1000 FT3 natural gas
	Total	8,738	4.59	¢/gal gasoline and diesel
2024	Gasoline	423	0.31	¢/gal gasoline
	Diesel Fuel	6,775	12.70	¢/gal diesel
	Natural Gas	137	0.4549	$/1000 FT3 natural gas
	Total	7,352	3.90	¢/gal gasoline and diesel
2025	Gasoline	458	0.34	¢/gal gasoline
	Diesel Fuel	7,769	14.69	¢/gal diesel
	Natural Gas	228	0.7645	$/1000 FT3 natural gas
	Total	8,455	4.55	¢/gal gasoline and diesel

[943] EIA, Annual Outlook 2023, Energy Information Administration, March 3, 2023.

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)	12242	27582	46757	Natural Gas	-12242	-27582	-46757
Corn Kernel Fiber Ethanol	6	50	76		4	33	51
Non-cellulosic adv.							
Biodiesel - Soy	-13	-28	-42	Diesel Fuel	-12	-26	-39
Biodiesel -FOG	-25	-43	-61	Diesel Fuel	-23	-40	-57
Biodiesel - Corn Oil	-15	-41	-67	Diesel Fuel	-14	-38	-62
Biodiesel - Canola	25	40	56	Diesel Fuel	23	37	52
Renewable Diesel - Soy	311	525	737	Diesel Fuel	-298	-502	-705
Renewable Diesel - FOG	249	215	295	Diesel Fuel	-238	-206	-282
Renewable Diesel - Corn	-4	30	63	Diesel Fuel	4	-29	-60
Renewable Diesel - Canola	216	182	291	Diesel Fuel	-207	-174	-278
Sugar Cane Ethanol	14	14	14	Gasoline	9	9	9
Conventional							
Ethanol - E10	-512	-482	-725	Gasoline	343	323	485
Ethanol - E15	14	27	40	Gasoline	-10	-18	-27
Ethanol - E85	10	21	33	Gasoline	-6	-14	-22
Change in Biogas Volume	12242	27582	46757	-	-	-	-
Change in Ethanol Volume	-482	-384	-576	-	-	-	-
Change in Biodiesel Volume	-28	-72	-114	-	-	-	-
Change in Renewable Diesel Volume	772	952	1386	-	-	-	-
Change in Gasoline Volume	-	-	-	-	327	291	437
Change in Diesel Fuel Volume	-	-	-	-	-765	-978	-1432
Change in Natural Gas Volume	-	-	-	-	-12242	-27582	-46757
Change in Imported Gasoline					26	23	35
Change in Imported Diesel Fuel					-62	-79	-115
Total Change in Crude Oil					-422	-622	-903
Change in Domestic Crude Oil					0	0	0
Change in Imported Crude Oil					-422	-622	-903

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; 2022$)

		Renewable Fuel			Petroleum Fuel		
		Production	Distribution	Blending	Production	Distribution	Total
2023	Cellulosic biofuel						
	CNG - landfill biogas	107	194	0	-83	-212	7
	Corn Kernel Fiber Ethanol	18	2	4	-11	-1	12
	Non-cellulosic adv.						
	Biodiesel - Soy	-89	-8	0	42	7	-48
	Biodiesel -FOG	-159	-15	0	48	8	-80
	Biodiesel - Corn Oil	-78	-9	0	-80	-14	-30
	Biodiesel - Canola	171	15	0	0	0	92
	Renewable Diesel - Soy	2308	185	0	-1023	-141	1329
	Renewable Diesel - FOG	1720	148	0	13	2	907
	Renewable Diesel - Corn	-21	-2	0	-710	-98	-8
	Renewable Diesel - Canola	1603	128	0	0	0	923
	Sugar Cane E10 Ethanol	38	6	-10	-26	-2	6
	Conventional						
	Ethanol - E10	-1549	-207	353	963	88	-353
	Ethanol - E15	43	13	-7	-27	-2	21
	Ethanol - E85	29	6	-1	-18	-2	14
2024	Cellulosic biofuel						
	CNG - landfill biogas	241	438	0	-153	-477	49
	Corn Kernel Fiber Ethanol	131	13	34	-83	-9	86
	Non-cellulosic adv.						
	Biodiesel - Soy	-184	-17	0	81	15	-104
	Biodiesel -FOG	-224	-26	0	125	24	-101
	Biodiesel - Corn Oil	-188	-24	0	119	23	-71
	Biodiesel - Canola	264	24	0	-116	-22	149
	Renewable Diesel - Soy	3753	437	0	-1565	-238	2388
	Renewable Diesel - FOG	1222	128	0	-641	-122	587
	Renewable Diesel - Corn	138	18	0	-89	-17	49
	Renewable Diesel - Canola	1301	173	0	-542	-82	849
	Sugar Cane E10 Ethanol	38	38	38	-23	-23	9
	Conventional						
	Ethanol - E10	-1261	-195	332	800	83	-242
	Ethanol - E15	70	25	-12	-45	-5	34
	Ethanol - E85	56	13	-2	-36	-4	28
2025	Cellulosic biofuel						
	CNG - landfill biogas	409	742	0	-231	-808	111
	Corn Kernel Fiber Ethanol	180	19	52	-115	-13	124
	Non-cellulosic adv.						
	Biodiesel - Soy	-279	-25	0	114	23	-167
	Biodiesel -FOG	-306	-36	0	166	34	-142
	Biodiesel - Corn Oil	-274	-40	0	182	37	-95
	Biodiesel - Canola	372	33	0	-153	-31	222
	Renewable Diesel - Soy	5325	437	0	-2063	-334	3366
	Renewable Diesel - FOG	1615	175	0	-826	-167	796
	Renewable Diesel - Corn	258	37	0	-176	-36	83
	Renewable Diesel - Canola	2103	173	0	-815	-132	1329
	Sugar Cane E10 Ethanol	38	38	38	-21	-21	11
	Conventional						
	Ethanol - E10	-1719	-293	499	1099	124	-289
	Ethanol - E15	95	38	-18	-61	-7	47
	Ethanol - E85	77	19	-3	-49	-6	39

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 (2022$)

		Total Cost (million $)	Per-Unit Cost	Units
2023	Gasoline	-301	-0.22	¢/gal gasoline
	Diesel Fuel	3,085	5.50	¢/gal diesel
	Natural Gas	18	0.06	¢/1000 FT3 natural gas
	Total	2,805	1.47	¢/gal gasoline and diesel
2024	Gasoline	-85	-0.06	¢/gal gasoline
	Diesel Fuel	3,745	7.02	¢/gal diesel
	Natural Gas	75	0.25	¢/1000 FT3 natural gas
	Total	3,712	1.95	¢/gal gasoline and diesel
2025	Gasoline	-70	-0.05	¢/gal gasoline
	Diesel Fuel	5,393	10.20	¢/gal diesel
	Natural Gas	155	0.52	¢/1000 FT3 natural gas
	Total	5,480	2.88	¢/gal gasoline and diesel

The total costs associated with the final volumes relative to the 2022 baseline do not include the supplemental standard that 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., $291 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	0.0	0.0	0.0
2024	-722	-87	0	452	67	-291
2025	-641	-87	0	412	67	-250

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 April 2023) as an estimate of future RIN prices, as shown in Table 10.5.1-1.

Table 10.5.1-1: Average RIN Prices (May 2022 – April 2023)

RFS Standard	RIN Type	Average RIN Price	2022 Percentage Standards	2023 Percentage Standard	2024 Percentage Standard	2025 Percentage Standard
Cellulosic Biofuel (D3)	D3	$2.79	0.35%	0.48%	0.63%	0.81%
Biomass-Based Diesel (D4)	D4	$1.67	2.33%	2.58%	2.82%	3.15%
Other Advanced Biofuel[a] (D5)	D5	$1.82	0.48%	0.33%	0.34%	0.35%
Conventional Renewable Fuel[b] (D6)	D6	$1.52	8.57%[c]	8.71%	8.71%	8.82%

[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 2022-2025

Year	RIN Cost ($/Gallon)
2022	$0.19
2023	$0.20
2024	$0.20
2025	$0.22

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	$0.15
E15	$0.23
E85	$1.13
Biodiesel	$2.50
Renewable Diesel	$2.83

10.5.2 Estimated Fuel Price Impacts (Gasoline)

In this section, we estimate 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,[944] 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 to get the total cost for each fuel. Finally, we calculated the average gasoline cost by dividing the total cost of all fuels by the total volume of all fuels. As shown in Tables 10.5.2-1 through 3, we estimate that average gasoline costs range from $2.52–3.05 per gallon.

Table 10.5.2-1: Gasoline Costs – 2023 (Candidate Volumes)

	E0	E10	E15	E85
Cost to Produce ($/gal)	$3.06	$3.03	$3.13	$3.40
RIN Cost ($/gal)	$0.20	$0.18	$0.17	$0.05
RIN Value ($/gal)	$0.00	-$0.15	-$0.23	-$1.13
Net Cost ($/gal)	$3.26	$3.05	$3.06	$2.32
Volume (mil gal)	2,209	131,015	535	352
Total Fuel Cost ($bil)	$7.2	$399.8	$1.6	$0.8
Average Cost ($/gal)	$3.05			

Table 10.5.2-2: Gasoline Costs – 2024 (Candidate Volumes)

	E0	E10	E15	E85
Cost to Produce ($/gal)	$2.64	$2.61	$2.71	$2.99
RIN Cost ($/gal)	$0.20	$0.18	$0.17	$0.05
RIN Value ($/gal)	$0.00	-$0.15	-$0.23	-$1.13
Net Cost ($/gal)	$2.84	$2.64	$2.65	$1.91
Volume (mil gal)	2,209	131,744	619	368
Total Fuel Cost ($bil)	$6.3	$347.8	$1.6	$0.7
Average Cost ($/gal)	$2.64			

[944] 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 10.5.2-3: Gasoline Costs – 2025 (Candidate Volumes)

	E0	E10	E15	E85
Cost to Produce ($/gal)	$2.52	$2.48	$2.57	$2.78
RIN Cost ($/gal)	$0.22	$0.19	$0.18	$0.06
RIN Value ($/gal)	$0.00	-$0.15	-$0.23	-$1.13
Net Cost ($/gal)	$2.74	$2.52	$2.52	$1.70
Volume (mil gal)	2,209	129,601	708	383
Total Fuel Cost ($bil)	$6.0	$326.3	$1.8	$0.7
Average Cost ($/gal)	$2.52			

Next we estimated the cost of gasoline-ethanol blends under the No RFS and 2022 baselines. For the No RFS baseline, we began with the production cost for each gasoline-ethanol blend and multiplied by the volume of each blend under the respective baseline to get the total cost for each fuel.[945] We then calculated the average gasoline cost by dividing the total cost of all fuels by the total volume of all fuels. As shown in Tables 10.5.2-4 through 6, we estimate that average gasoline costs under the No RFS baseline range from $2.48–3.03 per gallon.

Table 10.5.2-4: Gasoline Costs – 2023 (No RFS Baseline)

	E0	E10	E15	E85
Cost to Produce ($/gal)	$3.06	$3.03	$3.13	$3.40
Volume (mil gal)	2,209	133,140	0	0
Total Fuel Cost ($bil)	$6.8	$403.1	$0.0	$0.0
Average Cost ($/gal)	$3.03			

Table 10.5.2-5: Gasoline Costs – 2024 (No RFS Baseline)

	E0	E10	E15	E85
Cost to Produce ($/gal)	$2.64	$2.61	$2.71	$2.99
Volume (mil gal)	2,209	133,970	0	0
Total Fuel Cost ($bil)	$5.8	$349.5	$0.0	$0.0
Average Cost ($/gal)	$2.61			

Table 10.5.2-6: Gasoline Costs – 2025 (No RFS Baseline)

	E0	E10	E15	E85
Cost to Produce ($/gal)	$2.52	$2.48	$2.57	$2.78
Volume (mil gal)	2,209	131,910	0	0
Total Fuel Cost ($bil)	$5.6	$326.6	$0.0	$0.0
Average Cost ($/gal)	$2.48			

[945] 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 2.1.5-1 and dividing by 0.1.

For the 2022 baseline, we used the same approach described above for the 2023–2025 candidate volumes.[946] As shown in Tables 10.5.2-7 through 9, we estimate that average gasoline costs under the 2022 baseline range from $2.52–3.05 per gallon.

Table 10.5.2-7: Gasoline Costs – 2023 (2022 Baseline)

	E0	E10	E15	E85
Cost to Produce ($/gal)	$3.06	$3.03	$3.13	$3.40
RIN Cost ($/gal)	$0.20	$0.18	$0.17	$0.05
RIN Value ($/gal)	$0.00	-$0.15	-$0.23	-$1.13
Net Cost ($/gal)	$3.26	$3.05	$3.06	$2.32
Volume (mil gal)	2,128	135,972	440	339
Total Fuel Cost ($bil)	$6.9	$414.9	$1.3	$0.8
Average Cost ($/gal)	$3.05			

Table 10.5.2-8: Gasoline Costs – 2024 (2022 Baseline)

	E0	E10	E15	E85
Cost to Produce ($/gal)	$2.64	$2.61	$2.71	$2.99
RIN Cost ($/gal)	$0.20	$0.18	$0.17	$0.05
RIN Value ($/gal)	$0.00	-$0.15	-$0.23	-$1.13
Net Cost ($/gal)	$2.84	$2.64	$2.65	$1.91
Volume (mil gal)	2,128	135,972	440	339
Total Fuel Cost ($bil)	$6.1	$358.9	$1.2	$0.6
Average Cost ($/gal)	$2.64			

Table 10.5.2-9: Gasoline Costs – 2025 (2022 Baseline)

	E0	E10	E15	E85
Cost to Produce ($/gal)	$2.52	$2.48	$2.57	$2.78
RIN Cost ($/gal)	$0.22	$0.19	$0.18	$0.06
RIN Value ($/gal)	$0.00	-$0.15	-$0.23	-$1.13
Net Cost ($/gal)	$2.74	$2.52	$2.52	$1.70
Volume (mil gal)	2,128	135,972	440	339
Total Fuel Cost ($bil)	$5.8	$342.4	$1.1	$0.6
Average Cost ($/gal)	$2.52			

Finally, we calculated the fuel price impacts on gasoline for each year by subtracting the average gasoline cost for each baseline from the average gasoline cost for the candidate volumes. As shown in Table 10.5.2-10, we estimate that the fuel price impacts on gasoline under the No RFS baseline range from 2.4–4.2¢ per gallon. As shown in Table 10.5.2-11, we estimate that the fuel price impacts on gasoline under the 2022 baseline range are 0.0¢ per gallon.

[946] 2022 baseline gasoline-ethanol blend volumes from 2020-2022 Rule RIA Table 5.5.4-3.

Table 10.5.2-10: Gasoline Fuel Price Impacts (No RFS Baseline)

	2023	2024	2025
Average Cost (No RFS baseline) ($/gal)	$3.03	$2.61	$2.48
Average Cost (candidate volumes) ($/gal)	$3.05	$2.64	$2.52
Fuel Price Impact (¢/gal)	2.4¢	3.2¢	4.3¢

Table 10.5.2-11: Gasoline Fuel Price Impacts (2022 Baseline)

	2023	2024	2025
Average Cost (No RFS baseline) ($/gal)	$3.05	$2.64	$2.52
Average Cost (candidate volumes) ($/gal)	$3.05	$2.64	$2.52
Fuel Price Impact (¢/gal)	0.0¢	0.0¢	0.0¢

10.5.3 Estimated Fuel Price Impacts (Diesel)

In this section, we estimate 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,[947] 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 Table 3.1-4 (biodiesel and renewable diesel) or Preamble Table VII.C-1 (diesel) to get the total cost for each fuel. Finally, we calculated the average diesel cost by dividing the total cost of all fuels by the total volume of all fuels. As shown in Tables 10.5.3-1 through 3, we estimate that average diesel costs range from $3.58–4.08 per gallon.

Table 10.5.3-1: Diesel Costs – 2023 (Candidate Volumes)

		Biodiesel			Renewable Diesel		
	Diesel	Corn	FOG	Soybean/ Canola	Corn	FOG	Soybean/ Canola
Cost to Produce ($/gal)	$3.91	$5.78	$6.95	$7.43	$6.26	$7.50	$8.01
RIN Cost ($/gal)	$0.20	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RIN Value ($/gal)	$0.00	-$2.50	-$2.50	-$2.50	-$2.83	-$2.83	-$2.83
Tax Credit ($/gal)	$0.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00
Net Cost ($/gal)	$4.11	$2.28	$3.45	$3.93	$2.43	$3.67	$4.18
Volume (mil gal)	55,810	115	321	1,274	205	1,169	820
Total Fuel Cost ($bil)	$229.1	$0.3	$1.1	$5.0	$0.5	$4.3	$3.4
Total Cost ($/gal)	$4.08						

[947] 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 10.5.3-2: Diesel Costs – 2024 (Candidate Volumes)

		Biodiesel			Renewable Diesel		
	Diesel	Corn	FOG	Soybean/ Canola	Corn	FOG	Soybean/ Canola
Cost to Produce ($/gal)	$3.59	$5.19	$5.81	$7.18	$5.61	$6.28	$7.74
RIN Cost ($/gal)	$0.20	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RIN Value ($/gal)	$0.00	-$2.50	-$2.50	-$2.50	-$2.83	-$2.83	-$2.83
Tax Credit ($/gal)	$0.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00
Net Cost ($/gal)	$3.79	$1.69	$2.31	$3.68	$1.78	$2.45	$3.91
Volume (mil gal)	52,950	89	303	1,274	239	1,135	853
Total Fuel Cost ($bil)	$200.9	$0.2	$0.7	$4.7	$0.4	$2.8	$3.3
Total Cost ($/gal)	$3.75						

Table 10.5.3-3: Diesel Costs – 2025 (Candidate Volumes)

		Biodiesel			Renewable Diesel		
	Diesel	Corn	FOG	Soybean/ Canola	Corn	FOG	Soybean/ Canola
Cost to Produce ($/gal)	$3.40	$4.69	$5.60	$7.24	$5.09	$6.07	$7.82
RIN Cost ($/gal)	$0.22	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RIN Value ($/gal)	$0.00	-$2.50	-$2.50	-$2.50	-$2.83	-$2.83	-$2.83
Tax Credit ($/gal)	$0.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00
Net Cost ($/gal)	$3.62	$1.19	$2.10	$3.74	$1.26	$2.24	$3.99
Volume (mil gal)	52,400	63	285	1,276	272	1,215	1,174
Total Fuel Cost ($bil)	$189.5	$0.1	$0.6	$4.8	$0.3	$2.7	$4.7
Total Cost ($/gal)	$3.58						

Next we estimated the total cost of diesel under the No RFS and 2022 baselines. For the No RFS baseline, 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 to get the total cost for each fuel.[948] We then calculated the average diesel cost by dividing the total cost of all fuels by the total volume of all fuels. As shown in Tables 10.5.3-4 through 6, we estimate that average diesel costs under the No RFS baseline range from $3.46–3.98 per gallon.

[948] Biodiesel and renewable diesel volumes from Table 2.1.5-2. For purposes of the No RFS baseline analysis, we assumed that total diesel energy demand was held constant relative to the candidate volumes scenario to calculate petroleum diesel fuel volumes.

Table 10.5.3-4: Diesel Costs – 2023 (No RFS Baseline)

		Biodiesel			Renewable Diesel		
	Diesel	Corn	FOG	Soybean/ Canola	Corn	FOG	Soybean/ Canola
Cost to Produce ($/gal)	$3.91	$5.78	$6.95	$7.43	$6.26	$7.50	$8.01
Tax Credit ($/gal)	$0.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00
Net Cost ($/gal)	$3.91	$4.78	$5.95	$6.43	$5.26	$6.50	$7.01
Volume (mil gal)	57,810	69	422	141	75	1,070	0
Total Fuel Cost ($bil)	$226.0	$0.3	$2.5	$0.9	$0.4	$7.0	$0.0
Total Cost ($/gal)	$3.98						

Table 10.5.3-5: Diesel Costs – 2024 (No RFS Baseline)

		Biodiesel			Renewable Diesel		
	Diesel	Corn	FOG	Soybean/ Canola	Corn	FOG	Soybean/ Canola
Cost to Produce ($/gal)	$3.59	$5.19	$5.81	$7.18	$5.61	$6.28	$7.74
Tax Credit ($/gal)	$0.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00
Net Cost ($/gal)	$3.59	$4.19	$4.81	$6.18	$4.61	$5.28	$6.74
Volume (mil gal)	54,748	26	395	210	303	1,045	0
Total Fuel Cost ($bil)	$196.5	$0.1	$1.9	$1.3	$1.4	$5.5	$0.0
Total Cost ($/gal)	$3.64						

Table 10.5.3-6: Diesel Costs – 2025 (No RFS Baseline)

		Biodiesel			Renewable Diesel		
	Diesel	Corn	FOG	Soybean/ Canola	Corn	FOG	Soybean/ Canola
Cost to Produce ($/gal)	$3.40	$4.69	$5.60	$7.24	$5.09	$6.07	$7.82
Tax Credit ($/gal)	$0.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00
Net Cost ($/gal)	$3.40	$3.69	$4.60	$6.24	$4.09	$5.07	$6.82
Volume (mil gal)	54,372	43	398	198	292	1,105	154
Total Fuel Cost ($bil)	$184.9	$0.2	$1.8	$1.2	$1.2	$5.6	$1.1
Total Cost ($/gal)	$3.46						

For the 2022 baseline, we used the same approach described above for the 2023–2025 candidate volumes.[949] As shown in Tables 10.5.3-7 through 9, we estimate that average diesel costs under the 2022 baseline range from $3.58–4.08 per gallon.

[949] 2022 baseline biodiesel and renewable diesel volumes from Table 2.2-2. For purposes of the 2022 baseline analysis, we assumed that total diesel energy demand was held constant relative to the candidate volumes scenario to calculate petroleum diesel fuel volumes.

Table 10.5.3-7: Diesel Costs – 2023 (2022 Baseline)

		Biodiesel			Renewable Diesel		
	Diesel	Corn	FOG	Soybean/ Canola	Corn	FOG	Soybean/ Canola
Cost to Produce ($/gal)	$3.91	$5.78	$6.95	$7.43	$6.26	$7.50	$8.01
RIN Cost ($/gal)	$0.20	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RIN Value ($/gal)	$0.00	-$2.50	-$2.50	-$2.50	-$2.83	-$2.83	-$2.83
Tax Credit ($/gal)	$0.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00
Net Cost ($/gal)	$4.11	$2.28	$3.45	$3.93	$2.43	$3.67	$4.18
Volume (mil gal)	56,508	130	346	1,262	209	932	293
Total Blend Cost ($bil)	$232.0	$0.3	$1.2	$5.0	$0.5	$3.4	$1.2
Average Cost ($/gal)	$4.08						

Table 10.5.3-8: Diesel Costs – 2024 (2022 Baseline)

		Biodiesel			Renewable Diesel		
	Diesel	Corn	FOG	Soybean/ Canola	Corn	FOG	Soybean/ Canola
Cost to Produce ($/gal)	$3.59	$5.19	$5.81	$7.18	$5.61	$6.28	$7.74
RIN Cost ($/gal)	$0.20	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RIN Value ($/gal)	$0.00	-$2.50	-$2.50	-$2.50	-$2.83	-$2.83	-$2.83
Tax Credit ($/gal)	$0.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00
Net Cost ($/gal)	$3.79	$1.69	$2.31	$3.68	$1.78	$2.45	$3.91
Volume (mil gal)	56,508	130	346	1,262	209	932	293
Total Blend Cost ($bil)	$214.4	$0.2	$0.8	$4.6	$0.4	$2.3	$1.1
Average Cost ($/gal)	$3.75						

Table 10.5.3-9: Diesel Costs – 2025 (2022 Baseline)

		Biodiesel			Renewable Diesel		
	Diesel	Corn	FOG	Soybean/ Canola	Corn	FOG	Soybean/ Canola
Cost to Produce ($/gal)	$3.40	$4.69	$5.60	$7.24	$5.09	$6.07	$7.82
RIN Cost ($/gal)	$0.22	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RIN Value ($/gal)	$0.00	-$2.50	-$2.50	-$2.50	-$2.83	-$2.83	-$2.83
Tax Credit ($/gal)	$0.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00	-$1.00
Net Cost ($/gal)	$3.62	$1.19	$2.10	$3.74	$1.26	$2.24	$3.99
Volume (mil gal)	56,508	130	346	1,262	209	932	293
Total Blend Cost ($bil)	$204.3	$0.2	$0.7	$4.7	$0.3	$2.1	$1.2
Average Cost ($/gal)	$3.58						

Finally, we calculated the fuel price impacts on diesel for each year by subtracting the average diesel cost for each baseline from the average diesel cost for the candidate volumes. As shown in Table 10.5.3-10, we estimate that the fuel price impacts on diesel under the No RFS baseline range from 10.1–11.1¢ 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 -0.4–0.0¢ per gallon.

Table 10.5.3-10: Diesel Fuel Price Impacts (No RFS Baseline)

	2023	2024	2025
Average Cost (No RFS baseline) ($/gal)	$3.98	$3.64	$3.46
Average Cost (candidate volumes) ($/gal)	$4.08	$3.75	$3.58
Fuel Price Impact (¢/gal)	10.1¢	10.1¢	11.1¢

Table 10.5.3-11: Diesel Fuel Price Impacts (2022 Baseline)

	2023	2024	2025
Average Cost (2022 baseline) ($/gal)	$4.08	$3.75	$3.58
Average Cost (candidate volumes) ($/gal)	$4.08	$3.75	$3.58
Fuel Price Impact (¢/gal)	0.0¢	-0.4¢	-0.1¢

10.5.4 Cost to Transport Goods

In this section, 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 10.5.3-10, the projected price increase for diesel fuel relative to the No RFS baseline ranged from 10.1¢ per gallon in 2024 to 11.1¢ per gallon in 2025. As a worst case scenario, we will use the projected diesel fuel price increase of 11.1¢ 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.[950] 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 $3.40/gal in 2025 as summarized in Table 10.2.2-1 and adding 60¢ per gallon state and federal taxes to it, the projected 11.1¢ per gallon increase in diesel fuel price amounts to a 2.8 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 0.7%. 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 $0.02 per pound.[951] 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

[950] Volpe, Richard; How Transportation Costs Affect Fresh Fruit and Vegetable Prices; United States Department of Agriculture; November 2013.
[951] Comparing Prices on Groceries; May 4, 2021: https://web.archive.org/web/20210805005209/https://www.coupons.com/thegoodstuff/comparing-prices-on-groceries.

type estimate since impacts on food prices vary greatly depending on the distance that the particular food travels by truck.

10.6 Analysis of Alternative Scenarios

In the proposed rule EPA requested comment on alternative scenarios, including reducing the required total renewable fuel volume by 0.25 billion gallons in 2024 and 2025 and reducing the implied conventional renewable fuel volume to below the E10 blendwall. While the volumes we are finalizing in this rule do not reflect these alternative scenarios, for purposes of this RIA we have analyzed the impact these alternative volume scenarios would have on costs, energy security benefits, and fuel prices. The projected impacts of these alternative scenarios are summarized in the following sections.

10.6.1 Alternative Scenarios Descriptions

Prior to projecting the impacts of the alternative scenarios, we first had to define these scenarios and project the types of renewable fuel that would be used to satisfy the volume requirements.

10.6.1.1 Alternative Scenario 1

The first alternative scenario we considered is one in which we finalize total renewable fuel volumes for 2024 and 2025 that are 250 million gallons lower than the volumes we are finalizing in this rule. In this scenario we also reduced the advanced biofuel volumes for 2024 and 2025 by 250 million gallons to maintain an implied conventional renewable fuel volume of 15.0 billion gallons for these years, with corresponding reductions to the BBD volume requirement for each year. For this scenario we project that the volume of renewable diesel produced from canola oil in 2024 and 2025 would be 147 million gallons (equivalent to 250 million RINs) less than the volumes supplied to meet the volume requirements we are finalizing for 2024 and 2025. We projected that the reduction in the total renewable fuel volume would result in less renewable diesel produced from canola oil because this is projected to be the most expensive non-cellulosic biofuel supplied in these years.

Tables 10.6.1.1-1 through 3 summarize the renewable fuel volume requirements for this scenario, the renewable fuel volumes we project would be supplied to meet the required volumes, and the change in the supply of renewable fuels relative to the volumes we are finalizing in this rule.

Table 10.6.1.1-1: RFS Volume Requirements for Alternative Scenario 1 (Million RINs)

	2023	2024	2025
Cellulosic Biofuel	0.84	1.09	1.38
BBD[a]	2.82	2.89	3.20
Advanced Biofuel	5.94	6.29	7.08
Total Renewable Fuel	20.94	21.29	22.08
Implied Conventional Renewable Fuel	15.00	15.00	15.00
Supplemental Volume Requirement	0.25	0.00	0.00

[a] In million gallons rather than million RINs.

Table 10.6.1.1-2: Renewable Fuel Volumes for Alternative Scenario 1 (Million RINs)

	2023	2024	2025
Cellulosic Biofuel	838	1,090	1,376
CNG/LNG from biogas	831	1,039	1,299
Ethanol from CKF	7	51	77
Total Biomass-Based Diesel[a]	5,965	5,955	6,631
Biodiesel	2,565	2,500	2,436
Soybean oil	1,473	1,451	1,430
FOG	481	454	427
Corn oil	173	134	95
Canola oil	438	461	484
Renewable Diesel	3,376	3,431	4,171
Soybean oil	777	1,141	1,501
FOG	1,883	1,825	1,962
Corn oil	348	406	463
Canola oil	368	59	245
Jet fuel from FOG	24	24	24
Other Advanced Biofuels	290	290	290
Renewable diesel from FOG	104	104	104
Imported sugarcane ethanol	95	95	95
Domestic ethanol from waste ethanol	27	27	27
Other[b]	64	64	64
Conventional Renewable Fuel	13,845	13,955	13,779
Ethanol from corn	13,845	13,955	13,779
Renewable diesel from palm oil	0	0	0
Supplemental Standard	250	0	0
Biodiesel from Soybean Oil	250	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.

Table 10.6.1.1-3: Changes in Renewable Fuel Volumes for Alternative Scenario 1 (Million RINs)[a]

	2023	2024	2025
Canola Oil Renewable Diesel	0	-250	-250
Total	0	-250	-250

[a] Volume changes are relative to the volumes we project will be supplied to meet the volume requirements we are finalizing in this rule. The projected volume changes for fuels not listed in this table are zero for all three years.

10.6.1.2 Alternative Scenario 2

The second alternative scenario we considered was a scenario in which we further reduced the total renewable fuel volume requirement for each year such that the implied conventional biofuel volume requirement was 13.0 billion gallons each year—a level considered sufficiently low for the market to have confidence that it could be met with just E10. This amounts to a 2.0 billion gallon reduction in the total renewable fuel volume requirement in 2023–2025 (relative to Alternative Scenario 1).

For this scenario we project that the contribution of corn ethanol towards meeting the renewable fuel volume requirements would be limited to 13.0 billion gallons each year. We project that obligated parties would continue to blend ethanol up to the E10 blendwall because it is economical to do so, but that the quantity of conventional RINs obligated parties can use to meet their RFS obligations would be limited to 13.0 billion gallons based on the difference between the advanced biofuel and total renewable fuel standards.[952]

With the reduction in the conventional ethanol volumes to 13.0 billion gallons, less advanced biofuel volume would then be necessary to backfill for conventional biofuel to meet the total renewable fuel standard under this scenario. As such, we next reduced the projected volumes of renewable diesel from canola oil, renewable diesel from soybean oil, and biodiesel from canola oil (in that order) until we achieved the intended reduction in the renewable fuel supply each year. As noted above, renewable diesel produced from canola oil is the most expensive non-cellulosic biofuel supplied in these years, and renewable diesel produced from soybean oil is similarly priced. For 2023, even after reducing these fuel types to zero further reductions are necessary.

We next reduced biodiesel produced from canola oil, as we project that the incentive provided by California's LCFS program and other similar state programs would be large enough to prevent any reductions in the supply of renewable diesel produced from FOG or distillers corn oil. Tables 10.6.1.2-1 through 3 summarize the renewable fuel volume requirements for this scenario, the renewable fuel volumes we project would be supplied to meet the required volumes, and the change in the supply of renewable fuels relative to the volumes we are finalizing in this rule.

[952] Additional ethanol would be expected to be blended as E10 based on its favorable economics up to the E10 blendwall. RINs associated for ethanol beyond the 13.0 billion gallon implied conventional biofuel volume each year generally could not be used to meet the required volumes for that year, but could be used to satisfy deficits from the previous year or carried over to be used in the next year.

Table 10.6.1.2-1: RFS Volume Requirements for Alternative Scenario 2 (Million RINs)

	2023	2024	2025
Cellulosic Biofuel	0.84	1.09	1.38
BBD[a]	2.82	2.89	3.20
Advanced Biofuel	5.94	6.29	7.08
Total Renewable Fuel	18.94	19.29	20.08
Implied Conventional Renewable Fuel	13.00	13.00	13.00
Supplemental Volume Requirement	0.25	0.00	0.00

[a] In million gallons rather than million RINs

Table 10.6.1.2-2: Renewable Fuel Volumes for Alternative Scenario 2 (Million RINs)

	2023	2024	2025
Cellulosic Biofuel	838	1,090	1,376
CNG/LNG from biogas	831	1,039	1,299
Ethanol from CKF	7	51	77
Total Biomass-Based Diesel[a]	4,810	4,910	5,410
Biodiesel	2,555	2,500	2,436
Soybean oil	1,473	1,451	1,430
FOG	481	454	427
Corn oil	173	134	95
Canola oil	428	461	484
Renewable Diesel	2,231	2,386	2,950
Soybean oil	0	155	525
FOG	1,883	1,825	1,962
Corn oil	348	406	463
Canola oil	0	0	0
Jet fuel from FOG	24	24	24
Other Advanced Biofuels	290	290	290
Renewable diesel from FOG	104	104	104
Imported sugarcane ethanol	95	95	95
Domestic ethanol from waste ethanol	27	27	27
Other[b]	64	64	64
Conventional Renewable Fuel	13,000	13,000	13,000
Ethanol from corn	13,000	13,000	13,000
Renewable diesel from palm oil	0	0	0
Supplemental Standard	250	0	0
Biodiesel from Soybean Oil	250	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.

Table 10.6.1.2-3: Changes in Renewable Fuel Volumes for Alternative Scenario 2 (Million RINs)[a]

	2023	2024	2025
Canola Oil Biodiesel	-10	0	0
Soybean Oil Renewable Diesel	-777	-986	-976
Canola Oil Renewable Diesel	-368	-309	-495
Corn Ethanol	-845	-955	-779
Total	-2,000	-2,250	-2,250

[a] Volume changes are relative to the volumes we project will be supplied to meet the volume requirements we are finalizing in this rule. The projected volume changes for fuels not listed in this table are zero for all three years. The reduced vegetable oil volume is estimated to cause a reduction in soy oil price; for example, the 2024 soy oil price is estimated to decrease from 80¢/lb to 57¢/lb under this alternative scenario.

10.6.1.3 Alternative Scenario 3

The third alternative scenario we considered is a scenario in which we increased the advanced biofuel volumes by 2.0 billion RINs each year for 2023–2025 relative to Alternative Scenario 1, with corresponding increases to the BBD volume requirement for each year, but with no change to the total renewable fuel volume. This has the effect of decreasing the implied conventional renewable fuel volume by 2.0 billion RINs each year (to a volume below the E10 blendwall).

For this scenario we project that the contribution of corn ethanol towards meeting the renewable fuel volume requirements would be limited to 13.0 billion gallons each year, as in Alternative Scenario 2. However, because the total renewable fuel volume requirement is only reduced by 0.25 billion gallons in 2024 and 2025 (and not at all in 2023), additional volumes of renewable fuel are needed to offset the reduction in corn ethanol supplied. We project that this additional renewable fuel would be renewable diesel produced from soybean oil.

We project that in this scenario renewable diesel would be the most likely fuel type to increase due to the excess production capacity and the relative lack of infrastructure constraints or challenges associated with increasing the use of renewable diesel in the U.S. We further project that this renewable diesel would be produced from soybean oil, as we project that renewable diesel producers would have already utilized all available sources of FOG and distillers corn oil due to the relatively high value of fuels produced from these feedstocks in California's LCFS program.[953] The additional soybean oil would be expected to be sourced from imports and diversion from other domestic uses given that the finalized volumes are already expected to utilize all available increases in North American feedstock supplies. Tables 10.6.1.3-1 through 3 summarize the renewable fuel volume requirements for this scenario, the renewable fuel volumes we project would be supplied to meet the required volumes, and the change in the supply of renewable fuels relative to the volumes we are finalizing in this rule.

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[953] The additional volume of renewable diesel could also be produced from canola oil. We note that in our cost and fuel price impact analyses we project that renewable diesel produced from canola oil and soybean oil have the same costs, and therefore the projected impacts of this scenario would be the same whether this fuel was produced from soybean oil or canola oil.

Table 10.6.1.3-1: RFS Volume Requirements for Alternative Scenario 3 (Million RINs)

	2023	2024	2025
Cellulosic Biofuel	0.84	1.09	1.38
BBD[a]	4.07	4.14	4.45
Advanced Biofuel	7.94	8.29	9.08
Total Renewable Fuel	20.94	21.29	22.08
Implied Conventional Renewable Fuel	13.00	13.00	13.00
Supplemental Volume Requirement	0.25	0.00	0.00

[a] In million gallons rather than million RINs

Table 10.6.1.3-2: Renewable Fuel Volumes for Alternative Scenario 3 (Million RINs)

	2023	2024	2025
Cellulosic Biofuel	838	1,090	1,376
CNG/LNG from biogas	831	1,039	1,299
Ethanol from CKF	7	51	77
Total Biomass-Based Diesel[a]	6,810	6,910	7,410
Biodiesel	2,565	2,500	2,436
Soybean oil	1,473	1,451	1,430
FOG	481	454	427
Corn oil	173	134	95
Canola oil	438	461	484
Renewable Diesel	4,221	4,386	4,950
Soybean oil	1,622	1,846	2,030
FOG	1,883	1,825	1,962
Corn oil	348	406	463
Canola oil	368	309	495
Jet fuel from FOG	24	24	24
Other Advanced Biofuels	290	290	290
Renewable diesel from FOG	104	104	104
Imported sugarcane ethanol	95	95	95
Domestic ethanol from waste ethanol	27	27	27
Other[b]	64	64	64
Conventional Renewable Fuel	13,000	13,000	13,000
Ethanol from corn	13,000	13,000	13,000
Renewable diesel from palm oil	0	0	0
Supplemental Standard	250	0	0
Biodiesel from Soybean Oil	250	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.

Table 10.6.1.3-3: Changes in Renewable Fuel Volumes for Alternative Scenario 3 (Million RINs)[a]

	2023	2024	2025
Soybean Oil Renewable Diesel	+845	+705	+529
Corn Ethanol	-845	-955	-779
Total	0	-250	-250

[a] Volume changes are relative to the volumes we project will be supplied to meet the volume requirements we are finalizing in this rule. The projected volume changes for fuels not listed in this table are zero for all three years. The increased vegetable oil volume is estimated to cause an increase in soy oil price; for example, the 2024 soy oil price is estimated to increase from 80¢/lb to 93¢/lb under this alternative scenario.

10.6.2 Cost Impacts of Alternative Scenarios

After determining the renewable fuel volumes projected to be used to meet the three alternative scenarios, we next projected the costs of each alternative scenario. The methodology used to estimate the costs of each scenario is identical to the methodology used to project the costs of the volumes we are finalizing in this rule, discussed in greater detail in RIA Chapters 10.1 through 10.4. For these alternative scenarios we only projected costs relative to the No RFS baseline and did not also calculate costs relative to the 2022 baseline. The projected costs for each of the alternative scenarios are shown in Tables 10.6.2-1 through 3.[954]

Table 10.6.2-1: Alternative Scenario 1 Cost Relative to the No RFS baseline (2022$)

		Total Cost (million $)	Per-Unit Cost	Units
2023	Gasoline	445	0.33	¢/gal gasoline
	Diesel Fuel	7,610	13.56	¢/gal diesel
	Natural Gas	55	0.1753	$/1000 FT3 natural gas
	Total	8,110	4.26	¢/gal gasoline and diesel
2023 with Suppl. Std.	Gasoline	445	0.33	¢/gal gasoline
	Diesel Fuel	8,238	14.68	¢/gal diesel
	Natural Gas	55	0.1753	$/1000 FT3 natural gas
	Total	8,738	4.59	¢/gal gasoline and diesel
2024	Gasoline	440	0.33	¢/gal gasoline
	Diesel Fuel	6,199	11.62	¢/gal diesel
	Natural Gas	137	0.4549	$/1000 FT3 natural gas
	Total	6,777	3.60	¢/gal gasoline and diesel
2025	Gasoline	458	0.34	¢/gal gasoline
	Diesel Fuel	7,156	13.53	¢/gal diesel
	Natural Gas	228	0.7645	$/1000 FT3 natural gas
	Total	7,842	4.22	¢/gal gasoline and diesel

[954] More details on these cost projections can be found in the technical memorandum, “Cost Projections for Alternative Scenarios,” available in the docket for this action.

Table 10.6.2-2: Alternative Scenario 2 Cost Relative to the No RFS baseline (2022$)

		Total Cost (million $)	Per-Unit Cost	Units
2023	Gasoline	0	0.00	¢/gal gasoline
	Diesel Fuel	4,075	7.26	¢/gal diesel
	Natural Gas	55	0.1753	$/1000 FT3 natural gas
	Total	4,130	2.17	¢/gal gasoline and diesel
2023 with Suppl. Std.	Gasoline	0	0.00	¢/gal gasoline
	Diesel Fuel	4,615	8.23	¢/gal diesel
	Natural Gas	55	0.1753	$/1000 FT3 natural gas
	Total	4,670	2.45	¢/gal gasoline and diesel
2024	Gasoline	0	0.00	¢/gal gasoline
	Diesel Fuel	2,379	4.46	¢/gal diesel
	Natural Gas	137	0.4549	$/1000 FT3 natural gas
	Total	2,516	1.34	¢/gal gasoline and diesel
2025	Gasoline	0	0.00	¢/gal gasoline
	Diesel Fuel	1,984	3.75	¢/gal diesel
	Natural Gas	228	0.7645	$/1000 FT3 natural gas
	Total	2,212	1.19	¢/gal gasoline and diesel

Table 10.6.2-3: Alternative Scenario 3 Cost Relative to the No RFS baseline (2022$)

		Total Cost (million $)	Per-Unit Cost	Units
2023	Gasoline	0	0.00	¢/gal gasoline
	Diesel Fuel	10,929	19.48	¢/gal diesel
	Natural Gas	55	0.1753	$/1000 FT3 natural gas
	Total	10,984	5.77	¢/gal gasoline and diesel
2023 with Suppl. Std.	Gasoline	0	0.00	¢/gal gasoline
	Diesel Fuel	11,653	20.77	¢/gal diesel
	Natural Gas	55	0.1753	$/1000 FT3 natural gas
	Total	11,708	6.15	¢/gal gasoline and diesel
2024	Gasoline	0	0.00	¢/gal gasoline
	Diesel Fuel	10,566	19.81	¢/gal diesel
	Natural Gas	137	0.4549	$/1000 FT3 natural gas
	Total	10,703	5.68	¢/gal gasoline and diesel
2025	Gasoline	0	0.00	¢/gal gasoline
	Diesel Fuel	11,960	22.61	¢/gal diesel
	Natural Gas	228	0.7645	$/1000 FT3 natural gas
	Total	12,188	6.55	¢/gal gasoline and diesel

10.6.3 Fuel Price Impacts of Alternative Scenarios

In addition to the costs of the alternative scenarios, we also projected the fuel price impacts of each alternative scenario. The methodology used to estimate the fuel price impacts of each scenario is identical to the methodology used to project the fuel price impacts of the volumes we are finalizing in this rule, discussed in greater detail in RIA Chapter 10.5. As with the impacts on costs, we only projected fuel price impacts of the alternative scenarios relative to the No RFS baseline and did not also calculate fuel price impacts relative to the 2022 baseline. The projected fuel price impacts for each of the alternative scenarios are shown in Tables 10.6.3-1 through 3.[955]

Table 10.6.3-1: Alternative Scenario 1 Fuel Price Impacts (No RFS Baseline)

	Gasoline			Diesel		
	2023	**2024**	**2025**	**2023**	**2024**	**2025**
Average Cost (No RFS baseline) ($/gal)	$3.03	$2.61	$2.48	$3.98	$3.65	$3.46
Average Cost (candidate volumes) ($/gal)	$3.05	$2.64	$2.52	$4.08	$3.74	$3.57
Fuel Price Impact (¢/gal)	2.4¢	2.9¢	4.0¢	10.1¢	9.8¢	10.7¢

Table 10.6.3-2: Alternative Scenario 2 Fuel Price Impacts (No RFS Baseline)

	Gasoline			Diesel		
	2023	**2024**	**2025**	**2023**	**2024**	**2025**
Average Cost (No RFS baseline) ($/gal)	$3.03	$2.61	$2.48	$3.98	$3.64	$3.45
Average Cost (candidate volumes) ($/gal)	$3.08	$2.67	$2.55	$3.94	$3.59	$3.39
Fuel Price Impact (¢/gal)	5.5¢	6.0¢	7.0¢	-3.5¢	-5.1¢	-6.0¢

Table 10.6.3-3: Alternative Scenario 3 Fuel Price Impacts (No RFS Baseline)

	Gasoline			Diesel		
	2023	**2024**	**2025**	**2023**	**2024**	**2025**
Average Cost (No RFS baseline) ($/gal)	$3.03	$2.61	$2.48	$3.98	$3.65	$3.47
Average Cost (candidate volumes) ($/gal)	$3.10	$2.69	$2.56	$3.99	$3.67	$3.50
Fuel Price Impact (¢/gal)	7.2¢	7.8¢	8.7¢	1.2¢	1.8¢	3.4¢

10.6.4 Energy Security Benefits of Alternative Scenarios

We next projected the energy security benefits of each alternative scenario. The methodology used to estimate the energy security benefits of each scenario is identical to the methodology used to project the energy security benefits of the volumes we are finalizing in this

[955] More details on these fuel price impacts can be found in the technical memorandum, "Fuel Price Impacts of Alternative Scenarios," available in the docket for this action.

rule, discussed in greater detail in RIA Chapter 5. The projected energy security benefits for each of the alternative scenarios are shown in Tables 10.6.4-1 through 3.[956]

Table 10.6.4-1: Annual Energy Security Benefits of Alternative Scenario 1

Year	Net Crude Oil Import Reductions (millions of gallons)	Benefits (millions of 2022$)
2023		
Excluding Supplemental Standard	2,012	$180
Including Supplemental Standard	2,151	$192
2024	1,820	$161
2025	2,001	$175

Table 10.6.4-2: Annual Energy Security Benefits of Alternative Scenario 2

Year	Net Crude Oil Import Reductions (millions of gallons)	Benefits (millions of 2022$)
2023		
Excluding Supplemental Standard	1,215	$109
Including Supplemental Standard	1,354	$121
2024	1,076	$95
2025	1,151	$101

Table 10.6.4-3: Annual Energy Security Benefits of Alternative Scenario 3

Year	Net Crude Oil Import Reductions (millions of gallons)	Benefits (millions of 2022$)
2023		
Excluding Supplemental Standard	2,317	$207
Including Supplemental Standard	2,457	$219
2024	2,180	$192
2025	2,257	$197

10.6.5 Consideration of Other Impacts of the Alternative Scenarios

The discussion above of the impacts of the alternative scenarios only addresses costs, fuel prices, and energy security and does not include all the other factors also evaluated with respect to the final volumes. We note, however, that the impact of biofuel production on each of the statutory factors is generally proportional to the quantity of biofuel produced and used. We can therefore approximate the expected impact of each alternative scenario by considering the changes in the biofuel volumes projected to be used to meet the alternative scenario.

[956] More details on these energy security benefits can be found in the technical memorandum, "Energy Security Projections for Alternative Scenarios," available in the docket for this action.

In this section we present two sets of volume changes for each of the scenarios. The first is simply relative to the total volume of each fuel type we project will be supplied to meet the volumes we are finalizing in this rule (Table 10.6.5-1). For example, in Alternative Scenario 1 we expect that total renewable fuel use would be approximately 1% lower in 2024 and 2025 relative to the total renewable fuel volumes projected to be used to meet the volumes we are finalizing in this rule. We could therefore reasonably expect that employment at biofuel production facilities under this scenario may decrease by approximately 1%. The second set of volume changes considered is the change in volumes attributable to the rule (i.e., relative to the projected volume increases from the No-RFS baseline) for the alternative scenario in comparison to the change in volumes attributable to the volumes we are finalizing in this rule (Table 10.6.5-2). We project, for example, that the incremental total renewable fuel volume use attributable to the RFS program would decrease by about 5% in 2024 and 2025 in Alternative Scenario 1 relative to the volumes we are finalizing in this rule. Based on this information we could reasonably project that the impacts of this rule on some of the unquantified statutory factors would be approximately 5% lower under Alternative Scenario 1 relative to the volumes we are finalizing in this rule. We further note that the projected impacts on particular fuel types are much larger than the projected impacts on total renewable fuel use, and that the projected impacts for Alternative Scenario 2 are much larger than the projected impacts of Alternative Scenarios 1 and 3.

Table 10.6.5-1: Volume Changes of the Alternative Scenarios Relative to the Total Biofuel Volumes Finalized (million RINs)

	2023	2024	2025
Alternative Scenario 1			
Canola Oil Renewable Diesel	0.0%	-80.9%	-50.5%
Total	0.0%	-1.2%	-1.1%
Alternative Scenario 2			
Canola Oil Biodiesel	-2.3%	0.0%	0.0%
Soybean Oil Renewable Diesel	-100%	-86.4%	-65.0%
Canola Oil Renewable Diesel	-100%	-100%	-100%
Corn Ethanol	-6.1%	-6.8%	-5.7%
Total	-9.4%	-10.4%	-10.1%
Alternative Scenario 3			
Soybean Oil Renewable Diesel	+108.8%	+61.8%	+35.2%
Corn Ethanol	-6.1%	-6.8%	-5.7%
Total	0.0%	-1.2%	-1.1%

Table 10.6.5-2: Change in Volumes Attributable to the RFS program for the Alternative Scenarios Relative Compared to the Final Rule Volumes(million RINs)

	2023	2024	2025
Alternative Scenario 1			
Canola Oil Renewable Diesel	0.0%	-80.9%	-50.5%
Total	0.0%	-5.5%	-4.8%
Alternative Scenario 2			
Canola Oil Biodiesel	-2.3%	0.0%	0.0%
Soybean Oil Renewable Diesel	-100%	-86.4%	-78.7%
Canola Oil Renewable Diesel	-100%	-100%	-100%
Corn Ethanol	-100%	-100%	-100%
Total	-43.1%	-49.5%	-43.5%
Alternative Scenario 3			
Soybean Oil Renewable Diesel	+206.6%	+106.7%	+41.2%
Corn Ethanol	-100%	-100%	-100%
Total	0.0%	-5.5%	-4.8%

10.6.6 Summary of the Impacts of the Alternative Scenarios

Finally, we summed the projected fuel costs and energy security benefits of each alternative scenario. The costs and energy security benefits for each scenario are described in RIA Chapters 10.6.2 and 10.6.4. The projected costs and energy security benefits for each of the alternative scenarios are shown in Tables 10.6.6-1 through 3. Table 10.6.6-4 shows the costs and energy security benefits of the volumes we are finalizing in this rule and each of the three alternative scenarios for comparison.[957]

Table 10.6.6-1: Cumulative Monetized Fuel Costs and Energy Security Benefits of Alternative Scenario 1 with Respect to the No RFS Baseline (2022$, millions)

	Discount Rate	
	3%	**7%**
Excluding Supplemental Standard		
Fuel Costs	$22,081	$21,293
Energy Security Benefits	$501	$483
Including Supplemental Standard		
Fuel Costs	$22,709	$21,921
Energy Security Benefits	$513	$495

[957] More details on these discounted costs and energy security benefits can be found in the technical memorandum, "Summary Cost and Energy Security Projections for Alternative Scenarios," available in the docket for this action.

Table 10.6.6-2: Cumulative Monetized Fuel Costs and Energy Security Benefits of Alternative Scenario 2 with Respect to the No RFS Baseline (2022$, millions)

	Discount Rate	
	3%	**7%**
Excluding Supplemental Standard		
Fuel Costs	$8,658	$8,413
Energy Security Benefits	$296	$285
Including Supplemental Standard		
Fuel Costs	$9,198	$8,953
Energy Security Benefits	$308	$298

Table 10.6.6-3: Cumulative Monetized Fuel Costs and Energy Security Benefits of Alternative Scenario 3 with Respect to the No RFS Baseline (2022$, millions)

	Discount Rate	
	3%	**7%**
Excluding Supplemental Standard		
Fuel Costs	$32,864	$31,632
Energy Security Benefits	$580	$559
Including Supplemental Standard		
Fuel Costs	$33,588	$32,356
Energy Security Benefits	$592	$572

Table 10.6.6-4: Cumulative Monetized Fuel Costs and Energy Security Benefits of the Final Volumes and Alternative Scenarios with Respect to the No RFS Baseline (2022$, millions, 3% discount rate, including the supplemental standard)

	Final Volumes	**Alternative Scenario 1**	**Alternative Scenario 2**	**Alternative Scenario 3**
Fuel Costs	$23,846	$22,709	$9,198	$33,588
Energy Security Benefits	$536	$513	$308	$592

Chapter 11: Screening Analysis

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%.[958] 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.[959] 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.

11.1 Background

11.1.1 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.

11.1.2 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,

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[958] 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.

[959] 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.

and to annually establish renewable fuel standards that are used by obligated parties to determine their individual RVOs.

11.1.3 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,[960] 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 7 refiners (owning 9 refineries) producing gasoline and/or diesel that meet the small entity definition of having 1,500 employees or fewer.

[960] EIA Refinery Capacity Report. https://www.eia.gov/petroleum/refinerycapacity/archive/2022/refcap2022.php.

11.1.4 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.[961] 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.

11.2 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.[962] 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.[963] 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.

11.3 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 11.2, 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%.

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[961] 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).

[962] 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.

[963] Id.

11.4 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%.