Renewable Fuel Standard (RFS) Program - Standards for 2026 and 2027: Draft 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

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United States Environmental Protection Agency

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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:

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
CFPC	Clean Fuel Production Credit
CG	Conventional Gasoline
CI	Carbon Intensity
CNG	Compressed Natural Gas
CO	Carbon Monoxide
CWC	Cellulosic Waiver Credit
DDG	Dried Distillers Grains
DDGS	Dried Distillers Grains with Solubles
DOE	U.S. Department of Energy
DRIA	Draft Regulatory Impact Analysis
DWG	Distillers Wet Grains
EIA	U.S. Energy Information Administration
EISA	Energy Independence and Security Act of 2007
EMTS	EPA-Moderated Transaction System
EPA	U.S. Environmental Protection Agency
EPAct	Energy Policy Act of 2005
EU	European Union
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
GWP	Global Warming Potential
LCA	Lifecycle Analysis
IEA	International Energy Agency
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
NH3	Ammonia
NHTSA	National Highway Transportation Administration
NO_x	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
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
SO2	Sulfur Dioxide
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
VOC	Volatile Organic Compounds
WTI	West Texas Intermediate

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, the statute required EPA to translate them through 2022 into percentage standards that obligated parties then use to determine the compliance obligations that they must meet every year. As discussed in Preamble Section VI, we are continuing to use percentage standards as the implementing mechanism for 2026 and 2027.

In this action we are proposing to establish the applicable volume targets for all four categories of renewable fuel for the years 2026 and 2027. 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 2026 and 2027. Finally, in addition to these volumes and standards, we are proposing in this action a number of other changes, including that imported renewable fuel and renewable fuel produced from foreign feedstocks would generate fewer RINs, the removal of renewable electricity as a qualifying renewable fuel under the RFS program, and several other changes.

This Draft Regulatory Impact Analysis (DRIA) supports our proposal by addressing 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.

Table ES-1 summarizes certain potential impacts associated with the proposed volume requirements in this rule, including both quantified and unquantified impacts. Not all of the monetized impacts listed in Table ES-1 represent societal benefits or costs. Specifically, the only monetized societal benefits and costs are the energy security benefits and the fuel costs. The projected $11.4 billion annualized impacts in rural economic development generally do not represent societal benefits. The monetized societal benefits and costs of this proposed rule are shown in Table ES-2.

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

Table ES-1: Potential Annualized Quantified and Unquantified Impacts Associated with the Proposed Volumes in this Rule Relative to the No RFS Baseline[a]

Potential Impacts of Proposed Volumes	Effect	Effect Quantified	Quantified Impact	Chapter
Impacts on air quality from biofuel production, transport, and use	Increases in emissions associated with biofuel production	Emission inventory impacts	-	4.1.2.1
	Increases in emissions associated with biofuel transport	Qualitative	-	4.1.2.2
	Varying emission impacts from vehicles running on ethanol blends and pre-2007 diesel vehicles running on biodiesel blends	Qualitative	-	4.1.2.3
	Changes in ambient concentrations of air pollutants varied by location across the U.S.	Qualitative	-	4.1.3
Impacts on climate change from biofuel feedstock production and displacement of petroleum fuels	Reduced GHG emissions	Quantitative	1–16 MMT average annual CO_2e reductions	5
Impacts on conversion of natural lands, including wetlands, from biofuel feedstock production	Increased conversion of wetlands, forests, pasture, and grasslands to cropland	Qualitative	-	4.2
Impacts on soil and water quality from biofuel feedstock production	Impacts to soil and water quality from increased erosion, nutrient, and pesticide runoff due to agricultural conversion	Qualitative	-	4.3
	Other impacts to water quality, including but not limited to leaks and spills from aboveground and underground storage as well as biogas production	Qualitative	-	4.3
Impacts on water quantity and availability from biofuel and feedstock production	Use of water resources for cropland irrigation	Qualitative	-	4.4
	Use of water in production facilities	Qualitative	-	4.4

Potential Impacts of Proposed Volumes	Effect	Effect Quantified	Quantified Impact	Chapter
Impacts on ecosystems and wildlife habitat	Impacts due to loss of natural lands, changes to soil and water quality, air quality, and water quantity	Qualitative	-	4.5
Energy security	Increased energy security	Energy security benefits	$200 million	6
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	Quantitative	120,000 jobs	9.2
Rural economic development	Increased support for rural economic development associated with biofuel and feedstock production	Quantitative	$11.4 billion	9.3
Commodity supply and price impacts	Increased supply of certain agricultural commodities	Qualitative		9.4
	Higher corn, soybean, and soybean oil prices	Commodity price increases	-	9.5
	Higher food prices	Food price increases	-	9.6
Costs	Increased societal cost	Fuel costs	$6.7 billion	10.4
	Estimated Fuel Price Impacts	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) as well as distributional effects or transfers (jobs, rural economic development, etc.). Monetized fuel costs, energy security benefits, and rural economic development benefits in Table ES-1 represent annualized monetized impacts using a 3% discount rate. Alternative discount rates are considered in Preamble Section V.H and in the relevant chapters cited within the table.

Table ES-2: Societal Benefits and Costs of this Proposed Rule (million 2022$)[a]

Type	Category	2026	2027	Present Value	Annualized Value
Societal Benefits	Energy Security Benefits	$196	$210	$387	$202
Societal Costs	Fuel Costs	$7,494	$5,936	$12,871	$6,726
Net Benefits	Total	-$7,297	-$5,726	-$12,484	-$6,524

[a] Present and annualized values are estimated using a 3% discount rate. Computing annualized costs and benefits from present values spreads the costs and benefits equally over each period, taking account of the discount rate. The annualized value equals the present value divided by the sum of discount factors. For a calculation of present and annualized values from annual impact estimates, see "Set 2 NPRM Costs and Benefits Summary," available in the docket for this action.

The technical analyses supporting this proposed rule, summarized in Tables ES-1 and 2 and presented in greater detail in this document, are based on the information available at the time the analyses were completed. Since these analyses were completed, more recent data and projections have become available. One important projection that we used extensively in our analyses for this proposed rule was EIA's Annual Energy Outlook 2023 (AEO2023), which was the most current version of this report at the time the analyses were conducted.[1] Since that time, EIA released Annual Energy Outlook 2025 (AEO2025) on April 15, 2025.[2] Among other changes, AEO2025 projects lower crude oil prices than AEO2023 ($78–81 per barrel in AEO2025 vs $85–90 per barrel in AEO2023) and greater consumption of transportation fuel. All else equal, lower petroleum fuel prices will increase the cost of renewable fuels. For example, the projected wholesale diesel prices for 2026 and 2027 in AEO2025 are $0.52 and $0.39 per gallon lower, respectively, than in AE02023.[3] If we consider this change in isolation, it will increase the projected per gallon costs for renewable diesel produced from soybean oil by 26% in 2026 and 18% in 2027. Other fuel types will be similarly impacted, though the magnitude of the impact will vary be fuel type. While these per gallon cost increases provide some indication of the impact updating to AEO2025 will have on the projected costs of this proposed rule, we note that our consideration of new information and projections will impact the cost projections in a variety of ways (including our projection of the No RFS baseline) and that these impacts are not all simple to anticipate or project. For the final rule, we intend to update our analyses using the most recent available data and projections from EIA and other sources.

[1] EIA, "Annual Energy Outlook 2023" (AEO2023). https://www.eia.gov/outlooks/archive/aeo23.

[2] EIA, "Annual Energy Outlook 2025" (AEO2025). https://www.eia.gov/outlooks/aeo.

[3] Estimates calculated assuming that updating to AEO2025 will increase the cost of renewable diesel produced from soybean oil relative to petroleum diesel (projected to be $2.00 per gallon in 2026 and $2.12 per gallon in 2027) by $0.52 per gallon and $0.39 per gallon, respectively. See DRIA Chapter 10.4.1 for more detail on the cost projections of individual renewable fuels. Wholesale diesel prices from Table 57 – Components of Selected Petroleum Price Products.

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: Volumes Scenarios, Proposed Volumes, and Volume Changes
This chapter identifies the specific biofuel types and associated feedstocks that are projected to be used to meet the volumes in the Volume Scenarios and the Proposed Volumes. It also identifies the differences between the Volume Scenarios and Proposed Volumes and the baselines described in Chapter 2.

Chapter 4: Environmental Impacts
This chapter discusses the environmental factors EPA analyzed in developing the Proposed Volumes.

Chapter 5: Climate Change Analysis
This chapter describes potential climate impacts of the Proposed Volumes.

Chapter 6. Energy Security Impacts
This chapter reviews the literature on energy security impacts associated with petroleum consumption and imports and summarizes EPA's estimates of the benefits that would result from the Proposed Volumes.

Chapter 7: 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 8: Infrastructure
This chapter analyzes the impact of renewable fuels on the distribution infrastructure of the U.S.

Chapter 9: 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 10: Estimated Costs and Fuel Price Impacts
This chapter estimates the impact of the use of renewable fuels on the social cost, the cost to consumers (prices) of transportation fuel, and on the cost to transport goods.

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

Note: Unless otherwise stated, all documents cited in this document are available in the docket for this action (EPA-HQ-OAR-2024-0505). We have generally not included in the docket Federal Register notices, court cases, statutes, regulations, materials with a Digital Object Identifier (DOI), or previously docketed materials. These materials are easily accessible to the public via the Internet and other means.

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). The Set 1 Rule RIA contains EPA's review of the implementation of the RFS program from the passing of the Energy Policy Act of 2005 through 2022, the last calendar year specified in the statutory tables.[4] In determining the proposed RFS volumes in this rule we have once again considered the implementation of the RFS program since 2005, described in detail in the Set 1 Rule RIA. We have also considered developments in the petroleum fuel and renewable fuel sectors since 2022. Throughout this document, we use the term "supply" of renewable fuel to refer to the quantity of qualifying renewable fuel that can be used as transportation fuel, heating oil, or jet fuel in the U.S. Unless otherwise noted, all historical data on the supply of renewable fuel is based on data from the EPA Moderated Transaction System (EMTS).

This chapter focuses on our review of the implementation of the RFS program since 2022, with references to important observations from previous years where relevant. For a more extensive review of the implementation of the RFS program from 2005–2022, see Chapter 1 of the Set 1 Rule RIA.

1.1 Gasoline, Diesel, Crude Oil, and Renewable Fuels

This section compares recent and projected crude oil and renewable fuels feedstock prices, and discusses observed and projected petroleum imports, refinery margins, and transportation fuel demand prior to and during the recent and future years of the RFS program.

1.1.1 Crude Oil Prices vs. Renewable Fuel Feedstock Price Projections

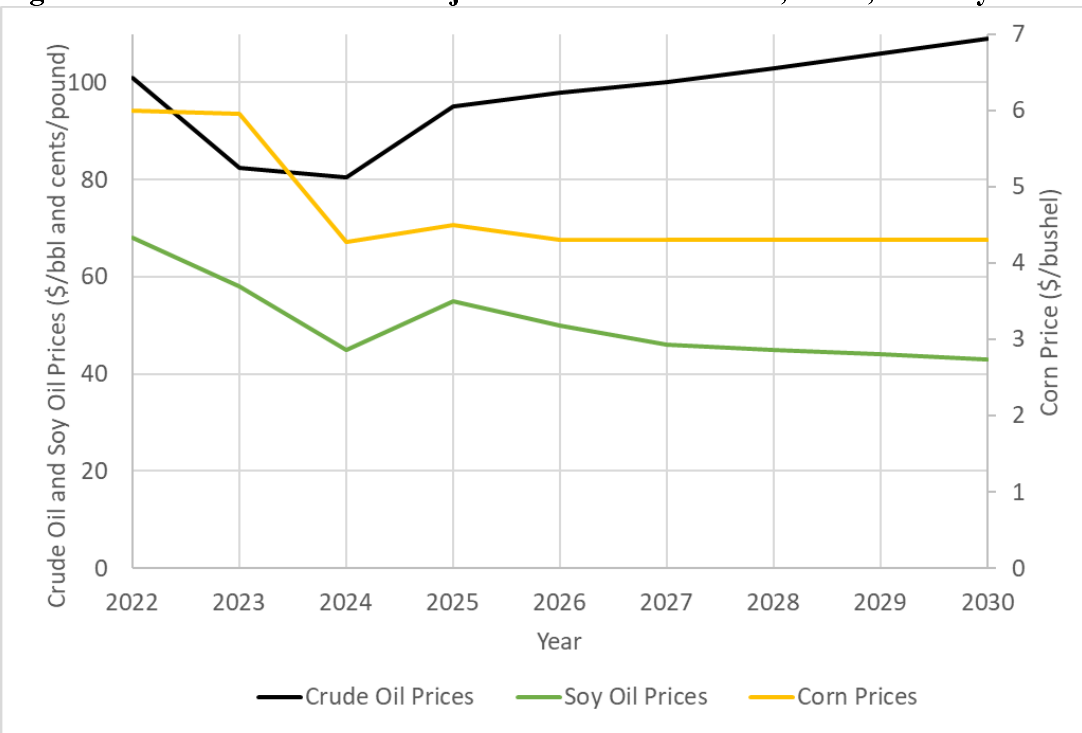
Crude oil prices have a significant impact on the economics of increased use of renewable fuels. When crude oil prices increase, both renewable fuel feedstock prices and gasoline and diesel prices tend to increase as well, although gasoline and diesel prices generally increase more relative to renewable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

Figure 1.1.1-1 compares the recent historical crude oil and corn and soy oil prices and their projected future prices in nominal dollars. The figure shows that after high crude oil and renewable fuels feedstock prices in 2022, those prices have decreased in 2023 and 2024. USDA projects corn and soy oil prices to increase somewhat in 2025 and then decrease very slightly, while EIA projects crude oil prices to increase in 2025 out to 2030. It is important to note that the crude oil price projections are from AEO2023, which is over two years old. However, a

[4] "EPA, Renewable Fuel Standard (RFS) Program: Standards for 2023–2025 and Other Changes – Regulatory Impact Analysis," EPA-420-R-23-015, June 2023.

preliminary review of AEO2025 indicates lower projections for crude oil prices from 2026–2030 (ranging from $78–81 per barrel) than AEO2023 ($85–90 per barrel).

Figure 1.1.1-1 Historical and Projected Future Crude Oil, Corn, and Soybean Oil Prices[a]



[a] 2024 and earlier are historical, 2025 and later are price projections in nominal dollars.
Source: EIA, "Spot Prices," *Petroleum & Other Liquids*, May 14, 2025. https://www.eia.gov/dnav/pet/pet_pri_spt_s1_a.htm. USDA, "Oil Crops Yearbook," March 2025. https://www.ers.usda.gov/data-products/oil-crops-yearbook. farmdoc, "US Average Farm Price Received Database," February 28, 2025. https://farmdoc.illinois.edu/decision-tools/us-average-farm-price-received-database. AEO2023, Table 12 – Petroleum and Other Liquids Prices. USDA, "USDA Agricultural Projections to 2033," OCE-2024-1, February 2024, https://www.usda.gov/sites/default/files/documents/USDA-Agricultural-Projections-to-2033.pdf.

1.1.2 Petroleum and Renewable Fuels Imports

As discussed further in Chapter 6, 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, as there could be significant costs to the U.S. economy if foreign supplies are 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 credited with causing the U.S. economy to slide into a recession.[5] It also led to Congress banning the export of U.S. crude oil from 1975 to 2015.[6]

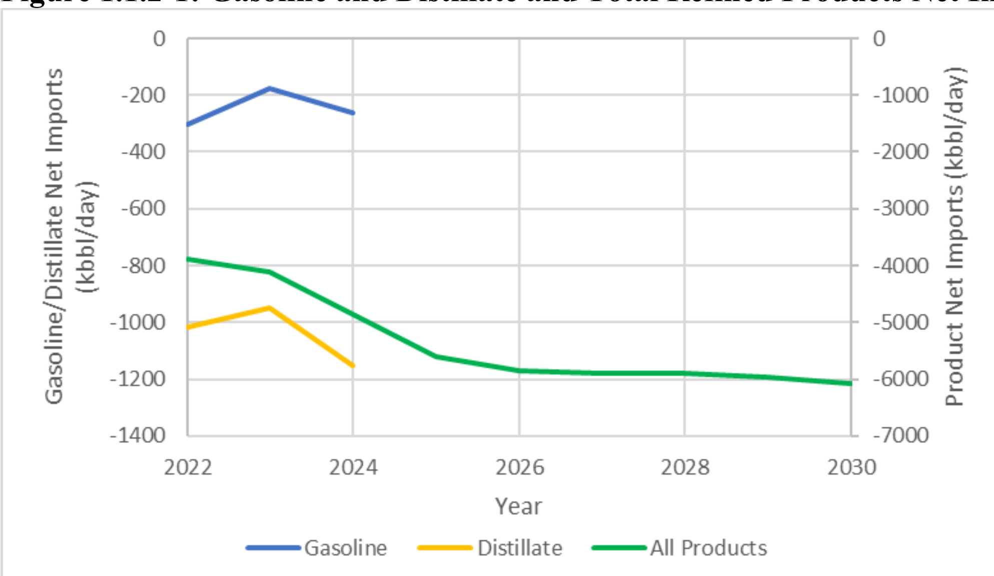
At the time that Congress passed EPAct and EISA and EPA promulgated the RFS1 and RFS2 rules, the U.S. was importing a large portion of its crude oil and significant quantities of

[5] Verrastro, Frank A. and Guy Caruso. "The Arab Oil Embargo-40 Years Later." *Center for Strategic & International Studies*, October 16, 2013. https://www.csis.org/analysis/arab-oil-embargo-40-years-later.
[6] 1975 Energy Policy and Conservation Act; Consolidated Appropriations Act of 2016.

gasoline, particularly on the East Coast. At the time, that trend was expected to continue indefinitely. This expectation did not factor in the eventual increase in U.S. tight oil crude oil production, which largely occurred after the passage and promulgation of these laws and rules. Using EIA data, we reviewed how petroleum imports changed before, during, and after the passage of EPAct and EISA, and implementation of the RFS program, in the Set 1 Rule. During the time period of 2005–2020, U.S. net imports of crude oil and refined products decreased substantially.

Since 2022, net imports of gasoline and distillate increased some and then decreased, but overall the changes are modest.[7] EIA does not specifically project future gasoline and diesel fuel net imports in its AEO reports. However, EIA does project and report a total refined product net import estimate which we show in the figure along with their historical values.[8] Figure 1.1.2-1 summarizes the gasoline, distillate, and total refined product volumes.

Figure 1.1.2-1: Gasoline and Distillate and Total Refined Products Net Imports[a]



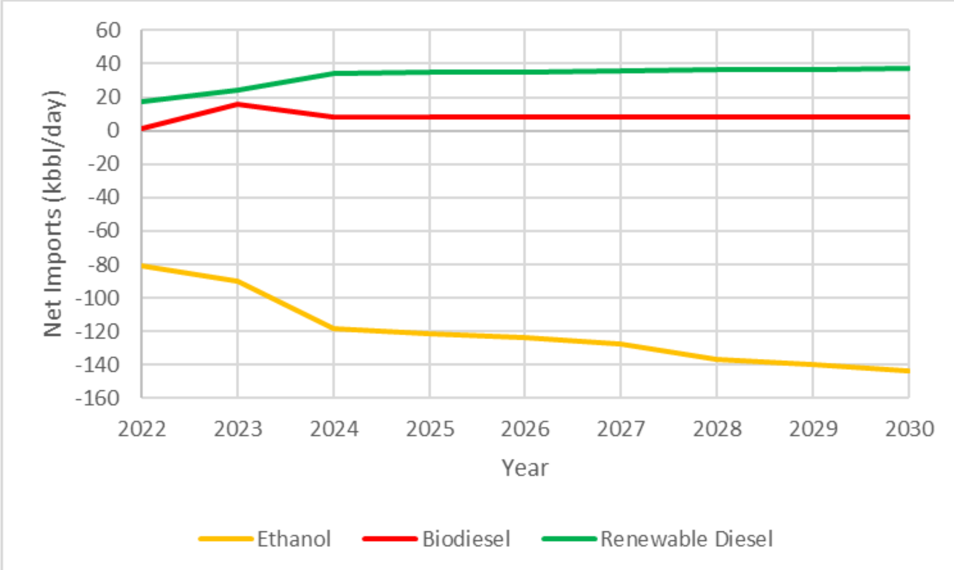
[a] 2024 and earlier are historical, 2025 and later are price projections.

The projected decrease in net imported total refined products could indicate that EIA projects further decreases in net imported gasoline and distillate; however, there are other refined products which can contribute significantly to net exports. For example, currently there are substantial exports of hydrocarbon gas liquids and residual fuel, thus, some or potentially most of the decrease in projected net refined products could be comprised of these other products instead of gasoline and distillate.

EIA also gathers information on, reports, and projects the net imports of ethanol, biodiesel, and renewable diesel. Figure 1.1.2-2 summarizes the historical and projected net imports of these renewable fuels.

[7] EIA, "U.S. Net Imports by Country," *Petroleum & Other Liquids*, April 30, 2025. https://www.eia.gov/dnav/pet/pet_move_neti_dc_NUS-Z00_mbblpd_a.htm.
[8] AEO2023, Table 11 – Petroleum and Other Liquids Supply and Disposition.

Figure 1.1.2-2: Corn Ethanol, Biodiesel and Renewable Diesel Net Imports[a]



[a] 2024 and earlier are historical, 2025 and later are projections.
Source: EIA, "U.S. Net Imports by Country," Petroleum & Other Liquids, April 30, 2025. https://www.eia.gov/dnav/pet/pet_move_neti_dc_NUS-Z00_mbblpd_a.htm. AEO2023, Table 11 – Petroleum and Other Liquids Supply and Disposition.

Figure 1.1.2-2 shows that biodiesel and renewable diesel net imports increased after 2022. After 2024, EIA projects biodiesel and renewable diesel net imports to essentially be flat going forward. Corn ethanol net imports decreased from 2022 to 2024. After 2024, EIA projects corn ethanol net imports to decrease further. This decrease may principally be due to EIA's projected decrease in gasoline demand, which would decrease the volume of ethanol blended into gasoline domestically at 10 volume percent. Consequently, corn ethanol producers would export the excess corn ethanol production volume which is not blended into gasoline as E15 or E85. The increased consumption of renewable fuels contributes to reductions in net petroleum imports, though by a very modest amount.

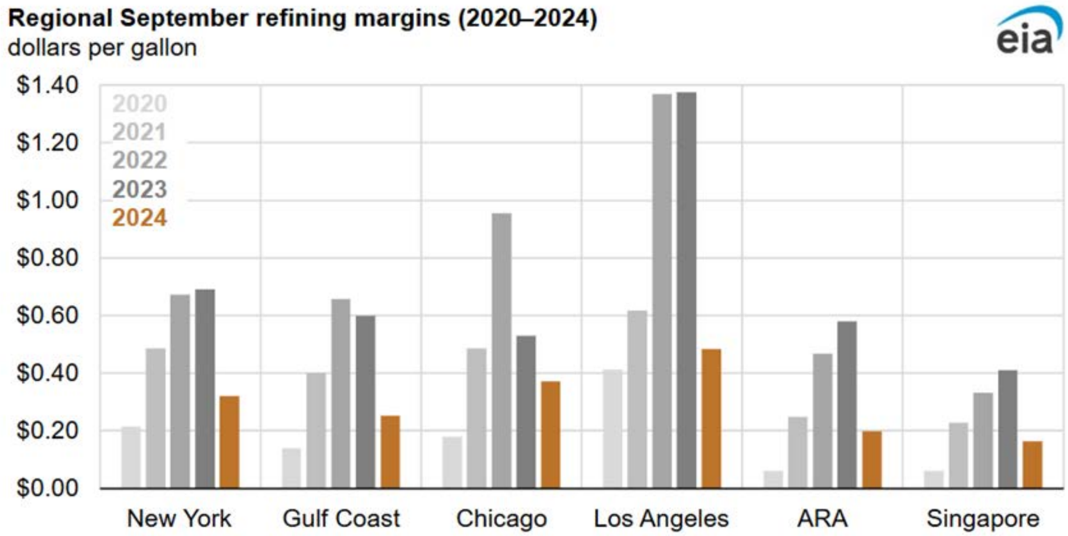
1.1.3 Refinery Margins

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 for refineries to be viable over the long term.

EIA reported refinery margin data for various U.S. refinery regions, as well as for Europe and Singapore, and is shown in Figure 1.1.3-1.[9] The refinery margin data are 3-2-1 cracked spreads, which are gross margins (excludes refinery operating costs) and the data is for the years 2020–2024.

[9] EIA, "Global refinery margins fall to multiyear seasonal lows in September," *Today in Energy*, October 15, 2024. https://www.eia.gov/todayinenergy/detail.php?id=63447.

Figure 1.1.3-1: Refinery Margins in the U.S. and Two Other Regions



Note: ARA = Amsterdam-Rotterdam-Antwerp

The figure shows that the disruption of fuel consumption in 2020 caused by the Covid-19 pandemic caused severely depressed refinery margins worldwide. However, as fuel demand rebounded in 2021 and 2022, refinery margins recovered through 2023. Due to falling U.S. refined product demand, particularly distillate, and falling demand in China and Europe, refinery margins dropped back down in 2024. In addition to falling demand, several large refineries began operating in the Middle East and Africa which also contributed to lower refinery margins.[10] Although refinery margins dropped in all regions in 2024, U.S. refinery margins are still somewhat higher than those in Western Europe and Singapore. U.S. refinery margins are typically better than overseas refinery regions due to lower prices for purchased crude oil, and natural gas which is used as a feedstock for refinery heat and hydrogen production.

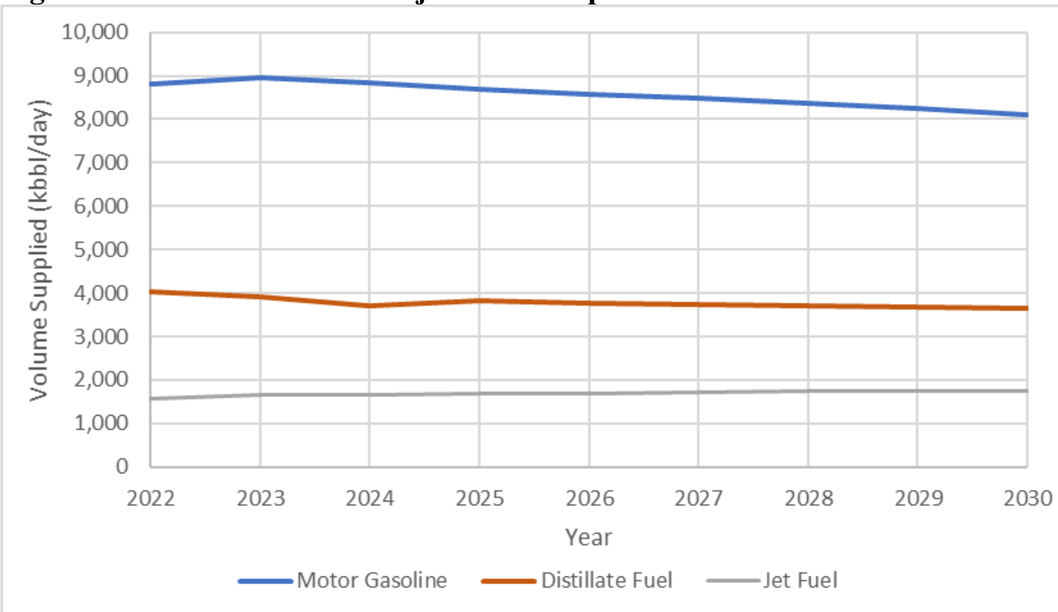
1.1.4 Transportation Fuel Demand

At the time the RFS2 program was being enacted through EISA in 2007, there had been a consistent increase in U.S. petroleum demand and crude oil prices were very high. The RFS program was implemented to help meet U.S. refined product demand and help to lower crude oil prices. However, transportation fuel demand slowed starting in 2008 and has remained relatively stable since that time.

Figure 1.1.4-1 shows the actual volume of gasoline, distillate, and jet fuel consumed in the U.S. from 2022–2024, as well as the projected demand of gasoline, distillate, and jet fuel from 2025–2030.

[10] Id.

Figure 1.1.4-1: Actual and Projected Transportation Fuel Demand



Source: 2022 – 2024 data is from EIA, "U.S. Product Supplied for Crude Oil and Petroleum Products," *Petroleum & Other Liquids*, April 30, 2025. https://www.eia.gov/dnav/pet/pet_cons_psup_dc_nus_mbblpd_a.htm. 2025 – 2023 data is from AEO2023, Table 11 – Petroleum and Other Liquids Supply and Disposition.

Figure 1.4.4-1 shows that gasoline demand increased from 2022 to 2023, but then decreased from 2023 to 2024. Distillate demand decreased from 2022 to 2024, while jet fuel increased. Based on projections in AEO2023, distillate demand is expected to decline slightly and jet fuel is expected to increase slightly over the years 2025 to 2030. AEO2023 projects that gasoline demand will begin to decline and continue to do so through 2030.

Several factors have contributed to lowering transportation fuel demand:

- *Increased crude oil prices*. Periods of higher crude oil prices as far back as 2007 and as recent as 2022, which resulted in increased transportation fuel prices during these time periods, which affected consumer behavior by impacting the number of miles traveled and vehicle purchase decisions.

- *Increasing fuel economy of the motor vehicle fleet*. EPA and the National Highway Transportation Safety 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 trend of decreasing fuel consumption intensity has been monitored and reported by EPA for decades.[11] On balance, newer vehicles consume fuel more efficiently; 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.

[11] "The 2024 EPA Automotive Trends Report," EPA-420-R-24-022, November 2024.

- *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). Based on data for electricity demand by light-duty vehicles, EIA estimates that EVs and PHEVs consumed 11.74 million MWh of electricity in 2024.[12] If we assume that EVs travel 3 miles per kWh of electricity consumed, and the in-use light-duty fleet travels 22.7 miles per gallon of gasoline consumed, then electricity consumption by light-duty vehicles displaced 1.55 billion gallons of gasoline in 2024.

1.2 Cellulosic Biofuel

The RFS2 Rule projected a favorable outlook for cellulosic biofuels, anticipating them becoming a major contributor to the total biofuel volumes.[13] Since the implementation of that rule however, commercial-scale production of cellulosic biofuels has fallen short of these expectations. For the first several years of the RFS2 Rule, actual production volumes were significantly below the targets set in the rule. A major shift occurred with the inclusion of compressed natural gas and liquified natural gas (CNG/LNG) derived from biogas as qualifying cellulosic biofuels. Although not originally identified as a potential cellulosic biofuel pathway in the RFS2 Rule, CNG/LNG derived from biogas has since become the primary source of cellulosic biofuel production. The RFS2 Rule initially included a pathway[14] for generating advanced (D5) RINs from biogas produced at landfills, wastewater treatment plants, and manure digesters.[15] However, in response to industry inquiries, EPA evaluated whether biogas from additional sources could also qualify as cellulosic biofuel. This led to the Pathways II Rule in 2014, which expanded the approved pathways to include CNG/LNG derived from biogas sourced from landfills, wastewater treatment facility digesters, and manure digesters. Additionally, biogas derived from the cellulosic components of biomass processed in other waste digesters was also approved to generate cellulosic (D3) RINs[16] when used as transportation fuel.[17] This expansion was a critical driver of growth in cellulosic biofuel volumes.

Following the implementation of the Pathways II Rule in 2014, the production of cellulosic biofuels has experienced rapid growth, increasing from approximately 33 million RINs in 2014 to over 920 million RINs in 2024, (see Figure 1.2-1), with around 95% of all cellulosic RINs generated under the RFS program in 2024 attributed to CNG/LNG derived from biogas. This trend is expected to continue, with total volumes steadily increasing and CNG/LNG remaining the primary source of cellulosic biofuels in the RFS program through 2030 (see

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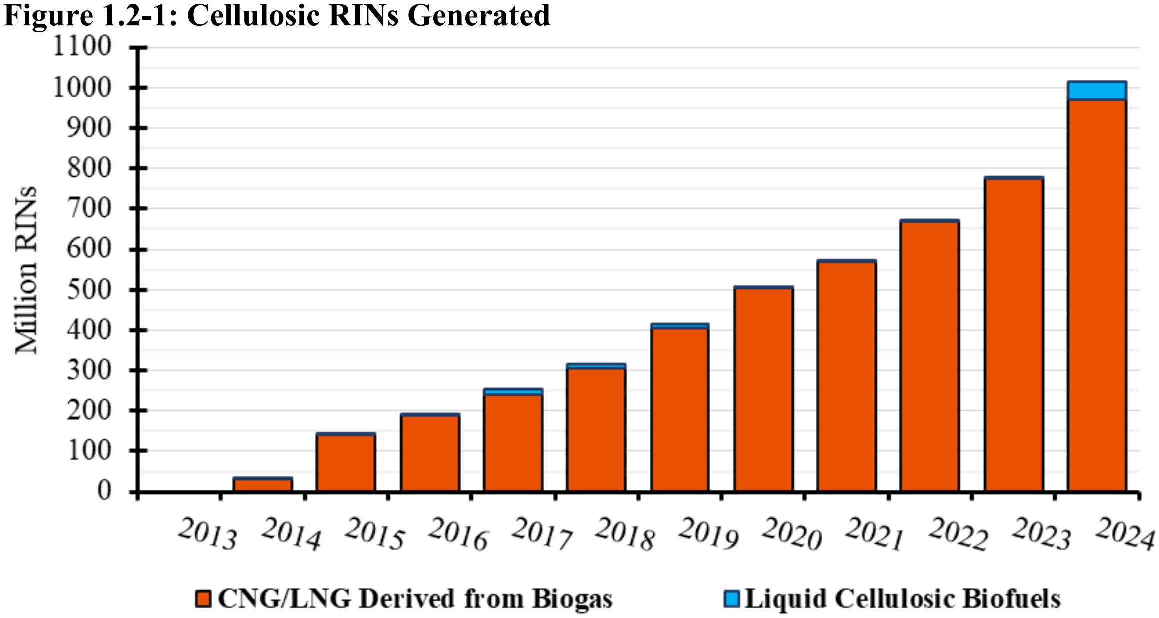
[12] EIA, "Electric Power Monthly," February 2025, Table D.1 – U.S. Estimated Consumption of Electricity by Light-Duty Electric Vehicles Types. https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=table_d_1.
[13] 75 FR 14674 (March 26, 2010).
[14] A pathway is a combination of feedstock, production 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).
[15] 75 FR 14872 (March 26, 2010).
[16] 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.
[17] 79 FR 42128 (July 18, 2014).

Chapter 7). Though, as discussed further in Chapter 7.1.4, EPA is also projecting smaller volumes of ethanol produced from corn kernel fiber (CKF) as part of its overall cellulosic biofuel volume projection.

The most significant change anticipated by EPA to impact the future of cellulosic biofuel revolves around a shift in market constraints. Since the Pathways II Rule, cellulosic volumes have been constrained solely by production capacity. However, for this proposal EPA expects the market to transition from being production-limited to consumption-limited. As discussed further in Chapter 7.1, EPA projects that the current capacity for using biogas-derived CNG/LNG as a transportation fuel may be approaching saturation, with the RFS-eligible fleet of active CNG/LNG vehicles being almost entirely fueled by biogas-derived CNG/LNG. Evidence of this shift is already noticeable, as EPA retroactively adjusted the 2024 cellulosic biofuel volume obligations.[18] This adjustment was necessary because CNG/LNG production failed to meet the volume requirement. Similarly, EPA anticipates that 2025 volumes will also fall short of the obligations in the Set 1 Rule and is therefore proposing adjustments in this action, as presented in Preamble Section VII and discussed in detail in Chapter 7.1.3. Therefore, while EPA is still projecting continued growth in cellulosic biofuel production, future growth is likely to be constrained by the ability to use it as a qualifying transportation fuel.

Figure 1.2-1: Cellulosic RINs Generated



1.3 Biodiesel and Renewable Diesel

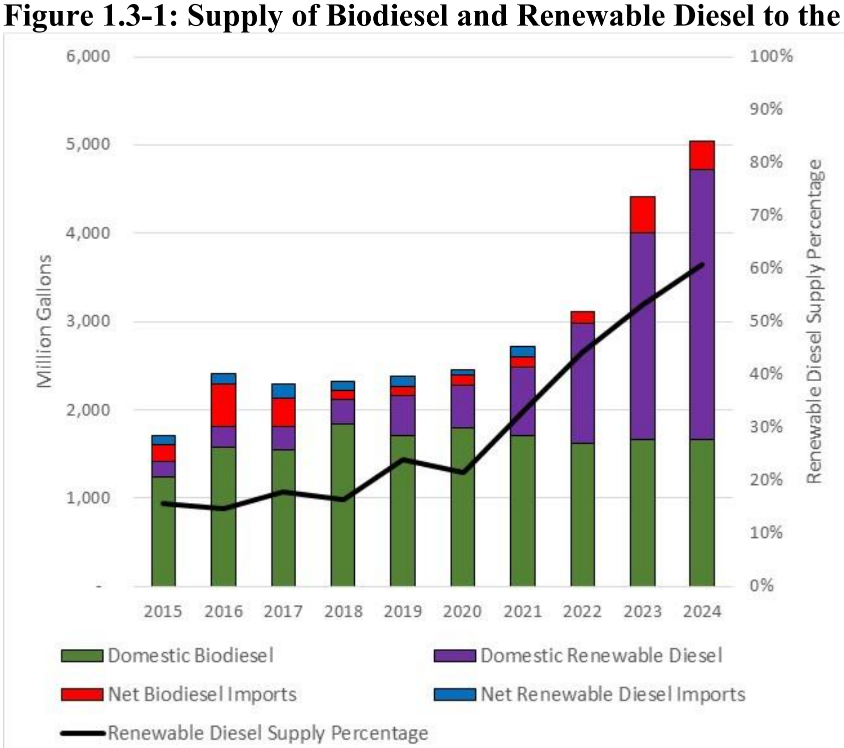
The actual supply of biodiesel and renewable diesel has continued to significantly exceed the BBD volume requirements since 2022, as volumes of BBD beyond the BBD volume requirement have been used to meet both the advanced biofuel and total renewable fuel volume requirements. These additional volumes reflect that BBD is generally the marginal gallon of advanced biofuel supplied to the market, as well as the marginal gallon of total renewable fuel. As discussed in Chapter 1.7.2, the status of BBD as the marginal gallon of both advanced biofuel

[18] 89 FR 100442 (December 12, 2024).

and total renewable fuel is also reflected in the convergence of the RIN prices for BBD (D4), advanced biofuels (D5), and conventional renewable fuel (D6). While we project that the supplies of other advanced biofuels and the use of ethanol in higher level ethanol blends will continue to increase in future years, we project that the advanced and total biofuel volumes we are proposing in this rule will continue to provide incentives for the production and use of BBD beyond the BBD volume requirement.

The supply of BBD to the U.S. has increased rapidly since 2022, with nearly all the increase in the supply of BBD coming from the increased domestic production of renewable diesel. The market preference for renewable diesel over biodiesel appears to be the result of a combination of different factors. First, renewable diesel production capacity has increased significantly in recent years, while the operable production capacity for biodiesel has decreased slightly (see Chapter 7.2.2 for more detail on BBD production capacity). Renewable diesel production facilities also tend to be much larger than biodiesel production facilities, allowing renewable diesel producers to benefit from economies of scale. Renewable diesel also currently generates more credits per gallon than biodiesel, providing additional revenue for renewable diesel producers and blenders. Perhaps most importantly, renewable diesel can generally be blended at higher blend rates without violating engine manufacturer fueling recommendations or requiring additives to meet state specifications. This has allowed greater quantities of renewable diesel to be used in states with low carbon fuel programs and claim additional financial incentives that are not readily available to biodiesel producers. As shown in Figure 1.3-1, the supply of renewable diesel has grown rapidly in recent years and exceeded the supply of biodiesel for the first time in 2023.

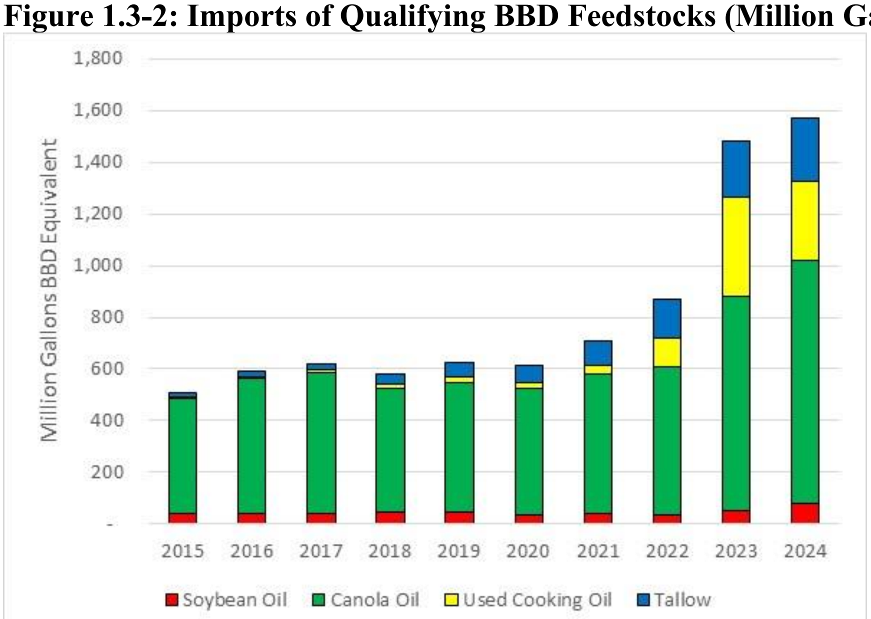
Figure 1.3-1: Supply of Biodiesel and Renewable Diesel to the U.S.



Source: EMTS.

Another significant development in the BBD industry is the recent increase in the quantities of BBD feedstocks imported into the U.S. Historically, the U.S. has imported very small quantities of qualifying BBD feedstocks such as soybean oil, canola oil, waste fats, oils, and greases (FOG), and animal fats. The biggest source of imported qualifying BBD feedstock through 2022 was canola oil from Canada, which is primarily used as a food ingredient rather than for biofuel production. In 2022 and 2023, imports of other qualifying BBD feedstocks, particularly animal fats and FOG, increased dramatically. These imports were likely driven by several factors, including increasing UCO collection rates in other countries, declining demand for these feedstocks and biofuels produced from them in the European Union (EU), and strong demand for these feedstocks for biofuel production in the U.S. driven by the combination of federal and state incentives. Notably, FOG and animal fats can be used to produce BBD with low carbon intensity (CI) scores. These fuels generate significantly more credits in state low carbon fuel programs and are expected to similarly be eligible for significantly greater tax credits under the Clean Fuel Production Credit (45Z). This combination of state and federal incentives is projected to continue to drive increasing volumes of feedstock imports in future years, particularly imports of feedstocks such as FOG and animal fats that can be used to produce BBD with low CI scores. The rate of future imports of feedstocks is highly uncertain, however, as the destination for globally traded feedstocks can change rapidly in response to changing market conditions and/or policy incentives. Tariffs on these feedstocks and other trade actions could also have a significant impact on imports of BBD feedstocks. The rapid observed increase in feedstock imports into the U.S. since 2022 illustrates how quickly feedstock suppliers can respond to changing market conditions. Imports of qualifying BBD feedstocks are shown in Figure 1.3-2. More detail on the projected supply of BBD feedstocks beyond 2025, including imported feedstocks, can be found in Chapter 7.2.3.

Figure 1.3-2: Imports of Qualifying BBD Feedstocks (Million Gallons BBD Equivalent)



Source: EMTS.

1.4 Ethanol

The predominant form of biofuel used to meet the standards under the RFS program—and the total renewable fuel standard in particular—has been fuel ethanol. Fuel ethanol has predominantly been produced from corn-derived biomass feedstocks, but smaller volumes are also produced from cellulosic biomass, non-cellulosic portions of separated food waste, and sugarcane feedstocks. In 2005, just prior to implementation of the RFS1 program, ethanol accounted for 97% of all biofuels consumed in the U.S. transportation sector. In the years that followed, the total volume of ethanol used in the U.S. more than tripled from 4.1 billion gallons in 2005 to 14.6 billion gallons in 2019, even as volumes of other biofuels grew concurrently.[19] Despite significant reductions in 2020 and 2021 due to the Covid-19 pandemic, domestic fuel ethanol production had returned to close to pre-pandemic levels in 2023 and 2024.[20] In 2024, ethanol accounted for approximately 70% of the biofuel consumed in the U.S.[21]

Total ethanol consumption is the sum of ethanol blended with fossil fuel gasoline (E0) to create motor gasoline ethanol blends (E10, E15, and E85). A common way to evaluate the relative growth of each of these different fuel blends is to measure the average ethanol concentration in the national gasoline pool. In 2007, national average ethanol concentration surpassed 5% for the first time and surpassed 10% (i.e. the "blend wall") for the first time in 2016. Since exceeding 10%, the share of ethanol in the gasoline pool has continued to increase, although at a slower pace as the market became saturated with E10. The total ethanol volume that can be consumed in the U.S. from all feedstocks is a function of the relative volumes of E0, E10, E15, and E85 that together comprise total motor gasoline consumption. Average ethanol concentration can exceed 10% only to the extent that E15 and E85 fuel volumes can exceed the ethanol content of E10 and more than offset the dilution caused by E0 volumes. Based on updated methodology, EPA projects in this proposed rulemaking an average ethanol concentration of 10.27% in 2026, rising to 10.38% in 2030. For a detailed look at how EPA has projected the consumption volumes of each of these fuel blends and thereby average ethanol concentration, refer to Chapter 7.5.1.

Domestic 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. This split is shown in Figure 1.4-1. While EPA is projecting continued growth in the consumption of higher-level ethanol blends such as E15 and E85, we are projecting that total ethanol consumption decreases slightly over the years covered by this proposed rule due to declining gasoline (E10) consumption.

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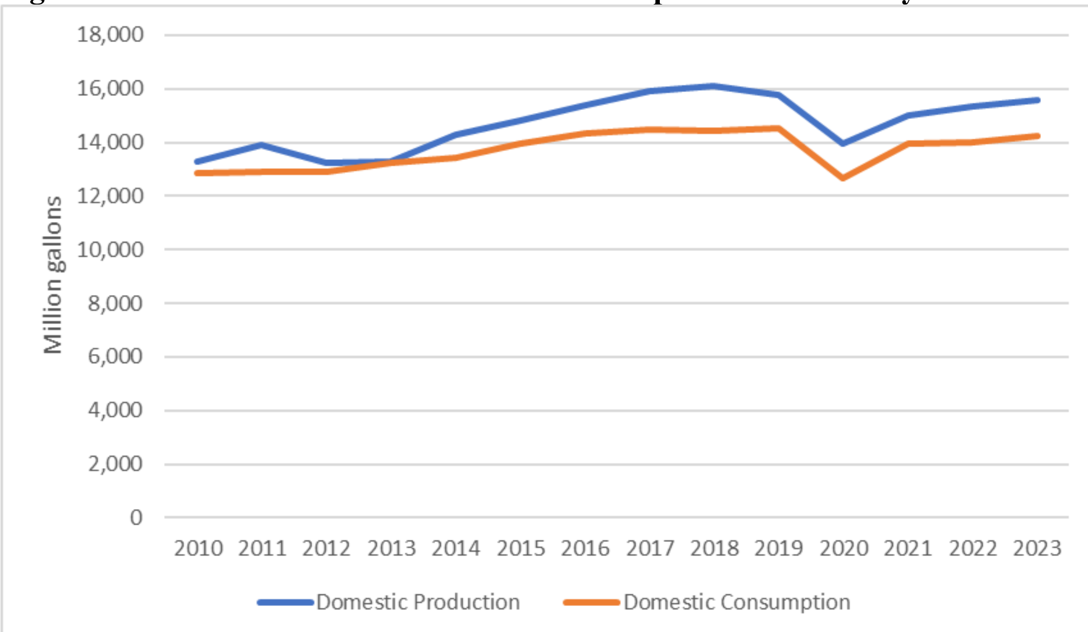
[19] EIA, "Monthly Energy Review," March 2025, Tables 10.3 and 10.4. https://www.eia.gov/totalenergy/data/monthly/archive/00352503.pdf. Comparison is based on ethanol-equivalence.
[20] Id.
[21] Id.

Figure 1.4-1: Domestic Production and Consumption of Ethanol by Year

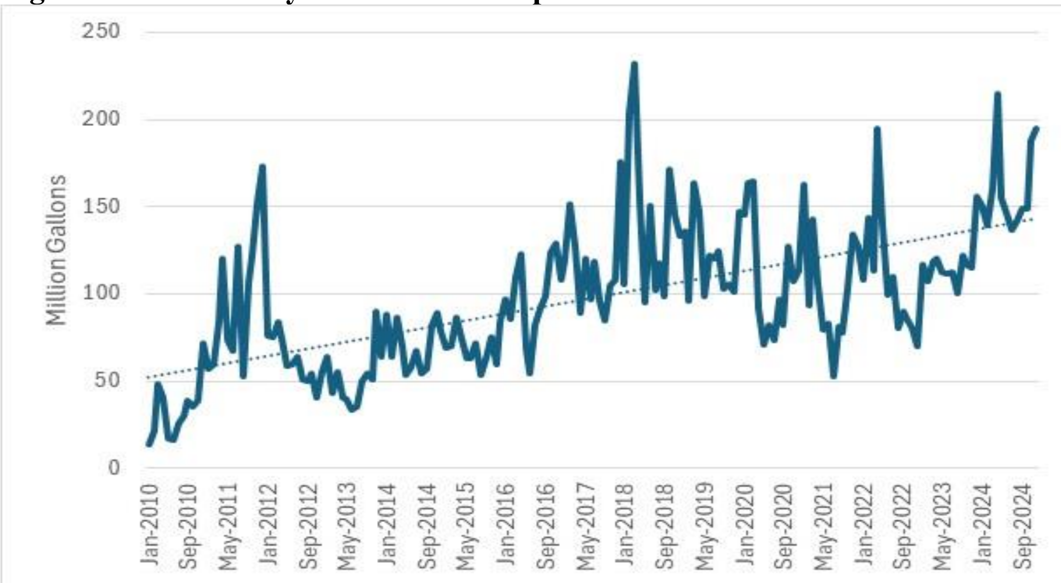


Source: EIA, "Monthly Energy Review," March 2025, Table 10.3. https://www.eia.gov/totalenergy/data/monthly/archive/00352503.pdf.

EIA does not report fuel ethanol export data for years prior to 2010. Since 2010, ethanol exports have grown steadily with only minor variations month to month, as shown by Figure 1.4-2. This growth is largely attributable to a combination of domestic and international market effects, with lower prices and plateauing demand on average for fuel ethanol in the U.S. even as prices and demand increase elsewhere. Exports of fuel ethanol reached record volumes in 2024 reflecting changes in renewable fuel mandates in other countries. For example, in early 2024, Colombia reinstated an E10 mandate for motor gasoline sold there, which required greater volumes of ethanol imports for the standard to be met and coincided with a sudden reduction in ethanol exports from Brazilian sources due to an increase in demand for fuel ethanol in Brazil.[22] The result is that more ethanol was exported from the U.S. to Colombia to fulfill their demand for fuel. For a more in-depth discussion of the history of fuel ethanol exports and their evolution through 2024, refer to Chapter 7.6.

[22] S&P Global, "US ethanol exports on pace for record year, fueled by low prices and increased opportunity overseas," November 19, 2024. https://www.spglobal.com/commodity-insights/en/news-research/latest-news/agriculture/111924-us-ethanol-exports-on-pace-for-record-year-fueled-by-low-prices-and-increased-opportunity-overseas.

Figure 1.4-2: Monthly Fuel Ethanol Exports from U.S.



Source: EIA, "U.S. Exports of Fuel Ethanol," *Petroleum & Other Liquids*, April 30, 2025. https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=M_EPOOXE_EEX_NUS-Z00_MBBL&f=m.

The gasoline market was historically dominated by ethanol-free gasoline (E0) and, since its approval for use in all vehicles in 1979, E10. Today, consumers in large swaths of the country have a choice between E0, E10, and higher-level ethanol blends of E15 and E85. Today's consumers of motor gasoline have to weigh a series of factors in their choice of what fuel to purchase, such as (in the case of E85, which is only approved for use in flex fuel vehicles) their vehicle's operability and longevity, relative price, and perceptions or knowledge gaps concerning impacts of each fuel type on fuel economy, the environment, and their wallet and the economy writ large. Since approaching and exceeding the E10 blendwall between 2010 and 2016, virtually all gasoline nationwide contains at least 10 percent ethanol content by volume, meaning most consumers today have little choice but to use E10 gasoline at a minimum. With the growth of retail fueling stations offering E15 and E85, the choice has now shifted between largely E10 and these higher-level ethanol blends. For higher-level ethanol blends, consumers likely consider all the factors from 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. The following sections will survey recent developments in E15 and E85 gasoline in the U.S.

1.4.1 E85

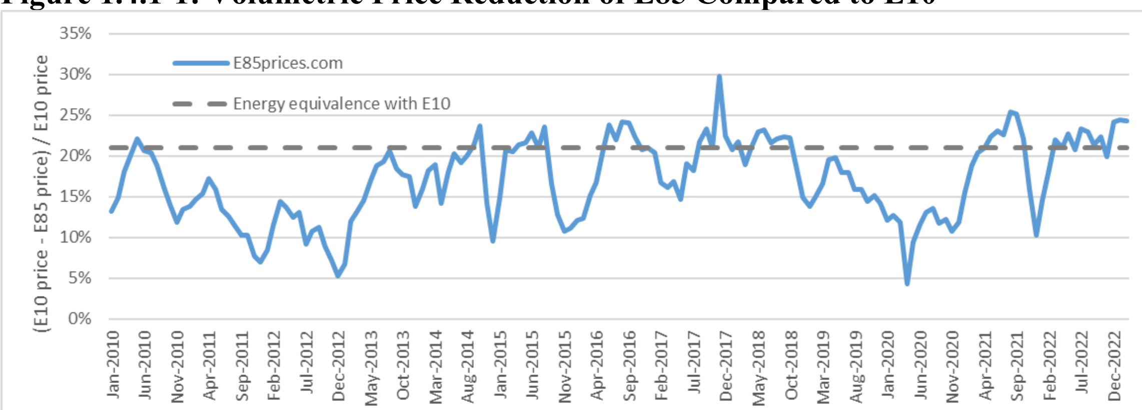
The earliest form of a higher-level ethanol blend was E85. In 1996, the first FFV was produced that could operate on fuel containing up to 85% denatured ethanol (83% ethanol).[23] Starting in 2007, ASTM International limited the maximum ethanol content of E85 to 83% in specification D5798, with a minimum ethanol content of 51%. EIA assumes that the annual,

[23] The Auto Channel, "Alternative Fuel Ford Taurus," January 1996

nationwide average ethanol concentration of E85 is 74% which is the value EPA has opted to use in this proposal, consistent with previous rulemakings.[24]

E85 is not considered gasoline under EPA's regulations, and as such is permitted to be used only in FFVs. However, FFVs can operate on either gasoline or E85. Under basic economic theory, and assuming all other factors are equal, FFV owners are more likely to purchase E85 if they believe that doing so reduces their fuel costs. E85 reduces fuel economy in comparison to E10, so E85 must sell at a discount to E10 if it is to represent equal or greater value in terms of energy content. For an average gallon of E85 containing 74% ethanol, its volumetric energy content is approximately 21% less than E10 (or 24% lower than that of E0).[25,26] 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 1.4.1-1, 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 1.4.1-1: 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.

California has been an exception recently in terms of E85 consumption, as retail station growth rates in California have surpassed the rest of the country. This is due largely to the price differential between E10 and E85. As shown in Figure 1.4.1-2, E85 in California has remained approximately $2 below the price of E10, which provides an incentive for consumers to utilize E85. Additional information on E85 nationwide and in California can be found in Chapter 7.5.

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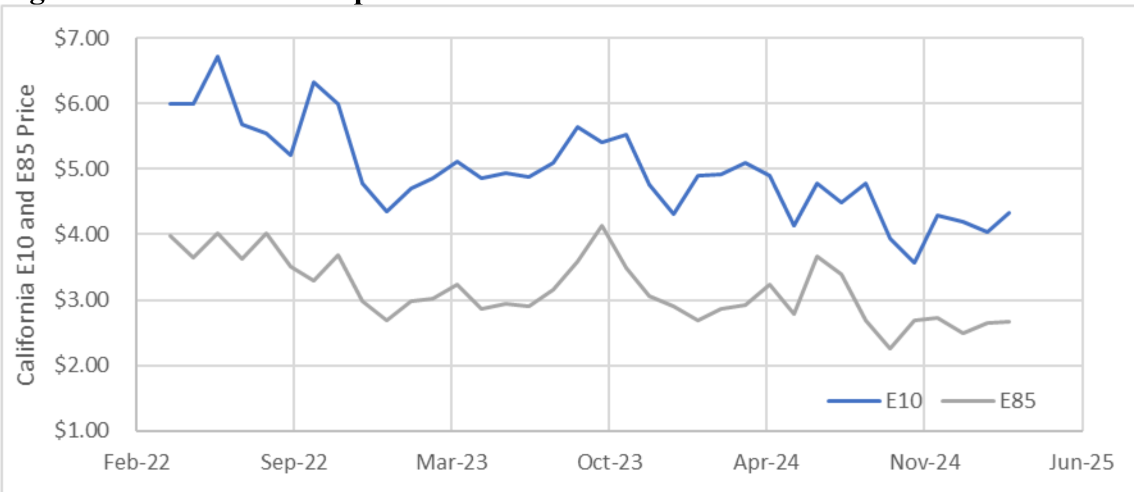
[24] AEO2023, Table 2 – Energy Consumption by Sector and Source.
[25] Assumes ethanol energy content is 3.554 mill Btu per barrel and gasoline energy content is 5.222 mill Btu per barrel. EIA, "Monthly Energy Review," March 2025, Tables A1 and A3. https://www.eia.gov/totalenergy/data/monthly/archive/00352503.pdf.
[26] A comparison to E0 would be more relevant prior to 2010 when there remained significant volumes of E0 for sale at retail stations.

Figure 1.4.1-2: Price Comparison of California E10 and E85



Source: e85prices.com.

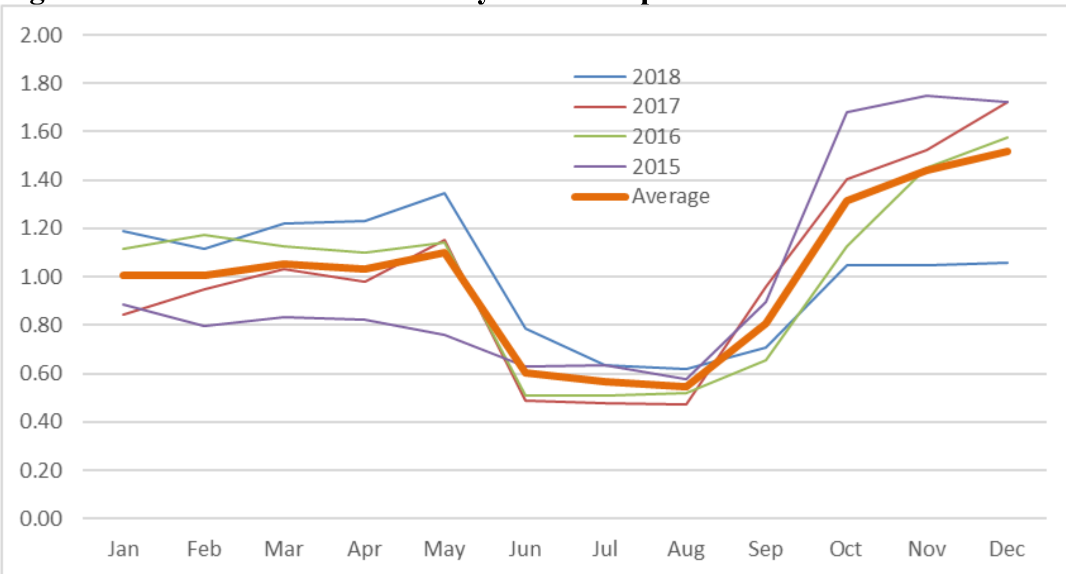
1.4.2 E15

In 2011, gasoline containing up to 15% ethanol was permitted to be used in model year (MY) 2001 and newer vehicles.[27] E15 has since been offered at an increasing number of retail service stations.[28] However, there is currently no publicly available data on actual nationwide E15 sales volumes.

Sales of E15 prior to 2019 were mostly 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.[29] As shown in Figure 1.4.2-1, 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.[30]

[27] 76 FR 4662 (January 26, 2011).
[28] See Chapter 6.4.3.
[29] 54 FR 11883 (March 22, 1989).
[30] The only source of data on E15 sales by month that we are aware of is from Minnesota.

Figure 1.4.2-1: Normalized Monthly E15 Sales per Station in Minnesota[a]

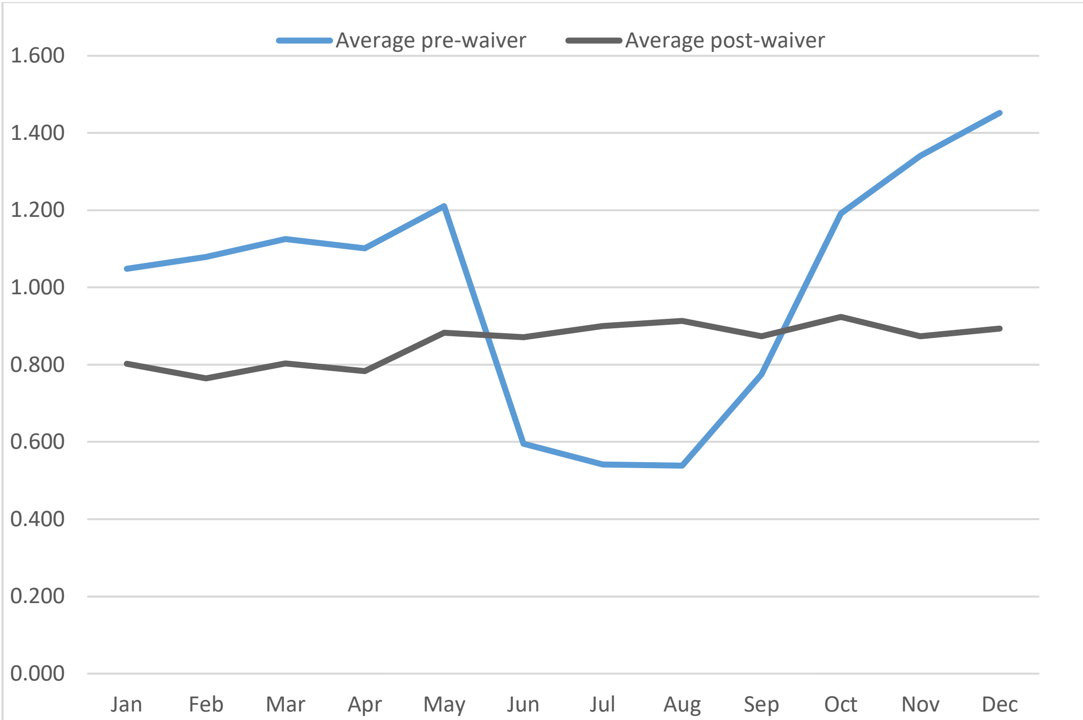


[a] Normalized values derived by dividing the monthly E15 sales volume per station by the annual average E15 sales volume per station.
Source: Minnesota Commerce Department, "Minnesota E85 + Mid-Blends Station Report." https://mn.gov/commerce/business/weights-measures/fuel/biodiesel/ethanol.jsp.

In 2019, EPA extended the 1-psi waiver to E15 by regulation.[31] 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.[32] On July 2, 2021, 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 the action. EPA subsequently issued emergency fuel waivers for the summers of 2022–2024 that allowed E15 to take advantage of the 1-psi waiver to address issues related to fuel price and supply. The impact of the 1-psi waiver for E15 on summer sales of E15 can be seen for 2019–2024 in Figure 1.4.2-2. 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. Average E15 sales post-waiver remain consistent year-round compared to pre-waiver, even though the overall E15 price is slightly lower. This is possibly due to impacts from the Covid-19 pandemic and decreased fuel sales during the start of the war in Ukraine.

[31] 84 FR 26980 (June 10, 2019).
[32] "Estimating the impacts of the 1psi waiver for E15," Docket Item No. EPA-HQ-OAR-2019-0136-2117. https://www.regulations.gov/document/EPA-HQ-OAR-2019-0136-2117.

Figure 1.4.2-2: Normalized Monthly E15 Sales per Station in Minnesota; Pre-and Post-Waiver for E15[a]



[a] Normalized values derived by dividing the monthly E15 sales volume per station by the annual average E15 sales volume per station.
Source: Minnesota Commerce Department, "Minnesota E85 + Mid-Blends Station Report." https://mn.gov/commerce/business/weights-measures/fuel/biodiesel/ethanol.jsp.

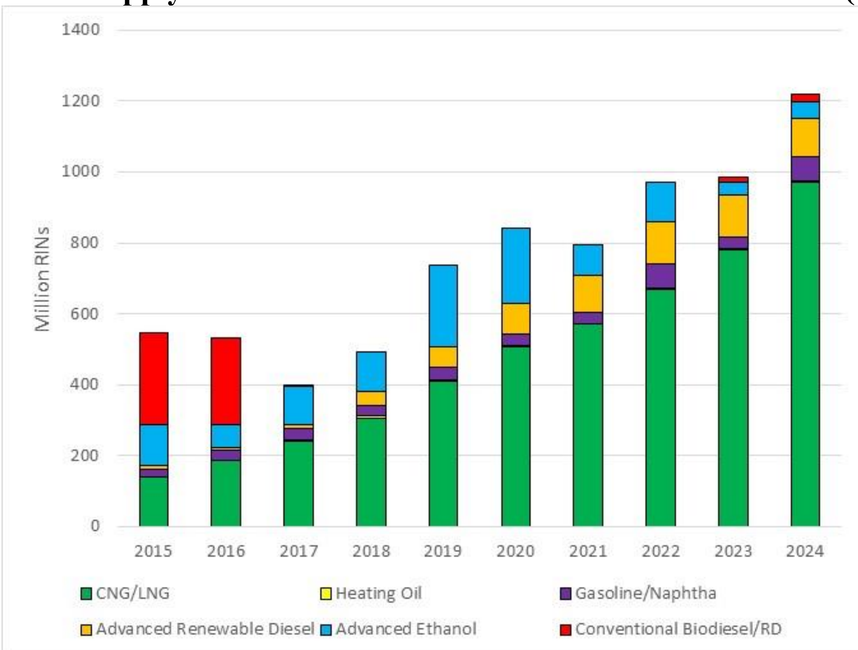
On February 29, 2024, EPA finalized a rule to remove the 1-psi waiver for E10 in eight Midwestern states.[33] On March 19, 2025, EPA finalized a one-year extension of the removal of the 1-psi waiver for Ohio and nine counties in South Dakota.[34] The result is that E10 and E15 are treated the same in these states with regard to RVP beginning with the summer of 2025 (or the summer of 2026 in the case of Ohio and the nine counties in South Dakota). Consequently, there may be no reduction in summer sales of E15 compared to other months in these states going forward.

1.5 Other Biofuels

Although 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 1.5-1, the supply of these "other biofuels" reached nearly 1 billion RINs in 2023. The annual supply of biofuels other than corn ethanol and BBD are shown in Figure 1.5-1.

[33] Illinois, Iowa, Minnesota, Missouri, Nebraska, Ohio, South Dakota, and Wisconsin. 89 FR 14760.
[34] 90 FR 13093.

1.5-1: Supply of Biofuels Other Than Corn Ethanol and BBD (million RINs)



Source: EMTS.

The largest supply of biofuel after corn ethanol and BBD has been CNG/LNG derived from biogas. As discussed in Chapter 1.2, and in greater detail in Chapter 7.1, we expect the supply of CNG/LNG derived from biogas to continue to increase in future years. However, we note that increases in future years may be smaller than in recent years if the supply of CNG/LNG is limited by the use of these fuels as qualifying transportation fuel. Advanced ethanol has been another significant source of biofuel in recent years. The supply of advanced ethanol has varied from year to year and appears to fluctuate depending on market conditions. In 2015 and 2016 significant volumes of conventional biodiesel and renewable diesel were supplied to the U.S., but since that time only very small volumes have been supplied. This likely reflects the growing impact state fuel programs have had on the supply of biofuels to the U.S., as conventional biodiesel and renewable diesel generally do not generate credits, and in some cases generate deficits, in these state programs. The supply of other types of renewable fuel such as renewable gasoline/naphtha and advanced renewable diesel have increased since the early years of the RFS program but have remained relatively stable since 2020.

1.6 Federal Tax Credits for Biofuels

For most of the history of the RFS program the only federal tax credit that was available to RFS qualifying fuels was the biodiesel blenders tax credit. This tax credit provided blenders with a $1 refundable credit for every gallon of biodiesel or renewable diesel that was either produced or used in the U.S. This tax credit lapsed several times over the past decade but has always been available (whether prospectively or retroactively) since the beginning of the RFS program. The Inflation Reduction Act (IRA) of 2022 extended the biodiesel blenders tax credit through 2024. The prospective availability of the biodiesel blenders tax credit for 2023 and 2024, in combination with the replacement of this tax credit with the Clean Fuel Production Credit (discussed below) were likely significant factors in the rapid increase in the supply of BBD to the U.S. in 2023 and 2024.

The IRA also established two new tax credits that could apply to qualifying fuels under the RFS program, the Sustainable Aviation Fuel Credit and the Clean Fuel Production Credit (CFPC). The Sustainable Aviation Fuel Credit provides a tax credit ranging from $1.25 to $1.75 per gallon to any renewable jet fuel that achieves at least a 50% reduction in lifecycle GHG emissions. The Sustainable Aviation Fuel Credit thus provides a larger incentive for renewable jet fuel in 2024 than the provided by the biodiesel blenders tax credit in the same year.

Starting in 2025 both the biodiesel blenders tax credit and the Sustainable Aviation Fuel Credit are replaced by the CFPC. The CFPC is available to all transportation fuel produced in the U.S. that has an emission factor less than 50 kilograms of CO_2 equivalent per million BTU. The magnitude of the CFPC varies depending on the type of fuel produced (renewable jet fuel vs. other transportation fuel), the emissions factor of the fuel, and whether the fuel producer meets prevailing wage and apprenticeship requirements.

The CFPC differs from the biodiesel blenders tax credit it replaces in several important ways. First, this tax credit is available to all transportation fuels with lifecycle GHG emissions under the specified threshold. Since 2012, BBD has been the only RFS-qualifying fuel that was eligible for a federal tax credit. This broader eligibility under the CFPC relative to the biodiesel blenders tax credit may open up opportunities for non-BBD advanced biofuels to better compete for market share under the RFS program as these fuels now have similar treatment under the federal tax provisions.

The CFPC is also only available for biofuels produced in the U.S. Historically significant volumes of imported biodiesel and renewable diesel have benefited from the biodiesel blenders tax credit. The restriction of the CFPC to biofuels produced in the U.S. may have multiple impacts on the supply of biofuel to the U.S. Imports of BBD are expected to decrease in future years, as these fuels will no longer be eligible for the $1 per gallon federal tax credit. The availability of the CFPC to domestic BBD producers will advantage these producers over imported BBD, which is projected to directionally result in lower volumes of imported BBD. Lower volumes of imported BBD may increase the market demand for BBD produced in the U.S., resulting in greater domestic BBD production and/or decreased BBD exports. The CFPC could also indirectly result in increased imports of BBD feedstocks. With the advantage of the CFPC, domestic BBD producers may be able to out-bid foreign BBD producers for foreign feedstocks. Relatedly, foreign parties with access to qualifying BBD feedstocks may find it more profitable to export the feedstock to the U.S. where it can be used to produce BBD that qualifies for the CFPC than to use the feedstock to produce BBD and export it to the U.S. or another country.

The CFPC also provides greater incentives for biofuels with lower emission rates. There are significant differences in the emission rates, and thus the magnitude of the incentive available through the CFPC, for fuels produced from wastes or by-products such as FOG or animal fats than there are for fuels produced from agricultural commodities such as virgin vegetable oils or corn starch. The structure of this tax credit, especially in combination with state low carbon fuel programs with similar structures, could have a significant impact on the types of biofuel supplied to the U.S. within each broad category. For example, all BBD is eligible to generate the same number of RINs under the RFS program whether it is produced from soybean or canola oil, FOG, or animal fats. But domestically produced renewable diesel from FOG at a facility that meets the prevailing wage and apprenticeship requirements would be eligible to claim a greater CFPC credit than renewable diesel produced from soybean oil at the same facility. If these fuels were sold in a state with a low carbon fuel program, the renewable diesel produced from FOG could receive even greater incentives relative to renewable produced from soybean oil. The combination of the CFPC and the state programs are projected to create a strong preference among biofuel producers for feedstocks that enable them to produce biofuel with low emission rates. As the supplies of these feedstocks available in the U.S. are limited and generally are already being used for biofuel production, we project that the structure of the CFPC and state programs will create a large incentive for imports of feedstocks such as FOG and animal fats that can be used to produce biofuels with low emission rates.

1.7 RIN System and Prices

1.7.1 RIN System

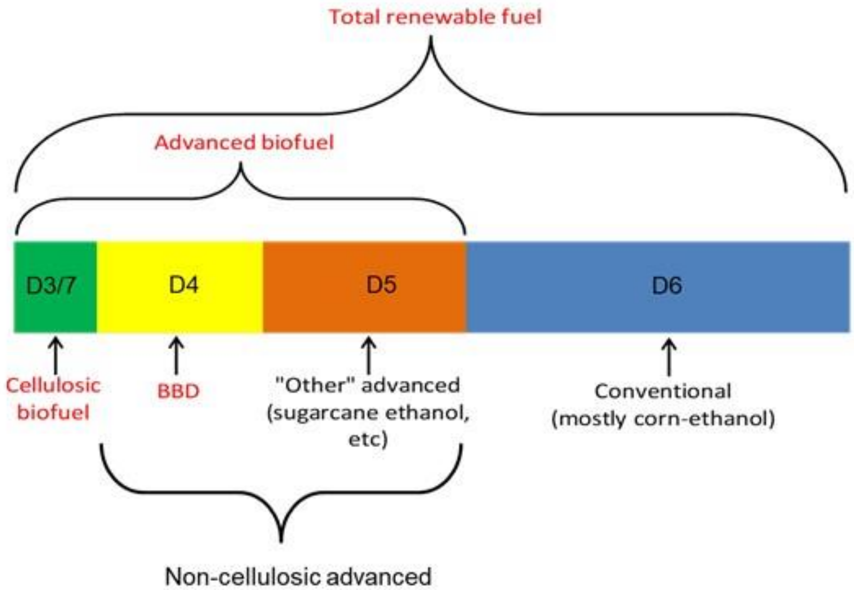
RINs were created by EPA under CAA section 211(o)(5) as a flexible credit and compliance mechanism to enable obligated parties across the country to meet their renewable fuel blending obligations under the RFS program without having to blend the renewable fuel themselves.[35] RINs allow: (1) Obligated 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. In this way the RIN system allows for the RFS program to function smoothly with less market disruption and at a lower overall cost. 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).[36] 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

[35] 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).
[36] 40 CFR 80.1425(g).

in Figure 1.7-1, the obligations under the RFS regulations are nested, such that some RIN types can be used to satisfy obligations in multiple categories.

Figure 1.7-1: Nested Structure of the RFS Program



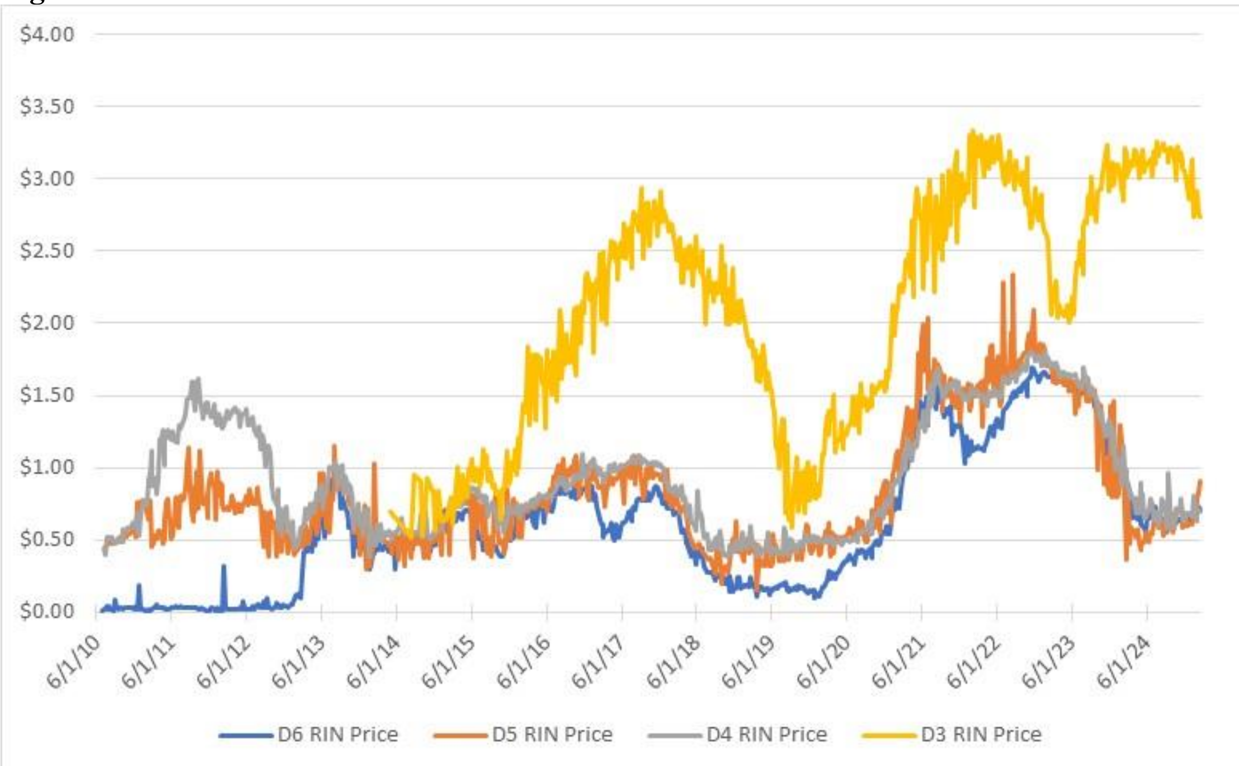
Since its creation the RIN system has grown and evolved along with the RFS program.

1.7.2 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 1.7.2-1.[37] 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.

[37] 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 1.7.2-1: Historical RIN Prices in Nominal Dollars



Source: EMTS.

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.[38] 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

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

obligations to make up for the shortfall in conventional biofuel volume and used those RINs to meet their total renewable fuel obligations. Essentially, given the inability to successfully introduce higher-level ethanol blends into the market in sufficiently large quantities, the market relied upon biodiesel and renewable diesel (primarily advanced biofuel and BBD, but also some volume of conventional biodiesel and renewable diesel) as the marginal RFS compliance option when other sources of conventional biofuel were not available at competitive prices. After 2018, D6 RIN prices were, for some time, significantly lower than D4 and D5 RIN prices, but still higher than the D6 RIN prices observed prior to 2013. These lower D6 RIN prices are largely the result of: (1) Small refinery exemptions (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 1.8.1. Beginning in the summer of 2020, D4, D5, and D6 RIN prices rose dramatically, reaching nearly $2 per RIN in the summer of 2021. These RIN prices remained around $1.50 per RIN through June 2023, before falling back to approximately $0.75 per RIN in the summer of 2023. The timing of the observed changes in RIN prices in the summer of 2023 strongly suggest that the finalization of the RFS volume requirements for 2023 – 2025 in June 2023 contributed to the drop in RIN prices. The prices for D4, D5, and D6 RINs also reflect the cost of biodiesel and renewable diesel production (the marginal supply). The prices for soybean and other vegetable oil feedstocks were unusually high from the summer of 2021 through the summer of 2023, a time period with corresponds to the period of high RIN prices for D4, D5, and D6 RINs.

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 2010–2024. Instead, higher D6 RIN prices have resulted in lower effective prices for ethanol after the RINs have been separated and sold.[39] Higher D6 RIN prices have thus served to subsidize fuel blends that contain higher proportions of conventional biofuel (e.g., E85) and increased the cost of fuel blends that contain little or no conventional biofuel (e.g., E0 and B0).[40]

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

[40] Burkholder, Dallas. “A Preliminary Assessment of RIN Market Dynamics, RIN Prices, and Their Effects.” EPA, May 2015.

Figure 1.7.2-2: Historical Ethanol Prices and D6 RIN Prices

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

D5 RINs were priced at a level between D4 and D6 RINs from 2010–2013. However, since 2013, D5 RIN prices have been nearly identical to D4 RIN prices. This shift in the relative pricing of D5 and D4 RINs also corresponds with the market reaching the E10 blendwall. This is because there are two primary fuel types that have been used to satisfy the advanced biofuel requirements: sugarcane ethanol and BBD. From 2010–2012, obligated parties generally met their implied requirements for "other advanced biofuel" with sugarcane ethanol.[41] 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.[42] It is also indicated by the prices for D5 RINs, which were significantly lower than the price of D4 RINs during this time, suggesting that it was more cost effective for obligated parties to meet their compliance obligations with D5 RINs (generated for sugarcane ethanol) than D4 RINs (generated for biodiesel and renewable diesel). When the E10 blendwall was reached in 2013, however, it became much more expensive to increase the volume of ethanol blended into the gasoline pool. While obligated parties could still import sugarcane ethanol to satisfy their advanced biofuel obligations, doing so would reduce the volume of corn ethanol that could be used as E10. Available non-ethanol renewable fuels were almost entirely advanced biodiesel and

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[41] "Other advanced biofuel" is not a category for which a volume requirement is established under the RFS program, 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.

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

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

D4 RIN prices, much like all RIN prices, have varied significantly since 2010. The pricing of these RINs, however, has been fairly straightforward. D4 RINs are generally priced to account for the price difference between biodiesel and petroleum diesel, which in turn are largely a function of the pricing of their respective oil supplies. Other factors can also impact this relationship; most significantly are the presence or absence of the biodiesel tax credit and the impact of other subsidies and credits (e.g., the $1.00 per gallon federal tax subsidy and state LCFS credits).[43] Recently, in 2021 and 2022, D4 RIN prices increased 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. By the beginning of 2024, soybean oil prices dropped to lower levels. This decrease in the price of soybean oil generally corresponded to a decrease in D4 RIN prices.

Figure 1.7.2-3: Historical Soybean Oil Prices ($/lb)

Source: Business Insider, "Soybean Oil," *Markets Insider*, May 19, 2025. https://markets.businessinsider.com/commodities/soybean-oil-price.

[43] A $1 per gallon biodiesel blenders tax credit was available to biodiesel blended every year from 2010–2024. 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 CFPC.

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 2020 paper exploring the relationship between the price of D4 RINs and economic fundamentals concluded that "movements in D4 biodiesel RIN prices at frequencies of a month or longer are well explained by two economic fundamentals: (a) the spread between the biodiesel and ULSD prices and (b) whether the $1 per gallon biodiesel tax credit is in effect."[44]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).[45] This is as expected, since obligated parties can satisfy their cellulosic biofuel obligations through the use of either cellulosic RINs or CWCs (if available) plus D4 or D5 RINs.[46] 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.[47] 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. 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. In 2023 EPA did not use the cellulosic waiver authority to reduce the required volume of cellulosic biofuel, and therefore did not offer CWCs. The price for D3 RINs dropped

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[44] Irwin, Scott H., Kristen McCormack, and James H. Stock. "The Price of Biodiesel RINs and Economic Fundamentals." *American Journal of Agricultural Economics* 102, no. 3 (February 3, 2020): 734–52. https://doi.org/10.1002/ajae.12014.

[45] 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, a CWC does not satisfy an obligated party's advanced biofuel and total renewable fuel obligations, unlike a cellulosic RIN, which can be used to meet all three obligations. A cellulosic RIN 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).

[46] CWCs are available to obligated parties for any year in which EPA implements the cellulosic waiver authority to reduce the cellulosic biofuel volume requirement. EPA implemented the cellulosic waiver authority to reduce the cellulosic biofuel volume requirement every year from 2010–2022 and again in 2024. EPA acknowledges that it did not waive the 2023 cellulosic biofuel requirement. EPA is also in this action proposing to reduce the 2025 cellulosic biofuel volume under the cellulosic waiver authority.

[47] 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.

shortly after the release of the proposed RFS standards for 2023–2025 at the end of 2022. The drop in the D3 RIN prices was likely due to the proposed rule, which included a proposed regulatory framework for generating D3 RINs from qualifying electricity used as transportation fuel (eRINs). Shortly after the final rule establishing RFS standards for 2023–2025 was released in June 2023 D3 RIN prices returned to about $3 per RIN. Notably, this rule did not finalize a regulatory framework for eRINs and included higher projections for CNG/LNG derived from biogas than the proposed rule.

Figure 1.7.2-4: D3 RIN Prices and D5 RIN Price Plus CWC Price

Source: EMTS. CWC prices are available at: https://www.epa.gov/renewable-fuel-standard-program/cellulosic-waiver-credits-under-renewable-fuel-standard-program.

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[48] and the relatively high cellulosic biofuel volumes in the Set 1 Rule have 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 from large landfills that can often be produced at a cost that is competitive with the petroleum fuels they displace even without the RIN value. 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 incentives to purchase CNG/LNG vehicles and lower cost fuel and/or longer term fixed-price fuel contracts. Even after accounting for these incentives, a significant portion of the RIN value may remain with the biofuel producer, the parties that dispense CNG/LNG derived from biogas, and any other parties involved in the production of this type of cellulosic biofuel.[49] Based on conversations with industry participants a portion of these funds have often been reinvested in expanded CNG/LNG fueling infrastructure and new biogas production facilities.

Unlike other RIN costs that are generally transferred 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, CNG/LNG fleet owners). For example, according to EMTS RIN price data, the average cellulosic RIN price was $2.65 in 2023; thus, the total cost associated with the 868 million cellulosic RINs required for compliance in 2023 was approximately $2.3 billion and the cellulosic biofuel requirement likely increased the price of gasoline and diesel sold in the U.S. in 2023 by approximately $0.013 per gallon.[50] These transfers are expected to increase through 2025 as a result of the cellulosic biofuel volumes finalizing in the Set 1 Rule. For example, using the average cellulosic RIN price for January 2024 – December 2024 of $3.11 and the revised cellulosic biofuel volume we are proposing for 2025 in this action of 1.19 billion RINs, we estimate that the cost associated with cellulosic RIN purchases would be $3.70 billion, and would be expected to increase the price of gasoline and diesel in 2025 by approximately $0.019 per gallon.[51]

1.8 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 proposed 2026 and 2027 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

[48] CAA section 211(o)(7)(D).
[49] 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.
[50] For the 2023 compliance year obligated parties reported an obligated volume of gasoline and diesel of 180.8 billion gallons. Dividing the total cost of cellulosic RINs in 2023 ($2.3 billion) by the total consumption of gasoline and diesel (180.8 billion gallons) results in an estimated cost of $0.013 per gallon of gasoline and diesel as a result of the cellulosic biofuel requirement.
[51] 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 ($3.70 billion) by the total consumption of gasoline and diesel (190.8 billion gallons) results in an estimated cost of $0.019 per gallon of gasoline and diesel as a result of the cellulosic biofuel requirement.

complete, we are able to project these values by using 2023 compliance data and assumptions about RIN generation relative to RIN obligations in 2024 and 2025.

1.8.1 Carryover RINs Available After Compliance With the 2023 Standards

In order to calculate the number of 2023 carryover RINs available for compliance with the 2024 standards, we began with the 2023 RFS compliance year data in Table 1.8.1-1. From this data, we calculated that approximately 22.53 billion total RINs were retired for compliance in the 2023 compliance year.[52] Of this total, approximately 20.19 billion 2023 RINs and 0.34 billion 2022 carryover RINs were used.

Table 1.8.1-1: RINs Retired by Obligated Parties and Exporters in the 2023 Compliance Year[a]

RIN Type	RIN Year		Total
	2022	2023	
D3	72,174,414	736,071,158	808,245,572
D4	76,167,987	7,026,064,533	7,102,232,520
D5	15,141,338	241,707,644	256,848,982
D6	178,935,665	14,186,802,096	14,365,737,761
D7	236,352	208,643	444,995
Total	342,655,756	22,190,854,074	22,533,509,830

[a] Data current as of December 10, 2024, and compiled from Table 4 at https://www.epa.gov/fuels-registration-reporting-and-compliance-help/annual-compliance-data-obligated-parties-and. 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 1.8.4-1 for more detailed data.

Next, we calculated the net number of RINs that were generated in 2023. To do this, we took the total number of RINs generated in 2023 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 1.8.1-2, we calculated that a net of approximately 23.37 billion RINs were generated in 2023.

[52] Includes RINs retired in the 2023 compliance year to satisfy 2022 compliance deficits.

Table 1.8.1-2: 2023 Net RINs Generated[a]

RIN Type	Total RINs Generated[b]	RIN Errors[c]	Other RIN Retirements[d]	Net RINs Generated[e]
D3	774,735,743	1,587,010	6,538,749	766,609,984
D4	7,970,109,655	8,579,454	209,386,480	7,752,143,721
D5	263,070,174	2,433,356	1,082,356	259,554,462
D6	14,838,755,529	8,301,447	241,505,732	14,588,948,350
D7	208,643	0	0	208,643
Total	23,846,879,744	20,901,267	458,513,317	23,367,465,160

[a] Data from December 2024 and compiled https://www.epa.gov/system/files/other-files/2025-01/availablerins_dec2024.csv and https://www.epa.gov/system/files/other-files/2025-01/retiretransaction_dec2024.csv.
[b] The total number of RINs generated includes those RINs generated for exported fuel.
[c] See Table 1.8.4-2 for more detailed data.
[d] See Table 1.8.4-3 for more detailed data.
[e] Net RINs Generated = Total RINs Generated – (RIN Errors + Other RIN Retirements).

To determine the total number of 2023 carryover RINs available for compliance with the 2024 standards, we then subtracted the number of 2023 RINs retired in the 2023 compliance year from the net number of 2023 RINs generated. We calculate that there are approximately 1.18 billion 2023 carryover RINs available, as shown in Table 1.8.1-3.

Table 1.8.1-3: 2023 Carryover RINs

RIN Type	Net 2023 RINs Generated	2023 RINs Retired for Compliance	2023 Carryover RINs
D3	766,609,984	736,071,158	30,538,826
D4	7,752,143,721	7,026,064,533	726,079,188
D5	259,554,462	241,707,644	17,846,818
D6	14,588,948,350	14,186,802,096	402,146,254
D7	208,643	208,643	0
Total	23,367,465,160	22,190,854,074	1,176,611,086

Obligated parties are also able to carryforward a compliance deficit from one year to the next year,[53] increasing their RVO for 2024 and effectively decreasing the number of 2023 carryover RINs available for compliance with the 2024 standards. In order to account for this, we calculate the effective number of 2023 carryover RINs available for compliance with the 2024 standards by subtracting out the 2023 compliance deficits, which have to be satisfied at the time of compliance with the 2024 standards.[54] We note, however, that 2023 compliance deficits exceeded the number of available 2023 carryover RINs for several standards, which means that there was a shortfall in the number of RINs available to comply with these standards in 2023 and that some obligated parties had to carry forward a deficit into 2024. After accounting for this

[53] See 40 CFR 80.1427(b).
[54] The compliance deadline for the 2024 standards will be the first quarterly reporting deadline after the effective date of the action revising the 2024 cellulosic biofuel standard. 90 FR 12109 (March 14, 2025).

adjustment, the effective number of 2023 carryover RINs available for compliance with the 2024 standards are shown in Table 1.8.1-4.[55]

Table 1.8.1-4: Effective 2023 Carryover RINs

RFS Standard	RIN Type	2023 Carryover RINs	2023 Compliance Deficits[a]	Net Surplus/ Deficit[b]	Effective 2023 Carryover RINs[c]
Cellulosic Biofuel	D3+D7	30,538,826	87,789,686	-57,250,860	0
Non-Cellulosic Advanced Biofuel[d]	D4+D5	743,926,006	329,874,322	414,051,684	414,051,684
Conventional Renewable Fuel[e]	D6	402,146,254	1,598,690,401	-1,196,544,147	0
Total Renewable Fuel	All D Codes	1,176,611,086	2,016,354,409	-839,743,323	0

[a] Data current as of December 10, 2024, and compiled from Table 6 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] Represents the effective number of 2023 carryover RINs that are available for compliance with the 2024 standards after accounting for deficits carried forward from 2023 into 2024. Standards for which deficits exceed the number of available carryover RINs are represented as zero.
[d] 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.
[e] 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.

1.8.2 Carryover RINs Available for 2026 and 2027

Given the uncertainty of the impact of compliance with the 2024 and 2025 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 2026 and 2027 standards.[56] However, if we assume that the uncertainties result in neither a net gain nor net loss of excess RINs for 2024 and 2025, and that this is also the case for 2026, then the carryover RINs that we projected to be available in Chapter 1.8.1 would represent the number of carryover RINs available for compliance with the 2026 and 2027 standards, as shown in Table 1.8.2-1.[57]

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[55] In other words, the number of available carryover RINs is effectively reduced in light of the volume of 2023 deficits carried forward to 2024. 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.

[56] 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.

[57] The actual number of RINs that will be available for use by obligated parties to use towards the 2026 and 2027 standards will not be known until the compliance deadline for the preceding compliance year. Even after this date,

Table 1.8.2-1: Projected Carryover RINs for 2026 and 2027

RFS Standard	RIN Type	Projected Effective Carryover RINs[a]
Cellulosic Biofuel	D3+D7	0
Non-Cellulosic Advanced Biofuel[b]	D4+D5	414,051,684
Conventional Renewable Fuel[c]	D6	0
Total Renewable Fuel	All D Codes	0

[a] Represents the effective number of 2023 carryover RINs that are available for compliance with the 2024 standards after accounting for deficits carried forward from 2023 into 2024. Standards for which deficits exceed the number of available carryover RINs are represented as zero.
[b] 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.
[c] 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 carryover RINs available for compliance with the 2026 and 2027 standards, this does not mean that actual carryover RINs will not be available in these years. As discussed in Chapter 1.8.1, 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.

1.8.3 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 1.8.1. The results are provided in Table 1.8.3-1 and Figures 1.8.3-1 through 4 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 2023 are those 2023 RINs that can be used to comply with the 2024 standards).

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 1.8.3-1: Number of Available Carryover RINs History (million RINs)

Compliance Year	Cellulosic Biofuel		Non-Cellulosic Advanced Biofuel		Conventional Renewable Fuel		Total Renewable Fuel	
	Absolute[a]	Effective[b]	Absolute[a]	Effective[b]	Absolute[a]	Effective[b]	Absolute[a]	Effective[b]
2013	0	0	565	538	1,087	1,045	1,652	1,583
2014	12	12	465	444	1,359	1,239	1,836	1,695
2015	39	39	372	367	1,248	1,242	1,659	1,649
2016	39	34	887	825	1,945	1,621	2,871	2,480
2017	28	8	801	683	2,981	2,437	3,810	3,129
2018	52	49	633	607	2,870	2,774	3,554	3,429
2019	46	34	173	0	2,095	1,652	2,315	1,661
2020	41	16	116	0	1,654	1,202	1,811	1,058
2021	25	0	59	0	1,048	502	1,132	95
2022	73	44	98	0	192	0	362	0
2023	31	0	744	414	402	0	1,177	0

[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 1.8.3-1: Number of Available Cellulosic Biofuel Carryover RINs

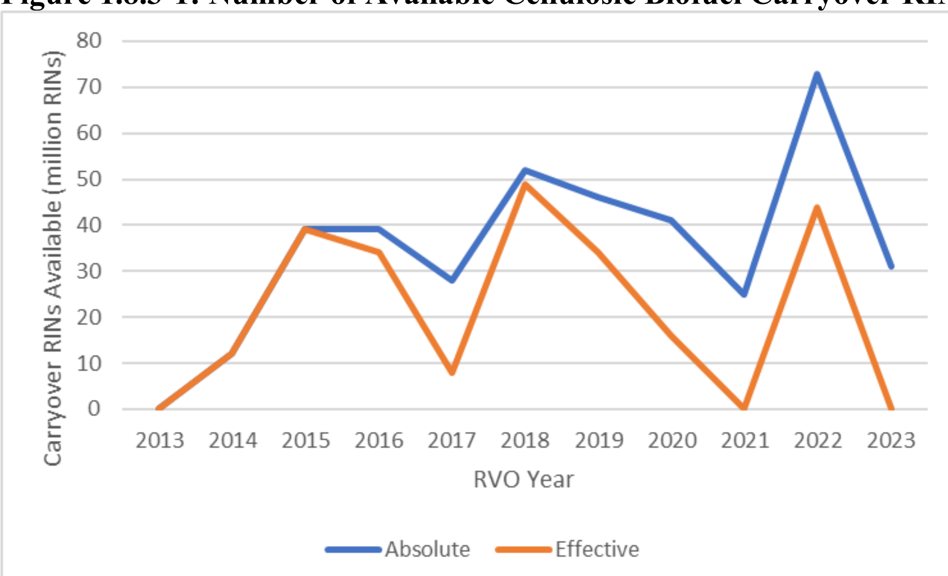


Figure 1.8.3-2: Number of Available Non-Cellulosic Advanced Biofuel Carryover RINs

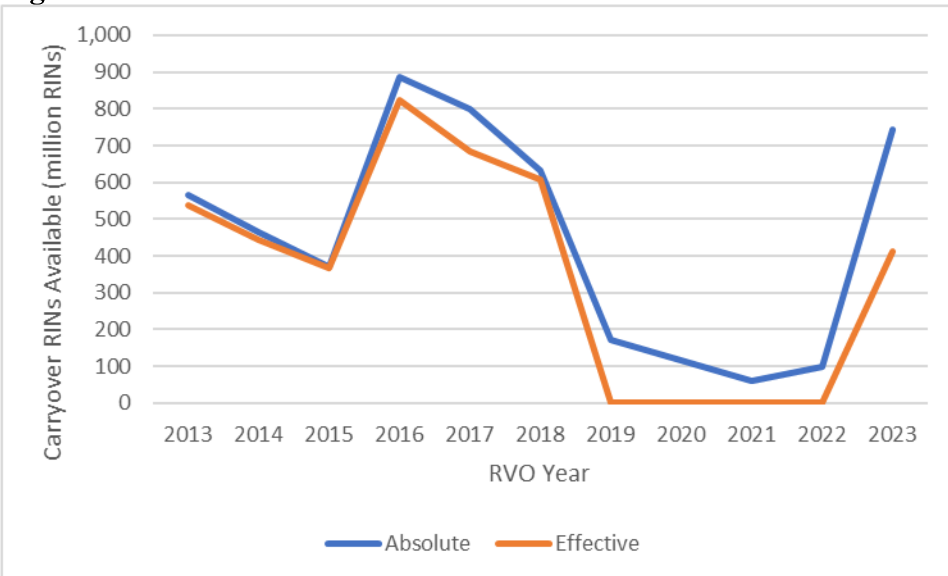


Figure 1.8.3-3: Number of Available Conventional Renewable Fuel Carryover RINs

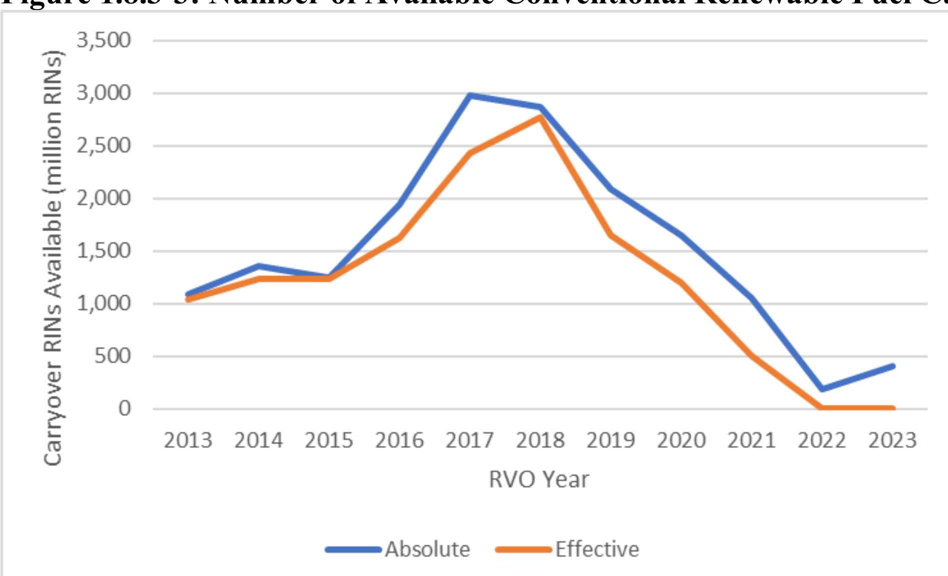
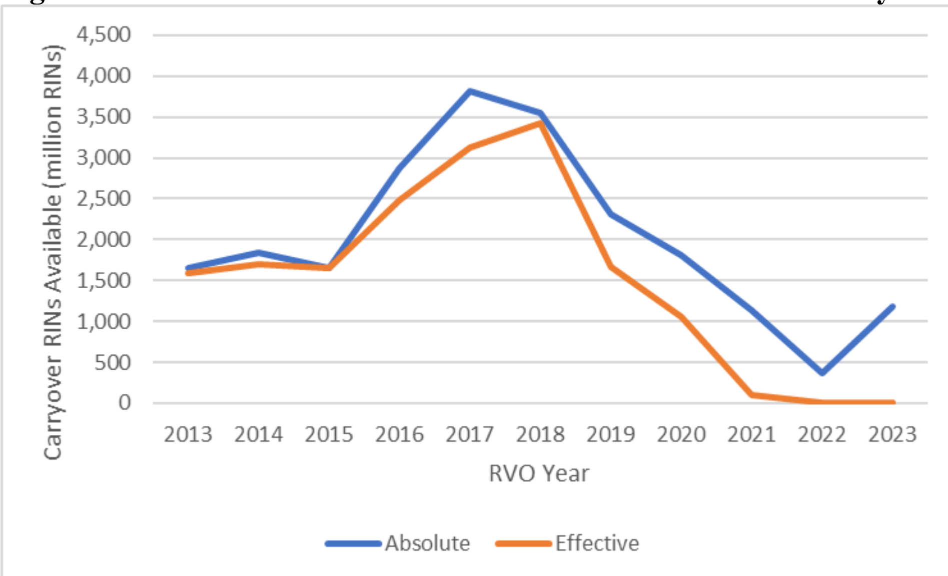


Figure 1.8.3-4: Number of Available Total Renewable Fuel Carryover RINs



1.8.4 EMTS RIN Data

Table 1.8.4-1: RINs Retired by Importers, Refiners, and Exporters in the 2023 Compliance Year[a]

RIN Type	Year	Importers	Refiners	Exporters	Total
D3	2022	8,374,444	63,799,970	0	72,174,414
	2023	52,025,191	684,045,967	0	736,071,158
D4	2022	10,433,480	65,189,093	545,414	76,167,987
	2023	265,471,820	5,935,234,828	825,357,885	7,026,064,533
D5	2022	21	15,121,907	19,410	15,141,338
	2023	9,358,170	174,238,256	58,111,218	241,707,644
D6	2022	28,194,281	144,174,697	6,566,687	178,935,665
	2023	340,053,222	13,416,038,371	430,710,503	14,186,802,096
D7	2022	0	236,352	0	236,352
	2023	0	208,643	0	208,643
Total		713,910,629	20,498,288,084	1,321,311,117	22,533,509,830

[a] Data current as of December 10, 2024, and compiled from Table 4 at https://www.epa.gov/fuels-registration-reporting-and-compliance-help/annual-compliance-data-obligated-parties-and.

Table 1.8.4-2: 2023 RIN Errors[a]

RIN Type	Import Volume Correction	Invalid RIN	Volume error correction	Total
Retirement Code	*30*	*50*	*60*	--
D3	0	1,587,010	0	1,587,010
D4	5,840,918	2,708,205	30,331	8,579,454
D5	0	2,408,108	25,248	2,433,356
D6	0	6,459,246	1,842,201	8,301,447
D7	0	0	0	0
Total	5,840,918	13,162,569	1,897,780	20,901,267

[a] Data from December 2024 and compiled from https://www.epa.gov/system/files/other-files/2025-01/retiretransaction_dec2024.csv.

Table 1.8.4-3: Other 2023 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	219,156
D4	286	2,330,849	7,134,963	0
D5	0	187,804	0	0
D6	109,459	497,103	0	0
D7	0	0	0	0
Total	109,745	3,015,756	7,134,963	219,156

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)	Remedial Action - Retire for Compliance
Retirement Code	*90*	*100*	*110*	*120*
D3	0	0	118,471	1,100
D4	67,740,162	0	1,189,847	0
D5	532,728	0	317,646	0
D6	101,241,955	0	3,666,099	1,018
D7	0	0	0	0
Total	169,514,845	0	5,292,063	2,118

RIN Type	Remediation of Invalid RIN Use for Compliance	2020 Small Refinery Alternative Compliance	Voluntary RIN Retirement	Feedstock using renewable fuel with RINs	Total
Retirement Code	*130*	*150*	*160*	*170*	--
D3	0	6,200,022	0	0	6,538,749
D4	12,000,000	81,321,123	0	37,669,250	209,386,480
D5	0	44,178	0	0	1,082,356
D6	24,895	135,965,203	0	0	241,505,732
D7	0	0	0	0	0
Total	12,024,895	223,530,526	0	37,669,250	458,513,317

[a] Data from December 2024 and compiled from https://www.epa.gov/system/files/other-files/2025-01/retiretransaction_dec2024.csv.

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 volumes proposed in this action for 2026 and 2027. Although we are proposing RFS volume standards for only 2026 and 2027, we projected the No RFS volumes for 2026–2030. This chapter describes our derivation of the No RFS Baseline, as well as an alternate baseline representing actual renewable fuel consumption in 2025.

2.1 No RFS Baseline

The No RFS Baseline represents our projection of biofuel consumption in the U.S. were the RFS program to cease to exist in 2026–2030. Conceptually, the No RFS Baseline allows EPA to directly project the impacts of the Low and High Volume Scenarios for 2026–2030 relative to a scenario without volume requirements. We also assumed that non-RFS federal and state programs that support renewable fuel production and use (e.g., the federal renewable fuels production credits and state LCFS programs), would continue to exist in 2026–2030; in other words, the only current policy not in place in this baseline scenario is the RFS standards.

To project the No RFS Baseline, we began by projecting renewable fuel use in the U.S. in 2026–2030 in the absence of RFS volume requirements for these years. 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.[58] The differences between the Volume Scenarios 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.

In some cases, the volume changes between the No RFS Baseline and the Volume Scenarios were 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 proposed volume for total domestic ethanol consumption is 212–266 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 proposed volumes. However, total domestic ethanol consumption in the Volume Scenarios for 2026–2030 is lower than total domestic ethanol consumption achieved in previous years. Thus, no additional ethanol production capacity or distribution infrastructure is projected to be needed to meet the ethanol volumes in the Volume Scenarios for 2026–2030. Furthermore, we are already producing considerably greater volumes of corn ethanol than we are able to use domestically and exporting

[58] Local renewable fuel production subsidies and renewable fuel plant construction subsidies were not considered. These subsidies could help support renewable fuel production volumes and support a slightly higher baseline volume.

the excess. Therefore, again, no additional production capacity needed. 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 Volume Scenarios, but also other relevant factors as they exist in 2025.

There are some effects of a No RFS Baseline, such as U.S. crop production, that we lack information, sufficient time, resources, or the necessary modeling tools to estimate. 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 2026–2030 if there was lower demand for crops for biofuel production from the RFS standards. But other scenarios are also possible and may be more likely. If demand for biofuel in the U.S. were lower in 2026–2030 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,[59] and both imports and exports of biodiesel and renewable diesel.[60] 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 2023 or 2024) 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 Volume Scenarios relative to both the No RFS Baseline and the 2025 Baseline. We recognize that the 2025 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 2026–2030 versus not taking that action.

The No RFS Baseline was derived based on 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, provided that the fuels distribution system can provide the fuels and vehicles can use those biofuels. 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)

[59] See Chapter 6.6.
[60] See Chapter 6.2.4.

- Federal and state subsidies
- Relative energy value of the fuel, which may or may 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 as they are considered transfer payments
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, soybean 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. Economic theory would say that this could lower the market prices for the agricultural feedstocks, making the renewable fuels made from them more attractive. Nevertheless, due to the complexity and uncertainty for undertaking such a market analysis, we did not attempt to evaluate such a feedback mechanism.[61] The various economic factors shown in Table 2.1-1 are further discussed below for each renewable fuel.[62]

Similarly, for the gasoline and diesel fuel prices, we use the most recent wholesale price projections in AEO2023. Since EIA models much of the RFS program in its AEO modeling, some price impacts of the RFS program are likely already represented in these wholesale gasoline and diesel fuel prices. Economic theory would again say that wholesale gasoline and diesel fuel prices would probably be lower under a No RFS scenario. However, we did not attempt to evaluate this and believe the impact would be 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 blended at higher blend percentages of 15% and 51-83% (i.e., E15 and E85, respectively).[63] 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.[64] That report and its appendix provide both a 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:

[61] By not estimating lower renewable fuel prices under the No RFS Baseline, it could underestimate renewable fuel demand under the No RFS Baseline and conservatively estimate higher costs for the proposed volume requirements.
[62] The spreadsheets used to estimate the No RFS Baseline for corn ethanol ("Corn Ethanol No RFS Baseline for Set 2 Proposed Rule") and biodiesel and renewable diesel ("Biodiesel and Renewable Diesel No RFS Baseline for Set 2 Proposed Rule") are available in the docket for this action.
[63] AFDC, "E85 (Flex Fuel)." https://afdc.energy.gov/fuels/ethanol_e85.html.
[64] EPA, "Economics of Blending 10 Percent Corn Ethanol into Gasoline," EPA-420-R-22-034, November 2022.

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

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[65] 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 more perceivably lower energy density). Thus, energy density is not a factor in this blending cost equation for E10. It is an important part of assessing the overall social costs of ethanol use but does not factor into the decision to blend ethanol as E10.

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.

[65] This is the case because the 3% reduction in average fuel economy equates to a reduction of 1 mile per gallon or less for most vehicles. This difference is difficult to perceive against the background of normal variation in vehicle performance under different conditions (e.g., weather), even for consumers who regularly track their fuel economy.

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 based on production costs are summarized in Table 2.1.1.1-2.[66]

Table 2.1.1.1-2: Projected Ethanol Plant Gate Prices (nominal $/gal)

Year	Price
2026	1.88
2027	1.89
2028	1.91
2029	1.92
2030	1.94

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.[67] 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.

[66] Projected corn ethanol production costs in nominal dollars are estimated by entering the costs of various inputs and accounting for the costs for various byproducts into a corn ethanol cost model using estimated prices for those inputs and byproducts in nominal dollars.
[67] ICF, "Modeling a 'No-RFS' Case," EPA Contract No. 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	18.7
	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 conventional gasoline (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.[68] It is likely that refiners make their decision on producing BOBs based on the economics of producing finished gasoline at terminals. In the case

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

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

The full value of ethanol is best reflected by the cost associated with meeting all of the gasoline standards and requirements through some means other than blending ethanol, including any capital costs to produce ethanol replacements. To assess this, ICF conducted refinery modeling for EPA for removing ethanol from the gasoline pool.[69] 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 increasing nominal 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 (nominal $/gal)

Gasoline Type	Gasoline Grade	Year				
		2026	**2027**	**2028**	**2029**	**2030**
Conventional Gasoline	Summertime Regular	2.23	2.28	2.35	2.42	2.48
	Summertime Premium	1.69	1.72	1.77	1.82	1.87
Reformulated Gasoline	Summer Regular	1.93	1.96	2.02	2.08	2.14
	Summer Premium	1.38	1.41	1.45	1.49	1.54
Conventional and Reformulated	Winter Regular	0.90	0.92	0.95	0.98	1.01
	Winter Premium	0.69	0.70	0.72	0.74	0.76

Federal and State Ethanol Tax Subsidies (FETS and SETS)

The federal ethanol blending tax subsidy expired in 2011, so that subsidy did not figure into the No RFS Baseline analysis. A potentially new federal subsidy for corn ethanol is established under the 45Z provisions of the Inflation Reduction Act; however, when this analysis was conducted, the guidance related to this tax credit had not yet been released and so we did not assume any 45Z subsidy for corn ethanol. For this reason, we did not assume any federal tax subsidy for corn ethanol.[70]

[69] The results of this refinery modeling are summarized in Chapter 10.1.3.1.1. MathPro, "Analysis of the Effects of Low-Biofuel Use on Gasoline Properties – An Addendum to the 'No-RFS' Study," EPA Contract EP-C-16-020, June 7, 2019.

[70] Based on our review of the U.S. Department of the Treasury and Internal Revenue Service (IRS) 45Z guidance released on January 10, 2025, corn ethanol will likely earn a subsidy of 1¢ or 6¢ per gallon, depending on whether the production facility meets prevailing wage and apprenticeship requirements. See Notice 2025-10, 2025-6 I.R.B. 682 (February 3, 2025) and Notice 2025-11, 2025-6 I.R.B. 704 (February 3, 2025). We intend to include this subsidy in the analysis for the final rule.

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 15¢/gal and 26¢/gal, respectively.[71] The California LCFS program is estimated to provide corn ethanol an average blending credit of 12¢/gal.[72,73] Several states, including Minnesota and Missouri, also have ethanol use mandates that require the use of ethanol regardless of the economics for doing so.[74] 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, although some of these subsidies, or a portion of them, may already be included in the price information we used to estimate ethanol's production cost for the No RFS Baseline. To the extent that these subsidies are not represented in our No RFS Baseline analysis will lead to slightly underestimating the volume of corn ethanol in our No RFS Baseline.

Gasoline Terminal Price (GTP)

Refinery rack price data from 2019—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.[75] However, these prices were not projected for future years. Instead, we used projected refinery wholesale price data from AEO2023 to adjust the 2019 refinery rack price data to represent gasoline rack prices in future years. We used 2019 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. Further price effects after the pandemic were caused by the geopolitical conflict between Russia and Ukraine which are avoided by using the earlier price data. The 2018 gasoline price data was used over that of 2019 because crude oil prices in 2018 are closer to the crude oil prices projected by AEO2023 and there likely would be less error involved with a smaller adjustment. This gasoline price data, summarized in Table 2.1.1.1-5, was collected for each state and is assumed to represent the average gasoline price for all the terminals in each state.[76]

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[71] The National Agricultural Law Center, States' Biofuels Statutory Citations. https://nationalaglawcenter.org/state-compilations/biofuels.
[72] California Air Resources Board (CARB), LCFS Pathway Certified Carbon Intensities. https://ww2.arb.ca.gov/resources/documents/lcfs-pathway-certified-carbon-intensities.
[73] CARB, "Weekly LCFS Credit Transfer Activity Reports," May 11, 2025. https://ww3.arb.ca.gov/fuels/lcfs/credit/lrtweeklycreditreports.htm.
[74] The National Agricultural Law Center, States' Biofuels Statutory Citations. https://nationalaglawcenter.org/state-compilations/biofuels.
[75] EIA, "Spot Prices," *Petroleum & Other Liquids*, May 14, 2025. https://www.eia.gov/dnav/pet/pet_pri_spt_s1_a.htm.
[76] EIA, "Refiner Gasoline Prices by Grade and Sales Type," *Petroleum & Other Liquids*, June 1, 2022. https://www.eia.gov/dnav/pet/pet_pri_refmg_dcu_nus_a.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 prices in a neighboring state or for that state in a previous year when crude oil prices were about the same as 2018.

The AEO2023 projected national average wholesale gasoline price information used to adjust gasoline prices in future years, and the national average wholesale gasoline price in 2018 that the projected wholesale 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 wholesale gasoline price in 2026 is $2.50 per gallon, which is 52¢ per gallon more than the national average gasoline price in 2018; therefore, gasoline prices in 2026 are 52¢ per gallon higher than the prices summarized in Table 2.1.1.1-5.

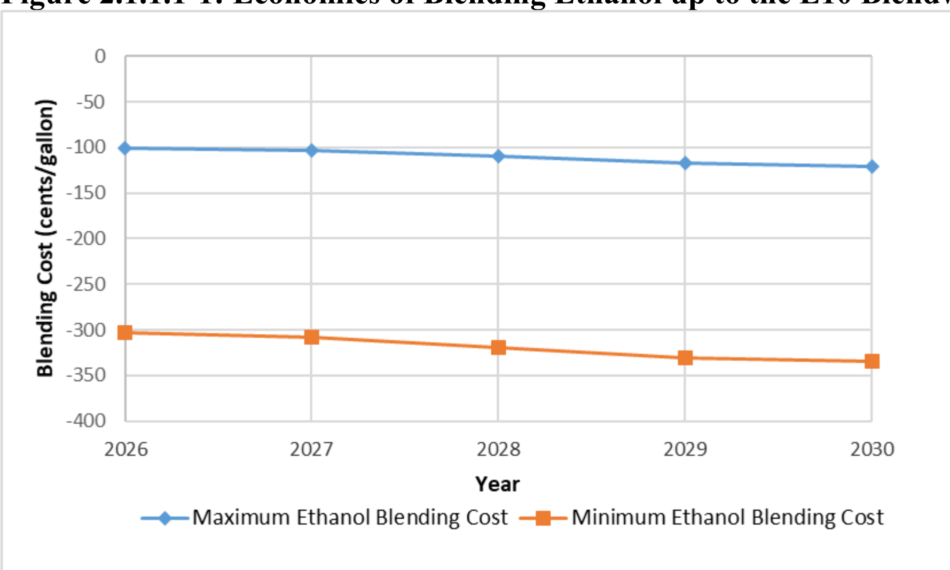
Table 2.1.1.1-6: National Average Wholesale Gasoline Prices

	Year	Wholesale Gasoline Price (AEO2023)	CPI	Wholesale Gasoline Price (nominal)	2018 Price Adjustment Factor
Actual National Average Gasoline Price	2018			$1.98	-
	2022		2.93		
Gasoline Price	2026	$2.24	3.06	$2.50	1.26
	2027	$2.22	3.14	$2.52	1.27
	2028	$2.23	3.20	$2.59	1.31
	2029	$2.24	3.27	$2.65	1.34
	2030	$2.25	3.33	$2.72	1.37

Source: AEO2023, Table 20 – Macroeconomic Indicators and Table 57 – Components of Selected Petroleum Product Prices.

The No RFS Baseline analysis revealed that it is economical 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 (nominal dollars)



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). We do not include a fuel economy effect for E10 because consumers bear this cost, both because they lack the ability to perceive the difference in fuel economy which creates the cost and because they generally lack reliable access to an alternative (e.g., E0 gasoline) at a more attractive price. However, in E85's case, consumers command a lower price for E85 before purchasing E85 because they are able to perceive the difference in fuel economy associated with it relative to E10, which affects ethanol's value to fuel blenders at these higher rates. 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.[77] 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.[78]

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[77] Octane giveaway occurs when the gasoline being sold has higher octane than required in the state where the gasoline is being sold. For example, regular grade gasoline must meet an (R+M)/2 octane standard of 86 in most states. When ethanol is blended into finished gasoline, the octane of the finished E10 will be approximately 3 octane numbers higher than required.

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

Although refiners do not create a lower octane BOB for blending into E85, ethanol producers nonetheless see 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, some ethanol producers blend E85 on-site using NGLs and then distribute the finished E85 from there. When blending up E85 with NGLs, the higher RVP of the NGLs allows blending a higher ethanol content of 83% in the summer. However, the RVP of NGLs is about the same or slightly higher than winter gasoline, so the winter blend percentage is the same. Because the more volatile NGLs are smaller hydrocarbons, they contain lower volumetric energy content, which is a factor in considering their value as well. Because NGLs are used as an E85 blendstock, we also evaluated the economics of blending E85 blended with NGLs.

Federal and State Ethanol Tax Subsidies (FETS and SETS)

There is no federal ethanol blending tax subsidy and there never has been one, for E85.[79] 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: Current State E85 Subsidies (¢/gal)

State	E85 Subsidy
Iowa	16
Kansas	12.5
Michigan	11
New York	53
Pennsylvania	25
South Dakota	14

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.[80] 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

[79] Based on our review of the U.S. Department of the Treasury and IRS 45Z guidance released on January 10, 2025, corn ethanol will likely earn a 6¢ per gallon subsidy. See Notice 2025-10, 2025-6 I.R.B. 682 (February 3, 2025) and Notice 2025-11, 2025-6 I.R.B. 704 (February 3, 2025). We intend to include this subsidy in the analysis for the final rule.
[80] The methodology used and the estimated costs for these revamps are discussed in Chapter 10.1.4.1.2.

average 84,000 gallons of E85 per year. When amortizing this capital cost over the gallons of E85 sold, the total cost of the revamp adds 15¢/gal to the cost of blending ethanol into E85 (accounting only for the estimated 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 compared to E10 on a volumetric basis—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 relative to E10, which therefore requires that the economics of E85 be assessed at retail. Price information collected for E85 shows that it is typically priced 16% lower than E10 at retail.[81,82] 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.[83]

Figure 2.1.1.2-1 provides an example for how the breakeven price for ethanol is estimated for E85 when blended with gasoline. At the top of the 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. 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.

[81] Fuels Institute, "Retailing E85: An Analysis of Market Performance, July 2014 – August 2015," March 23, 2017. https://www.transportationenergy.org/wp-content/uploads/2022/10/E85_2017_Report_FINAL.pdf.
[82] AAA, "National average gas prices," December 12, 2022. https://gasprices.aaa.com.
[83] It is unclear why E85's price only reflects a portion of its lower energy content. Retailers may be choosing to balance their profit with consumer demand, or consumers may value E85's much higher octane content, which offsets its lower energy density.

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

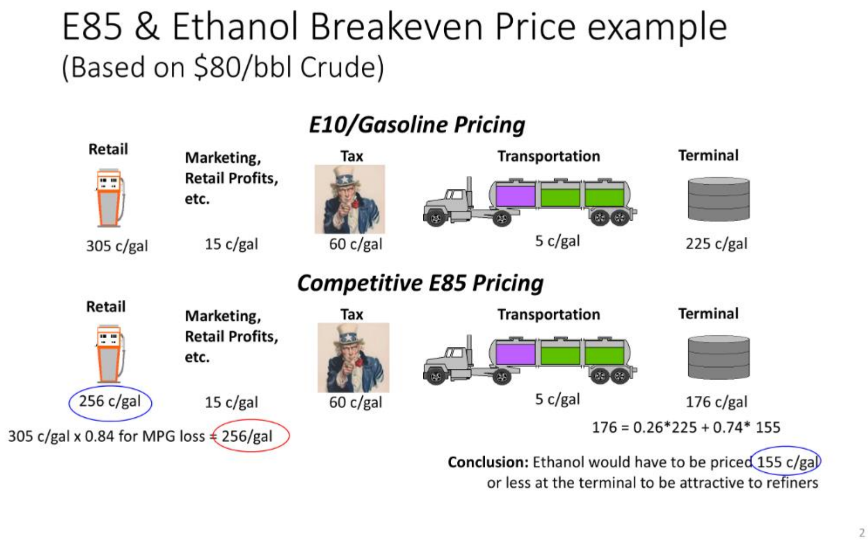


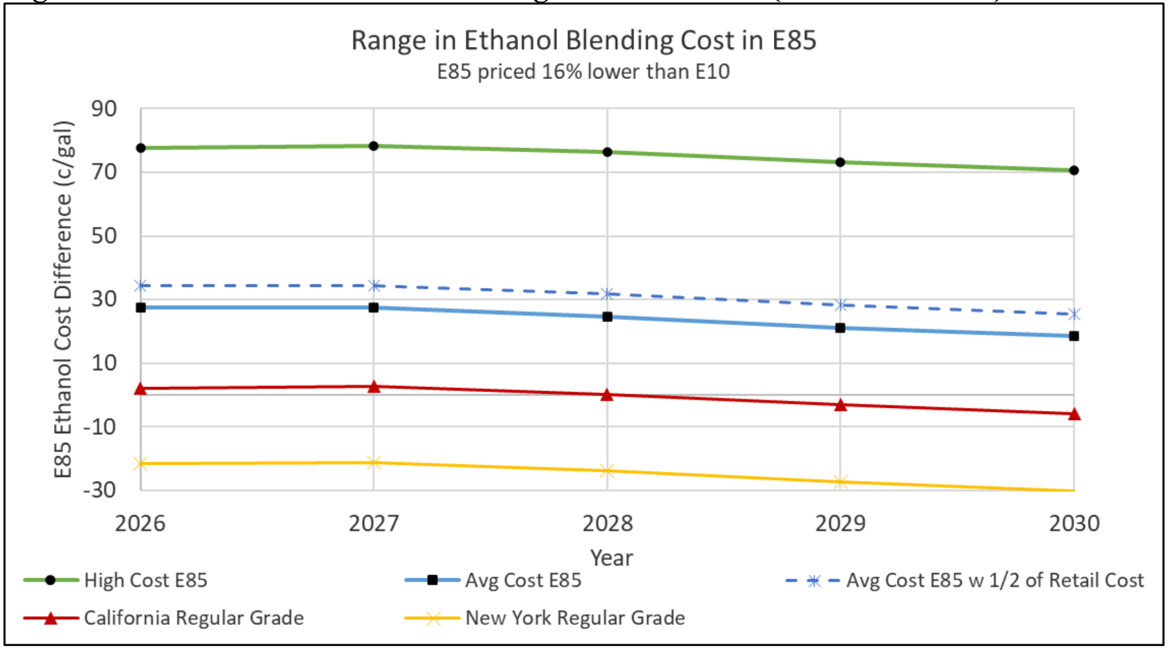
Figure 2.1.1.2-1 shows that when the E85 is blended with gasoline, the breakeven price of ethanol in E85 is 155¢/gal, which is 70¢/gal lower than the gasoline terminal price, although the breakeven price varies by state depending on the gasoline terminal price and tax rates. A list of gasoline tax rates by state (including all federal and state taxes) is provided in Table 2.1.1.2-2.

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

State	Tax Rate		State	Tax Rate
Alaska	27		Montana	51
Alabama	48		North Carolina	55
Arkansas	43		North Dakota	41
Arizona	37		Nebraska	49
California	79		New Hampshire	42
Colorado	40		New Jersey	60
Connecticut	66		New Mexico	37
DC	42		Nevada	52
Delaware	41		New York	63
Florida	61		Ohio	57
Georgia	55		Oklahoma	38
Hawaii	70		Oregon	54
Iowa	49		Pennsylvania	76
Idaho	51		Rhode Island	55
Illinois	58		South Carolina	47
Indiana	69		South Dakota	48
Kansas	49		Tennessee	68
Kentucky	44		Texas	38
Louisiana	38		Utah	50
Massachusetts	45		Virginia	40
Maryland	55		Vermont	49
Maine	48		Washington	68
Michigan	51		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 as 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 70-80¢/gal higher than its breakeven price. But for lowest cost market for E85, ethanol is 60-70¢/gal lower than its breakeven price. It is important to understand which gasoline in which states are economically attractive to blend E85 since this determines the potential market size.

Figure 2.1.1.2-3: Economics of Blending Ethanol in E85 (nominal dollars)



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 compared to E0 gasoline. 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.[84] This retrofit cost does not have a large cost impact because E85 contains mostly ethanol, which defrays this cost.

The lowest cost market for E85 in any state is that relative to premium gasoline. 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 this reason, we did not consider E85 to be economical in any state if it was solely economic relative to premium gasoline, and we did not represent E85 relative to premium gasoline in Figure 2.1.1.2-3.

The most economical market for E85 relative to regular grade gasoline is New York, due to its 53¢/gal blending subsidy for E85. For regular gasoline outside of New York, ethanol's blending economics is favorable in E85 in California's regular gasoline pool in some years. When modeling the economics of E85 in California, we do not assume any change in the projected LCFS subsidy amount; however, the LCFS subsidy would most likely increase without the RFS program in place. Assuming even a small increase in the LCFS subsidy without the RFS program in place would likely make E85 economic in all years in California, and we are seeing significant increased demand for E85 in California. Thus, for the No RFS Baseline analysis, we estimated there to be a significant amount of E85 consumption in California. Ironically, while

[84] 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.

New York is the lowest cost market for E85, there are very few E85 stations there, even with the RFS program in place, so we did not assume any E85 sales in New York 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%.

Another issue for E15 is that it does not receive a 1-psi waiver like E10 does in the summer. 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 summers of 2022–2024, which further allowed E15 to take advantage of the 1-psi waiver.[85] A number of Midwestern states petitioned EPA to remove the 1-psi waiver for E10[86] and EPA responded by finalizing a rulemaking to grant those states' request to remove the 1 psi waiver for E10 starting in 2025.[87] Because the E10 1-psi waiver was removed in those states, a new lower-RVP, higher-cost BOB would be required for E10, which would also accommodate E15 and thus remove a hurdle for selling E15 in the summer months in those states. However, EPA extended the deadline for the removal of the 1-psi waiver in Ohio and nine counties in South Dakota to 2026 in response to requests by the Governors of those states due to concerns about the supply of gasoline in the summer of 2025.[88] EPA subsequently issued emergency fuel waivers in the summer of 2025 to facilitate continued E15 availability in the Midwestern states.[89] Any permanent solution that allows E15 to be blended into the same BOB as E10 during the summer is expected to encourage investment and increase sales of E15.

Federal and State Ethanol Tax Subsidies (FETS and SETS)

There is no federal nor state ethanol blending tax subsidy for E15.[90] It is important to know that California does not allow the sale of E15, although California could allow E15 in the future. 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.[91] We estimated the total cost for a typical retail station revamp to enable selling E15 to be $133,000 (although there is a large range from zero costs up to many hundreds of thousand dollars), and that these stations sell on average 229,000 gallons of E15 per year. When amortizing this capital cost over the gallons of E15 sold, the total cost of the revamp adds over $2/gal to the cost of blending ethanol into E15 (accounting only for the 5% of ethanol in E15 above the ethanol in E10).

A new E15 marketing strategy has emerged by a small number of retailers, which is to solely sell E15 as the regular grade, thus discontinuing the sale of E10 as the regular grade. Since the retailer is not adding a new grade of gasoline—it is merely exchanging E10 for E15—this strategy will increase the sales of E15 at these retail stations since consumers will not have a

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[85] EPA, "Fuel Waivers," May 20, 2025. https://www.epa.gov/gasoline-standards/fuel-waivers.

[86] 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 the No RFS Baseline would still be governed by the relative economics of blending additional ethanol into E10 relative to continuing to use petroleum gasoline.

[87] 89 FR 14760 (February 29, 2024).

[88] 90 FR 13093 (March 20, 2025).

[89] EPA, "EPA Addresses E-10 Standards, Allows for Nationwide Year-Round E15 Sales," April 28, 2025. https://www.epa.gov/newsreleases/epa-addresses-e-10-standards-allows-nationwide-year-round-e15-sales.

[90] Based on our review of the U.S. Department of the Treasury and IRS 45Z guidance released on January 10, 2025, corn ethanol will likely earn a 6¢ per gallon subsidy. See Notice 2025-10, 2025-6 I.R.B. 682 (February 3, 2025) and Notice 2025-11, 2025-6 I.R.B. 704 (February 3, 2025). We intend to include this subsidy in the analysis for the final rule.

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

choice to refuel with E10, and this would reduce the per-gallon cost of the retail station E15 retrofit costs. Selling E15 as a feature grade provides costs savings to retail stations since it reduces the number of tanks at the station and increases ethanol sales without marketing or price discounts. We will continue to monitor this trend and if it seems to be adopted more widely, we will incorporate it in future No RFS Baseline analyses.

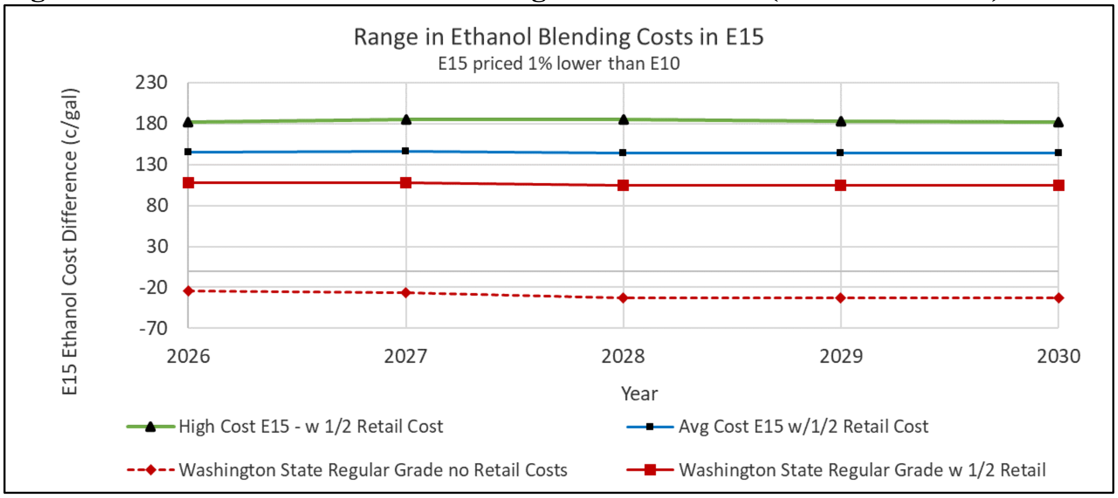
E15 has different properties than E10 that allow it to be priced differently than E10. E15 has higher octane than E10, so the fuels industry could set E15 prices higher on that basis. Conversely, E15 has lower energy density than E10, which means that consumers are not able to drive the same distance 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. It is likely that a significant portion of this discount is due to the value of the RIN, which normally is passed through to the refiner, but due to the higher cost of providing E15, the RIN value would be used by the retailer.

However, if this is a marketing strategy, this practice would likely diminish over time and would change without the RFS program in place. We do not know what the ultimate price of E15 would be relative to E10 if the RFS program was not in place 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.[92] Since E15 contains less energy than E10, we assumed that E15 is priced 1.3%, or about 3¢/gal, less than E10 which is reflective of the price discount that typically is used with E85 based on E85's energy content.

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.

[92] E85, which contains 74% ethanol and 21% less energy than E10, is typically priced 16% lower than E10.

Figure 2.1.1.3-1: Economics of Blending Ethanol in E15 (nominal dollars)



The three solid lines at the top of the figure show the estimated low, average, and high cost of blending the incremental 5 volume percent ethanol in regular grade E10 to produce E15. The lowest cost estimate represented by the solid red line is for producing an E15 blend in the State of Washington, a lowest cost state for blending 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 Higher Blends Infrastructure Incentive Program (HBIIP) program subsidized half the cost, the retail station is estimated to need to cover a cost of about 80¢ per gallon for that 5% increment of ethanol in E15. This is shown in Figure 2.1.1.3-1 as the difference between the dashed red line and the solid red line, which represents the average E15 cost without any retail cost included. While it would not be economic anywhere to blend E15 if the retail outlet would need to cover half of the estimated retail cost, if the retail cost is fully covered by subsidies, or if the retail station is already E15 compatible and the fuel dispensers are already capable of dispensing E15, the E15 would be economic in many cases. For example, if excluding the estimated retail cost for blending E15 in Washington State, there would be a blending advantage of about 20¢ per gallon.[93]

There are two cases that would help to make E15 economic. In one case, over 500 gasoline retailers are electing to only sell E15, which increases E15 sales at those retail stations. This lowers the per-gallon cost of retrofitting those stations to accommodate E15.

In the second case, if refiners and terminal operators could overcome the steep logistical hurdles of producing and moving a separate lower-octane BOB for E15 to terminals and eventually to retail stations, the gained ethanol replacement value for the E15 BOB would also help to offset the retail cost of making E15 available, and E15 would likely be economical in some summertime regular gasoline markets. Refiners and terminal operators are unlikely to create a separate E15 BOB until sales of E15 increase significantly. Prior to that occurring,

[93] The economics of blending economics of E15 is even more favorable when referenced to premium gasoline; however, premium gasoline demand only comprises about 10% of total gasoline demand. Due to the low sales volume, retailers are unlikely to justify modifying their stations to offer E15 if they were solely targeting the premium gasoline market. For this reason, our analysis only assesses the economics of blending E15 relative to regular grade gasoline.

anecdotal evidence suggests that a new low-RVP BOB could be produced to meet either E10 or E15 volatility specifications without a waiver.[94] 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 projected to generate substantial RINs from 2026–2030 is CNG/LNG derived from biogas. Additionally, we believe that some volume of liquid cellulosic ethanol from corn kernel fiber (CKF) will be produced during this period. Cellulosic biofuels generally cost more to produce than the fossil fuels they displace and, as a result, would generally not be used without the incentives provided by the RFS program. There are, however, certain state incentive programs that we project would sufficiently support the use of some cellulosic biofuels, even without the added incentives from the RFS program. This section outlines our projections for cellulosic biofuel use under the No RFS Baseline.

2.1.2.1 CNG/LNG Derived from Biogas

As detailed in Chapter 10, CNG/LNG derived from biogas is generally more expensive to produce than fossil-based natural gas. Due to this higher production cost and the demand for RNG in sectors outside of transportation, we project that, without incentives specifically supporting the use of renewable CNG/LNG in transportation, very little or none of this fuel would be used in the transportation sector. Currently, three states[95]—California, Oregon, and Washington—have LCFS programs that offer incentives for using CNG/LNG as a transportation fuel. We assume that these state-level incentives would support some use of CNG/LNG in transportation even in the absence of the RFS program.

To project the amount of CNG/LNG used as transportation fuel in these states, we relied on data from each state's programs and extrapolated it through 2030. Specifically, for California and Oregon, we examined total CNG/LNG volumes (including both fossil and biogas-derived), as well as volumes solely derived from biogas. Using this information, we calculated both the year-over-year growth for each year and the blend rate showing the percentage of total CNG/LNG that was biogas-derived. This data, summarized in Table 2.1.2.1-1, indicates that the CNG/LNG markets in Oregon and California have shifted to be almost entirely biogas-based, with biogas-derived volumes averaging 97% of the total market from 2022 to 2023. This suggests limited capacity in both states for new sources of biogas-derived CNG/LNG to replace fossil-based CNG/LNG, meaning that the total market has been saturated with biogas-derived CNG/LNG.

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[94] Hoekstra Trading, "Midwest States Pose New Challenges for Gasoline Supply," April 21, 2025. https://hoekstratrading.com/midwest-states-pose-new-challenges-for-gasoline-supply.

[95] New Mexico also has a state-level program to promote low-carbon fuel use (the Clean Transportation Fuel Standard (CTFS)). However, since this program was only authorized in March 2024, there is currently insufficient information for EPA to incorporate potential volumes from this program into this analysis. New Mexico Environment Department, "Clean Transportation Fuel Program," March 19, 2025. https://www.env.nm.gov/climate-change-bureau/clean-fuel-standard.

Table 2.1.2.1-1: CNG/LNG Usage in California and Oregon (million ethanol-equivalent gallons)[a]

		2019	2020	2021	2022	2023
California[b]	Total CNG/LNG	305.0	278.0	302.6	335.4	355.8
	Year-over-year growth	7%	-9%	9%	11%	6%
	Biogas-derived CNG/LNG	236.1	256.9	295.9	323.3	344.2
	Blend Rate	77%	92%	98%	96%	97%
Oregon[c]	Total CNG/LNG	5.6	5.6	6.5	6.7	6.7
	Year-over-year growth	7%	-1%	16%	4%	0%
	Biogas-derived CNG/LNG	3.8	4.9	5.9	6.3	6.6
	Blend Rate	67%	89%	91%	94%	99%

[a] Only the last five years of data are shown; however, data is available for California from 2011–2023, and for Oregon from 2016–2023.
[b] CARB, Low Carbon Fuel Standard Reporting Tool Quarterly Summaries. https://ww2.arb.ca.gov/resources/documents/low-carbon-fuel-standard-reporting-tool-quarterly-summaries.
[c] Oregon DEQ, Oregon Clean Fuels Program – Quarterly Data Summaries. https://www.oregon.gov/deq/ghgp/cfp/pages/quarterly-data-summaries.aspx.

Despite this saturation, volumes of biogas-derived CNG/LNG can continue to rise as the overall CNG/LNG market grows. To project future volumes of biogas-derived CNG/LNG in Oregon and California, EPA calculated the average year-over-year growth rate of the total CNG/LNG market based on the last three years of data.[96] Doing so results in average year-over-year growth rates for the total CNG/LNG market of 8% and 2% for California and Oregon, respectively. This rate was then applied to the most recent full year of available biogas-derived CNG/LNG data (2023), as shown in Table 2.1.2.1-2, and used to project future production by compounding each successive year.[97]

Table 2.1.2.1-2: Projected Biogas-derived CNG/LNG Usage in California and Oregon (million ethanol-equivalent gallons)

Year	Data Type	California (8% Year-over-year Growth)	Oregon (2% Year-over-year Growth)
2023	Actual	344.2	6.6
2024	Projected[a]	373.3	6.8
2025	Projected	404.9	6.9
2026	Projected	439.1	7.0
2027	Projected	476.2	7.2
2028	Projected	516.4	7.3
2029	Projected	560.1	7.5
2030	Projected	607.4	7.6

[a] At the time we developed the No RFS Baseline for this proposal, full-year 2024 data was not yet available for California or Oregon.

[96] Only the last three years (2021–2023) were chosen to potentially minimize any impacts that the Covid-19 pandemic may have had on growth.
[97] We used the year-over-year growth in the rate of the total CNG/LNG market rather than only the biogas-derived market as the total CNG/LNG market should better reflect future growth in a vehicle consumption-limited market.

Given that Washington's CNG/LNG fuel market is much newer than those in California and Oregon, having only started in 2023, we used a slightly different approach to estimate future volumes. First, we calculated the blend rate of biogas-derived CNG/LNG as a percentage of the total CNG/LNG market, as shown in Table 2.1.2.1-3. Then, using a year-over-year growth rate determined by averaging the rates of both Oregon and California, we projected the total CNG/LNG market size for Washington in 2024. Given the saturation in California and Oregon's markets, we assumed that significant volumes of biogas-derived CNG/LNG would quickly fill the Washington market, as it may be easier for producers to find consumers in a less saturated market. Accordingly, we projected that Washington's blend rate would reach 97% of total CNG/LNG by the end of 2024—an assumption that we believe is reasonable given that Washington reported an RNG blend rate of 53% in their program's first year (2023), which had already increased to around 75% by the first quarter of 2024.[98] After 2024, however, we applied only the average year-over-year growth rate averaged from California and Oregon to future Washington projections, as shown in Table 2.1.2.1-4.

Table 2.1.2.1-3: CNG/LNG Usage in Washington (million ethanol-equivalent gallons)

	2023
Total CNG/LNG	10.7
Year-over-year growth	N/A
Biogas-derived CNG/LNG	5.72
Blend Rate	53%

Table 2.1.2.1-4: Projected Biogas-derived CNG/LNG Usage in Washington (million ethanol-equivalent gallons)

Year	**Data Type**	**Biogas-derived CNG/LNG Usage (5% year-over-year Growth)**
2023	Actual	5.7
2024	Projected[99]	10.9[a]
2025	Projected	11.5
2026	Projected	12.1
2027	Projected	12.7
2028	Projected	13.4
2029	Projected	14.1
2030	Projected	14.8

[a] Projected using both 5% year-over-year growth rate and the assumption that biogas-derived CNG/LNG would reach a 97% blend rate in 2024.

[98] State of Washington Department of Ecology, "Clean Fuel Standard – Quarter 1, 2024 Data Summary," September 2024. https://apps.ecology.wa.gov/publications/documents/2414075.pdf.

[99] At the time we developed the No RFS Baseline for this proposal, full-year 2024 data was not yet available for Washington.

Totaling the projected volumes from each state, the projected volume of renewable CNG/LNG used as transportation fuel under the No RFS Baseline is summarized in Table 2.1.2.1-5.

Table 2.1.2.1-5: Biogas-derived CNG/LNG for the No RFS Baseline (million ethanol-equivalent gallons)

State	2026	2027	2028	2029	2030
California	439.1	476.2	516.4	560.1	607.4
Oregon	7.0	7.2	7.3	7.5	7.6
Washington	12.1	12.7	13.4	14.1	14.8
Total	458.2	496.1	537.2	581.6	629.8

2.1.2.2 Liquid Cellulosic Biofuels

In recent years, only small quantities of liquid cellulosic biofuels have been produced, despite substantial financial incentives from programs like the RFS, federals tax credits, and state initiatives, such as California's LCFS program. While these state and federal incentives are expected to continue in the coming years, we do not anticipate that they will be sufficient to support most types of liquid cellulosic biofuel production between 2026 and 2030.

One likely exception is ethanol produced from CKF at existing ethanol facilities. Many corn ethanol producers have indicated that their facilities can produce ethanol from CKF, sometimes by adding cellulose enzymes and, in other cases, by relying solely on enzymes naturally present in the corn kernel. In either case, we project that the cost of producing ethanol from CKF would be comparable to, or only slightly higher than, the cost of producing ethanol from corn starch. Because CKF-based ethanol is eligible for additional incentives through programs such as California's LCFS, we expect that it would continue to be produced without the RFS standards at the volumes proposed in this rule. These volumes are shown in Table 2.1.2.2-1. More information on the methodologies used to determine the proposed liquid cellulosic biofuel volumes can be found in Chapter 7.1.5.

Table 2.1.2.2-1: Ethanol from CKF in the No RFS Baseline (million ethanol-equivalent gallons)

Year	Volume
2026	124
2027	123
2028	122
2029	120
2030	119

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.[100] 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.

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

Projected Production Cost	2026	2027	2028	2029	2030
Soybean Oil	4.45	4.15	4.10	4.02	3.95
Corn Oil	3.78	3.54	3.50	3.44	3.37
Waste Oil	3.50	3.28	3.24	3.19	3.13

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 2020 EIA data, we estimated the quantity

[100] USDA, "U.S. Bioenergy Statistics," October 2024, Table 16 – Biodiesel and Diesel Prices. https://www.ers.usda.gov/data-products/us-bioenergy-statistics.

of biodiesel produced within each PADD,[101] the movement of biodiesel between PADDs, and the imports and exports of biodiesel into and out of each PADD, as summarized in Table 2.1.3.1-2.[102,103,104,105]

Table 2.1.3.1-2: Biodiesel Production, Imports, Export, and Movement Between PADDs and Consumption in 2020 (million gallons)

PADD	Production	Imports	Exports	From PADD 2	From PADD 3	Other Movement	Consumption
PADD 1	74	91	8	120	2	-4	275
PADD 2	1,304	47	84	-	0	1	1,268
PADD 3	315	11	21	168	0	0	473
PADD 4	0	20	3	15	0	0	32
PADD 5	125	27	26	157	39	1	323
Total	1,818	197	142	460	41	-2	2,372

ICF estimated the distribution costs for distributing biodiesel both within and between PADDs, as summarized in Table 2.1.3.1-3.[106] An additional cost is added on to account for the addition of biodiesel additives, for example, to improve biodiesel cold flow properties and reduce oxidation downstream of the production facility—the total cost of these additives is estimated to be 7¢ per gallon. The costs, estimated in 2017 dollars, are adjusted to the year dollars being analyzed. For example, in 2026, these distribution costs are increased by 34% and increased to 45% in 2030.

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

	Originally Estimated Costs 2017 dollars			Adjusted to 2026 dollars	
PADD	Within PADD	From Outside the PADD	Additives Cost	Within PADD	From Outside the PADD
PADD 1	15	35	7	29.4	56.1
PADD 2	15	15	7	29.4	29.4
PADD 3	15	18	7	29.4	33.4
PADD 4	15	25	7	29.4	42.7
PADD 5	15	32	7	29.4	52.1

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

[101] 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.
[102] EIA, "Monthly Biodiesel Production Report," February 2021, Table 5 – Biodiesel (B100) production by petroleum administration for defense district. https://www.eia.gov/biofuels/biodiesel/production/archive/2020/2020_12/biodiesel.pdf.
[103] EIA, "Exports," *Petroleum & Other Liquids*, April 30, 2025. https://www.eia.gov/dnav/pet/pet_move_exp_dc_NUS-Z00_mbbl_a.htm.
[104] EIA, "Imports by Area of Entry," *Petroleum & Other Liquids*, April 30, 2025. https://www.eia.gov/dnav/pet/pet_move_imp_dc_NUS-Z00_mbbl_a.htm.
[105] EIA, "Movements by Pipeline, Tanker, Barge, and Rail between PAD Districts," *Petroleum & Other Liquids*, April 30, 2025. https://www.eia.gov/dnav/pet/pet_move_ptb_dc_R20-R10_mbbl_a.htm.
[106] ICF, "Modeling a 'No-RFS' Case," EPA Contract No. EP-C-16-020, July 17, 2018.

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

Federal and State Biodiesel Tax Subsidies (FBTS and SBTS)

Historically, there has been 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 20 years. However, in the Inflation Reduction Act passed in 2022, Congress replaced the biodiesel and renewable diesel blending subsidy with a production subsidy starting in 2025. The amount of the production credit is based on certain employment wage criteria, and estimated impact on GHG emissions. When we were conducting our No RFS Baseline case for this proposed rulemaking, the Department of Treasury had not yet established the credit amounts, so we projected the value of biodiesel subsidies based on information and conversations with Treasury at the time.[107] The estimated value of the biodiesel and renewable diesel production credit by feedstock type is summarized in Table 2.1.3.1-4.

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

Feedstock Type	Biodiesel Subsidy
Soy Oil	20
Corn Oil	70
Waste Oil and Fats	59

States also provide subsidies to blend biodiesel into diesel. These state subsidies were enacted in previous years and are presumed to continue through 2030. Table 2.1.3.1-5 summarizes the states that offer such subsidies and their amounts.

[107] Based on our review of the U.S. Department of the Treasury and IRS 45Z guidance released on January 10, 2025, biodiesel produced from soybean oil, corn oil, and UCO will likely earn a 39¢, 80¢, and 80¢ per gallon subsidy, respectively, which are slightly higher than what we estimated and used in this analysis. See Notice 2025-10, 2025-6 I.R.B. 682 (February 3, 2025) and Notice 2025-11, 2025-6 I.R.B. 704 (February 3, 2025). Thus, the No RFS Baseline may be slightly higher due to the larger biodiesel production subsidies. We intend to include these updated biodiesel production subsidies in the analysis for the final rule.

Table 2.1.3.1-5: Current State Biodiesel Subsidies (¢/gal)

State	Biodiesel Subsidy
Hawaii	12
Iowa	3.5
Illinois	19
North Dakota	100
Rhode Island	30
Texas	20

The California and Oregon Low Carbon Fuel Standards (LCFS) and Washington State's Clean Fuels program do not offer specific subsides per se, but through the cap-and-trade nature of their programs, they can be equated to subsidies.[108] Oregon also has a biodiesel blending mandate, which requires that their diesel contain 5% biodiesel. For California, Oregon and Washington, we estimated the equivalent per-gallon subsidy amount from the incentives offered by its LCFS program which vary by year.[109] Table 2.1.3.1-6 summarizes the projected LCFS subsidies by year.

Table 2.1.3.1-6: Projected California and Oregon LCFS subsidies ($/gal)

State	Feedstock	2026	2027	2028	2029	2030
California and Oregon	Soy, Canola	0.45	0.43	0.42	0.40	0.38
	Waste Fats and Grease	0.87	0.85	0.83	0.81	0.80
Washington	All Feedstocks	0.24	0.24	0.24	0.24	0.24

Although different than subsidies, several states have mandates that require the diesel within their state contain a minimum quantity of biodiesel. Table 2.1.3.1-7 lists the states that have such a mandate and the percentage of biodiesel required to be blended into diesel.

Table 2.1.3.1-7: State Biodiesel Mandates

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

[108] New Mexico's CFTS program is scheduled to take effect by July 1, 2026. We will continue to follow the implementation of the CFTS program and include its incentives for future analyses once the program has been fully implemented.

[109] The blending incentives are based on recent carbon credit values reported by each of the states. While it is probable that the state incentive values would increase if the RFS program was not in place, we did not attempt to estimate what the credit price if the RFS program was not in place. California recently approved more stringent LCFS standards that will likely increase the carbon credit value. CARB, Monthly LCFS Credit Transfer Activity Report for March 2024. https://ww2.arb.ca.gov/resources/documents/monthly-lcfs-credit-transfer-activity-reports.

Diesel Terminal Price (DTP)

Refinery rack price data—which already includes 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.[110] Instead, we used projected refinery wholesale price data from AEO2023 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 emergence and recovery from the Covid-19 pandemic and the emergence of geopolitical conflicts.[111] This diesel price data, summarized in Table 2.1.3.1-6, was collected by state and is assumed to represent the average diesel price for all the terminals in each state. The projected U.S. average wholesale diesel prices are presented in the table, after adjusting the prices to nominal year dollars.

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

State	2026	2027	2028	2029	2030		State	2026	2027	2028	2029	2030
Alaska	3.88	3.78	3.72	3.81	3.90		Montana	3.19	3.11	3.06	3.13	3.21
Alabama	3.07	2.99	2.94	3.02	3.09		North Carolina	3.11	3.03	2.98	3.05	3.12
Arkansas	3.09	3.02	2.96	3.04	3.11		North Dakota	3.16	3.08	3.02	3.10	3.17
Arizona	3.31	3.22	3.17	3.25	3.33		Nebraska	3.16	3.08	3.03	3.11	3.18
California	3.51	3.42	3.37	3.45	3.53		New Hampshire	3.16	3.08	3.03	3.10	3.18
Colorado	3.22	3.13	3.08	3.16	3.23		New Jersey	3.08	3.00	2.95	3.02	3.09
Connecticut	3.13	3.05	3.00	3.08	3.15		New Mexico	3.26	3.18	3.13	3.20	3.28
District of Columbia	3.11	3.03	2.98	3.05	3.13		Nevada	3.33	3.24	3.19	3.26	3.34
Delaware	3.11	3.03	2.98	3.05	3.13		New York	3.19	3.11	3.05	3.13	3.20
Florida	3.16	3.08	3.02	3.10	3.17		Ohio	3.05	2.97	2.92	3.00	3.07
Georgia	3.10	3.02	2.97	3.04	3.11		Oklahoma	3.05	2.97	2.92	2.99	3.06
Hawaii	3.46	3.37	3.31	3.39	3.47		Oregon	3.26	3.18	3.12	3.20	3.28
Iowa	3.15	3.07	3.02	3.09	3.17		Pennsylvania	3.09	3.01	2.96	3.03	3.11
Idaho	3.20	3.12	3.07	3.14	3.22		Rhode Island	3.11	3.03	2.98	3.06	3.13
Illinois	2.99	2.92	2.87	2.94	3.01		South Carolina	3.10	3.02	2.97	3.04	3.12
Indiana	3.03	2.95	2.90	2.97	3.04		South Dakota	3.19	3.11	3.06	3.13	3.21
Kansas	3.09	3.01	2.96	3.04	3.11		Tennessee	3.10	3.02	2.97	3.04	3.12
Kentucky	3.15	3.07	3.01	3.09	3.16		Texas	3.05	2.97	2.92	2.99	3.06
Louisiana	3.00	2.93	2.88	2.95	3.02		Utah	3.28	3.20	3.14	3.22	3.30
Massachusetts	3.16	3.08	3.02	3.10	3.17		Virginia	3.11	3.03	2.98	3.05	3.13
Maryland	3.11	3.03	2.98	3.05	3.13		Vermont	3.18	3.10	3.04	3.12	3.19
Maine	3.17	3.09	3.04	3.11	3.18		Washington	3.16	3.08	3.03	3.10	3.18
Michigan	3.05	2.98	2.93	3.00	3.07		Wisconsin	3.09	3.01	2.96	3.03	3.10
Minnesota	3.18	3.10	3.05	3.12	3.20		West Virginia	3.14	3.06	3.00	3.08	3.15
Missouri	3.12	3.04	2.99	3.06	3.13		Wyoming	3.39	3.30	3.24	3.32	3.40
Mississippi	3.05	2.97	2.92	2.99	3.06		U.S. Average	3.12	3.05	2.99	3.07	3.14

Estimating the Biodiesel Volume Under the No RFS Baseline

Because there are state mandates and biodiesel blending subsidies offered by individual states, each state is represented in EPA's analysis. There are two different steps for determining

[110] EIA, "Spot Prices," *Petroleum & Other Liquids*, May 14, 2025. https://www.eia.gov/dnav/pet/pet_pri_spt_s1_a.htm.
[111] We intend to update the base refinery rack price data to include year 2024 price data for the final rule analysis.

the No RFS Baseline. First, the biodiesel volume due to the state mandates are estimated by applying the mandate percentage to the projected diesel fuel consumption of that state.

The second step for estimating the No RFS Baseline involves estimating the biodiesel volume which has a beneficial blending cost based on the equation in Chapter 2.1.3.1. If the biodiesel blending cost is negative, biodiesel is considered economical to blend into diesel and additional nonmandated volumes are assumed to be blended. Conversely, biodiesel is assumed to not be blended into diesel if the biodiesel blending value is positive. Because of its relative cost, biodiesel consumption without the RFS program would be driven mostly by the state mandates but would also occur absent the RFS program due to state subsidies, mainly the California and Oregon LCFS programs.

Using the estimated year-by-year biodiesel volumes estimated or projected by the No RFS Baseline analysis would potentially result in large volumetric swings in some years based on the changing economics of biodiesel in certain states 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 demand in any one historical or future year was not allowed to exceed the demand that occurred under the RFS program. During 2021–2023, the total volume of biodiesel blended into diesel fuel averaged 1,847 million gallons per year. Since we are estimating biodiesel demand by state, we limit the total volume of biodiesel in each state to the volume of biodiesel blended into diesel fuel in that state in 2021, which was the most recent data available at the time this analysis was conducted. Because biodiesel consumption has generally been on a plateau, these percentages are assumed to be the maximum biodiesel percentages in any year through 2030. The volume of biodiesel consumed in each state is estimated by EIA and reported in its State Energy Data System (SEDS).[112] Table 2.1.3.1-6 summarizes the percent of biodiesel in diesel fuel for each state based on the SEDS information.

[112] EIA, "State Energy Data System," 2022, Table C2 – Energy consumption estimates for selected energy sources in physical units. https://www.eia.gov/state/seds/sep_sum/html/pdf/sum_use_tot.pdf.

Table 2.1.3.1-6: Maximum Percent of Biodiesel in Diesel Fuel by State (percent)

Alaska	7.2		Montana	0.0
Alabama	2.8		North Carolina	1.0
Arkansas	13.3		North Dakota	2.9
Arizona	1.4		Nebraska	2.4
California	8.6		New Hampshire	2.4
Colorado	0.8		New Jersey	1.0
Connecticut	2.5		New Mexico	2.0
District of Columbia	3.5		Nevada	1.4
Delaware	0.8		New York	6.4
Florida	1.0		Ohio	2.4
Georgia	0.9		Oklahoma	2.2
Hawaii	0.9		Oregon	9.9
Iowa	6.0		Pennsylvania	2.7
Idaho	0.7		Rhode Island	1.4
Illinois	8.2		South Carolina	1.0
Indiana	2.6		South Dakota	2.3
Kansas	2.0		Tennessee	2.1
Kentucky	2.6		Texas	2.4
Louisiana	2.0		Utah	0.6
Massachusetts	3.0		Virginia	1.1
Maryland	1.2		Vermont	2.8
Maine	2.3		Washington	2.1
Michigan	2.4		Wisconsin	2.5
Minnesota	12.8		West Virginia	1.5
Missouri	2.1		Wyoming	0.8
Mississippi	2.9			

Tables 2.1.3.1-7a and 2.1.3.1-7b list the states expected to consume biodiesel under the No RFS Baseline in the years 2026 to 2030 and summarizes the 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 mix of these vegetable oils being used to produce biodiesel.[113] The mix of biooil feedstocks for producing mandated biodiesel is 50%, 42%, and 8% of soy oil, waste oil, and corn oil, respectively. For cases where our analysis shows biodiesel is economically viable in a state, our analysis determines if biodiesel is economically viable for only one, or more than one feedstock. In a common situation where both corn and waste oil are economically viable, we estimate the proportion of each based on the portion of each used today. For the states that would use biodiesel based on economics, the volume of biodiesel in any state is estimated by multiplying the biodiesel fraction in each state from Table 2.1.3.1-6 by the

[113] 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 free fatty acid content that causes operational problems in their plants. Biodiesel plants also tend to be located more in the Midwest—which is the agricultural center for the production of corn and soy oil—and they may actually have a lower cost and more reliable option to purchase these vegetable oil types that are produced close to their plants.

volume of diesel fuel consumed in that state.[114] The tables list the mandated volume by each state at the top and the volume for states where it is economical to use biodiesel. Only California and Oregon are listed separately since these states have the largest subsidies without a mandate, while the projected volumes for the other states are aggregated together. In the next rows in the tables, the total biodiesel volumes by vegetable oil type and year are totaled.

Table 2.1.3.1-7a: 2026-2028 Biodiesel in No RFS Baseline (million gal/yr)

		2026			2027			2028		
	State	**Soy Oil**	**Corn Oil**	**FOG**	**Soy Oil**	**Corn Oil**	**FOG**	**Soy Oil**	**Corn Oil**	**FOG**
Volume in States with Mandates	Oregon	19	4	15	18	3	15	18	3	15
	New Mexico	18	2	15	17	2	15	17	1	15
	Minnesota	58	12	50	58	12	50	57	11	49
	Washington	11	2	9	11	2	9	11	2	9
	Pennsylvania	17	2	10	16	2	10	17	2	10
	Total	244			242			240		
Economic Volume	California	0	56	240	0	56	240	0	56	240
	Oregon	0	7	31	0	7	31	0	7	31
	Other States	0	7	49	0	6	640	0	36	546
	Total	390			979			916		
Total of Mandated and Economic Volumes		123	92	420	120	90	1,010	120	121	915
Total Volumes by Year		634			1,221			1,156		

Table 2.1.3.1-7b: 2029-2030 Biodiesel in No RFS Baseline (million gal/yr)

		2029			2030		
	State	**Soy Oil**	**Corn Oil**	**FOG**	**Soy Oil**	**Corn Oil**	**FOG**
Volume in States with Mandates	Oregon	18	3	15	18	3	15
	New Mexico	17	2	15	17	1	15
	Minnesota	57	11	49	56	11	48
	Washington	11	2	9	11	2	9
	Pennsylvania	16	2	10	16	2	10
	Total	238			235		
Economic Volume	California	0	56	240	0	56	240
	Oregon	0	3	14	8	2	7
	Other States	0	115	926	0	110	937
	Total	1,354			1,360		
Total of Mandated and Economic Volumes		119	196	1,277	126	188	1280
Total Volumes by Year		1,592			1,594		

The total mandated and economic volume of biodiesel varies by a significant amount over 2026–2030. Such swings in the economic attractiveness of biodiesel would confound efforts on the part of investors to project future returns on their investments to determine whether to invest to expand their plants, continue to operate their plants, or shut down. Thus, to smooth out

[114] Historical diesel sales volumes and projected future diesel volumes were used to project the volume of diesel sold in each state. EIA, "Prime Supplier Sales Volume," *Petroleum & Other Liquids*, June 1, 2022. https://www.eia.gov/dnav/pet/pet_cons_prim_dcu_nus_a.htm. AEO2023, Table 11 – Petroleum and Other Liquids Supply and Disposition.

the swings in the economics for using biodiesel and look at it the way plant operators and their investors would have in the absence of the RFS program, we calculated the average of biodiesel demand for the year of interest and the previous three years. This step attempts to reflect how potential biodiesel investors or banks would seek to assess the economics for operating or investing in expanding biodiesel plant capacity. Thus, to assess the volume of biodiesel which would be economical in 2026, it was necessary to also assess the economics of producing biodiesel in 2023, 2024, and 2025. For this reason, biodiesel economics were assessed historically for 2023–2025, and projected for 2026–2030, to determine the volume of biodiesel which would be economical to blend absent the RFS program. Table 2.1.3.1-8 summarizes the mandated biodiesel volume, the yearly economics biodiesel volume, the 4-year average economic biodiesel volume and finally the total of mandated and 4-year average biodiesel volume.

Table 2.1.3.1-8 Year-by-Year Analysis of Biodiesel Volumes for the No RFS Baseline

Year	State Mandated Biodiesel Volume	Economic Biodiesel Volume	4-Year Average Volume of Economic Biodiesel Volume	Total of State Mandated Biodiesel Volume and 4-Year Volume
2023	254	870	552	806
2024	249	929	641	891
2025	246	359	632	878
2026	245	390	539	784
2027	242	979	567	809
2028	240	916	563	803
2029	238	1354	812	1050
2030	235	1360	812	1048

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).

2.1.3.2 Renewable Diesel

While renewable diesel is produced using 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

The diesel terminal prices (DTP) are the same as that described in Chapter 2.1.3.1 for biodiesel, so the diesel terminal prices will not be discussed further here. However, each of the other variables in the above equation are discussed further. 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 described 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 produced from soybean oil and have the same production costs as that produced domestically.[115] 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 (nominal $/gal)

Feedstock	2026	2027	2028	2029	2030
Soybean Oil	5.20	4.89	4.83	4.75	4.67
Corn Oil	4.50	4.24	4.19	4.12	4.06
Waste Oil	4.20	3.96	3.92	3.86	3.80

Renewable Diesel Distribution Cost (RDDC)

This factor represents the added cost of moving renewable diesel 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, renewable diesel is predominantly produced on the Gulf and West Coasts. Based on the SEDS data, all the renewable diesel is being consumed in PADD 5, mostly in California, but also some in Oregon and Washington. If the renewable diesel is produced on the Gulf Coast, the distribution cost is assumed to be the same as inter-PADD distribution for biodiesel. If the renewable diesel is produced on the West Coast, the vegetable oil feedstock is likely to be virgin oil imported from the Midwest or

[115] EIA, "U.S. biodiesel imports have doubled since 2022 due to low prices in Europe," *Today in Energy*, May 28, 2024. https://www.eia.gov/todayinenergy/detail.php?id=62123.

imported use cooking oil, both of which would be expected to incur an inter-PADD distribution cost. Thus, in all cases we used the biodiesel inter-PADD distribution costs.

ICF estimated the distribution costs for distributing renewable diesel both within and between PADDs, as summarized in Table 2.1.3.2-3.[116] An additional cost is added on to account for the addition of renewable diesel additives, for example to improve renewable diesel flow properties downstream of the production facility—the total cost of these additives is estimated to be 3¢ per gallon. The costs, estimated in 2017 dollars, are adjusted higher to the year dollars being analyzed which is 34% higher in 2026 as shown in the table. Although not shown in the table, the adjustment for 2030 increases the distribution and additive costs by 45%.

Table 2.1.3.2-3: Renewable Diesel Distribution Costs (¢/gal)

	Originally Estimated Costs 2017$			Distribution and Additive Costs Adjusted to 2026$	
PADD	**Within PADD**	**From Outside the PADD**	**Additives Cost**	**Within PADD**	**From Outside the PADD**
PADD 1	7	30	3	13.4	44.1
PADD 2	7	12	3	13.3	20.0
PADD 3	7	15	3	13.4	24.0
PADD 4	7	20	3	13.4	30.7
PADD 5	7	25	3	13.4	37.4

Like for biodiesel, the Inflation Reduction Act provides renewable diesel a production subsidy starting in 2025 based on certain employment wage criteria and the fuel's emissions rate. Since the U.S. Department of Treasury and IRS had not yet published the emissions rate table as we were analyzing the No RFS Baseline, we projected the value of biodiesel subsidies based on conversations with the Department of Treasury and IRS at the time.[117] The estimated value of the renewable diesel production credit by feedstock type is summarized in Table 2.1.3.2-4.

Table 2.1.3.2-4: Estimated Federal Renewable Diesel Subsidies (¢/gal)

Feedstock Type	Renewable Diesel Subsidy
Soy Oil	15
Corn Oil	73
Waste Oil and Fats	62

The California and Oregon Low Carbon Fuel Standards (LCFS) and Washington State's Clean Fuels program do not offer specific subsides per se, but through the cap-and-trade nature

[116] ICF, "Modeling a 'No-RFS' Case," EPA Contract No. EP-C-16-020, July 17, 2018.

[117] Based on our review of the U.S. Department of the Treasury and IRS 45Z guidance released on January 10, 2025, renewable diesel produced from soybean oil, corn oil, and UCO will likely earn a 27¢, 75¢, and 66¢ per gallon subsidy, respectively, which are slightly higher than what we estimated and used in this analysis. See Notice 2025-10, 2025-6 I.R.B. 682 (February 3, 2025) and Notice 2025-11, 2025-6 I.R.B. 704 (February 3, 2025). Thus, the No RFS Baseline may be slightly higher than what we estimated for this proposed rule due to the larger renewable diesel production subsidies. We intend to include these updated renewable diesel production subsidies in the analysis for the final rule.

of their programs, they can be equated to subsidies.[118] For California, Oregon and Washington, we estimated the equivalent per-gallon subsidy amount from the incentives offered by its LCFS program which vary by year.[119] Table 2.1.3.2-6 summarizes the projected LCFS subsidies by year.

Table 2.1.3.2-6: Projected California and Oregon LCFS subsidies ($/gal)

State	Feedstock	2026	2027	2028	2029	2030
California and Oregon	Soy, Canola	0.45	0.43	0.42	0.40	0.38
	Waste Fats and Grease	0.87	0.85	0.83	0.81	0.80
Washington	All Feedstocks	0.24	0.24	0.24	0.24	0.24

Estimating the Renewable Diesel Volume Under the No RFS Baseline

The methodology for analyzing renewable diesel volumes is structured similar to that for biodiesel described in Chapter 2.1.3.1. The state with the lowest renewable diesel blending cost (e.g., states with blending subsidies) would receive renewable diesel first. The percent of renewable diesel in any state's diesel fuel is considered the maximum volume of renewable diesel fuel which could occur under the No RFS Baseline. Because renewable diesel volumes are increasing under the combination of RFS and LCFS programs in California and Oregon, we projected the future volume of renewable diesel assuming recent volumetric growth rates and established those volumes as the maximums without the RFS program in place. An important difference from the analysis for biodiesel, however, is that states are able to displace a much higher percentage of their diesel fuel, potentially up to the quantity of biodiesel in their diesel pool.[120]

Like 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 relatively high 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.

Since renewable diesel is only consumed in several states and nearly all of that in California, we partitioned the maximum renewable diesel demand primarily to California and some to Oregon. While some renewable diesel is currently being sold in Washington State under the federal RFS and State Clean Renewable Fuels programs there, due to the low amount of the state renewable diesel subsidy there as shown in Table 2.1.3.2-6, we did not allocate any of the

[118] New Mexico's CFTS program is scheduled to take effect by July 1, 2026. We will continue to follow the implementation of the CFTS program and include its incentives for future analyses once the program has been fully implemented.

[119] The blending incentives are based on recent carbon credit values reported by each of the states. While it is probable that the state incentive values would increase if the RFS program was not in place, we did not attempt to estimate what the credit price if the RFS program was not in place. California recently approved more stringent LCFS standards that will likely increase the carbon credit value. CARB, Monthly LCFS Credit Transfer Activity Report for March 2024. https://ww2.arb.ca.gov/resources/documents/monthly-lcfs-credit-transfer-activity-reports.

[120] Renewable diesel has properties similar to petroleum diesel and thus can displace petroleum diesel without causing vehicle compatibility or drivability issues.

maximum renewable diesel volume to Washington because the state subsidy was insufficient to cause any demand under the No RFS program. However, we show what the estimated extrapolated renewable diesel volume is for Washington State.[121] The projected maximum renewable diesel volumes are summarized in Table 2.1.3.2-2.

Table 2.1.3.2-2 Maximum Renewable Diesel Volume by State Under the RFS Program

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Volume	582	991	1,360	1,476	1,703	1,931	2,159	2,387	2,615	2,843	3,071
California							2,136	2,362	2,587	2,813	2,992
Oregon							55	61	67	73	79
Washington							74	94	114	134	154

Table 2.1.3.2-3 lists the volume of renewable diesel which is economically favorable for blending into diesel fuel by state for the years 2026–2030. Although several states are economical for renewable diesel, the renewable diesel is essentially only being consumed in California, with small amounts in Oregon and Washington State. For this reason, we show the potential maximum volume of renewable diesel which can be consumed in California and Oregon, 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 average percentage of vegetable oils consumed in the year 2023 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	
2026	California	0	403	1733	2136
	Oregon	0	0	50	50
	Other States	0	7	38	45
2027	California	0	446	1916	2362
	Oregon	0	10	45	55
	Other States	0	8	75	83
2028	California	0	488	2099	2587
	Oregon	0	11	49	60
	Other States	0	9	47	56
2029	California	0	531	2282	2813
	Oregon	0	12	54	66
	Other States	0	10	42	52
2030	California	0	531	2282	2813
	Oregon	0	14	59	72
	Other States	0	13	106	119

[121] The estimated maximum renewable diesel demand is somewhat academic since the total volume of renewable diesel is determined by the volume of available feedstock, as described in Chapter 2.1.3.3.

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
2026	2,003	303	1,700
2027	2,117	321	1,797
2028	2,231	338	1,894
2029	2,345	355	1,990
2030	2,458	373	2,087

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, and limited by the maximum vegetable oil volumes in Table 2.1.3.3-1, are shown in Table 2.1.3.3-2. Based on economics, we used the following hierarchy for estimating the total volume of biomass-based diesel by feedstock type and availability:

1) The state mandates are satisfied first which is met using biodiesel. The mix of vegetable oil types is the same as that consumed under the RFS program in 2023.
2) The biodiesel demand in California and Oregon are the second most economical biomass-based diesel type, but only FOG and corn oil are estimated to be cost-effective.
3) Renewable diesel demand in California and Oregon is the third most cost-effective biomass-based diesel, and once again only FOG and corn oil are estimated to be cost effective.
4) The last cost-effective biomass-based diesel is biodiesel sold outside of California and Oregon.

Since FOG and corn oil vegetable oils are the lowest in cost, the biodiesel and renewable diesel plants are assumed to use this vegetable oil feedstock up to the maximum projected amount.

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

Year	Biodiesel				Renewable Diesel				Total
	Soy	Corn Oil	FOG	Total	Soy	Corn Oil	FOG	Total	Biodiesel and Renewable Diesel
2026	114	87	379	580	0	201	1,225	1,426	2,006
2027	116	66	387	569	0	235	1,299	1,533	2,102
2028	110	85	371	566	0	230	1,381	1,611	2,177
2029	104	88	382	573	0	244	1,475	1,719	2,292
2030	109	86	376	571	0	256	1,543	1,799	2,369

The amount of renewable diesel in the No RFS Baseline is estimated to be higher for this action than the Set 1 Rule due to lower projected vegetable oil feedstocks prices.

2.1.4 Other Advanced Biofuel

In addition to ethanol, cellulosic biofuel, and BBD, we also estimated volumes of other advanced biofuels 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 7.3 and 7.4, we present a derivation of the projected volumes of these other advanced biofuels for 2026–2030 in the context of the Volume Scenarios 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 2018–2021, and the majority did so in 2022 and 2023.[122] 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 2026–2030. 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 7.2, a similar situation exists for advanced renewable diesel. The vast majority of the renewable diesel consumed in the U.S. has been consumed in states with incentives for low carbon fuels such as California and Oregon. 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 CI score 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

[122] EIA, "Fuel Ethanol Imports by Area of Entry," *Petroleum & Other Liquids*, May 30, 2025. https://www.eia.gov/dnav/pet/pet_move_imp_a_epooxe_IM0_mbbl_a.htm.

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 2026–2030.

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 2026–2030 (million RINs)

	2026	2027	2028	2029	2030
Cellulosic Biofuel	582	619	659	702	749
CNG/LNG from biogas	458	496	537	582	630
Ethanol from CKF	124	123	122	120	119
Total Biomass-Based Diesel	3,156	3,310	3,429	3,614	3,753
Biodiesel	884	868	878	889	885
Soybean oil	122	132	119	120	126
FOG	587	591	584	592	583
Corn oil	135	101	134	136	134
Canola oil	0	0	0	0	0
Renewable Diesel	2,267	2,438	2,547	2,719	2,862
Soybean oil	0	0	0	0	0
FOG	1,950	2,065	2,186	2,333	2,455
Corn oil	317	373	360	387	407
Canola oil	0	0	0	0	0
Jet fuel from FOG	5	5	5	5	5
Other Advanced Biofuels	197	197	197	197	197
Renewable diesel from FOG	111	111	111	111	111
Imported sugarcane ethanol	58	58	58	58	58
Domestic ethanol from waste ethanol	28	28	28	28	28
Other[a]	0	0	0	0	0
Conventional Renewable Fuel					
Ethanol from corn	13,571	13,434	13,278	13,099	12,906
Biodiesel and renewable diesel from palm oil	0	0	0	0	0

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

Table 2.1.5-2: No RFS Baseline for 2026–2030 (million gallons)

	2026	2027	2028	2029	2030
Cellulosic Biofuel	582	619	659	702	749
CNG/LNG from biogas	458	496	537	582	630
Ethanol from CKF	124	123	122	120	119
Diesel/jet fuel from wood waste/MSW	0	0	0	0	0
Total Biomass-Based Diesel	2,009	2,105	2,180	2,296	2,382
Biodiesel	589	579	585	593	590
Soybean oil	81	88	80	80	84
FOG	391	394	389	395	388
Corn oil	90	67	89	91	89
Canola oil	27	27	27	27	29
Renewable Diesel	1,417	1,524	1,592	1,700	1,789
Soybean oil	0	0	0	0	0
FOG	1,218	1,290	1,366	1,458	1,535
Corn oil	198	233	225	242	254
Canola oil	0	0	0	0	0
Jet fuel from FOG	3	3	3	3	3
Other Advanced Biofuels	155	155	155	155	155
Renewable diesel from FOG	69	69	69	69	69
Imported sugarcane ethanol	58	58	58	58	58
Domestic ethanol from waste ethanol					
Other[a]					
Conventional Renewable Fuel	13,571	13,434	13,278	13,099	12,906
Ethanol from corn	13,571	13,434	13,278	13,099	12,906
Biodiesel and renewable diesel from palm oil	0	0	0	0	

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

2.2 2025 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 Volume Scenarios, we have also estimated some of the impacts (e.g., costs) of this rule relative to the renewable fuel volumes we projected would be used to meet the 2025 volume requirements finalized in the Set1 Rule as an additional informational case. This allows for an estimate of the incremental impacts of the proposed renewable fuel volumes compared to those previously finalized.[123]

For this proposal, we used the projected the mix from the Set 1 Rule of the biofuels that would be used to meet the 2025 volume requirements.[124] These volumes are shown in Table 2.2-1 (in million RINs) and Table 2.2-2 (in million gallons).

[123] These are not necessarily the volumes that we might expect to occur in 2025 based on information available today. Such a baseline may also be relevant when assessing some of the impacts of the proposed volumes for 2026 and 2027.

[124] Set 1 Rule RIA, Table 3.1-3.

Table 2.2-1: Set 1 Rule Projected Mix of Biofuels in 2025 (million RINs)

Cellulosic Biofuel	1,376
CNG/LNG from biogas	1,299
Ethanol from CKF	77
Diesel/jet fuel from wood waste/MSW	0
Total Biomass-Based Diesel	6,881
Biodiesel	2,436
Soybean oil	1,430
FOG	427
Corn oil	95
Canola oil	484
Renewable Diesel	4,421
Soybean oil	1,501
FOG	1,962
Corn oil	463
Canola oil	495
Jet fuel from FOG	24
Other Advanced Biofuels	290
Renewable diesel from FOG	104
Imported sugarcane ethanol	95
Domestic ethanol from waste ethanol	27
Other[a]	64
Conventional Renewable Fuel	13,779
Ethanol from corn	13,779
Renewable diesel from palm oil	0

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

Table 2.2-2: Set 1 Rule Projected Mix of Biofuels in 2025 (million gallons)

Cellulosic Biofuel	1,376
CNG/LNG from biogas	1,299
Ethanol from CKF	77
Diesel/jet fuel from wood waste/MSW	0
Total Biomass-Based Diesel	4,239
Biodiesel	1,624
Soybean oil	953
FOG	285
Corn oil	62
Canola oil	323
Renewable Diesel	2,601
Soybean oil	883
FOG	1,154
Corn oil	272
Canola oil	291
Jet fuel from FOG	14
Other Advanced Biofuels	232
Renewable diesel from FOG	61
Imported sugarcane ethanol	95
Domestic ethanol from waste ethanol	27
Other[a]	49
Conventional Renewable Fuel	13,779
Ethanol from corn	13,779
Renewable diesel from palm oil	0

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

The renewable fuel volumes in Tables 2.2-1 and 2.2-2 represent the volumes of renewable fuel EPA projected would be supplied to meet the volume requirements for 2025 in the Set 1 Rule. Since publishing the Set 1 Rule, EPA has continued to monitor available data on renewable fuel production and use in the U.S. While many of the projections made in the Set 1 Rule appear to be reasonably accurate, more recent data suggests other projected volumes are likely to over-project or under-project the quantity of renewable fuel supplied in 2025. Specifically, recent data suggests that greater quantities of biodiesel and renewable diesel will be supplied and lower volumes of CNG/LNG derived from biogas will be supplied in 2025 relative to the projections in the 2025 rule. In some cases, it may be informative to consider the impacts of this proposed rule relative to our updated renewable fuel supply projections for 2025. These updated projections are shown in Tables 2.2-3 and 2.2-4. Note that the only volumes that have been updated in these tables (relative to Tables 2.2-1 and 2.2-2) are the projected volumes of biomass-based diesel (including the volumes of biodiesel and renewable diesel from all feedstocks) and the volume of CNG/LNG from biogas. For more detail on how these updated projections were calculated see Chapter 7.2.2 (for BBD) and 7.1.3 (for CNG/LNG from biogas).

Table 2.2-3: Updated Projection of Biofuels Supply for 2025 (million RINs)

Cellulosic Biofuel	1,190
CNG/LNG from biogas	1,113
Ethanol from CKF	77
Diesel/jet fuel from wood waste/MSW	0
Total Biomass-Based Diesel	8,181
Biodiesel	3,150
Soybean oil	1,915
FOG	514
Corn oil	186
Canola oil	535
Renewable Diesel	5,008
Soybean oil	1,120
FOG	3,203
Corn oil	466
Canola oil	219
Jet fuel from FOG	24
Other Advanced Biofuels	290
Renewable diesel from FOG	104
Imported sugarcane ethanol	95
Domestic ethanol from waste ethanol	27
Other[a]	64
Conventional Renewable Fuel	13,939
Ethanol from corn	13,939
Renewable diesel from palm oil	0

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

Table 2.2-4: Updated Projection of Biofuels Supply for 2025 (million gallons)

Cellulosic Biofuel	1,190
CNG/LNG from biogas	1,113
Ethanol from CKF	77
Diesel/jet fuel from wood waste/MSW	0
Total Biomass-Based Diesel	5,060
Biodiesel	2,100
Soybean oil	1,277
FOG	343
Corn oil	124
Canola oil	357
Renewable Diesel	2,946
Soybean oil	659
FOG	1,884
Corn oil	274
Canola oil	129
Jet fuel from FOG	14
Other Advanced Biofuels	232
Renewable diesel from FOG	65
Imported sugarcane ethanol	95
Domestic ethanol from waste ethanol	27
Other[a]	45
Conventional Renewable Fuel	13,939
Ethanol from corn	13,939
Renewable diesel from palm oil	0

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

Chapter 3: Volume Scenarios, Proposed Volumes, and Volume Changes

For analyses in which we have quantified the impacts of the volume scenarios for 2026–2030 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 volume scenarios, we believe that the mix of biofuel types described in this chapter are reasonable projections based on historical data and current market trends 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 volume scenarios. This chapter identifies the mix of biofuels that could result from the volume scenarios and the change in volumes in comparison to the No RFS and 2025 Baselines. More information on the methodologies used to determine these volumes can be found in Chapter 7.

3.1 Mix of Renewable Fuel Types for Volume Scenarios

The volume scenarios that we developed for 2026–2030 are presented in Preamble Section III.C.5 and are repeated in Tables 3.1-1 and 2 by the component fuel types and in Tables 3.1-3 and 4 by the statutory and implied categories.

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

	D Code[a]	2026	2027	2028	2029	2030
Cellulosic biofuel	D3 + D7	1,298	1,362	1,431	1,504	1,583
Biomass-based diesel	D4	8,410	8,910	9,410	9,910	10,410
Other advanced biofuel	D5	249	249	249	249	249
Conventional renewable fuel	D6	13,783	13,662	13,516	13,352	13,172

[a] 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: High Volume Scenarios Components (million RINs)[a]

	D Code[a]	2026	2027	2028	2029	2030
Cellulosic biofuel	D3 + D7	1,298	1,362	1,431	1,504	1,583
Biomass-based diesel	D4	8,910	9,910	10,910	11,910	12,910
Other advanced biofuel	D5	249	249	249	249	249
Conventional renewable fuel	D6	13,783	13,662	13,516	13,352	13,172

[a] 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 3.1-3: Low Volume Scenario in Statutory and Implied Categories (million RINs)[a]

	D Code	2026	2027	2028	2029	2030
Cellulosic biofuel	D3 + D7	1,298	1,362	1,431	1,504	1,583
Non-cellulosic advanced biofuel[a]	D4 + D5	8,659	9,159	9,659	10,159	10,659
Advanced biofuel	D3 + D4 + D5 + D7	9,957	10,521	11,090	11,664	12,242
Conventional renewable fuel[a]	D6	13,783	13,662	13,516	13,352	13,172
Total renewable fuel	All	23,740	24,183	24,606	25,015	25,414

[a] These are implied volume requirements, not regulatory volume requirements.

Table 3.1-4: High Volume Scenario in Statutory and Implied Categories (million RINs)[a]

	D Code	2026	2027	2028	2029	2030
Cellulosic biofuel	D3 + D7	1,298	1,362	1,431	1,504	1,583
Non-cellulosic advanced biofuel[a]	D4 + D5	9,159	10,159	11,159	12,159	13,159
Advanced biofuel	D3 + D4 + D5 + D7	10,457	11,521	12,590	13,664	14,742
Conventional renewable fuel[a]	D6	13,783	13,662	13,516	13,352	13,172
Total renewable fuel	All	24,240	25,183	26,106	27,015	27,914

[a] 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 volume scenarios as shown in Tables 3.1-5 (in million RINs) and 3.1-6 (in million gallons).[125]

[125] The analyses leading to the mix of renewable fuel types and feedstocks are presented in Chapter 7.

Table 3.1-5: Low Volume Scenario Biofuel Supply for 2026–2030 (million RINs)

	2026	2027	2028	2029	2030
Cellulosic Biofuel	1,298	1,362	1,431	1,504	1,583
CNG/LNG from biogas	1,174	1,239	1,309	1,384	1,464
Ethanol from CKF	124	123	122	120	119
Total Biomass-Based Diesel[a]	8,410	8,910	9,410	9,910	10,410
Biodiesel	3,150	3,150	3,150	3,150	3,150
Soybean oil	1,915	1,915	1,915	1,915	1,915
FOG	514	514	514	514	514
Corn oil	186	186	186	186	186
Canola oil	535	535	535	535	535
Renewable Diesel	5,261	5,761	6,261	6,761	7,261
Soybean oil	1,124	1,184	1,244	1,304	1,364
FOG	3,485	3,925	4,365	4,805	5,245
Corn oil	443	443	443	443	443
Canola oil	208	208	208	208	208
Other Advanced Biofuels	249	249	249	249	249
Renewable diesel from FOG	111	111	111	111	111
Sugarcane ethanol	58	58	58	58	58
Domestic ethanol from waste ethanol	28	28	28	28	28
Other[b]	52	52	52	52	52
Conventional Renewable Fuel	13,783	13,662	13,516	13,352	13,172
Ethanol from corn	13,783	13,662	13,516	13,352	13,172

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

Table 3.1-6: High Volume Scenario Biofuel Supply for 2026–2030 (million RINs)

	2026	2027	2028	2029	2030
Cellulosic Biofuel	1,298	1,362	1,431	1,504	1,583
CNG/LNG from biogas	1,174	1,239	1,309	1,384	1,464
Ethanol from CKF	124	123	122	120	119
Total Biomass-Based Diesel[a]	8,910	9,910	10,910	11,910	12,910
Biodiesel	3,150	3,150	3,150	3,150	3,150
Soybean oil	1,915	1,915	1,915	1,915	1,915
FOG	514	514	514	514	514
Corn oil	186	186	186	186	186
Canola oil	535	535	535	535	535
Renewable Diesel	5,761	6,761	7,761	8,761	9,761
Soybean oil	1,464	1,864	2,264	2,664	3,064
FOG	3,485	3,925	4,365	4,805	5,245
Corn oil	443	443	443	443	443
Canola oil	368	528	688	848	1,008
Other Advanced Biofuels	249	249	249	249	249
Renewable diesel from FOG	111	111	111	111	111
Sugarcane ethanol	58	58	58	58	58
Domestic ethanol from waste ethanol	28	28	28	28	28
Other[b]	52	52	52	52	52
Conventional Renewable Fuel	13,783	13,662	13,516	13,352	13,172
Ethanol from corn	13,783	13,662	13,516	13,352	13,172

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

Table 3.1-7: Low Volume Scenario Biofuel Supply for 2026–2030 (million gallons)

	2026	2027	2028	2029	2030
Cellulosic Biofuel	1,298	1,362	1,431	1,504	1,583
CNG/LNG from biogas	1,174	1,239	1,309	1,384	1,464
Ethanol from CKF	124	123	122	120	119
Total Biomass-Based Diesel[a]	5,388	5,700	6,013	6,325	6,638
Biodiesel	2,100	2,100	2,100	2,100	2,100
Soybean oil	1,277	1,277	1,277	1,277	1,277
FOG	342	342	342	342	342
Corn oil	124	124	124	124	124
Canola oil	357	357	357	357	357
Renewable Diesel	3,288	3,600	3,913	4,255	4,538
Soybean oil	703	740	778	815	853
FOG	2,178	2,453	2,728	3,003	3,278
Corn oil	277	277	277	277	277
Canola oil	130	130	130	130	130
Other Advanced Biofuels	192	192	192	192	192
Renewable diesel from FOG	69	69	69	69	69
Sugarcane ethanol	58	58	58	58	58
Domestic ethanol from waste ethanol	28	28	28	28	28
Other[b]	37	37	37	37	37
Conventional Renewable Fuel	13,783	13,662	13,516	13,352	13,172
Ethanol from corn	13,783	13,662	13,516	13,352	13,172

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

Table 3.1-8: High Volume Scenario Biofuel Supply for 2026–2030 (million gallons)

	2026	2027	2028	2029	2030
Cellulosic Biofuel	1,298	1,362	1,431	1,504	1,583
CNG/LNG from biogas	1,174	1,239	1,309	1,384	1,464
Ethanol from CKF	124	123	122	120	119
Total Biomass-Based Diesel[a]	5,700	6,325	6,950	7,575	8,200
Biodiesel	2,100	2,100	2,100	2,100	2,100
Soybean oil	1,277	1,277	1,277	1,277	1,277
FOG	342	342	342	342	342
Corn oil	124	124	124	124	124
Canola oil	357	357	357	357	357
Renewable Diesel	3,600	4,255	4,850	5,475	6,100
Soybean oil	915	1,165	1,415	1,665	1,915
FOG	2,178	2,453	2,728	3,003	3,278
Corn oil	277	277	277	277	277
Canola oil	230	330	430	530	630
Other Advanced Biofuels	192	192	192	192	192
Renewable diesel from FOG	69	69	69	69	69
Sugarcane ethanol	58	58	58	58	58
Domestic ethanol from waste ethanol	28	28	28	28	28
Other[b]	37	37	37	37	37
Conventional Renewable Fuel	13,783	13,662	13,516	13,352	13,172
Ethanol from corn	13,783	13,662	13,516	13,352	13,172

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

3.2 Mix of Renewable Fuel Types for the Proposed Volumes

To assess the projected impacts of this proposed rule we also identified the specific biofuel types and associated feedstocks that are projected to be used to meet the proposed volume requirements for 2026 and 2027 (the "Proposed Volumes"). As with the Volume Scenarios, we acknowledge that there is significant uncertainty about the types of renewable fuels that would be used to meet the Proposed Volumes. We believe that the mix of biofuel types described in this chapter are reasonable projections based on historical data, current market trends, and our projections of the potential supply in 2026 and 2027.

For three of the component volume categories (cellulosic biofuel, other advanced biofuel, and conventional renewable fuel), the Proposed Volumes are identical those in both the Low and High Volume Scenarios discussed in Chapter 3.1. The volumes of cellulosic biofuel and conventional renewable fuel are expected to be limited by the quantity of these fuels (RNG and ethanol) that will be used as transportation fuel in 2026 and 2027. Our projection of the volume of other advanced biofuel is based on the supply of these fuels observed in throughout the history of the RFS program.

Unlike the other three component categories of renewable fuel, the number of BBD RINs we expected to be supplied to meet the Proposed Volumes differs from both the Low and High Volume Scenarios. The projected supply of BBD to meet the Proposed Volumes is based on an updated projection of the supply of BBD in 2025[126] and a projected annual growth rate of 500 million RINs per year. Tables 3.2-1 and 3.2-2 show the supply of renewable fuels projected to be used to meet the Proposed Volumes, listed by the component volume categories and statutory and implied categories respectively.

Table 3.2-1: Proposed Volumes Components (million RINs)[a]

	D Code[a]	2026	2027
Cellulosic biofuel	D3 + D7	1,298	1,362
Biomass-based diesel	D4	8,690	9,190
Other advanced biofuel	D5	249	249
Conventional renewable fuel	D6	13,783	13,662

[a] 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 3.2-2: Proposed Volumes in Statutory and Implied Categories (million RINs)[a]

	D Code	2026	2027
Cellulosic biofuel	D3 + D7	1,298	1,362
Non-cellulosic advanced biofuel[a]	D4 + D5	8,939	9,439
Advanced biofuel	D3 + D4 + D5 + D7	10,237	10,801
Conventional renewable fuel[a]	D6	13,783	13,662
Total renewable fuel	All	24,020	24,463

[a] These are implied volume requirements, not regulatory volume requirements.

As with the volume scenarios, we next estimated the constituent mix of renewable fuel types and feedstocks that could be used to meet the volume scenarios.[127] Consistent with the previous tables, the projected volumes for cellulosic biofuel, other advanced biofuel, and conventional renewable fuel are identical to the projected volumes for both the Low and High Volume Scenarios.

The BBD volumes projected to be used to meet the Proposed Volumes, however, are significantly different than either the Low or High Volume Scenario. There are two reasons for these differences. The first reason is that while both the Low and High Volume Scenarios and the Proposed Volumes increase volumes in future years from the projected supply in 2025, we used different data set to project the supply of BBD in 2025. For the Low and High Volume Scenarios we projected the BBD supply in 2024 and 2025 using data through May 2024, the most recent data available when the volume scenarios were developed. For the Proposed Volumes, we used data through the end of 2024 to project the BBD supply for 2025. While the total volume of BBD projected to be supplied in 2025 is very similar in both cases (8.16 billion RINs using data

[126] We based our updated projection of the BBD supply in 2025 on the actual volume of BBD supplied in 2024. Due to the significant uncertainty in the BBD market for 2025, we believe the actual supply of BBD in 2024 is the best projection available for the supply of BBD in 2025. We anticipate updating our projection of the BBD supply in 2025 based on the most recent available data for the final rule.
[127] The analyses leading to the mix of renewable fuel types and feedstocks are presented in Chapter 7.

through May 2024 vs. 8.19 billion RINs using data through the end of 2024), the mix of biofuels and feedstocks used to produce these biofuels differ between the two projections.

The more significant difference between the Volume Scenarios and the Proposed Volumes is that unlike the Volume Scenarios, the Proposed Volumes include our proposal to reduce the number of RINs generated for imported biofuels and biofuels produced from imported feedstocks starting in 2026. As discussed further in this section, we project that even with the increased incentive to use renewable fuel produced domestically from domestic feedstocks provided by the reduction of RINs for imported renewable fuel and renewable fuel produced from foreign feedstocks, some quantity of imported renewable fuel and renewable fuel produced from foreign feedstocks will still be used to meet the Proposed Volumes for 2026 and 2027. Because these imported renewable fuels and renewable fuels produced from imported feedstocks would generate fewer RINs per gallon, we project that the total volume of renewable fuel needed to meet the Proposed Volumes would be higher than the volumes estimated in both the Low and High Volume Scenarios.

To project the supply of BBD that could be used to meet the Proposed Volumes, we started by estimating the portion of the BBD supplied in 2024 that was imported versus produced in the U.S. This data is summarized in Table 3.2-3.

Table 3.2-3: Supply of Domestic vs. Imported BBD in 2024 (million RINs)

Biofuel	Supply
Domestic BBD (Total)	7,723
Domestic Biodiesel	2,494
Domestic Renewable Diesel[a]	5,229
Imported BBD (Total)	1,445
Imported Biodiesel	597
Imported Renewable Diesel[a]	848
Domestic and Imported BBD	9,168
Exported BBD (Total)	980
Net BBD Supply	8,188

[a] Includes renewable jet fuel.
Source: EMTS.

Next, we estimated what proportion of the domestic BBD was produced from domestic feedstocks compared to imported feedstocks. EPA currently does not collect data on the point of origin of feedstocks used to produce renewable fuels in the RFS program. In the absence of data directly from the BBD producers we used alternative data sources to estimate the origin used for BBD production. In 2024, there were four primary feedstocks used by domestic BBD producers: soybean oil, canola oil, distillers corn oil, and waste fats, oils, and greases (FOG).[128] According to data from USDA, imports of soybean oil and corn oil represent a very small portion of the U.S. supply of these feedstocks. For the 2023/24 agricultural marketing year, USDA forecasted that less than 2% of the U.S. supply of soybean oil would be imported and less than 4% of the

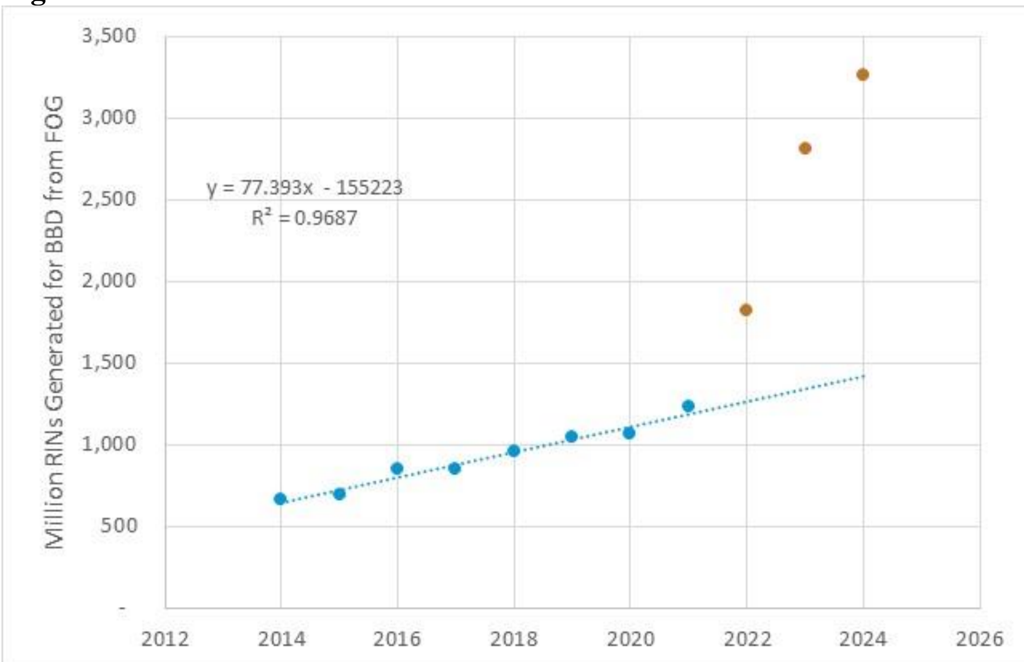
[128] In addition to these feedstocks, there were smaller volumes of BBD produced from comingled distillers corn oil and sorghum oil (which we have included in the total for distillers corn oil) and camelina (which we have included in the total for soybean oil).

U.S. supply of corn oil would be imported.[129] We therefore projected that all of the domestic BBD produced from soybean oil and corn oil was sourced from domestic feedstocks in 2024. We note, however, that while we do not project that any of the domestic biodiesel and renewable diesel was produced from imported soybean oil, EMTS data indicates that some of the imported biodiesel and renewable diesel produced in other countries was produced from soybean oil. Conversely, the majority of the canola oil supplied to the U.S. (about 70%) in the 2023/24 agricultural marketing year was projected to be imported. Based on this information, we project that in 2024, all the canola oil used to produce BBD in the U.S. was imported.

Projecting the total of FOG that is used by domestic BBD producers is more complex, as domestic BBD producers rely on significant quantities of domestic and imported FOG. To project the quantity of FOG used for BBD production in 2024 sourced domestically (as well as the potential for growth in the domestic supply of FOG) we considered the historic data on the use of FOG for domestic biofuel production (see Figure 3.2-1). From 2014–2020 the number of RINs generated for BBD produced from FOG increased steadily, at a rate of approximately 80 million RINs per year. The number of RINs generated for BBD produced from FOG increased dramatically in 2022–2024, when the U.S. began importing significant quantities of used cooking oil and animal fats. Based on the observed trend in the increase of RINs generated for BBD produced from FOG from 2014–2020, which we estimate contained little to no imported FOG, we project that approximately 1.42 billion RINs were generated for BBD produced from domestically sourced FOG in 2024, or about 43% of the total number of RINs generated for BBD produced from FOG. Absent any other data sources, we estimated that 43% of the domestic biodiesel and renewable diesel produced from FOG used domestic feedstocks, while the remaining 57% was produced from imported feedstocks. Our total estimates of the production of BBD by fuel type and feedstock in 2024 are shown in Table 3.2-4.

[129] USDA, "Oil Crops Yearbook," March 2025. https://www.ers.usda.gov/data-products/oil-crops-yearbook.

Figure 3.2-1: RINs Generated for BBD Produced from FOG



Source: EMTS.

Table 3.2-4: BBD Production by Fuel and Feedstock in 2024 (billion gallons)

Biofuel	Volume Produced
BBD (Total)	**5.76**
Biodiesel (Total)[a]	**2.15**
Domestic FOG	0.15
Domestic Soybean Oil[c]	1.00
Domestic Canola Oil	0.00
Domestic Distillers Corn Oil	0.20
Imported FOG	0.22
Imported Soybean Oil	0.26
Imported Canola Oil	0.32
Imported Distillers Corn Oil	0.00
Renewable Diesel (Total)[b]	**3.61**
Domestic FOG	0.70
Domestic Soybean Oil[c]	0.69
Domestic Canola Oil	0.00
Domestic Distillers Corn Oil	0.40
Imported FOG	1.33
Imported Soybean Oil	0.10
Imported Canola Oil	0.39
Imported Distillers Corn Oil	0.00

[a] Includes heating oil.
[b] Includes renewable jet fuel.
[c] Includes camelina oil.
Source: EMTS. Imported categories include both imported biofuels and biofuels produced in the U.S. from imported feedstocks.

After estimating the supply of BBD in 2024 by fuel type and feedstock, we next projected which feedstocks would likely increase through 2027 for the Proposed Volumes. In making these projections we first considered potential growth in the supply of domestic feedstocks, as domestic biofuels produced from these feedstocks would generate twice the number of RINs as those from imported feedstocks under our proposal to reduce the number of RINs generated for imported biofuels and biofuels produced from imported feedstocks.

Our assessment of the potential for growth in the supply of BBD feedstocks is presented in Chapter 7.2.4. In this Chapter we projected annual increases in the supply of domestic soybean oil at 250 million gallons per year and domestic FOG of 25 million gallons per year, with no projected growth in domestic distillers corn oil or canola oil. In all cases, we acknowledged the uncertainty in these projections and generally presented a range of estimates of future growth from public sources. For the Proposed Volumes, we are generally projecting annual growth rates that are consistent with those presented in Chapter 7.2.4 (250 million gallons per year of domestic soybean oil and no growth for domestic distillers corn oil and canola oil). The one exception is slightly higher projected growth rate for domestic FOG (50 million gallons per year in the Proposed Volumes based on the historic data from 2014-2020 presented in Figure 3.2-1 vs. 25 million gallons per year in the High and Low Volume Scenarios based on the data presented in Chapter 7.2.4).

The other significant difference in the Proposed Volumes are shifts in the use of domestic canola oil and domestic corn oil from non-biofuel markets to biofuel markets in 2026. These shifts are based on our projection that the potential to generate a higher number of RINs per gallon for domestic feedstocks will incentivize BBD producers to pay higher prices for these domestic vegetable oils than their current markets. As we are not projecting that the domestic production of these feedstocks grows significantly in future years these feedstock increases represent a one-time shift, which we project will occur in 2026, rather than ongoing annual increases. We are not projecting that the use of these feedstocks in non-biofuel markets will cease, but rather that the domestic feedstocks will be preferentially used by BBD producers and that other markets will turn to imported canola oil and/or corn oil to satisfy their market demand, or alternatively will switch to other vegetable oils in greater supply or reduce their use of vegetable oils. We are not projecting a similar shift in soybean oil from non-biofuel uses to BBD production. This is both because the use of soybean oil in non-biofuel markets has been very stable over the past decade, suggesting that shifting soybean oil from non-biofuel markets may prove difficult, and also because there is currently a tariff on imported soybean oil which increases the cost of replacing domestic soybean oil with imported soybean oil in all markets. Over time, we may see a shift of domestic soybean oil from non-biofuel markets to biofuel production and a simultaneous increase in the imports of other vegetable oils for non-biofuel markets, but we expect these market shifts will take time and will not significantly impact the availability of domestic soybean oil to renewable fuel producers through 2027. We acknowledge that there is significant fungibility between different types of vegetable oils and that in reality we may see slightly lower shifts in the quantity of canola oil and corn oil used for BBD production and slightly higher shifts in the quantity of soybean oil used for BBD production. Nevertheless, we believe the total volume of domestic vegetable oils projected to shift from non-biofuel markets to BBD production in the Proposed Volumes is reasonable.

After accounting for these changes in the supply of BBD produced from domestic feedstocks, along with the other changes we are proposing in this rule such as the reduction of RINs generated for imported renewable fuels and renewable fuels produced from foreign feedstocks, the total supply of BBD is very slightly higher than needed in 2026. To balance the projected supply of BBD and the Proposed Volumes, we reduced the projected volume of imported biodiesel produced from soybean oil slightly to balance the projected supply and demand of BBD. We selected imported biodiesel produced from soybean oil for this reduction as we project this biofuel would generally be eligible for the lowest quantity of incentives under the various state and federal incentive programs (California's LCFS program, the RFS program, etc.).

The projected supply of BBD in the Proposed Volumes, broken out by domestic versus imported sources, fuel type, and feedstock, are presented in Tables 3.2-5 (in million RINs) and 3.2-6 (in million gallons). Note that Table 3.2-5 takes into account the proposal to reduce the number of RINs generated for imported renewable fuels and renewable fuels produced from imported feedstocks and the proposed reduction in the number of RINs generated for renewable diesel to 1.6 RINs per gallon. Tables 3.2-7 and 3.2-8 show the supply of all the renewable fuels, broken out by fuel type and feedstock, that we project would be supplied to meet the Proposed Volumes.

Table 3.2-5: Proposed Volumes BBD Supply (million RINs)

Biofuel	2026	2027
BBD (Total)	**8,690**	**9,190**
Biodiesel (Total)[a]	**2,599**	**2,621**
Domestic FOG	220	220
Domestic Soybean Oil[c]	1,494	1,494
Domestic Canola Oil	0	0
Domestic Distillers Corn Oil	310	310
Imported FOG	165	165
Imported Soybean Oil	168	190
Imported Canola Oil	241	241
Imported Distillers Corn Oil	1	1
Renewable Diesel (Total)[b]	**6,090**	**6,570**
Domestic FOG	1,278	1,358
Domestic Soybean Oil[c]	1,909	2,309
Domestic Canola Oil	370	370
Domestic Distillers Corn Oil	1,085	1,085
Imported FOG	1,056	1,056
Imported Soybean Oil	81	81
Imported Canola Oil	308	308
Imported Distillers Corn Oil	3	3

[a] Includes heating oil.
[b] Includes renewable jet fuel.
[c] Includes camelina oil.

Table 3.2-6: Proposed Volumes BBD Supply (Million Gallons)

Biofuel	2026	2027
BBD (Total)	**6,826**	**7,155**
Biodiesel (Total)[a]	**2,116**	**2,145**
Domestic FOG	146	146
Domestic Soybean Oil[c]	996	996
Domestic Canola Oil	0	0
Domestic Distillers Corn Oil	207	207
Imported FOG	220	220
Imported Soybean Oil	224	253
Imported Canola Oil	322	322
Imported Distillers Corn Oil	1	1
Renewable Diesel (Total)[b]	**4,711**	**5,011**
Domestic FOG	799	849
Domestic Soybean Oil[c]	1,193	1,443
Domestic Canola Oil	231	231
Domestic Distillers Corn Oil	678	678
Imported FOG	1,320	1,320
Imported Soybean Oil	101	101
Imported Canola Oil	385	385
Imported Distillers Corn Oil	3	3

[a] Includes heating oil.
[b] Includes renewable jet fuel.
[c] Includes camelina oil.

Table 3.2-7: Proposed Volumes Biofuel Supply (million RINs)

Biofuel	2026	2027
Cellulosic Biofuel	1,298	1,362
CNG/LNG from biogas	1,174	1,239
Ethanol from CKF	124	123
Total Biomass-Based Diesel[a]	8,690	9,190
Biodiesel	2,600	2,620
Soybean oil	1,664	1,684
FOG	384	384
Corn oil	311	311
Canola oil	241	241
Renewable Diesel	6,090	6,570
Soybean oil	1,990	2,390
FOG	2,335	2,415
Corn oil	1,087	1,087
Canola oil	678	678
Other Advanced Biofuels	249	249
Renewable diesel from FOG	111	111
Sugarcane ethanol	58	58
Domestic ethanol from waste ethanol	28	28
Other[b]	52	52
Conventional Renewable Fuel	13,783	13,662
Ethanol from corn	13,783	13,662

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

Table 3.2-8: Proposed Volumes Biofuel Supply (million gallons)

Biofuel	2026	2027
Cellulosic Biofuel	1,298	1,362
CNG/LNG from biogas	1,174	1,239
Ethanol from CKF	124	123
Total Biomass-Based Diesel[a]	6,826	7,155
Biodiesel	2,116	2,145
Soybean oil	1,220	1,249
FOG	366	366
Corn oil	208	208
Canola oil	322	322
Renewable Diesel	4,710	5,010
Soybean oil	1,294	1,544
FOG	2,119	2,169
Corn oil	681	681
Canola oil	616	616
Other Advanced Biofuels	192	192
Renewable diesel from FOG	69	69
Sugarcane ethanol	58	58
Domestic ethanol from waste ethanol	28	28
Other[b]	37	37
Conventional Renewable Fuel	13,783	13,662
Ethanol from corn	13,783	13,662

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

3.3 Volume Changes Analyzed with Respect to the No RFS Baseline

For those factors for which we quantified the impacts of the volume scenarios for 2026–2030, the impacts were based on the difference in the volumes of specific renewable fuel types between the Volume Scenarios and the No RFS Baseline. These differences are shown in Tables 3.3-1, 2, and 5 in terms of RINs and in Tables 3.3-3, 4, and 6 in physical volumes. The values in these tables reflect the difference between values of: (1) The tables containing the Low and High Volume Scenarios (Tables 3.1-5 through 8) and Proposed Volumes (Tables 3.2-7 and 8), and (2) The tables containing the No RFS Baseline volumes (Tables 2.1.5-1 and 2).

Table 3.3-1: Volume Changes for the Low Volume Scenario Relative to the No RFS Baseline (million RINs)

	2026	2027	2028	2029	2030
Cellulosic Biofuel	716	743	772	802	834
CNG/LNG from biogas	716	743	772	802	834
Ethanol from CKF	0	0	0	0	0
Total Biomass-Based Diesel	5,255	5,600	5,981	6,297	6,658
Biodiesel	2,266	2,282	2,272	2,260	2,264
Soybean oil	1,793	1,783	1,796	1,795	1,789
FOG	-73	-77	-70	-79	-69
Corn oil	52	85	52	50	52
Canola oil	535	535	535	535	535
Renewable Diesel	2,994	3,323	3,714	4,041	4,399
Soybean oil	1,124	1,184	1,244	1,304	1,364
FOG	1,536	1,861	2,179	2,473	2,790
Corn oil	126	70	83	56	36
Canola oil	208	208	208	208	208
Jet fuel from FOG	-5	-5	-5	-5	-5
Other Advanced Biofuels	52	52	52	52	52
Renewable diesel from FOG	0	0	0	0	0
Sugarcane ethanol	0	0	0	0	0
Domestic ethanol from waste ethanol	0	0	0	0	0
Other[a]	52	52	52	52	52
Conventional Renewable Fuel	212	228	238	252	266
Ethanol from corn	212	228	238	252	266

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

Table 3.3-2: Volume Changes for the High Volume Scenario Relative to the No RFS Baseline (million RINs)

	2026	2027	2028	2029	2030
Cellulosic Biofuel	716	743	772	802	834
CNG/LNG from biogas	716	743	772	802	834
Ethanol from CKF	0	0	0	0	0
Total Biomass-Based Diesel	5,755	6,600	7,481	8,297	9,158
Biodiesel	2,266	2,282	2,272	2,260	2,264
Soybean oil	1,793	1,783	1,796	1,795	1,789
FOG	-73	-77	-70	-79	-69
Corn oil	52	85	52	50	52
Canola oil	535	535	535	535	535
Renewable Diesel	3,494	4,323	5,214	6,041	6,899
Soybean oil	1,464	1,864	2,264	2,664	3,064
FOG	1,536	1,861	2,179	2,473	2,790
Corn oil	126	70	83	56	36
Canola oil	368	528	688	848	1,008
Jet fuel from FOG	-5	-5	-5	-5	-5
Other Advanced Biofuels	52	52	52	52	52
Renewable diesel from FOG	0	0	0	0	0
Sugarcane ethanol	0	0	0	0	0
Domestic ethanol from waste ethanol	0	0	0	0	0
Other[a]	52	52	52	52	52
Conventional Renewable Fuel	212	228	238	252	266
Ethanol from corn	212	228	238	252	266

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

Table 3.3-3: Volume Changes for the Low Volume Scenario Relative to the No RFS Baseline (million gallons)

	2026	2027	2028	2029	2030
Cellulosic Biofuel	716	743	772	802	834
CNG/LNG from biogas	716	743	772	802	834
Ethanol from CKF	0	0	0	0	0
Total Biomass-Based Diesel	3,379	3,595	3,833	4,030	4,255
Biodiesel	1,511	1,521	1,515	1,507	1,509
Soybean oil	1,196	1,189	1,197	1,196	1,192
FOG	-49	-51	-47	-53	-46
Corn oil	34	57	35	33	35
Canola oil	319	327	330	329	328
Renewable Diesel	1,871	2,077	2,321	2,526	2,749
Soybean oil	703	740	778	815	853
FOG	960	1,163	1,362	1,545	1,744
Corn oil	79	44	52	35	22
Canola oil	130	130	130	130	130
Jet fuel from FOG	-3	-3	-3	-3	-3
Other Advanced Biofuels	37	37	37	37	37
Renewable diesel from FOG	0	0	0	0	0
Sugarcane ethanol	0	0	0	0	0
Domestic ethanol from waste ethanol	0	0	0	0	0
Other[a]	37	37	37	37	37
Conventional Renewable Fuel	212	228	238	252	266
Ethanol from corn	212	228	238	252	266

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

Table 3.3-4: Volume Changes for the High Volume Scenario Relative to the No RFS Baseline (million gallons)

	2026	2027	2028	2029	2030
Cellulosic Biofuel	716	743	772	802	834
CNG/LNG from biogas	716	743	772	802	834
Ethanol from CKF	0	0	0	0	0
Total Biomass-Based Diesel	3,691	4,220	4,770	5,280	5,818
Biodiesel	1,511	1,521	1,515	1,507	1,509
Soybean oil	1,196	1,189	1,197	1,196	1,192
FOG	-49	-51	-47	-53	-46
Corn oil	34	57	35	33	35
Canola oil	319	327	330	329	328
Renewable Diesel	2,184	2,702	3,259	3,766	4,312
Soybean oil	915	1,165	1,415	1,665	1,915
FOG	960	1,163	1,362	1,545	1,744
Corn oil	79	44	52	35	22
Canola oil	230	330	430	530	630
Jet fuel from FOG	-3	-3	-3	-3	-3
Other Advanced Biofuels	37	37	37	37	37
Renewable diesel from FOG	0	0	0	0	0
Sugarcane ethanol	0	0	0	0	0
Domestic ethanol from waste ethanol	0	0	0	0	0
Other[a]	37	37	37	37	37
Conventional Renewable Fuel	212	228	238	252	266
Ethanol from corn	212	228	238	252	266

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

Table 3.3-5: Volume Changes for the Proposed Volumes Relative to the No RFS Baseline (million RINs)

	2026	2027
Cellulosic Biofuel	716	743
CNG/LNG from biogas	716	743
Ethanol from CKF	0	0
Total Biomass-Based Diesel	5,534	5,880
Biodiesel	1,716	1,752
Soybean oil	1,542	1,552
FOG	-203	-207
Corn oil	176	210
Canola oil	241	241
Renewable Diesel	3,823	4,132
Soybean oil	1,990	2,390
FOG	385	350
Corn oil	770	714
Canola oil	678	678
Jet fuel from FOG	-5	-5
Other Advanced Biofuels	52	52
Renewable diesel from FOG	0	0
Sugarcane ethanol	0	0
Domestic ethanol from waste ethanol	0	0
Other[a]	52	52
Conventional Renewable Fuel	212	228
Ethanol from corn	212	228

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

Table 3.3-6: Volume Changes for the Proposed Volumes Relative to the No RFS Baseline (million gallons)

	2026	2027
Cellulosic Biofuel	716	743
CNG/LNG from biogas	716	743
Ethanol from CKF	0	0
Total Biomass-Based Diesel	4,817	5,050
Biodiesel	1,527	1,566
Soybean oil	1,139	1,161
FOG	-25	-28
Corn oil	118	141
Canola oil	295	292
Renewable Diesel	3,293	3,486
Soybean oil	1,294	1,544
FOG	901	879
Corn oil	483	448
Canola oil	616	616
Jet fuel from FOG	-3	-3
Other Advanced Biofuels	37	37
Renewable diesel from FOG	0	0
Sugarcane ethanol	0	0
Domestic ethanol from waste ethanol	0	0
Other[a]	37	37
Conventional Renewable Fuel	212	228
Ethanol from corn	212	228

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

Note that the changes in ethanol from corn shown in Tables 3.3-1 through 3.3-4 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 E15 and/or E85 would only be used in a very few states with state incentives and mandates.[130] There is some uncertainty related to how changes in ethanol consumption will impact ethanol production. For example, ethanol producers could respond to decreased domestic demand by decreasing production or by increasing ethanol exports. In this latter case, decreases in domestic ethanol demand would have little to no impact on domestic ethanol production. 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. This would be the maximum expected impact we would expect from any changes in ethanol consumption attributable to the RFS program.

Tables 3.3-1 through 3.3-4 represent the change in biofuel use in the transportation sector that could occur if the Low or High Volume Scenarios were to become the basis for the applicable percentage standards. Tables 3.3-5 and 3.3-6 represent the change in biofuel use in the transportation sector that could occur if the Proposed Volumes were to become the basis for the applicable percentage standards.

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

We determined that a more robust analysis could be performed for some statutory factors if BBD produced from FOG could be disaggregated into specific types. EMTS, which is the source of the feedstock data used in this rule, does not differentiate between different types of FOG. Therefore, EPA used data from EIA's Monthly Biofuels Capacity and Feedstocks Update, to determine that FOG consisted of about 52% used cooking oil (UCO) and 48% tallow in 2023, the last full year for which information was available at the time this analysis was completed.[131] These fractions were applied to the volumes projected to be supplied in 2025. EPA then projected the increases in biodiesel and renewable diesel produced from UCO and tallow for 2026–2030 (these projections are described in Chapter 7.2). The projected volumes of biodiesel and renewable diesel produced from UCO and tallow are shown in Table 3.3-7. Note that the volume of biodiesel and renewable diesel produced from FOG are the same in both the Low Volume Scenario and the High Volume Scenario. The projected increase in biodiesel and renewable diesel produced from UCO and tallow relative to the No RFS Baseline is shown in Table 3.2-8.

Table 3.3-7: Disaggregated Biofuels Produced from FOG (million gallons)

	2026	2027	2028	2029	2030
Biodiesel from FOG	342	342	342	342	342
UCO	179	179	179	179	179
Tallow	164	164	164	164	164
Renewable diesel from FOG	2,178	2,453	2,728	3,003	3,278
UCO	1,217	1,442	1,667	1,892	2,117
Tallow	961	1,011	1,061	1,111	1,161

Table 3.3-8: Volume Changes in Biodiesel and Renewable Diesel Produced from FOG and Tallow Relative to the No RFS Baseline (million gallons)

	2026	2027	2028	2029	2030
Biodiesel from FOG	-49	-51	-47	-53	-46
UCO	-25	-27	-24	-28	-24
Tallow	-25	-25	-23	-25	-22
Renewable diesel from FOG	960	1,163	1,362	1,545	1,744
UCO	499	605	708	803	907
Tallow	461	558	654	742	837

3.4 Volume Changes Analyzed with Respect to the 2025 Baseline

As described in Chapter 2.2, for some of the factors (e.g. cost) we also analyzed the impacts of volume changes with respect to the 2025 Baseline. These differences are shown in Tables 3.4-1, 2, and 5 in terms of RINs and in Tables 3.4-3, 4, and 6 in physical volumes. The values in these tables reflect the difference between values of: (1) The tables containing the Low and High Volume Scenarios (Tables 3.1-5 through 8) and Proposed Volumes (Tables 3.2-7 and 8), and (2) The tables containing the 2025 Baseline volumes (Tables 2.2-1 and 2).

[131] EIA, "Monthly Biofuels Capacity and Feedstocks Update," August 2024, Table 2b – U.S. Feedstocks consumed for production of biofuels. https://www.eia.gov/biofuels/update/archive/2024/2024_08/table2.pdf.

Table 3.4-1: Volume Changes for the Low Volume Scenario Relative to 2025 Baseline (million RINs)

	2026	2027	2028	2029	2030
Cellulosic Biofuel	-78	-14	-55	128	207
CNG/LNG from biogas	-125	-60	10	85	165
Ethanol from CKF	47	46	45	43	42
Total Biomass-Based Diesel	1,529	2,029	2,529	3,029	3,529
Biodiesel	714	714	714	714	714
Soybean oil	485	485	485	485	485
FOG	87	87	87	87	87
Corn oil	91	91	91	91	91
Canola oil	51	51	51	51	51
Renewable Diesel	840	1,340	1,840	2,340	2,840
Soybean oil	-377	-317	-257	-197	-137
FOG	1,523	1,963	2,403	2,843	3,283
Corn oil	-20	-20	-20	-20	-20
Canola oil	-287	-287	-287	-287	-287
Jet fuel from FOG	-24	-24	-24	-24	-24
Other Advanced Biofuels	-41	-41	-41	-41	-41
Renewable diesel from FOG	7	7	7	7	7
Sugarcane ethanol	-37	-37	-37	-37	-37
Domestic ethanol from waste ethanol	1	1	1	1	1
Other	-12	-12	-12	-12	-12
Conventional Renewable Fuel	-156	-277	-423	-587	-767
Ethanol from corn	-156	-277	-423	-587	-767

Table 3.4-2: Volume Changes for the High Volume Scenario Relative to 2025 Baseline (million RINs)

	2026	2027	2028	2029	2030
Cellulosic Biofuel	-78	-14	-55	128	207
CNG/LNG from biogas	-125	-60	10	85	165
Ethanol from CKF	47	46	45	43	42
Total Biomass-Based Diesel	2,029	3,029	4,049	5,029	6,029
Biodiesel	714	714	714	714	714
Soybean oil	485	485	485	485	485
FOG	87	87	87	87	87
Corn oil	91	91	91	91	91
Canola oil	51	51	51	51	51
Renewable Diesel	1,340	2,340	3,340	4,340	5,340
Soybean oil	-37	363	763	1,163	1,563
FOG	1,523	1,963	2,403	2,843	3,283
Corn oil	-20	-20	-20	-20	-20
Canola oil	-127	33	193	353	513
Jet fuel from FOG	-24	-24	-24	-24	-24
Other Advanced Biofuels	-41	-41	-41	-41	-41
Renewable diesel from FOG	7	7	7	7	7
Sugarcane ethanol	-37	-37	-37	-37	-37
Domestic ethanol from waste ethanol	1	1	1	1	1
Other	-12	-12	-12	-12	-12
Conventional Renewable Fuel	-156	-277	-423	-587	-767
Ethanol from corn	-156	-277	-423	-587	-767

Table 3.4-3: Volume Changes for the Low Volume Scenario Relative to 2025 Baseline (million gallons)

	2026	2027	2028	2029	2030
Cellulosic Biofuel	-78	-14	-55	128	207
CNG/LNG from biogas	-125	-60	10	85	165
Ethanol from CKF	47	46	45	43	42
Total Biomass-Based Diesel	986	1,298	1,611	1,923	2,236
Biodiesel	476	476	476	476	476
Soybean oil	323	323	323	323	323
FOG	58	58	58	58	58
Corn oil	61	61	61	61	61
Canola oil	34	34	34	34	34
Renewable Diesel	525	837	1,150	1,462	1,775
Soybean oil	-235	-198	-160	-123	-85
FOG	952	1.227	1,502	1,777	2,052
Corn oil	-13	-13	-13	-13	-13
Canola oil	-179	-179	-179	-179	-179
Jet fuel from FOG	-15	-15	-15	-15	-15
Other Advanced Biofuels	-40	-40	-40	-40	-40
Renewable diesel from FOG	4	4	4	4	4
Sugarcane ethanol	-37	-37	-37	-37	-37
Domestic ethanol from waste ethanol	1	1	1	1	1
Other	-8	-8	-8	-8	-8
Conventional Renewable Fuel	-156	-277	-423	-587	-767
Ethanol from corn	-156	-277	-423	-587	-767

Table 3.4-4: Volume Changes for the High Volume Scenario Relative to 2025 Baseline (million gallons)

	2026	2027	2028	2029	2030
Cellulosic Biofuel	-78	-14	-55	128	207
CNG/LNG from biogas	-125	-60	10	85	165
Ethanol from CKF	47	46	45	43	42
Total Biomass-Based Diesel	1,298	1,923	2,548	3,173	3,798
Biodiesel	476	476	476	476	476
Soybean oil	323	323	323	323	323
FOG	58	58	58	58	58
Corn oil	61	61	61	61	61
Canola oil	34	34	34	34	34
Renewable Diesel	837	1,462	2,087	2,712	3,337
Soybean oil	-23	227	477	727	977
FOG	952	1,227	1,502	1,777	2,052
Corn oil	-13	-13	-13	-13	-13
Canola oil	-79	21	121	221	321
Jet fuel from FOG	-15	-15	-15	-15	-15
Other Advanced Biofuels	-40	-40	-40	-40	-40
Renewable diesel from FOG	4	4	4	4	4
Sugarcane ethanol	-37	-37	-37	-37	-37
Domestic ethanol from waste ethanol	1	1	1	1	1
Other	-8	-8	-8	-8	-8
Conventional Renewable Fuel	-156	-277	-423	-587	-767
Ethanol from corn	-156	-277	-423	-587	-767

Table 3.4-5: Volume Changes for the Proposed Volumes Relative to 2025 Baseline (million RINs)

	2026	2027
Cellulosic Biofuel	-78	-14
CNG/LNG from biogas	-125	-60
Ethanol from CKF	47	46
Total Biomass-Based Diesel	1,809	2,309
Biodiesel	164	184
Soybean oil	234	254
FOG	-43	-43
Corn oil	216	216
Canola oil	-243	-243
Renewable Diesel	1,669	2,149
Soybean oil	489	889
FOG	373	453
Corn oil	624	624
Canola oil	183	183
Jet fuel from FOG	-24	-24
Other Advanced Biofuels	-41	-41
Renewable diesel from FOG	7	7
Sugarcane ethanol	-37	-37
Domestic ethanol from waste ethanol	1	1
Other	-12	-12
Conventional Renewable Fuel	-156	-277
Ethanol from corn	-156	-277

Table 3.4-6: Volume Changes for the Proposed Volumes Relative to 2025 Baseline (million gallons)

	2026	2027
Cellulosic Biofuel	-78	-14
CNG/LNG from biogas	-125	-60
Ethanol from CKF	47	46
Total Biomass-Based Diesel	2,424	2,753
Biodiesel	492	521
Soybean oil	267	296
FOG	81	81
Corn oil	145	145
Canola oil	-1	-1
Renewable Diesel	1,947	2,247
Soybean oil	356	606
FOG	893	943
Corn oil	392	392
Canola oil	307	307
Jet fuel from FOG	-15	-15
Other Advanced Biofuels	-40	-40
Renewable diesel from FOG	4	4
Sugarcane ethanol	-37	-37
Domestic ethanol from waste ethanol	1	1
Other	-8	-8
Conventional Renewable Fuel	-156	-277
Ethanol from corn	-156	-277

Unlike for the comparison to the No RFS Baseline, the changes in ethanol from corn shown in Table 3.4-1 through 6 are a function of both changes in total gasoline demand as well as changes in the consumption of E15 and E85. Table 3.4-7 shows the amount of ethanol that can be attributed to each. Note that because the only differences between the Volume Scenarios and the Proposed Volumes are the quantities of biodiesel and renewable diesel supplied, the total ethanol consumption and the consumption of the various ethanol blends are identical under all scenarios.

Table 3.4-7: Source of Ethanol Changes in the Volume Scenarios and Proposed Volumes Relative to the 2025 Baseline (million gallons)

	2026	2027	2028	2029	2030
Changes in ethanol consumption attributable to changes in gasoline demand	-193	-373	-561	-777	-1,011
Changes in ethanol consumption attributable to changes in E15 and E85 consumption	48	106	143	197	250
Total	-145	-267	-414	-580	-761

Finally, as noted in Chapter 2.2, for some of the factors it may be informative to consider the impacts of this proposed rule relative to our updated renewable fuel supply projections for 2025. This is particularly of interest for cellulosic biofuel (for which we currently project a shortfall relative to our projections for 2025 in the Set 1 Rule) and BBD (for which we currently project a significant over-supply relative to our projections for 2025 in the Set 1 Rule). These differences are shown in Tables 3.4-8, 9, and 12 in terms of RINs and in Tables 3.4-10, 11, and 13 in physical volumes. The values in these tables reflect the difference between values of: (1) The tables containing the Low and High Volume Scenarios (Tables 3.1-5 through 8) and the Proposed Volumes (Tables 3.2-7 and 8), and (2) The tables containing the updated projection of biofuel supply for 2025 (Tables 2.2-3 and 4).

Table 3.4-8: Volume Changes in the Low Volume Scenario Relative to Updated Projection of Biofuel Supply for 2025 Baseline (million RINs)

	2026	2027	2028	2029	2030
Cellulosic Biofuel	108	172	241	314	393
CNG/LNG from biogas	61	126	196	271	351
Ethanol from CKF	47	46	45	43	42
Total Biomass-Based Diesel	229	729	1,229	1,729	2,229
Biodiesel	0	0	0	0	0
Soybean oil	0	0	0	0	0
FOG	0	0	0	0	0
Corn oil	0	0	0	0	0
Canola oil	0	0	0	0	0
Renewable Diesel	253	753	1,253	1,753	2,253
Soybean oil	4	64	124	184	244
FOG	282	722	1,162	1,602	2,042
Corn oil	-23	-23	-23	-23	-23
Canola oil	-11	-11	-11	-11	-11
Jet fuel from FOG	-24	-24	-24	-24	-24
Other Advanced Biofuels	-41	-41	-41	-41	-41
Renewable diesel from FOG	7	7	7	7	7
Sugarcane ethanol	-37	-37	-37	-37	-37
Domestic ethanol from waste ethanol	1	1	1	1	1
Other	-12	-12	-12	-12	-12
Conventional Renewable Fuel	-156	-277	-423	-587	-767
Ethanol from corn	-156	-277	-423	-587	-767

Table 3.4-9: Volume Changes in the High Volume Scenario Relative to Updated Projection of Biofuel Supply for 2025 Baseline (million RINs)

	2026	2027	2028	2029	2030
Cellulosic Biofuel	108	172	241	314	393
CNG/LNG from biogas	61	126	196	271	351
Ethanol from CKF	47	46	45	43	42
Total Biomass-Based Diesel	729	1,729	2,729	3,729	4,729
Biodiesel	0	0	0	0	0
Soybean oil	0	0	0	0	0
FOG	0	0	0	0	0
Corn oil	0	0	0	0	0
Canola oil	0	0	0	0	0
Renewable Diesel	753	1,753	2,753	3,753	4,753
Soybean oil	344	744	1,144	1,544	1,944
FOG	282	722	1,162	1,602	2.042
Corn oil	-23	-23	-23	-23	-23
Canola oil	149	309	469	629	789
Jet fuel from FOG	-24	-24	-24	-24	-24
Other Advanced Biofuels	-40	-40	-40	-40	-40
Renewable diesel from FOG	4	4	4	4	4
Sugarcane ethanol	-37	-37	-37	-37	-37
Domestic ethanol from waste ethanol	1	1	1	1	1
Other	-8	-8	-8	-8	-8
Conventional Renewable Fuel	-156	-277	-423	-587	-767
Ethanol from corn	-156	-277	-423	-587	-767

Table 3.4-10: Volume Changes in the Low Volume Scenario Relative to Updated Projection of Biofuel Supply for 2025 Baseline (million gallons)

	2026	2027	2028	2029	2030
Cellulosic Biofuel	108	172	241	314	393
CNG/LNG from biogas	61	126	196	271	351
Ethanol from CKF	47	46	45	43	42
Total Biomass-Based Diesel	328	640	953	1,265	1,578
Biodiesel	0	0	0	0	0
Soybean oil	0	0	0	0	0
FOG	0	0	0	0	0
Corn oil	0	0	0	0	0
Canola oil	0	0	0	0	0
Renewable Diesel	342	654	967	1,309	1,592
Soybean oil	44	81	119	156	194
FOG	294	569	844	1,119	1,394
Corn oil	3	3	3	3	3
Canola oil	1	1	1	1	1
Jet fuel from FOG	-14	-14	-14	-14	-14
Other Advanced Biofuels	-41	-41	-41	-41	-41
Renewable diesel from FOG	7	7	7	7	7
Sugarcane ethanol	-37	-37	-37	-37	-37
Domestic ethanol from waste ethanol	1	1	1	1	1
Other	-12	-12	-12	-12	-12
Conventional Renewable Fuel	-156	-277	-423	-587	-767
Ethanol from corn	-156	-277	-423	-587	-767

Table 3.4-11: Volume Changes in the High Volume Scenario Relative to Updated Projection of Biofuel Supply for 2025 Baseline (million gallons)

	2026	2027	2028	2029	2030
Cellulosic Biofuel	108	172	241	314	393
CNG/LNG from biogas	61	126	196	271	351
Ethanol from CKF	47	46	45	43	42
Total Biomass-Based Diesel	640	1,265	1,890	2,515	3,140
Biodiesel	0	0	0	0	0
Soybean oil	0	0	0	0	0
FOG	0	0	0	0	0
Corn oil	0	0	0	0	0
Canola oil	0	0	0	0	0
Renewable Diesel	654	1,309	1,904	2,529	3,154
Soybean oil	256	506	756	1,006	1,256
FOG	294	569	844	1,119	1,394
Corn oil	3	3	3	3	3
Canola oil	101	201	301	401	501
Jet fuel from FOG	-14	-14	-14	-14	-14
Other Advanced Biofuels	-40	-40	-40	-40	-40
Renewable diesel from FOG	4	4	4	4	4
Sugarcane ethanol	-37	-37	-37	-37	-37
Domestic ethanol from waste ethanol	1	1	1	1	1
Other	-8	-8	-8	-8	-8
Conventional Renewable Fuel	-156	-277	-423	-587	-767
Ethanol from corn	-156	-277	-423	-587	-767

Table 3.4-12: Volume Changes in the Proposed Volumes Relative to Updated Projection of Biofuel Supply for 2025 Baseline (million RINs)

	2026	2027
Cellulosic Biofuel	108	172
CNG/LNG from biogas	61	126
Ethanol from CKF	47	46
Total Biomass-Based Diesel	509	1,009
Biodiesel	-550	-530
Soybean oil	-251	-231
FOG	-130	-130
Corn oil	125	125
Canola oil	-294	-294
Renewable Diesel	1,082	1,562
Soybean oil	870	1,270
FOG	-868	-788
Corn oil	621	621
Canola oil	459	459
Jet fuel from FOG	-24	-24
Other Advanced Biofuels	-41	-41
Renewable diesel from FOG	7	7
Sugarcane ethanol	-37	-37
Domestic ethanol from waste ethanol	1	1
Other	-12	-12
Conventional Renewable Fuel	-156	-277
Ethanol from corn	-156	-277

Table 3.4-13: Volume Changes in the Proposed Volumes Relative to Updated Projection of Biofuel Supply for 2025 Baseline (million gallons)

	2026	**2027**
Cellulosic Biofuel	108	172
CNG/LNG from biogas	61	126
Ethanol from CKF	47	46
Total Biomass-Based Diesel	1,766	2,095
Biodiesel	16	45
Soybean oil	-57	-28
FOG	23	23
Corn oil	84	84
Canola oil	-35	-35
Renewable Diesel	1,764	2,064
Soybean oil	635	885
FOG	235	285
Corn oil	407	407
Canola oil	487	487
Jet fuel from FOG	-14	-14
Other Advanced Biofuels	-40	-40
Renewable diesel from FOG	4	4
Sugarcane ethanol	-37	-37
Domestic ethanol from waste ethanol	1	1
Other	-8	-8
Conventional Renewable Fuel	-156	-277
Ethanol from corn	-156	-277

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, including factors on air quality, climate change, conversion of wetlands, ecosystems, wildlife habitat, water quality, and water supply. This chapter discusses these environmental factors except for climate change, which is evaluated separately in Chapter 5. Where applicable, this chapter discusses additional factors, such as soil quality and ecosystem services, per EPA's authority to consider "other" factors as explained in more detail in Preamble Section II.B. For example, soil quality is evaluated due to its close association and impacts to water quality. In addition, the discussions in this chapter reference and leverage the findings from the Third Triennial Report to Congress on Biofuels and the Environment (RtC3), finalized in January 2025, which provides additional information on environmental impacts from biofuels and the RFS program.[132]

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 (NO_x)), while other air pollutants are formed secondarily in the atmosphere (e.g., ozone), and some air pollutants are both emitted directly and formed secondarily (e.g., particulate matter (PM) and aldehydes). Air quality can be affected by emissions from: (1) Production and transport of feedstocks, (2) Emissions from conversion of feedstocks to biofuels, (3) Emissions from transport of the finished biofuels, and (4) Emissions from combustion of biofuels in vehicles. Emissions from increased production and use of biofuels contribute to ambient concentrations of air pollutants, and the health and environmental effects associated with exposure to these air pollutants, including effects on children, are discussed further in a memorandum to this docket.[133]

The emissions from production and transport of biofuel feedstocks and finished biofuels, and from combustion of biofuels in vehicles, differ depending on the type of biofuel. In addition to the type of biofuel, other factors may affect emissions, including but not limited to whether biofuel is blended with petroleum fuel and the blend fractions, vehicle technology, emissions control technology, and operating conditions.

4.1.1 Background on Air Quality Impacts of Biofuels

This section summarizes current knowledge about the air quality impacts of biofuels, specifically biofuels whose volumes are impacted by this rule. The biofuels we focus on in this section are BBD, including biodiesel and renewable diesel, ethanol, and compressed natural

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[132] EPA, "Biofuels and the Environment: Third Triennial Report to Congress," EPA/600/R-24/343F, January 2025.
[133] See "Health and environmental effects of pollutants discussed in Chapter 4 of Draft Regulatory Impact Analysis (DRIA) supporting the proposed Renewable Fuel Standard (RFS) standards for 2026-2027," available in the docket for this action.

gas/liquified natural gas (CNG/LNG).[134] Chapter 4.1.2 includes an evaluation of the emission impacts associated with the Proposed Volumes when compared to the No RFS Baseline and Chapter 4.1.3 describes the likely air quality impacts associated with the Proposed Volumes when compared to the No RFS Baseline.

When considering background information from previous work on emissions and air quality impacts of biofuels, it is important to understand whether the rule would be increasing or decreasing volumes of biofuels; this requires defining the baseline volume of biofuels for comparison. Preamble Section III.D and Chapter 2 detail the determination of the Proposed Volumes as compared with the No RFS and 2025 Baselines. Generally, the No RFS Baseline is used for analytical purposes and the 2025 Baseline is an additional informational case.

EPA has previously assessed the air quality impacts of biofuels in prior RFS rules, including the RFS2 Rule and in the "anti-backsliding study" (ABS).[135] Air quality modeling was done for the RFS2 Rule in order to assess the impacts of the required RFS2 volumes compared to two different baselines or reference cases, both of which included some usage of ethanol fuels.[136] The RFS2 modeling indicated that the increased use of renewable fuels increased emissions of hydrocarbons, NO_X, acetaldehyde, and ethanol and decreased emissions of other pollutants such as carbon monoxide (CO) and benzene when evaluating production, transport, and end use. However, the impacts of these emissions on criteria air pollutants were highly variable from region to region. Overall, the emission changes were projected to lead to increases in national population-weighted annual average ambient $PM_{2.5}$ and ozone concentrations. Air quality impacts associated with changes in ethanol production and transport are expected to be primarily in the local area where the emissions occur.[137]

The ABS examined the impacts on air quality in 2016 that might result from changes in vehicle and engine emissions associated with renewable fuel volumes under the RFS relative to approximately 2005 levels.[138] The ABS found potential increases and decreases in ambient concentrations of pollutants. For example, compared to the "pre-RFS" scenario, the 2016 "with-RFS" scenario had increased ozone concentrations across the eastern U.S. and in some areas in the western U.S., with some decreases in localized areas. In the 2016 "with-RFS" scenario, concentrations of fine particulate matter ($PM_{2.5}$) were relatively unchanged in most areas, with increases in some areas and decreases in some localized areas.

[134] This includes all fuel categories appearing in Tables 3.2-1 and 2 with one exception: "Other Advanced Biofuels – Other" shows a relatively small volume (52 million RINs delta compared to the No RFS Baseline) and represents an unknown mix of various fuel types with smaller volumes.
[135] EPA, "Clean Air Act Section 211(v)(1) Anti-backsliding Study," EPA-420-R-20-008, May 2020.
[136] See RFS2 Rule RIA Tables 3.2.7 and 3.2.8 for the emissions impacts associated with biodiesel and ethanol volume changes.
[137] Cook, Rich, Sharon Phillips, Marc Houyoux, Pat Dolwick, Rich Mason, Catherine Yanca, Margaret Zawacki, et al. "Air Quality Impacts of Increased Use of Ethanol Under the United States' Energy Independence and Security Act." *Atmospheric Environment* 45, no. 40 (September 16, 2010): 7714–24. https://doi.org/10.1016/j.atmosenv.2010.08.043.
[138] The ABS focused on the impacts of statutorily required renewable fuel volumes on concentrations of criteria and toxic pollutants due to changes in vehicle and engine emissions; this study was not an examination of the lifecycle impacts of renewable fuels on air quality.

In this rule we rely primarily on the conclusions from the Third Triennial Report to Congress on Biofuels (RtC3), which summarized available information on air quality impacts associated with biofuels.[139] The RtC3 notes that there is no new evidence that contradicts the fundamental conclusions of previous reports to Congress.[140] The RtC3 concluded that emissions of NO_x, sulfur oxides (SO_X), carbon monoxide (CO), volatile organic compounds (VOCs), ammonia (NH_3), $PM_{2.5}$, and PM_{10}, can be impacted at each stage of biofuel production, distribution, and usage, and emphasized that the impacts associated with feedstock and fuel production and distribution are important to consider, along with those associated with fuel usage.

4.1.1.1 Corn Ethanol

Corn can be used to produce fuel ethanol, and the RtC3 states that increased corn production results in higher agricultural dust and NH_3 emissions from fertilizer use, although improved nitrogen management practices can reduce these increases in NH_3 emissions. Increased corn ethanol production and combustion also leads to increased NO_x, SO_X, VOCs, $PM_{2.5}$, and PM_{10}, and dispersion modeling has shown elevated pollutant concentrations near corn biorefineries.[141] Additional pollutant emissions result from evaporative losses of VOCs during storage and transport, as well as combustion emissions from commercial marine vessels, rail, tanker trucks, and pipeline pumps used to transport the ethanol to end use. Finally, the combustion of ethanol in end use applications causes emissions of NO_x, VOCs, $PM_{2.5}$, and CO as well. As increased ethanol volumes are displacing petroleum and its related emissions in each of these areas, the overall impact on the environment is a complex issue.

The RtC3 also included a comparison of air quality impacts from corn ethanol and gasoline.[142] Overall the total potential air quality impacts were much lower from corn ethanol than from gasoline because much less corn ethanol is consumed than gasoline. However, results also show a trend of increased life cycle emissions for the corn ethanol pathways compared with petroleum-based gasoline. The trend is stronger for some pollutants (e.g., SO_X and $PM_{2.5}$) and nearly negligible for others (e.g., CO and VOCs). In addition, per megajoule potential life cycle air quality impacts were larger for corn ethanol compared with gasoline but were decreasing through time as the industry matured and efficiencies improved.

A study published since the RtC3, focused on papers relevant to California, reviewed available literature and concluded that while the use of bioethanol (ethanol produced from plants,

[139] RtC3 Chapter 8 "Air Quality."
[140] The cutoff date for publication of literature included in the RtC3 was early- to mid-2022.
[141] Lee, Eun Kyung, Xiaobo Xue Romeiko, Wangjian Zhang, Beth J. Feingold, Haider A. Khwaja, Xuesong Zhang, and Shao Lin. "Residential Proximity to Biorefinery Sources of Air Pollution and Respiratory Diseases in New York State." *Environmental Science & Technology* 55, no. 14 (July 7, 2021): 10035–45. https://doi.org/10.1021/acs.est.1c00698.
[142] See RtC3 Chapter 8.5 "Comparison with Petroleum" for more details on results. The models run were the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model and the Bio-based circular carbon economy Environmentally-extended Input-Output Model (BEIOM).

such as sugarcane or corn) was beneficial with respect to GHG emissions, it was associated with an increase in criteria air pollutant emissions relative to petroleum gasoline on a per-unit basis.[143]

4.1.1.2 Biomass-based diesel

For the purposes of this analysis, biomass-based diesel (BBD) includes biodiesel and renewable diesel. Although BBD is sourced from a variety of feedstocks, domestic soybean oil and domestic biogenic waste fats, oils, grease (FOG) make up greater than 80% of the proposed BBD proposed fuel and feedstock volumes. The RtC3 states that emissions from production of biodiesel from soybean oil vary depending on the oil extraction method and that mechanical extraction is associated with the highest emissions. RtC3 also states that compared to corn ethanol, data are lacking on emission and air quality impacts of the feedstock production (soybean), storage, and transport stages of biomass-based diesel production.[144] The RtC3 concluded that impacts of biodiesel on end use emissions of criteria pollutants and precursors are insignificant compared to petroleum diesel for heavy-duty diesel engines from model years 2007 and forward.

The RtC3 also included a comparison of air quality impacts from soy biodiesel and petroleum diesel.[145] The results generally show a trend of increased life cycle emissions for the soy oil biodiesel pathways compared with petroleum diesel. The trend is stronger for some pollutants (e.g., SO_X and VOC) and less conclusive for others (e.g., CO and $PM_{2.5}$). In addition, the per megajoule potential life cycle air quality effects were larger for biodiesel compared with petroleum diesel. However, the report also observed that per megajoule effects were decreasing through time as the industry matured and efficiencies improved.

The aforementioned post-RtC3, California-based study reviewed available literature and concluded that the use of biodiesel is mostly seen as having a beneficial impact on criteria pollutant emissions relative to petroleum diesel use.[146] Recent dispersion modeling has shown elevated pollutant concentrations near soybean biorefineries.[147]

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[143] Freer-Smith, Peter, Jack H. Bailey-Bale, Caspar L. Donnison, and Gail Taylor. "The Good, the Bad, and the Future: Systematic Review Identifies Best Use of Biomass to Meet Air Quality and Climate Policies in California." *GCB Bioenergy* 15, no. 11 (September 23, 2023): 1312–28. https://doi.org/10.1111/gcbb.13101.

[144] We do not include information on production impacts on air quality for BBD made from FOG in this section because FOG are considered byproducts or waste products of other processes that occur regardless of producing BBD from FOG.

[145] See RtC3 Chapter 8.5 "Comparison with Petroleum" for more details on results. The models run were the GREET model and BEIOM.

[146] Freer-Smith, Peter, Jack H. Bailey-Bale, Caspar L. Donnison, and Gail Taylor. "The Good, the Bad, and the Future: Systematic Review Identifies Best Use of Biomass to Meet Air Quality and Climate Policies in California." *GCB Bioenergy* 15, no. 11 (September 23, 2023): 1312–28. https://doi.org/10.1111/gcbb.13101.

[147] Lee, Eun Kyung, Xiaobo Xue Romeiko, Wangjian Zhang, Beth J. Feingold, Haider A. Khwaja, Xuesong Zhang, and Shao Lin. "Residential Proximity to Biorefinery Sources of Air Pollution and Respiratory Diseases in New York State." *Environmental Science & Technology* 55, no. 14 (July 7, 2021): 10035–45. https://doi.org/10.1021/acs.est.1c00698.

4.1.1.3 Renewable CNG/LNG

Renewable CNG and LNG, categorized as cellulosic biofuel in RFS, can be derived from biogas that is produced by the anaerobic digestion of biomass by natural organisms and collected and upgraded for use in CNG/LNG vehicles. Similar to BBD made from FOG, biogas produced at landfills, municipal wastewater treatment facilities, agricultural waste digesters, and separated municipal solid waste digesters, we currently assume for the purposes of the RFS program that biogas would otherwise have been flared were it not productively used to produce transportation fuel.

The RtC3 notes that research on biofuel impacts on air quality has focused on corn ethanol and soy biodiesel more than on biofuels from other feedstocks. A 2023 review of studies on biomass use pathways determined that utilizing biogas recovered from the anaerobic digestions of municipal solid waste, water waste, animal waste, and food waste results in an overall reduction of criteria air pollutant emissions compared to allowing the waste to decompose in a landfill or by natural composting or decomposition.[148]

4.1.2 Emission Impacts of Proposed Volumes

We have evaluated air pollutant emissions impacts from biofuels determined to have an increase in production due to this rule. These fuels include corn ethanol, biodiesel, renewable diesel, and renewable CNG/LNG from biogas. Chapter 4.1.2.1 estimates emissions impacts associated with increased biofuel production, Chapter 4.1.2.2 discusses expected emissions from the transport of additional biofuels, and Chapter 4.1.2.3 focuses on impacts on end-use or onroad emissions due to increases in the Proposed Volumes.

As discussed in Preamble Section III.D, there are several baselines to which we can compare the Proposed Volumes and determine the air quality impacts of this rule. The difference between the Proposed Volumes and the No RFS Baseline, representing the use of biofuels in a scenario where the RFS program did not continue to exist, was used to determine the emissions impacts presented here. Chapter 3 details the volume changes associated with this rule relative to the No RFS Baseline (Table 3.2-1 through Table 3.2-4). While using the No RFS Baseline is most appropriate in evaluating the total impact of this rule, the 2025 Baseline, representing the current RFS biofuels requirements, could be used to determine the emission impacts of this rule compared to current conditions. As shown in Tables 3.3-1 through 6, the Volume Scenarios and Proposed Volumes are lower than the 2025 Baseline volumes for several of the fuel categories.

4.1.2.1 Emissions from the Production of Biofuels

In this section, we estimate emissions associated with producing biofuels with a proposed increase in production volumes, relative to a No RFS Baseline, due to this rule.[149] These biofuels include conventional corn ethanol (D6), biomass-based diesel (D4), including biodiesel and

[148] Freer-Smith, Peter, Jack H. Bailey-Bale, Caspar L. Donnison, and Gail Taylor. "The Good, the Bad, and the Future: Systematic Review Identifies Best Use of Biomass to Meet Air Quality and Climate Policies in California." *GCB Bioenergy* 15, no. 11 (September 23, 2023): 1312–28. https://doi.org/10.1111/gcbb.13101.

[149] Biofuel volume production impacts relative to the No RFS Baseline are presented in Tables 3.3-1 through 4.

renewable diesel, and renewable CNG and LNG derived from biogas (D3). We have not addressed production emissions from other categories of biofuels, including renewable diesel co-processed with petroleum diesel (RFS Fuel Code D5, Other Advanced Biofuel). In this analysis, we are defining production emissions as those produced at the biorefinery and not including emissions upstream of the refining facility (for example, emissions associated with crop production or transport of the feedstock to the refinery). While much of the focus on emissions from the production of biofuels has been on criteria air pollutants, there are also emissions of hazardous air pollutants at biorefineries that can impact air quality.[150] We have estimated emissions of selected HAPs, or air toxics, from the production of biofuels where possible. The air toxics chosen were those determined to be risk drivers in the 2020 AirToxScreen and could reasonably be emitted during the refining of biofuel feedstocks.[151] This list includes 1,3-butadiene, acetaldehyde, acrolein, benzene, formaldehyde, and naphthalene.

There are several approaches, each with varying strengths and weaknesses, that could be used to estimate pollutant emissions from the production of biofuel. A global equilibrium model, such as the Global Change Analysis Model (GCAM), can account for interactions between various biofuels and petroleum fuels over a full lifecycle; however, the comprehensive, global nature of the model does not allow for the individual determination of emissions associated with incremental processes in the full life cycle of a biofuel.[152] Another option for a quantitative evaluation of the production emissions impact from the production of biofuels is to use Argonne National Laboratory's R&D GREET (Greenhouse gases, Regulated Emissions, and Energy use in Technologies) model.[153] The GREET model allows for the evaluation of production emissions from all biofuels impacted by this rule; however, only a limited number of CAP emission rates, and no HAP emission rates, are available from fuel production in GREET, and GREET cannot project market-mediated CAP or HAP emissions impacts of changes to fuel pathways. Another approach is to evaluate annual biorefining facility emissions using EPA's Air Emissions Modeling Platform (EMP) as a function of the volume of fuel each facility produced. The most recent version, the 2022 EMP, is based on the emissions in the 2020 National Emissions Inventory and contains both CAP and HAP annual emissions reported to state and regional air agencies, EPA, and Federal Land Management agencies by individual biorefining facilities.[154] In this analysis, we chose to use the EMP as the preferred data source to determine biofuel

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[150] Environmental Integrity Project, "Farm to Fumes: Hazardous Air Pollution from Biofuel Production," June 12, 2024. https://environmentalintegrity.org/wp-content/uploads/2024/06/EIP_Report_FarmtoFumes_06.12.2024.pdf.
[151] 2020 AirToxScreen Risk Drivers. https://www.epa.gov/system/files/documents/2024-08/2020-airtoxscreen-risk-drivers.pdf
[152] GCIMS, "GCAM: Global Change Analysis Model." https://gcims.pnnl.gov/modeling/gcam-global-change-analysis-model
[153] Wang, Michael, Elgowainy, Amgad, Lee, Uisung, Baek, Kwang H., Balchandani, Sweta, Benavides, Pahola T., Burnham, Andrew, Cai, Hao, Chen, Peter, Gan, Yu, Gracida-Alvarez, Ulises R., Hawkins, Troy R., Huang, Tai-Yuan, Iyer, Rakesh K., Kar, Saurajyoti, Kelly, Jarod C., Kim, Taemin, Kolodziej, Christopher, Lee, Kyuha, Liu, Xinyu, Lu, Zifeng, Masum, Farhad, Morales, Michele, Ng, Clarence, Ou, Longwen, Poddar, Tuhin, Reddi, Krishna, Shukla, Siddharth, Singh, Udayan, Sun, Lili, Sun, Pingping, Sykora, Tom, Vyawahare, Pradeep, and Zhang, Jingyi. "Greenhouse gases, Regulated Emissions, and Energy use in Technologies Model ® (2023 Excel)." Computer software. October 09, 2023. https://doi.org/10.11578/GREET-Excel-2023/dc.20230907.1.
[154] An emissions modeling platform is the full set of emissions inventories, other data files, software tools, and scripts that process the emissions into the form needed for air quality modeling. As discussed in Chapter 4.1.3, we did not perform air quality modeling for this rule.

production emissions.[155] However, as described below, facility process-level data is not available for all biofuels, namely renewable CNG/LNG from biogas, and we used GREET to determine production emissions of these fuels.[156]

4.1.2.1.1 Corn Ethanol and Biomass-based Diesel

To estimate the emissions impacts of fuel production from the Proposed Volumes for corn ethanol and biomass-based diesel, RINs generated for corn ethanol, biodiesel, and renewable diesel were compared to reported air emissions at the facility level. The facility-level emissions rates were then used to determine a national emission factor for each pollutant and fuel type that could then be applied to the fuel volume differences between this rule and the No RFS Baseline. Emission factors were determined for the year 2022 as this was the most recent year that facility-level emissions were available at the time of this analysis.

Facilities that generated corn ethanol, biodiesel, and renewable diesel RINs in 2022 were identified through the EPA Moderated Transaction System (EMTS) RFS RIN generation records specifying the fuel type, number of RINs generated, and total volume of fuel produced.[157] These facilities were then matched to their reported 2022 emissions inventory in the 2022 Emission Modeling Platform (EMP) version 1.1 through the Emissions Information Systems (EIS).[158,159,160]

As shown in Table 4.1.2.1.1-1, most ethanol biorefineries, but only some biodiesel and renewable diesel refineries, reported emissions in 2022. For example, 175 of the 187 domestic ethanol biorefineries generating RINs in 2022 have reported air pollutant emissions available in the EMP, and these 175 ethanol facilities with reported emissions generated 97% of the total ethanol RINs in 2022. Facilities with reported emissions information were generally larger, with an average 85 million RINs generated in 2022 compared to an average of 33 million RINs for facilities that did not report emissions.

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[155] EPA, "Emissions Modeling Platforms." https://www.epa.gov/air-emissions-modeling/emissions-modeling-platforms.
[156] The methodology for determining pollutant emission rates from biofuel production is discussed in "Determination of Air Pollutant Emissions Factors from the Production of Biofuels," available in the docket for this action.
[157] EPA, "EMTS: RFS RIN Generation Report." https://www.epa.gov/fuels-registration-reporting-and-compliance-help/emts-rfs-rin-generation-report.
[158] EPA, "2022v1 Emissions Modeling Platform." https://www.epa.gov/air-emissions-modeling/2022v1-emissions-modeling-platform.
[159] EPA, "Emissions Inventory System (EIS) Gateway." https://www.epa.gov/air-emissions-inventories/emissions-inventory-system-eis-gateway.
[160] EPA, "Technical Support Document (TSD): Preparation of Emissions Inventories for the 2022v1 North American Emissions Modeling Platform," EPA-454/B-25-001, May 2025. https://www.epa.gov/system/files/documents/2024-10/2021_emismod_tsd_october2024.pdf.

Table 4.1.2.1.1-1: Number of Domestic Biorefineries Producing Ethanol, Biodiesel, and Renewable Diesel in 2022 and the Percentage of RINs Generated at Facilities Reporting Pollutant Emissions to Federal, State, or Local Agencies

	Ethanol	Biodiesel	Renewable Diesel
Number of facilities generating RINs	187	57	9
Number of facilities with reported emissions	175	21	4
Percentage of RINs at facilities with reported emissions	97%	61%	78%

Using the 2022 EMP annual emissions mass and total RINs generated at each biorefinery, an emissions rate was determined for each pollutant at each facility. National weighted emissions factors were then calculated using each facility's emission rate and fraction of the total volume of fuel produced by category. The resulting national emissions factors are presented in Table 4.1.2.1.1-2. The weighting was determined separately for each pollutant based on available data. No biodiesel refining facilities reported emissions of 1,3-butadiene; therefore, a production emissions factor of 1,3-butadiene was unable to be determined from biodiesel production.

Table 4.1.2.1.1-2: Pollutant Emission Factors From Ethanol, Biodiesel, and Renewable Diesel Production (tons/million RINs)

Pollutant	Ethanol	Biodiesel	Renewable Diesel
CO	0.835	0.398	0.395
NH_3	0.082	0.008	0.012
NO_x	1.090	0.606	0.203
PM_{10}	0.618	0.247	0.073
$PM_{2.5}$	0.498	0.162	0.072
SO_2	0.919	1.943	0.055
VOC	1.366	2.693	0.605
1,3-Butadiene	9.99×10^{-6}	-	1.17×10^{-6}
Acetaldehyde	0.07143	0.00187	0.00040
Acrolein	0.01512	0.00002	0.00003
Benzene	0.00112	0.00081	0.00676
Formaldehyde	0.01026	0.00056	0.00363
Naphthalene	7.79×10^{-5}	5.25×10^{-6}	0.00433

The emission factors were then applied to the additional fuel volumes for ethanol, biodiesel, and renewable diesel estimated from the Low and High Volume Scenarios as well as the Proposed Volumes as compared to the No RFS Baseline for the years 2026–2030. The emissions impacts resulting from the production of these additional biofuel volumes are presented in Tables 4.1.2.1.1-3 through 8.

Table 4.1.2.1.1-3: Emission Impact Estimates of CO, NH_3, NO_x, PM_{10}, $PM_{2.5}$, SO_2, and VOCs From the Production of Biofuels for the 2026–2030 Low Volume Scenario Relative to the No RFS Baseline

Year	Volume Difference to No RFS (million RINs)	CO	NH_3	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
		Ethanol Production Emissions (tons)						
2026	212	177	17	231	131	106	195	290
2027	228	190	19	249	141	113	210	311
2028	238	199	20	260	147	118	219	325
2029	252	210	21	275	156	125	232	344
2030	266	222	22	290	164	132	245	363
		Biodiesel Production Emissions (tons)						
2026	2,266	901	19	1,374	559	367	4,402	6,101
2027	2,282	907	19	1,384	563	369	4,434	6,144
2028	2,272	903	19	1,378	561	368	4,414	6,118
2029	2,260	899	19	1,371	558	366	4,391	6,085
2030	2,264	900	19	1,373	559	366	4,399	6,096
		Renewable Diesel Production Emissions (tons)						
2026	2,994	1,182	35	607	219	214	166	1,812
2027	3,323	1,312	38	674	243	238	184	2,011
2028	3,714	1,466	43	753	272	266	206	2,248
2029	4,041	1,595	47	819	296	289	224	2,446
2030	4,399	1,736	51	892	322	315	244	2,662

Table 4.1.2.1.1-4: HAP Emissions Impact Estimates for the Production of Biofuels for the 2026–2030 Low Volume Scenario Relative to the No RFS Baseline[a]

Year	Volume Difference to No RFS (million RINs)	1,3-Butadiene	Acetaldehyde	Acrolein	Benzene	Formaldehyde	Naphthalene
		Ethanol Production Emissions (tons)					
2026	212	0	15	3	0	2	0
2027	228	0	16	3	0	2	0
2028	238	0	17	4	0	2	0
2029	252	0	18	4	0	3	0
2030	266	0	19	4	0	3	0
		Biodiesel Production Emissions (tons)					
2026	2,266	-	4	0	2	1	0
2027	2,282	-	4	0	2	1	0
2028	2,272	-	4	0	2	1	0
2029	2,260	-	4	0	2	1	0
2030	2,264	-	4	0	2	1	0
		Renewable Diesel Production Emissions (tons)					
2026	2,994	0	1	0	20	11	13
2027	3,323	0	1	0	22	12	14
2028	3,714	0	1	0	25	13	16
2029	4,041	0	2	0	27	15	17
2030	4,399	0	2	0	30	16	19

[a] An emissions estimate of zero indicates the production emissions to be less than 0.45 tons/year

Table 4.1.2.1.1-5: Emission Impact Estimates of CO, NH_3, NO_x, PM_{10}, $PM_{2.5}$, SO_2, and VOCs From the Production of Biofuels for the 2026–2030 High Volume Scenario Relative to the No RFS Baseline

Year	Volume Difference to No RFS (million RINs)	CO	NH_3	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
		Ethanol Production Emissions (tons)						
2026	212	177	17	231	131	106	195	290
2027	228	190	19	249	141	113	210	311
2028	238	199	20	260	147	118	219	325
2029	252	210	21	275	156	125	232	344
2030	266	222	22	290	164	132	245	363
		Biodiesel Production Emissions (tons)						
2026	2,266	901	19	1,374	559	367	4,402	6,101
2027	2,282	907	19	1,384	563	369	4,434	6,144
2028	2,272	903	19	1,378	561	368	4,414	6,118
2029	2,260	899	19	1,371	558	366	4,391	6,085
2030	2,264	900	19	1,373	559	366	4,399	6,096
		Renewable Diesel Production Emissions (tons)						
2026	3,494	1,379	40	708	256	250	194	2,114
2027	4,323	1,706	50	876	316	309	240	2,616
2028	5,214	2,058	60	1,057	381	373	289	3,155
2029	6,041	2,384	70	1,225	442	432	335	3,656
2030	6,899	2,723	80	1,399	505	494	382	4,175

Table 4.1.2.1.1-6: HAP Emissions Impact Estimates for the Production of Biofuels for the 2026–2030 High Volume Scenario Relative to the No RFS Baseline[a]

Year	Volume Difference to No RFS (million RINs)	1,3-Butadiene	Acetaldehyde	Acrolein	Benzene	Formaldehyde	Naphthalene
		Ethanol Production Emissions (tons)					
2026	212	0	15	3	0	2	0
2027	228	0	16	3	0	2	0
2028	238	0	17	4	0	2	0
2029	252	0	18	4	0	3	0
2030	266	0	19	4	0	3	0
		Biodiesel Production Emissions (tons)					
2026	2,266	-	4	0	2	1	0
2027	2,282	-	4	0	2	1	0
2028	2,272	-	4	0	2	1	0
2029	2,260	-	4	0	2	1	0
2030	2,264	-	4	0	2	1	0
		Renewable Diesel Production Emissions (tons)					
2026	3,494	0	1	0	24	13	15
2027	4,323	0	2	0	29	16	19
2028	5,214	0	2	0	35	19	23
2029	6,041	0	2	0	41	22	26
2030	6,899	0	3	0	47	25	30

[a] An emissions estimate of zero indicates the production emissions to be less than 0.45 tons/year.

Table 4.1.2.1.1-7: Emission Impact Estimates of CO, NH_3, NO_x, PM_{10}, $PM_{2.5}$, SO_2, and VOCs From the Production of Biofuels for the Proposed Volumes Relative to the No RFS Baseline

Year	Volume Difference to No RFS (million RINs)	CO	NH_3	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
		Ethanol Production Emissions (tons)						
2026	212	177	17	231	131	106	195	290
2027	228	190	19	249	141	113	210	311
		Biodiesel Production Emissions (tons)						
2026	1,716	682	15	1,041	423	278	3,334	4,620
2027	1,752	697	15	1,062	432	284	3,404	4,717
		Renewable Diesel Production Emissions (tons)						
2026	3,823	1,509	44	775	280	274	212	2,314
2027	4,132	1,631	48	838	302	296	229	2,501

Table 4.1.2.1.1-8: HAP Emissions Impact Estimates From the Production of Biofuels for the Proposed Volumes Relative to the No RFS Baseline[a]

Year	Volume Difference to No RFS (million RINs)	1,3-Butadiene	Acetaldehyde	Acrolein	Benzene	Formaldehyde	Naphthalene
		Ethanol Production Emissions (tons)					
2026	212	0	15	3	0	2	0
2027	228	0	16	3	0	2	0
		Biodiesel Production Emissions (tons)					
2026	1,716	-	3	0	1	1	0
2027	1,752	-	3	0	1	1	0
		Renewable Diesel Production Emissions (tons)					
2026	3,823	0	2	0	26	14	17
2027	4,132	0	2	0	28	15	18

[a] An emissions estimate of zero indicates the production emissions to be less than 0.45 tons/year.

These emissions estimates assume the full additional fuel volume relative to the No RFS Baseline will be fulfilled by increasing biofuel production at domestic biorefineries. However, we note that some of this additional biofuel volume may be fulfilled both by reducing exports, whereby no changes in domestic biofuel production will occur, or by increasing imports, whereby emission impacts would occur abroad. As such, this analysis may overestimate domestic emissions. For example, in 2022, approximately 0.098% of corn ethanol, 13% of biodiesel, and 21% of renewable diesel RINs were issued to importers or foreign producers.[161]

4.1.2.1.2 Renewable CNG/LNG from Biogas

Renewable compressed natural gas (CNG) and liquefied natural gas (LNG) is produced from biogas generated during the decomposition of organic waste products from several feedstock pathways under the RFS program. These feedstocks include gas produced at landfills and wastewater treatment facilities as well as animal waste and food waste decomposed through anaerobic digestion by natural organisms. Biogas collected from these feedstock sources can be purified and compressed or liquefied for use as a transportation fuel.

As biogas is often produced at facilities like landfills or dairy farms that have a main purpose other than the production of renewable fuel, using facility-wide emission inventories as an estimate for fuel production emissions, as used with liquid renewable fuels, would be inappropriate. Consequently, to estimate emission impacts from the production of fuels from biogas, we have used emission factors determined in Argonne National Laboratory's R&D GREET (Greenhouse gases, Regulated Emissions, and Energy use in Technologies) 2023rev1

[161] EPA, "RINs Generated Transactions." https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rins-generated-transactions.

model for CO, NO_x, PM_{10}, $PM_{2.5}$, SO_2, and VOCs.[162] Table 4.1.2.1.2-1 summarizes emissions resulting from the process steps of upgrading, purifying, and compressing or liquifying biogas to create transportation fuel as published in GREET. We have excluded emissions from process steps that would occur regardless of if the waste product would be used to produce renewable CNG/LNG or handled through typical disposal method, e.g., onsite transport and anaerobic breakdown. Analogous to our analysis of emissions from the production of ethanol, biodiesel, and renewable diesel, we have also excluded emissions occurring upstream of the CNG or LNG production facility and those from transport and storage of the finished fuel.

Table 4.1.2.1.2-1: GREET Pollutant Emission Factors From the Production of Renewable CNG and LNG from Biogas by Various Feedstocks (g/mmBtu)

	CNG				LNG		
Pollutant	**Landfill Gas**	**Wastewater Treatment**	**Animal Waste Digestion**	**Food Waste Digestion**	**Landfill Gas**	**Wastewater Treatment**	**Animal Waste Digestion**
VOC	1.0934	0.6654	0.6654	1.1278	1.4576	1.0674	1.0674
CO	3.8889	2.3666	2.3666	8.8899	5.1842	3.7964	3.7964
NO_x	6.8882	4.1917	4.1917	8.6340	9.1824	6.7243	6.7243
PM_{10}	0.9967	0.6065	0.6065	0.8545	1.3287	0.9730	0.9730
$PM_{2.5}$	0.5630	0.3426	0.3426	0.4132	0.7505	0.5496	0.5496
SO_2	5.7654	3.5084	3.5084	3.6803	7.6856	5.6282	5.6282

While biogas CNG and LNG are considered a single fuel category in this rule, pollutant emission rates differ dependent on the biogas feedstock and product. To determine emissions factors that can be applied nationally to future years, the ratio of RINs generated from biogas feedstock sources for the year 2023 was used to determine a weighted emissions factor to apply to 2026–2030. While we do not anticipate this rule would significantly alter the ratio of biogas feedstock sources or renewable CNG:LNG, external factors may influence the industry and affect these ratios. Comparing the 2026–2030 CNG/LNG from biogas proposed fuel volumes to the 2025 Baseline volumes, there is projected to be a reduction in renewable CNG/LNG production from biogas in future years as compared to current production (see Preamble Section 3). We assume in this analysis that this reduction will equally impact current biogas feedstocks and fuel products.

The breakdown of biogas feedstock sources was determined using the 2023 RIN generation feedstock summary report and presented in Tables 4.1.2.1.2-2 and 3.[163] The number of domestic facilities for each feedstock type was obtained through EPA EMTS records and

[162] Wang, Michael, Elgowainy, Amgad, Lee, Uisung, Baek, Kwang H., Balchandani, Sweta, Benavides, Pahola T., Burnham, Andrew, Cai, Hao, Chen, Peter, Gan, Yu, Gracida-Alvarez, Ulises R., Hawkins, Troy R., Huang, Tai-Yuan, Iyer, Rakesh K., Kar, Saurajyoti, Kelly, Jarod C., Kim, Taemin, Kolodziej, Christopher, Lee, Kyuha, Liu, Xinyu, Lu, Zifeng, Masum, Farhad, Morales, Michele, Ng, Clarence, Ou, Longwen, Poddar, Tuhin, Reddi, Krishna, Shukla, Siddharth, Singh, Udayan, Sun, Lili, Sun, Pingping, Sykora, Tom, Vyawahare, Pradeep, and Zhang, Jingyi. "Greenhouse gases, Regulated Emissions, and Energy use in Technologies Model ® (2023 Excel)." Computer software. October 09, 2023. https://doi.org/10.11578/GREET-Excel-2023/dc.20230907.1.

[163] EPA, "RINs Generated Transactions." https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rins-generated-transactions.

excludes facilities that produced imported renewable CNG/LNG.[164] The feedstock summary report does not distinguish RINs generated at facilities producing biogas domestically from RINs generated for imported biogas CNG and LNG. Therefore, both imported and domestic RINs are used in determining the production emission factors for biogas. In 2023, less than 1% of renewable CNG generating RINs was imported. Approximately 43% of renewable LNG RINs were generated by importers representing about 5% of the total CNG/LNG biogas RINs.

Table 4.1.2.1.2-2: RINs Generated in 2023 From the Production of Renewable CNG From Biogas

Facility Type	Number of Domestic Facilities	million RINs	% of CNG RINs
Landfill	96	484	70%
Animal Waste Digester	118	182	26%
Wastewater Treatment or Food Waste Digester	21	21	3%
Total	235	688	

Table 4.1.2.1.2-3: RINs Generated in 2023 From the Production of Renewable LNG From Biogas

<table>
<tr><th>Facility Type</th><th>Number of Domestic Facilities</th><th>million RINs</th><th>% of LNG RINs</th></tr>
<tr><td>Landfill</td><td>-</td><td>85</td><td>99.4%</td></tr>
<tr><td>Wastewater Treatment</td><td>-</td><td rowspan="2">0.5</td><td rowspan="2">0.6%</td></tr>
<tr><td>Animal Waste Digester</td><td>-</td></tr>
<tr><td>Total</td><td>20</td><td>85.5</td><td></td></tr>
</table>

Applying the 2023 fractions of biogas RINs from feedstock and fuel types, and weighting by number of RINs produced from each pathway, total emissions rates for criteria air pollutants were determined for biogas production as shown in Table 4.1.2.1.2-4. Emission rates are presented as mass of pollutant per million RINs using the 77,000 Btu per RIN equivalence value for renewable CNG/LNG. Emissions impacts from the production of renewable CNG/LNG from biogas resulting from the difference between the Proposed Volumes and Volume Scenarios and the No RFS Baseline are presented in Table 4.1.2.1.2-5.[165]

[164] The EMTS reports contain CBI regarding RINs generated at individual biogas facilities. These data were used in this analysis; however, we have aggregated some facility types in Tables 4.1.2.1.2-2 and 3 to protect this information.
[165] The renewable CNG/LNG from biogas volumes are identical in the both the Low and High Volume Scenarios as well as the Proposed Volumes. Therefore, the emission impacts are also identical and presented here as a single result.

Table 4.1.2.1.2-4: Pollutant Emissions Factors From Production of Biogas Renewable CNG and LNG

Pollutant	Weighted Emission Factors (g/mmBtu) CNG	LNG	Total Biogas	Biogas Production Emissions Factor (tons/million RIN)
CO	3.45	5.18	3.64	0.309
NO_x	6.10	9.17	6.44	0.546
PM_{10}	0.88	1.33	0.93	0.079
$PM_{2.5}$	0.50	0.75	0.53	0.045
SO_2	5.10	7.67	5.38	0.457
VOC	0.97	1.46	1.02	0.087

Table 4.1.2.1.2-5: Pollutant Emission Impact Estimates From Production of Biogas Renewable CNG and LNG Relative to the No RFS Baseline

Year	Volume Difference to No RFS (million RINs)	Biogas CNG/LNG Production Emissions (tons)					
		CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
2026	715	221	391	56	32	327	62
2027	682	211	373	54	30	312	59
2028	646	200	353	51	29	295	56
2029	609	188	333	48	27	278	53
2030	570	176	311	45	25	260	49

We also acknowledge that biogas is generated from landfill and wastewater treatment facility waste products, and the typical treatment of these waste products also result in pollutant emissions. Biogas generated at landfills and wastewater treatment plants is typically flared for safety and odor purposes, and these flares also generate emissions that are avoided when using the landfill gas or wastewater treatment gas to produce biofuel. The avoided flared emissions are not accounted for in this quantitative analysis.

4.1.2.1.3 Comparison of Emissions from the Production of Renewable Fuels to Petroleum and Fossil Fuels

We compared the emission rates of criteria air pollutants from the production of renewable fuels, as determined in this analysis, to fossil fuels. While the production and use of renewable fuels may not actually reduce one-for-one the production and use of fossil fuels, for the purposes of this comparison, we have assumed such a one-for-one displacement. Emission rates from the production of petroleum and fossil fuels were determined with the GREET model using process steps analogous to the steps included in our estimates for renewable fuels.[166] As

[166] Wang, Michael, Elgowainy, Amgad, Lee, Uisung, Baek, Kwang H., Balchandani, Sweta, Benavides, Pahola T., Burnham, Andrew, Cai, Hao, Chen, Peter, Gan, Yu, Gracida-Alvarez, Ulises R., Hawkins, Troy R., Huang, Tai-Yuan, Iyer, Rakesh K., Kar, Saurajyoti, Kelly, Jarod C., Kim, Taemin, Kolodziej, Christopher, Lee, Kyuha, Liu,

with renewable fuels, we did not estimate emissions from the transportation and storage of finished fuels. For direct comparison, production emission rates are presented as mass of pollutant per unit energy as renewable fuels do not necessarily have the same energy density as their petroleum and fossil counterparts. Pollutant emission factors from fuel production are presented in Tables 4.1.2.1.3-1 and 2.[167]

Emission rates from the production of petroleum gasoline were compared to those from production of ethanol, and emission rates from production of diesel were compared to those from production of biomass-based biodiesel and renewable diesel. Specifically, emission rates for gasoline blendstock (E0) production were used as a comparison to emission rates for ethanol production as GREET models gasoline containing 10% ethanol. Gasoline blendstock and petroleum diesel production emission rates included emissions that occur at the refinery, including intermediate product combustion, and facility non-combustion emissions. Feedstock emissions upstream of the petroleum refinery were not included.

To compare emission rates from the production of fossil natural gas to renewable CNG and LNG, we used emission rates which included the compression or liquefaction of natural gas along with pipeline transport of natural gas and upstream feedstock emissions. Emissions from feedstocks and transport for fossil natural gas were included while upstream emissions of biogas were not, as biogas is the waste product of other industrial processes and onsite fueling of renewable CNG/LNG was assumed.

Table 4.1.2.1.3-1: Comparison of Emission Rates From the Production of Corn Ethanol, Gasoline Blendstock, Biodiesel, Renewable Diesel, and Petroleum Diesel (g/mmBtu)

Pollutant	Corn Ethanol	Gasoline Blendstock (E0)	Biodiesel	Renewable Diesel	Petroleum Diesel
CO	9.93	2.38	4.52	4.95	1.52
NO_x	12.96	3.64	6.90	2.54	2.25
PM_{10}	7.35	0.96	2.81	0.92	0.54
$PM_{2.5}$	5.92	0.84	1.84	0.90	0.47
SO_2	10.93	1.23	22.10	0.70	0.78
VOC	16.23	2.21	30.63	7.59	1.65

Xinyu, Lu, Zifeng, Masum, Farhad, Morales, Michele, Ng, Clarence, Ou, Longwen, Poddar, Tuhin, Reddi, Krishna, Shukla, Siddharth, Singh, Udayan, Sun, Lili, Sun, Pingping, Sykora, Tom, Vyawahare, Pradeep, and Zhang, Jingyi. "Greenhouse gases, Regulated Emissions, and Energy use in Technologies Model ® (2023 Excel)." Computer software. October 09, 2023. https://doi.org/10.11578/GREET-Excel-2023/dc.20230907.1.
[167] The GREET model determines emission rates for only certain pollutants, limiting our analysis to those presented in this section.

Table 4.1.2.1.3-2: Comparison of Emission Rates From the Production of Renewable CNG/LNG and Fossil CNG/LNG (g/mmBtu)

Pollutant	Renewable CNG	Fossil CNG	Renewable LNG	Fossil LNG
CO	3.45	39.63	5.18	43.84
NO_x	6.10	47.31	9.17	50.14
PM_{10}	0.88	0.70	1.33	0.80
$PM_{2.5}$	0.50	0.55	0.75	0.76
SO_2	5.10	12.92	7.67	12.40
VOC	0.97	12.09	1.46	12.58

As seen in Table 4.1.2.1.3-1, emission rates from the production of ethanol are higher than gasoline, and, with the exception of SO_2 emissions from renewable diesel, biodiesel and renewable diesel emissions are higher than petroleum diesel. Particulate emission rates, both PM_{10} and $PM_{2.5}$, are comparable from the production of renewable CNG/LNG and fossil CNG/LNG, as shown in Table 4.1.2.1.3-2. However, emission rates of other CAPs are higher for fossil CNG/LNG than renewable CNG/LNG, primarily as a result of emissions from sourcing fossil natural gas.

Emission impacts presented in Tables 4.1.2.1.1-3 and 4 are from the production of biofuels resulting from the difference in the fuel volumes of this rule and the No RFS Baseline. However, a No RFS scenario could result in the increased production of petroleum or fossil fuels to meet transportation needs, and the production of those fuels would also produce emissions. As discussed at the beginning of this section, we have compared the emissions resulting from the potential additional production of petroleum and fossil fuels in a No RFS Baseline scenario to the production of biofuels from this rule in Table 4.1.2.1.3-3 assuming the production of those fuels will be reduced by the equivalent energy volume. We determined the equivalent energy volume of gasoline, diesel, and fossil CNG/LNG to the proposed renewable fuel volume differences and, using the emission rates in Tables 4.1.2.1.3-1 and 2, the emissions resulting from the production of those volumes of petroleum and fossil fuel. The net emissions presented are the difference between emissions from the production of the biofuel and the corresponding petroleum or fossil-based fuel.

Table 4.1.2.1.3-3: Net Emissions Impacts From the Production of Biofuels Relative to the No RFS Baseline for Low and High Volume Scenarios Accounting for the Potential Reduction in Petroleum and Fossil Fuel Production

Year	Fuel	Volume Difference to No RFS (million RINs)	Net Pollutant Emissions (tons)					
			CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
2026	Ethanol	212	135	166	114	91	173	250
	Biodiesel	2,266	598	927	451	273	4,247	5,773
	Renewable Diesel (Low Volume Scenario)	2,994	818	71	90	102	-20	1,419
	Renewable Diesel (High Volume Scenario)	3,494	955	83	105	120	-23	1,656
	Biogas CNG/LNG	715	-2,212	-2,500	13	-3	-454	-675
2027	Ethanol	228	145	179	122	97	186	269
	Biodiesel	2,282	602	933	454	275	4277	5,814
	Renewable Diesel (Low Volume Scenario)	3,323	908	79	99	114	-22	1,575
	Renewable Diesel (High Volume Scenario)	4,323	1,181	103	129	148	-29	2,049
	Biogas CNG/LNG	682	-2,110	-2,384	13	-3	-433	-644
2028	Ethanol	238	151	187	128	102	194	281
	Biodiesel	2,272	599	929	452	274	4,259	5,789
	Renewable Diesel (Low Volume Scenario)	3,714	1,015	88	111	127	-25	1,760
	Renewable Diesel (High Volume Scenario)	5,214	1,425	124	156	178	-35	2,471
	Biogas CNG/LNG	646	-1,999	-2,258	12	-3	-410	-610
2029	Ethanol	252	160	198	135	108	206	297
	Biodiesel	2,260	596	924	450	273	4,236	5,758
	Renewable Diesel (Low Volume Scenario)	4,041	1,104	96	121	138	-27	1,915
	Renewable Diesel (High Volume Scenario)	6,041	1,651	144	181	207	-40	2,863
	Biogas CNG/LNG	609	-1,884	-2,129	11	-3	-387	-575
2030	Ethanol	266	169	209	143	114	217	314
	Biodiesel	2,264	597	926	451	273	4,244	5,768
	Renewable Diesel (Low Volume Scenario)	4,399	1,202	105	132	151	-29	2,085
	Renewable Diesel (High Volume Scenario)	6,899	1,885	164	206	236	-46	3,270
	Biogas CNG/LNG	570	-1,764	-1,993	10	-3	-362	-538

Table 4.1.2.1.3-4: Net Emissions Impacts From the Production of Biofuels Relative to the No RFS Baseline for Proposed Volumes Accounting for the Potential Reduction in Petroleum and Fossil Fuel Production

Year	Fuel	Volume Difference to No RFS (million RINs)	Net Pollutant Emissions (tons)					
			CO	NO_x	PM_{10}	$PM_{2.5}$	SO_2	VOC
2026	Ethanol	212	135	166	114	91	173	250
	Biodiesel	1,716	453	702	341	207	3216	4372
	Renewable Diesel	3,823	1,045	91	114	131	-26	1,812
	Biogas CNG/LNG	715	-2,212	-2,500	13	-3	-454	-675
2027	Ethanol	228	145	179	122	97	186	269
	Biodiesel	1,752	462	717	349	211	3284	4464
	Renewable Diesel	4,132	1,129	98	124	141	-28	1,959
	Biogas CNG/LNG	682	-2,110	-2,384	13	-3	-433	-644

As seen in Tables 4.1.2.1.3-4 and 4, our analysis estimates the production of ethanol, biodiesel, and renewable diesel due to both the Low and High Volume Scenarios as well as the Proposed Volumes would result in additional emissions of CO, NO_x, PM_{10}, $PM_{2.5}$, and VOCs even after accounting for the potential reduction in petroleum fuel production emissions. The production of ethanol and biodiesel contributes to additional SO_2 emissions compared to a No RFS Baseline; however, the production of the proposed volumes of renewable diesel reduces SO_2 emissions if petroleum-based diesel production is reduced by an equivalent amount. We also estimate the proposed volumes of renewable CNG/LNG would reduce emissions of CO, NO_x, $PM_{2.5}$, SO_2, and VOCs if the production of fossil CNG/LNG is reduced by the same volume, but additional PM_{10} emissions would occur. In total across all biofuels, this results in a reduction in CO and NO_x from the large reductions from renewable CNG/LNG, and an increase in $PM_{2.5}$, PM_{10}, SO_2, and VOCs, mostly from the increases from biodiesel.

4.1.2.2 Emissions from the Transport of Biofuels

Emissions are also associated with the transport of biofuels from the production facility to the user. This includes emissions occurring from the storage of finished fuel, leakage during fueling or transport, and combustion emissions from the distribution mode of transport (e.g. road, rail). With biodiesel, renewable diesel, and renewable CNG/LNG from biogas, transport-related emissions are expected to be comparable to those from the transport of petroleum or fossil fuels.

As ethanol is blended with gasoline before use as a transportation fuel, there are emissions due to the additional transport and storage for blending that would not exist for a single product fuel. At the blending terminal, ethanol and gasoline are combined for various fuel combinations (e.g., E10, E15, E85), and 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. Previous modeled emissions from the transportation and storage of ethanol found the largest emission contribution was to VOCs due to evaporation.[168]

[168] Set 1 Rule RIA, Chapter 4.1.1.

4.1.2.3 Emissions from the End Use of Biofuels

End-use emissions are generated when biofuels are used in vehicles and include tailpipe exhaust emissions from the combustion of the fuels as well as non-tailpipe emissions generated by evaporation from dispensing, leakage, permeation, and venting. As ethanol differs in chemical composition from gasoline, and biodiesel and renewable diesel differ from petroleum-based diesel, tailpipe and non-tailpipe emissions from these fuels may also differ.

Renewable CNG and LNG are predominantly methane and not distinct chemically from fossil CNG and LNG. Therefore, end-use emissions of renewable CNG/LNG fuels are expected to be similar to vehicles using fossil CNG/LNG.

4.1.2.3.1 Ethanol

After distribution of ethanol-gasoline fuel blends to the retail outlet stations, end use at the vehicle occurs. Emissions at this step include evaporative losses during fueling, permeation, leaking, and diurnal tank venting, as well as 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.[169,170,171,172,173] However, as E10 gasoline is economical to blend in the absence of the RFS program after 2020, the only volumes of ethanol expected to result from this proposal are relatively small increases in ethanol used as E15 and E85. These small increases in E15 and E85 use, as discussed in Chapter 6, are not expected to have a significant impact on overall vehicle evaporative and exhaust emissions.

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[169] EPA, "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)," EPA-420-R-13-002. https://nepis.epa.gov/Exe/ZyPDF.cgi/P100GA0V.PDF?Dockey=P100GA0V.PDF.

[170] EPA, "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," EPA-420-R-13-004, April 2013. https://nepis.epa.gov/Exe/ZyPDF.cgi/P100GA80.PDF?Dockey=P100GA80.PDF.

[171] Morgan, Peter, Peter Lobato, Vinay Premnath, Svitlana Kroll, Kevin Brunner, and Robert Crawford. "Impacts of Splash-Blending on Particulate Emissions for SIDI Engines." *Coordinating Research Council Report*, June 26, 2018. https://crcsite.wpengine.com/wp-content/uploads/2019/05/CRC-E-94-3_Final-Report_2018-06-26.pdf.

[172] Morgan, Peter, Ian Smith, Vinay Premnath, Svitlana Kroll, and Robert Crawford. "Evaluation and Investigation of Fuel Effects on Gaseous and Particulate Emissions on SIDI in-Use Vehicles." *Coordinating Research Council Report*, March 2017. https://crcsite.wpengine.com/wp-content/uploads/2019/05/CRC_2017-3-21_03-20955_E94-2FinalReport-Rev1b.pdf.

[173] Karavalakis, Georgios, Thomas Durbin, Tianbo Tang. "Comparison of Exhaust Emissions Between E10 CaRFG and Splash Blended E15." June 2022. https://ww2.arb.ca.gov/sites/default/files/2022-07/E15_Final_Report_7-14-22_0.pdf.

4.1.2.3.2 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 MOVES model estimates criteria pollutant emission impacts for pre-2007 engines based on data generated for B20 (20 vol%) blends of soybean-based biodiesel in petroleum diesel and the percent change in emissions of total hydrocarbons, CO, NO_x, and $PM_{2.5}$ are shown in Table 4.1.2.3.2-1.[174] The biodiesel effects implemented in MOVES were obtained from an analysis conducted as part of the 2010 RFS2 Rule.[175] Studies of engines equipped with particulate filter and selective catalytic reduction aftertreatment systems that became widespread in 2007 and later models had shown no effect of B20 blends on emissions.

Table 4.1.2.3.2-1: 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

4.1.2.3.3 Renewable Diesel

Renewable diesel is made by hydrotreating vegetable oils or other fats or greases to remove oxygen and unsaturated bonds leaving a primarily paraffinic fuel. As a result, renewable diesel has a very high cetane index and very low aromatics and sulfur content in comparison to petroleum diesel fuel but is chemically analogous to petroleum diesel blendstocks. Studies indicate no impact, and in some cases reductions, of regulated pollutant and toxic emissions from vehicles operating on renewable diesel as compared to petroleum diesel.[176,177,178,179,180]

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[174] EPA, "Fuel Effects on Exhaust Emissions from Onroad Vehicles in MOVES3," EPA-420-R-20-016, November 2020.

[175] RFS2 Rule RIA Appendix A.

[176] Karavalakis, Georgios, Kent Johnson, and Thomas D. Durbin. "Combustion and Engine-Out Emissions Characteristics of a Light Duty Vehicle Operating on a Hydrogenated Vegetable Oil Renewable Diesel." *Coordinating Research Council Report*. July 2022. https://crcao.org/wp-content/uploads/2022/07/CRC-E-117-2022-Revised-CRC-Final-Report.pdf.

[177] Coordinating Research Council, "Biodiesel and Renewable Diesel Characterization and Testing in Modern LD Diesel Passenger Cars and Trucks," Project CRC AVFL-17b, November 2014.

[178] Na, Kwangsam, Subhasis Biswas, William Robertson, Keshav Sahay, Robert Okamoto, Alexander Mitchell, and Sharon Lemieux. "Impact of Biodiesel and Renewable Diesel on Emissions of Regulated Pollutants and Greenhouse Gases on a 2000 Heavy Duty Diesel Truck." *Atmospheric Environment* 107 (February 24, 2015): 307–14. https://doi.org/10.1016/j.atmosenv.2015.02.054.

[179] Singh, Devendra, K.A. Subramanian, and Mo Garg. "Comprehensive Review of Combustion, Performance and Emissions Characteristics of a Compression Ignition Engine Fueled With Hydroprocessed Renewable Diesel." *Renewable and Sustainable Energy Reviews* 81 (July 3, 2017): 2947–54. https://doi.org/10.1016/j.rser.2017.06.104.

[180] California EPA, "Staff Report – Multimedia Evaluation of Renewable Diesel," May 2015. https://ww2.arb.ca.gov/sites/default/files/2018-08/Renewable_Diesel_Multimedia_Evaluation_5-21-15.pdf.

Therefore, we do not expect an emissions impact from the end use of renewable diesel from this proposal.

4.1.3 Air Quality Impacts of Proposed Volumes

The geographic distribution of emissions impacts due to the Proposed Volumes varies depending on the feedstock and the process step, and the overall impact on air quality is a complex issue. At each step in the production, distribution, and end use stages, there are changes to the location, amount, and composition of emissions. Full-scale photochemical air quality modeling would be necessary to accurately project impacts on concentrations of various criteria and air toxic pollutants across the country. However, photochemical air quality modeling is time and resource intensive and as such requires knowledge of the proposed volume requirements early in the analytical process. Additionally, the spatial resolution of the air quality modeling data (12km by 12km grid cells) is not sufficient to capture very local impacts from production or the pollution concentration gradients near roads and other transport routes. For these reasons we use the emission impacts discussed above, rather than conducting photochemical modeling, to draw broad conclusions regarding the likely air quality impacts associated with the Proposed Volumes as compared to the No RFS Baseline.

Comparing the Proposed Volumes to the No RFS Baseline, we would expect some localized increases in some air pollutant concentrations, particularly at locations near production and transport routes. Production emissions from processing biofuel feedstocks would vary by pollutant, location, and magnitude, but we would expect increases in emissions at production facilities, due to the Proposed Volumes, that could impact local air quality. The location of emissions from biofuel production tends to be in more rural areas. Simultaneously, the production of petroleum fuels could decrease due to increased volumes of biofuels, but it could also stay the same with exports increasing or imports decreasing.[181] The location, composition, and magnitude of emissions from storage and transport of fuel would also be impacted as additional biofuels are stored and transported; the storage and transport of petroleum fuels could also change (e.g., transport to shipping terminals rather than gas stations). We would also expect varying impacts on end use emissions from vehicles running on fuels containing biofuel. We would expect emission increases for some pollutants and emission decreases for other pollutants from vehicles running on fuel with biodiesel, renewable CNG/LNG, or corn ethanol, and negligible impacts from vehicles running on fuel with renewable diesel. Overall, we expect the emission impacts from the Proposed Volumes to be variable in how they affect ambient concentrations of ozone and $PM_{2.5}$ in specific locations across the U.S.

The per gallon results of the LCA modeling included in the RtC3 indicate that we would expect that increased volumes of biofuels would lead to increased emissions and air quality impacts, however as the biofuels industry continues to mature those increases are likely to become smaller. We can also compare the changes in volumes and emissions for increased volumes of corn ethanol to the RFS2 air quality modeling analysis and we would expect the impacts of the proposed corn ethanol volumes on air quality to be relatively minor compared to RFS2, with any significant impacts likely to be localized in rural areas. RFS2 included a smaller

[181] Further discussion on the potential impacts of the Proposed Volumes on the production of petroleum fuels can be found in Chapter 6.4.1.

impact on BBD than what is being proposed in this rule. In addition to RFS2 comparisons, we can also compare the changes in volume and emissions for increased end use emissions of vehicles running on fuel with corn ethanol and biodiesel to the ABS. The ABS only considered impacts of the RFS program on end use emissions and overall, found relatively little change in $PM_{2.5}$ concentrations and increases and decreases in ozone concentrations depending on the location.

4.2 Conversion of Natural Lands

Regarding the conversion of wetlands and other natural lands to agriculture to meet demand for biofuel, EPA has explored this topic extensively in the Biofuels and the Environment: First Triennial Report to Congress[182] and the Biofuels and the Environment: Second Triennial Report to Congress.[183] These reports are led by EPA's Office of Research and Development (ORD) in accordance with Section 204 of EISA, which requires that EPA assess and report to Congress every three years on the current and potential future environmental and resource conservation impacts associated with increased biofuel production and use.

The first and second Reports to Congress assessed how biofuels broadly may be increasing cropland and driving conversion of natural lands (e.g., wetlands, forests, grasslands) for feedstock production. In January 2025, EPA finalized and published the RtC3. The third report builds on the previous two reports and includes new analyses to estimate the separable effects of the RFS program from the impacts of biofuels generally.

EPA further assessed how the Set 1 Rule for years 2023–2025 may increase cropland in the Set 1 Rule RIA and Biological Evaluation,[184] the latter of which was completed in accordance with the Endangered Species Act (ESA) Section 7 consultation process. The findings and conclusions from these documents, as well as all three Reports to Congress, relied heavily on studies from the peer reviewed literature in addition to additional analyses completed by the EPA.

In this chapter, we first summarize the historical data and information contributing to our current understanding of natural land conversion effects from agriculture and biofuels, as well as our understanding of potential effects from past RFS volumes specifically (Chapter 4.2.1). Because the Set 1 Rule RIA, finalized in 2023, included a literature review of articles examining conversion of wetlands and other lands, we also reviewed and discuss new literature that has come out in 2023-2024 related to this topic (Chapter 4.2.2). The last subsection explores the potential natural land conversion impacts from this rule (Chapter 4.2.3).

4.2.1 Natural Land Conversion Effects

The aforementioned documents (Biofuels and the Environment: Reports to Congress, Set 1 Rule RIA, and Biological Evaluation) have greatly contributed to EPA's understanding of how

[182] EPA, "Biofuels and the Environment: First Triennial Report to Congress," EPA/600/R-10/183F, December 2011.
[183] EPA, "Biofuels and the Environment: Second Triennial Report to Congress," EPA/600/R-18/195F, June 2018.
[184] EPA, "Biological Evaluation of the Renewable Fuel Standard Set Rule and Addendum," EPA-420-R-23-029, May 2023.

agriculture, biofuel production and consumption, and past RFS renewable volume obligations influenced the conversion of natural lands. A summary of findings and EPA's understanding in these areas are explained in this subsection.

The conversion of natural lands (e.g., wetlands, grasslands, forests) is associated with biofuel production and consumption through the growth of crop-based feedstocks, rather than through the production of waste fats, oils and greases, or biogas. Corn and soybeans are the dominant crop-based feedstocks used for biofuel production, followed by canola. As such, the production of these three feedstocks is the main concern when it comes to conversion of natural lands.[185]

The RtC3 discusses historical trends from several land cover federal datasets. Data from the USDA National Resource Inventory (NRI), Cropland Data Layer (CDL), and Census of Agriculture support a finding that from 2007 to 2017 there has been a 10 million-acre increase in cultivated cropland.[186] The report found that more than half of the corn and soybean increase in this time period came from other cultivated cropland (56%). Additionally, the 10 million-acre increase in cultivated cropland from 2007 to 2017 coincided with a 15 million-acre decline in perennially managed land, including Conservation Reserve Program (CRP) lands, pasture, and noncultivated cropland.

Findings from a study by Lark et al. (2015)[187] showed that, from 2008 to 2012, grasslands were the source for 77% of all new croplands. The category of "grasslands" in this study included both native and planted grasslands, as well as those that may have been cultivated for pasture or hay. The study authors found that just over a quarter of these grasslands, or 22% of all lands converted, qualified as long-term grasslands. Further, they found that shrubland and long-term idle lands each accounted for 8% of all new croplands. In contrast, 3% of forested areas and 2% of wetlands were converted to agriculture.

Similarly, Lark et al. (2020)[188] found that 88% of grasslands were the source of new cropland when looking at a longer timeframe, from 2008-2016. A total of 2.8 million acres of new cropland (28%) originated from longstanding habitat sites, of which 2.3 million acres, or 81%, were long-term grasslands. They found that, relative to all converted land, 26% of converted grasslands, 29% of converted wetlands, 44% of converted forest, and 52% of converted shrublands were previously categorized as long-term sites.

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[185] Though it should be highlighted that to the extent the use of FOG for biofuel production comes from shifting the uses of those feedstocks from other uses, they may then be backfilled with crop-based feedstocks, resulting in the very same concerns with respect to conversion of natural lands.

[186] Despite the observed increase in cropland from 2007–2017, cultivated cropland for this period was still below historic levels. Further, the latest Census of Agriculture data suggests that harvested cropland has declined since 2017, from about 320 million acres in 2017 to 301 million acres in 2022. Though, it is important to note that this was likely affected by a drought in the Midwestern U.S. in 2022, and since that drought planted and harvested acres have recovered.

[187] Lark, Tyler J, J Meghan Salmon, and Holly K Gibbs. "Cropland Expansion Outpaces Agricultural and Biofuel Policies in the United States." *Environmental Research Letters* 10, no. 4 (April 1, 2015): 044003. https://doi.org/10.1088/1748-9326/10/4/044003.

[188] Lark, Tyler J., Seth A. Spawn, Matthew Bougie, and Holly K. Gibbs. "Cropland Expansion in the United States Produces Marginal Yields at High Costs to Wildlife." *Nature Communications* 11, no. 1 (September 9, 2020). https://doi.org/10.1038/s41467-020-18045-z.

The studies referenced above examined historical land use changes and natural land conversion patterns that can be attributed to various causes. One potential cause for the observed land use changes is demand for renewable fuel and production of crop-based feedstocks. Regarding the potential natural land conversion effects from the RFS program alone, however, it is important to note that there are many factors, including economic and policy drivers at local, state, nation, and global scales, that influence renewable fuel production and consumption in the U.S. For example, biodiesel tax policy in the U.S. has had a significant impact on the volume of biodiesel and renewable diesel used in the U.S. historically, as discussed in more detail in Chapter 7. The RFS program is only one factor that influences renewable fuel use and consumption, and it is challenging to separate out the effects of the RFS program from other factors. Despite the challenges, EPA has worked in recent years to evaluate the potential effects of the RFS program alone. We summarize what EPA has previously evaluated for past RFS volumes in the text immediately below. A discussion on the potential effects of this rule is included in Chapter 4.2.3.

EPA's analyses conducted in past years, separate from this proposal, demonstrate that the RFS program has played a larger role in production and consumption of biodiesel and renewable diesel compared to corn ethanol. For example, the RtC3 completed an attribution analysis for corn ethanol and estimated that 0–9% of corn ethanol production and consumption is likely attributable to the RFS program historically from 2006–2019. In contrast, 36% of biodiesel production was found to be attributable to the RFS program from 2002-2020 based on a study that used the Bioenergy Scenario Model.[189] Another study which used a multi-period, partial equilibrium economic model (BEPAM) found that land use change intensity of biodiesel ranged from 0.78–1.5 million acres per billion gallons in 2018; in comparison, the values for corn ethanol ranged from 0.57–0.75 million acres per billion gallons.[190] Given these findings, potential land use changes from the RFS program in past years would likely have been greater for soybean production for biodiesel and renewable diesel, relative to corn production for corn ethanol.

Because grasslands, pasturelands, CRP lands, idle lands, and noncultivated cropland have been most impacted by agricultural expansion historically, any land conversion due to the RFS program likely affected these land types to a greater extent (i.e., more acres of conversion) relative to wetlands and forests. Still, some effects of past RFS volumes on wetland and forest conversion may have occurred. An analysis in the RtC3, for example, estimated that nearly 275,000 acres of wetlands concentrated in the Prairie Pothole Region were lost from 2008–2016. However, the report recognized that only a percentage of this (0–20%) may be attributable to the RFS program.

In addition, the Set 1 Rule's RIA and Biological Evaluation discussed the potential for an associated increase in crop production from the 2023-2025 Set 1 Rule alone. In the Set 1 Rule

[189] Miller, Jesse, Christopher Clark, Steve Peterson, and Emily Newes. "Estimated Attribution of the RFS Program on Soybean Biodiesel in the U.S. Using the Bioenergy Scenario Model." *Energy Policy* 192 (July 3, 2024): 114250. https://doi.org/10.1016/j.enpol.2024.114250.
[190] Wang, Weiwei, and Madhu Khanna. "Land Use Effects of Biofuel Production in the US." *Environmental Research Communications* 5, no. 5 (May 1, 2023): 055007. https://doi.org/10.1088/2515-7620/acd1d7.

Biological Evaluation, EPA's analyses estimated that the Set 1 Rule could potentially lead to an increase of as much as 2.65 million acres of cropland by 2025, approximately 1% of the projected U.S. acreage for major field crops in 2025. Related to this finding, it is important to note the following:

- The estimated 2.65 million acres of cropland increase from the Set 1 Rule represents the maximum potential impact based on a number of assumptions, many of which were very conservative in nature, that EPA made in the Biological Evaluation.
- Additional analyses supporting the Biological Evaluation suggested that the demand for biodiesel and renewable diesel from the Set 1 Rule could be met fully by changes to imports/exports or by projected increases in feedstock yields on existing soybean lands, highlighting the uncertainty in knowing the exact impacts from the Set 1 Rule.

Out of the estimated 2.65 million acres, a maximum potential acreage impact of 1.93 million acres by 2025 (or 1.57 and 1.78 million acres by 2023 and 2024, respectively) was estimated to come from soybean biodiesel volume increases in the Set 1 Rule. In addition, a maximum potential acreage impact of 0.26 million acres by 2025 was estimated to come from canola biodiesel. Since 2023 and 2024 have come to pass, we can look at BBD supply data from those years to infer what may have actually happened. For example, in the year 2023 alone, additional BBD supply came from a significant increase in biodiesel imports. There was very little increase in domestic feedstock production; instead, feedstock was sourced from increased FOG imports, canola imports from Canada, and a diversion of soybean oil from other uses. In the case of FOG as an example, imports have risen gradually since 2014 followed by rapid increase in more recent years (2022 and 2023) in particular. This rise is likely due to multiple factors, including a rapid increase in renewable diesel production capacity domestically, greater incentives from California's LCFS program and other state clean fuels programs for BBD produced from FOG, the anticipated changes to the federal tax credit in 2025, and biofuel policies internationally. This and other information and data regarding imports of BBD supply is discussed in more detail in Chapter 7.

With regard to BBD supply, Chapter 7 also discusses trends in exports. Soybean oil exports peaked in 2009/2010 and since then exports have generally decreased as the quantity of soybean oil used for domestic biofuel production has gone up. USDA estimates that in the 2022/2023 agricultural marketing year soybean oil exports decreased by approximately 90%. Given these significant changes in soybean oil exports, and well as increases in imports as described above, it is very possible that very minimal to no land use impacts have occurred in years 2023 and 2024 so far from the final BBD volumes.

Moreover, EPA acknowledges that, for any effects that may have occurred from the RFS program, it is currently not possible to project the precise locations of agricultural expansion with confidence due to the vast quantity of potential cropland in the U.S. and the multitude of factors that contribute to an individual farmer's decision whether to bring additional land into crop production. For natural lands that were converted to agriculture in past years, it is also not possible to say which parcels of lands were converted due to the RFS program alone. To date, EPA has advanced our knowledge of the land use impacts from the RFS program at a national scale but understanding the impacts at the local level remains a challenge. In fact, with the currently available science, the finest level possible for understanding the effect of biofuel production on cropland is at the county scale, though such analyses for the Set 1 Rule rendered limited information.[191] It is currently not possible to know effects at an even smaller scale, such as the field or 30-meter scale, for example, due to many degrees of freedom leading to irreducible uncertainty.

4.2.2 New Literature on the Conversion of Natural Lands

The above subsection summarizes information known by EPA from previous work completed, including the Triennial Reports to Congress and Set 1 Biological Evaluation. To keep abreast of the latest science, EPA also completed a literature review of research of articles and other federal agency assessments published in 2023-2024.

In conducting this literature review, EPA did not find any articles or publications examining the potential impacts of the RFS program alone on conversion of natural lands. Nonetheless, other publications, such as the 2024 Status and Trends of Wetlands in the Conterminous United States Report to Congress by the U.S. Fish and Wildlife Service (FWS),[192] provide insights into how agriculture impacted wetland ecosystems from 2009–2019. The report shows that agricultural activities have been a significant cause of wetland loss. From 2009–2019, the U.S. experienced a net loss of 221,000 acres of wetlands. Of this total, the report states that "[c]onversion to upland categories (agriculture, urban, forested plantation, rural development, other upland) was the dominant driver of net wetland loss," contributing to a total loss of 194,000 wetland acres.

The report also explains that vegetated wetlands, and freshwater vegetated wetlands in particular, were especially impacted. These wetlands are important for controlling floods, improving water quality, and storing carbon. According to the report, the largest driver of all freshwater wetland net loss was an increase in upland forested plantations, followed by increases in upland agriculture.

In addition, the Status and Trends of Wetlands in the Conterminous United States report from FWS highlights that net wetland loss has accelerated by more than half of the previous study period (2004–2009), continuing a long-term pattern of wetland degradation. This ongoing loss has reduced wetlands' ability to provide critical ecosystem services such as flood control. The report also emphasizes that agriculture not only replaces wetlands, but also "reduces wetland pollutant removal services, and increases pollutant inputs in the form of fertilizer, waste, sediment, and toxins."

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[191] In the Set 1 Rule, county-level estimates would have been possible by leveraging an econometric analysis for corn ethanol effects due to proximity to ethanol facilities, specifically, as opposed to corn ethanol crop price effects. However, the proximity to ethanol facility effects were estimated to be zero for total cropland in the Set 1 Rule Biological Evaluation, so EPA was not able to accomplish county-level estimates for this. See Li et al. (2019) and updated analyses by Madhu Khanna as described in the Set 1 Rule Biological Evaluation for more information.

[192] U.S. Fish & Wildlife Services, "Status and Trends of Wetlands in the Conterminous United States 2009 to 2019," 2024. https://www.fws.gov/sites/default/files/documents/2024-04/wetlands-status-and-trends-report-2009-to-2019_0.pdf.

Another study by Guptaa (2024)[193] highlights the concerning rate of green cover loss worldwide, with a specific focus on wetlands, forests, and grasslands impacted by agricultural expansion and biofuel production. The study details that agricultural expansion remains a primary driver of green cover depletion, particularly for crops like soy and palm oil, which replace diverse ecosystems with monocultures, "severely affecting biodiversity and carbon storage." The report adds that wetland areas in the Mississippi River Delta have been significantly impacted, as human activities such as "levee construction and oil extraction" compound climate-driven stressors like sea-level rise, leading to further degradation of these ecosystems.

Findings from other studies published in the year 2023 or 2024 uphold our understanding that cropland expansion in the U.S. has historically come from conversion of forest, shrubland, and grassland and that agriculture continues to be an ongoing threat to grasslands.[194,195] Bedrosian et al. (2024)[196] further highlight the risk of conversion of the sagebrush biome (e.g., in the Northern Great Plains), and the importance of land conservation efforts to protect these vulnerable ecosystems. As stated above, EPA found no studies or publications linking the effects of the RFS specifically to conversion of natural lands such as grasslands and wetlands.

4.2.3 Potential Natural Land Conversion Impacts From This Rule

A first step to understanding the potential natural land conversion impacts from this rule is looking at the volume changes expected from this rule relative to the No RFS and 2025 Baselines. In the process of developing proposed volume requirements for this rule, EPA completed 5-year analyses for two Volume Scenarios. EPA then completed additional analyses for the Proposed Volumes for 2026 and 2027. The projected BBD and conventional renewable fuel volume changes for the Low Volume Scenario, High Volume Scenario, and Proposed Volumes are shown in Tables 4.2-1 and 2. More detailed information can be found in Chapter 3.

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193 Guptaa, Rakshan. "Green Cover Depletion and Its Projection Over the Upcoming Years." *Darpan International Research Analysis* 12, no. 2 (May 23, 2024): 76–87. https://doi.org/10.36676/dira.v12.i2.06.

194 Li, Xiaoyong, Hanqin Tian, Chaoqun Lu, and Shufen Pan. "Four-century History of Land Transformation by Humans in the United States (1630–2020): Annual and 1 Km Grid Data for the HIStory of LAND Changes (HISLAND-US)." *Earth System Science Data* 15, no. 2 (March 3, 2023): 1005–35. https://doi.org/10.5194/essd-15-1005-2023.

195 Douglas, David J. T., Jessica Waldinger, Zoya Buckmire, Kathryn Gibb, Juan P. Medina, Lee Sutcliffe, Christa Beckmann, et al. "A Global Review Identifies Agriculture as the Main Threat to Declining Grassland Birds." *Ibis* 165, no. 4 (May 9, 2023): 1107–28. https://doi.org/10.1111/ibi.13223.

196 Bedrosian, Geoffrey, Kevin E. Doherty, Brian H. Martin, David M. Theobald, Scott L. Morford, Joseph T. Smith, Alexander V. Kumar, et al. "Modeling Cropland Conversion Risk to Scale-Up Averted Loss of Core Sagebrush Rangelands." *Rangeland Ecology & Management* 97 (October 15, 2024): 73–83. https://doi.org/10.1016/j.rama.2024.08.011.

Table 4.2-1: Total BBD Renewable Fuel Volume Changes Relative to the No RFS Baseline and 2025 Baseline (million gallons)

Low Volume Scenario - Total Biomass-Based Diesel Volumes					
	2026	**2027**	**2028**	**2029**	**2030**
Relative to the No RFS Baseline	3,379	3,595	3,833	4,030	4,255
Relative to the 2025 Baseline	986	1,298	1,611	1,923	2,236
High Volume Scenario - Total Biomass-Based Diesel Volumes					
	2026	**2027**	**2028**	**2029**	**2030**
Relative to the No RFS Baseline	3,691	4,220	4,770	5,280	5,818
Relative to the 2025 Baseline	1,298	1,923	2,548	3,173	3,798
Proposed Volumes - Total Biomass-Based Diesel Volumes					
	2026	**2027**	**2028**	**2029**	**2030**
Relative to the No RFS Baseline	4,817	5,050	n/a	n/a	n/a
Relative to the 2025 Baseline	2,424	2,753	n/a	n/a	n/a

Table 4.2-2: Conventional Renewable Fuel Volume Changes Relative to the No RFS Baseline and 2025 Baseline (million gallons)

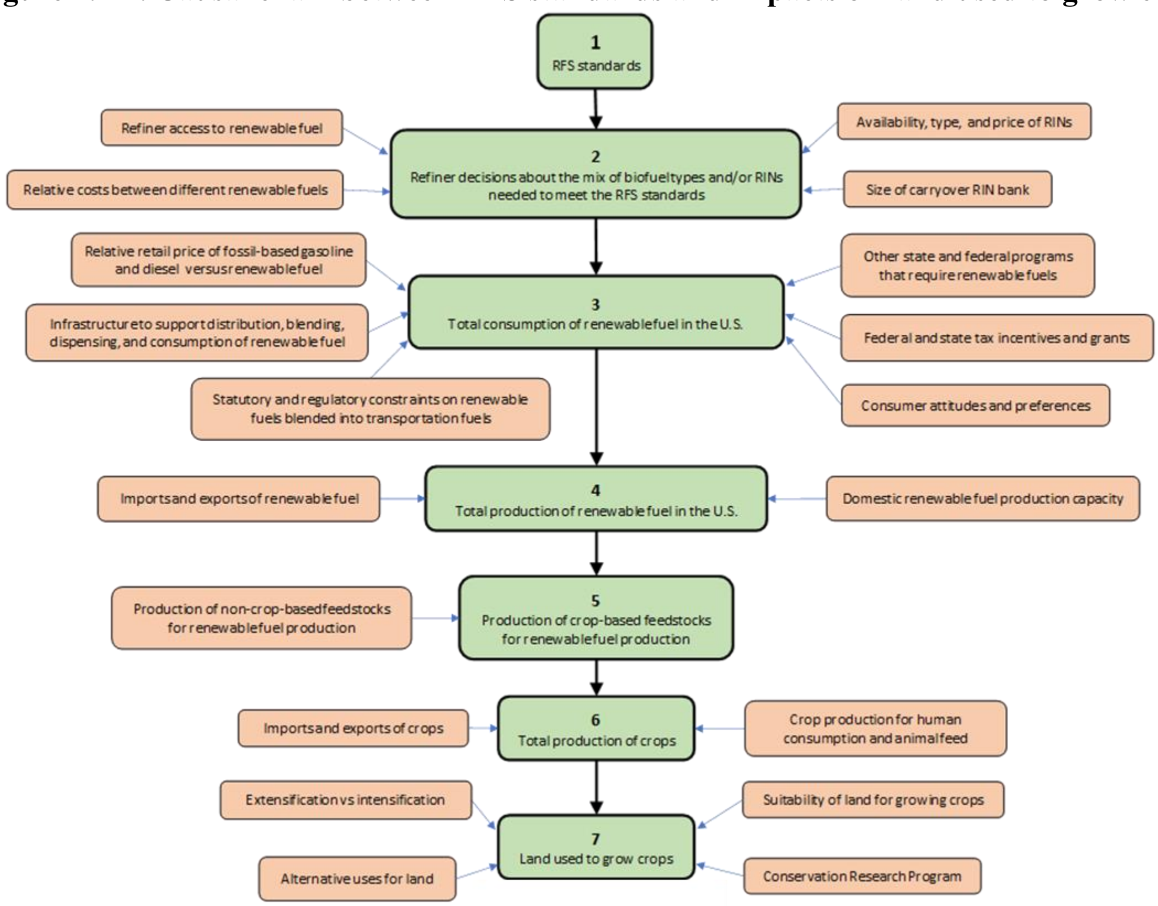
Low Volume Scenario - Conventional Volumes					
	2026	**2027**	**2028**	**2029**	**2030**
Relative to the No RFS Baseline	212	228	238	252	266
Relative to the 2025 Baseline	-158	-279	-425	-589	-769
High Volume Scenario - Conventional Volumes					
	2026	**2027**	**2028**	**2029**	**2030**
Relative to the No RFS Baseline	212	228	238	252	266
Relative to the 2025 Baseline	-158	-279	-425	-589	-769
Proposed Volumes - Conventional Volumes					
	2026	**2027**	**2028**	**2029**	**2030**
Relative to the No RFS Baseline	212	228	n/a	n/a	n/a
Relative to the 2025 Baseline	-156	-277	n/a	n/a	n/a

Based on the values in Table 4.2-1, for all scenarios we would expect increases in BBD volumes attributable to this rule. As expected, compared to the Low Volume Scenario, the High Volume Scenario volume increases would be higher, which could potentially lead to greater land use effects. Since this proposal would reduce the number of RINs generated for imported renewable fuel and renewable fuel produced from imported feedstocks, the analyses demonstrate that we would see relatively high BBD volume increases for 2026 and 2027 years as well, even higher than the numbers for the High Volume Scenario in those two years. Even with lower RINs for imported renewable fuel and feedstocks, however, BBD volumes could be met through a variety of ways, for example by increased imports of FOG or diversions from other feedstock uses. But it could also lead to a potential increase in land conversion for agricultural lands to produce more feedstock (soy and canola, specifically) to meet extra BBD volume demands generated by this rule. An increase in land conversion for agricultural lands, as a result, could contribute to further loss of natural lands such as grasslands, wetlands, and forests.

The conventional renewable fuel projected volumes relative to the No RFS and 2025 Baselines tell a different story (Table 4.2-2). For all scenarios, the numbers suggest we would see an increase in volumes from this rule relative to the No RFS Baseline. However, compared to the existing 2025 Baseline as it exists following the Set 1 Rule and previous RFS annual rules, this rule would not lead to higher convention renewable fuel volumes as seen by the negative values in the table. As such, with respect to potential increases in agricultural conversion to meet conventional volume demands from this rule, we would not expect to see any increases because this rule would not generate additional demand for conventional biofuel.

For any conclusions drawn regarding the potential natural land conversion effects from this rule (e.g., from increased BBD volumes), it is important to note the significant assumptions and high uncertainty inherent in estimating acreage impact numbers at every step in the underlying causal relationship between the RFS standards and the land use effects that could result from increased production of crop-based feedstocks (Figure 4.2-1). For example, projecting the impact of increased biofuel demand on crop-based feedstock production is complicated by the fact that the majority of feedstocks are used in non-biofuel markets as well.

Figure 4.2-1. Causal chain between RFS standards and impacts on land used to grow crops



Of note is the "imports and exports of crops" factor in Figure 4.2-1, especially due to trends in recent years. As explained further in Chapter 7, additional U.S. soybean oil production could be possible in the future if we crushed more of our soybeans domestically and decreased exportation of whole soybeans. Furthermore, additional quantities of soybean oil could be made available for biofuel production from decreased exports of soybean oil itself. Potential changes in these and other export and import dynamics complicate our understanding of the actual land use change and natural land conversion effects from this rule.

Assuming some natural land loss effects could occur, and that past is prologue, any future expansion of agriculture from this rule would most likely impact grasslands, pasturelands, CRP lands, idle lands, and noncultivated cropland as demonstrated by findings from studies discussed in Section 4.2.1. Increased cropland may contribute to additional declines in wetlands and forests, but likely to a much lesser extent. As such, EPA expects that any potential extensification of agriculture from this rule would likely occur on these lands that have historically been impacted the most by agricultural expansion. Any impacts to wetlands and forests would likely occur at a much smaller scale since historically they have been impacted by agricultural conversion to a lesser degree than other land types. Still, additional losses of wetlands and forests could occur in ecologically sensitive areas or in places that are already experiencing cumulative environmental effects.

Regarding potential conversion of grasslands, pasture, idle lands, shrubland, and CRP lands, it is also important to note that only a portion of these lands would qualify as loss of long-term grasslands that likely support greater wildlife biodiversity, soil carbon storage, and ecosystem services. As stated previously, Lark et al. (2015) found that, from 2008-2012, grasslands were the source of 77% of new cropland and just over a quarter of these grasslands or 22% of all lands converted qualified as long-term grasslands. Pasture, idle croplands, and CRP lands that could fall under the category of grasslands or natural lands may also be converted due to land use changes from this rule, but ecosystem impacts such as soil carbon and species impacts, would likely occur to a lesser extent on these lands compared to scenarios in which conversion of long-term grasslands occurs.

EPA plans to further explore the potential land use change effects from this rule in a Biological Evaluation document for this rule to be completed in consultation with the Fish and Wildlife and National Marine Fisheries Services (NMFS). EPA expects to largely use the same analytical approaches that were used in the Set 1 Biological Evaluation. For the Set 1 Biological Evaluation, we leveraged econometric analyses available in published literature (Li et al. 2019) combined with updated data from Dr. Madhu Khanna to estimate the change in corn acres and total cropland per billion gallons of ethanol production. EPA is currently working to update this data again with more recent years of data and explore whether the analyses could be modified and used in combination with other observed trends to estimate the potential change in soybean acres and total cropland in response to soybean oil production from this rule. EPA anticipates finishing these analyses before this rule is finalized.

4.3 Soil and Water Quality

As was done in the Set 1 Rule RIA, soil and water quality are addressed together in one section because in many ways they are intertwined. Soil health, organic matter content, erosion, and nutrient leaching from agricultural soils affects the water quality of nearby and downstream water bodies. 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.

On the topic of how biofuel production and use may impact soil and water quality, like the topic of conversion of natural lands this has been discussed in detail in the three Biofuels and the Environment: Triennial Reports to Congress, in addition to the 2023-2025 Set 1 Rule RIA and Biological Evaluation. The past effects of the RFS program alone have also been assessed in more recent years, and in particular are discussed in the RtC3 as well as the Biological Evaluation for the Set 1 Rule.

In this section, we first explore the historical data and information contributing to our understanding of soil and water quality effects from agriculture and biofuels broadly, as well as our understanding of potential effects from past RFS volumes (Chapter 4.3.1). Because the Set 1 Rule RIA, finalized in 2023, included a literature review of articles examining soil and water quality effects, we also reviewed and discuss new literature that has come out in 2023–2024 related to this topic (Chapter 4.3.2). The last subsection explores the potential soil and water quality impacts from this rule (Chapter 4.3.3).

4.3.1 Soil and Water Quality Impacts

A summary of findings and EPA's understanding of how agriculture, biofuel production, and the RFS program have historically impacted soil and water quality is included below.

First, it is well understood that soil and water quality effects from biofuels are largely associated with production of crop-based feedstocks (corn, soybean, canola) rather than waste fats, oils and greases, or biogas. The conversion of grasslands or other lands to production of agriculture for biofuel feedstocks adversely affects soil quality, with increases in erosion and the loss of soil nutrients, soil organic matter, and soil carbon.

With regard to water quality, extensification of cropland typically corresponds with an increase in nutrient (nitrogen and phosphorus) and sediment pollution from agricultural runoff, which impairs local water quality and contributes to algal blooms and hypoxia in the Gulf of Mexico and other water bodies. An increase in cropland also typically corresponds with an increase in pesticide use which detrimentally affects nearby and downstream water quality. It is also well understood that 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 natural lands such as grasslands.

The unique physical, biological, and geological characteristics of the land affected are important to understanding the magnitude of soil and water quality effects. For example, as referenced in the Set 1 Rule RIA, LeDuc et al. (2017)[197] simulated greater erosion and loss of soil carbon and nitrogen from converting low productivity, highly sloped Conservation Reserve Program grasslands compared to those with higher productivity soils and lower slopes.

[197] LeDuc, Stephen D., Xuesong Zhang, Christopher M. Clark, and R. César Izaurralde. "Cellulosic Feedstock Production on Conservation Reserve Program Land: Potential Yields and Environmental Effects." *GCB Bioenergy* 9, no. 2 (February 26, 2016): 460–68. https://doi.org/10.1111/gcbb.12352.

The type of feedstock being grown also matters. Soybean, a nitrogen fixer, generally requires less fertilizer application compared to corn and other crops. As such, nitrogen runoff from soybean cropland may be lower relative to other crops. Soil and water quality impacts further depend on whether best management practices, if any, are being applied on the agricultural land. The adoption of conservation tillage, cover crops, and soil amendments among other practices can help counterbalance the detrimental effects to soil and water quality from agriculture. That said, there is nuance in the scientific literature that suggests there is still much to be learned about these practices, as for example a recent meta-analysis suggests that some conservation tillage (e.g., no till) actually increases nitrate leaching.[198]

The weather conditions on a given day or year matter as well. The amount of precipitation will affect runoff of nutrients and sediment from agricultural lands, affecting both edge of stream environments and the size of dead zones such as in the Gulf of Mexico.[199,200]

It is also important to recognize other potential effects from biofuel production and consumption that may affect to soil and water quality. For example, although perennial grasses and other types of feedstocks are not grown at the commercial scale, the scientific literature shows that perennial grasses or woody biomass grown on marginal lands can help restore soil quality,[201] depending on the plant species being grown and the type of land being converted.[202]

Chemical releases, biofuel leaks, and spills from above-ground and underground storage tanks as well as transportation tanks can contaminate soil and groundwater. As such, increased consumption of biofuels could increase leaks that affect soil and water quality. This is discussed in more detail in the Set 1 Rule RIA.

In addition, biogas used that is upgraded to RNG may have localized soil or water impacts. The associated manure collection and agricultural anaerobic digesters may decrease pathogen risk in water, but without proper treatment, excess nutrient pollution can also be a concern.

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[198] Li, Jinbo, Wei Hu, Henry Wai Chau, Mike Beare, Rogerio Cichota, Edmar Teixeira, Tom Moore, et al. "Response of Nitrate Leaching to No-tillage Is Dependent on Soil, Climate, and Management Factors: A Global Meta-analysis." *Global Change Biology* 29, no. 8 (January 26, 2023): 2172–87. https://doi.org/10.1111/gcb.16618.
[199] Chang, Di, Shuo Li, and Zhengqing Lai. "Effects of Extreme Precipitation Intensity and Duration on the Runoff and Nutrient Yields." *Journal of Hydrology* 626 (October 6, 2023): 130281. https://doi.org/10.1016/j.jhydrol.2023.130281.
[200] Lu, Chaoqun, Jien Zhang, Hanqin Tian, William G. Crumpton, Mathew J. Helmers, Wei-Jun Cai, Charles S. Hopkinson, and Steven E. Lohrenz. "Increased Extreme Precipitation Challenges Nitrogen Load Management to the Gulf of Mexico." *Communications Earth & Environment* 1, no. 1 (September 18, 2020). https://doi.org/10.1038/s43247-020-00020-7.
[201] Blanco-Canqui, Humberto. "Growing Dedicated Energy Crops on Marginal Lands and Ecosystem Services." *Soil Science Society of America Journal* 80, no. 4 (July 1, 2016): 845–58. https://doi.org/10.2136/sssaj2016.03.0080.
[202] Robertson, G. Philip, Stephen K. Hamilton, Bradford L. Barham, Bruce E. Dale, R. Cesar Izaurralde, Randall D. Jackson, Douglas A. Landis, Scott M. Swinton, Kurt D. Thelen, and James M. Tiedje. "Cellulosic Biofuel Contributions to a Sustainable Energy Future: Choices and Outcomes." *Science* 356, no. 6345 (June 30, 2017). https://doi.org/10.1126/science.aal2324.

Lastly, palm oil production for biodiesel is an established industry in Southeast Asia for exportation to other countries such as the U.S. and should be considered. There is strong evidence that expanded palm oil production adversely affects soil and water quality in Southeast Asia as well as carbon sequestration.

For the purposes of this rulemaking, however, we are most interested in the potential effects from domestic production of crop-based feedstocks. An increase in cropland acreage for renewable fuel production and consumption in the U.S. would generally be expected to lead to more negative soil and water quality impacts. There are many factors that influence cropland acreage in the U.S., and the RFS program is only one factor. The EPA has also worked in recent years to evaluate the potential effects of the RFS program specifically on soil and water quality, and in particular from past RFS volumes.

As described in the RtC3, EPA ran an analysis using the Environmental Policy Integrated Climate (EPIC) model and found that the RFS program increased erosion, nitrogen loss, and soil organic carbon loss from 0–1.6%, 0–0.7%, and 0–1.1%, respectively, across a 12-state region between 2008–2016. As the report notes, these modeling estimates represent RFS effects for corn ethanol only. At the time of the analysis EPA was not able to evaluate additional quantitative effect from the RFS Program on soybean biodiesel and soybean acreage, nor any effect from crop switching on existing cropland. The report also notes that this finding comparatively represents up to 3.7% of the nitrogen retention benefits of the Conservation Reserve Program for the entire U.S.

The RtC3 also evaluated the potential water quality impacts from agriculture and the RFS program historically. Using the Soil and Water Assessment Tool (SWAT) model, EPA completed an analysis of estimated cropland expansion on water quality in the Missouri River Basin from 2008–2016. Grassland conversion to continuous corn resulted in the greatest increase in total nitrogen and total phosphorus loads (6.4% and 8.7% increase, respectively); followed by conversion to corn/soybean (6.0% and 6.5%); and then conversion to corn/wheat (2.5% and 3.9%). These results represent estimated water quality effects from general agricultural expansion in the Missouri River Basin from 2008-2016 and not the effects from the RFS program alone. Based on other analyses, the report suggests that approximately 0-20% of the observed changes may have been due to the RFS program.

Additionally, EPA's Biological Evaluation for the Set 1 Rule leveraged the Missouri River Basin SWAT analysis from the Triennial Report to Congress to assess the potential water quality effects from the Set 1 Rule. Results indicated that, even if the maximum projected acreage impacts from the Set 1 Rule (2.65 million acres total) were to occur, the water quality impacts would be small relative to total nutrient, sediment, and pesticide effects already happening at the mouth of the Mississippi and other larger water bodies within the action area. Moreover, based on additional qualitative analyses, EPA found in the Biological Evaluation that localized water quality impacts from the Set 1 Rule were likely to be discountable as defined under the ESA.

As discussed in Chapter 4.2.1, based on what we know happened in 2023 and 2024, those estimates from the Set 1 Biological Evaluation likely overestimated the actual effects from the

Set 1 Rule. For example, in 2023 alone there was very little increase in domestic feedstock production and additional BBD supply came from a significant increase in imports. These observed trends from recent years are discussed in more detail in Chapter 7.

Beyond EPA's work in these areas, a study by Lark and coauthors (2022)[203] examined the specific impacts from the RFS in past years. The authors found that, from 2008–2016, the RFS expanded corn cultivation in the U.S. by 2.8 million acres and total cropland by 2.1 million acres. These changes corresponded with an estimated increase in annual nationwide fertilizer use by 3–8% and an increase in water quality degradants by 3–5%. EPA explains in the Set 1 Biological Evaluation how the coefficients Lark et al. used for estimating these effects compare to the coefficients EPA used for its evaluation for the Set 1 Rule. With respect to EPA's findings from the same years in the RtC3, we find that they are similar to those from Lark et al. (2022), though lower because we account for other factors like MTBE effects on corn price.

4.3.2 New Literature on Soil and Water Quality Effects

To assess the current state of the science, EPA also completed a literature review of research of articles related to agriculture and biofuel production soil and water quality effects. EPA looked for articles published in 2023-2024. EPA found no studies that directly linked potential soil and water quality effects to the RFS program.

One study by Byers et al. (2024)[204] shows how intensified agriculture disrupts soil health, particularly through soil carbon loss and microbiome degradation. As they note, "human-driven land use change, such as agricultural intensification, is a major driver of soil [carbon] loss globally," making sustainable land use challenging. The study emphasizes the importance of soil microbes in "regulating soil biogeochemical cycling processes, including soil [carbon] cycling." By analyzing microbial DNA, the researchers discovered that intense farming areas had more microbial genes that break down soil carbon, potentially leading to "greater loss of soil C as respired CO_2 into the atmosphere". This increase in carbon loss suggests that intensive farming may boost GHG emissions.

The research also shows that areas with more intense land use, such as pastures, have lower soil carbon and less microbial diversity, following what the authors call a "disturbance gradient." This pattern of soil degradation due to intensive farming hopes to discover a balance between high productivity and healthy ecosystems.

Byers et al. recommends strategies like "protection of remnant native forest fragments and greater incorporation of regenerating native vegetation" to preserve soil carbon levels. These types of practices focus on sustainable land use that can help maintain long-term soil health and climate adaptability by diminishing some of the negative impacts of intensive agriculture.

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[203] Johnson, David R., Nathan B. Geldner, Jing Liu, Uris Lantz Baldos, and Thomas Hertel. "Reducing US Biofuels Requirements Mitigates Short-term Impacts of Global Population and Income Growth on Agricultural Environmental Outcomes." *Energy Policy* 175 (February 24, 2023): 113497. https://doi.org/10.1016/j.enpol.2023.113497.

[204] Byers, Alexa K., Leo Condron, Steve A. Wakelin, and Amanda Black. "Land Use Intensity Is a Major Driver of Soil Microbial and Carbon Cycling Across an Agricultural Landscape." *Soil Biology and Biochemistry* 196 (June 26, 2024): 109508. https://doi.org/10.1016/j.soilbio.2024.109508.

Other studies focused on the impacts of pesticide use on soil and water quality. Traditionally, pesticides have been employed in the agricultural sector to minimize the yield losses due to insects, disease, and weeds, however, the chemicals in pesticides have significant consequences, especially when overused. When pesticides are over-applied, the excess cannot be absorbed by the plants, and is susceptible to being washed off by precipitation into the soil; as Zhou et al. (2025)[205] explain, once these chemicals enter the soil, they can react to form new compounds, and depending on how deep into the soil they penetrate, can either leach into groundwater or get carried to a body of water downstream. These chemicals then contaminate water bodies and impact both the health of aquatic ecosystems and human health. In the case of aquatic ecosystems, these chemicals can enter the food chain and bioaccumulate at higher trophic levels. Human health implications of pesticides include linkages to increased risk of cancer, diabetes, respiratory disease, neurological disorders, organ damage, and reproductive syndromes.

Using a partial equilibrium model of corn-soy production and trade, Johnson et al. (2023)[206] estimated that a reduction of 24% of U.S. demand for corn as a renewable fuel feedstock would sustain land use and nitrogen leaching below 2020 levels through the year 2025. Further, they found that a 41% reduction would do the same but through 2030. The authors discuss how such demand reductions have potential to mitigate short-term impacts of population and income growth over the next decade.

In a review of consequential life cycle assessments (CLCAs), Bamber et al. (2023)[207] compared a series of 23 papers from several countries comparing the environmental impact of grain and oilseed crops used in biofuel production to traditional fossil fuels. Among other metrics, the team compared the CLCA results on differences in eutrophication, acidification, and toxicity, which had conflicting results. Compared to conventional fuels, the studies ranged from a 100-fold decrease in eutrophication to a 45-fold increase in eutrophication; for acidification, this ranged from a 248% decrease to a 500% increase; for toxicity, this ranged up to a 20,000-fold increase, with some decreases being reported but no calculable percentage changes.

Of the five studies focusing on water quality impacts of corn, soybean, and canola, which came out of the United States, Sweden, Switzerland, Spain, and Argentina, there was still disagreement among results: three of the five studies determined that biofuel production had greater acidification and eutrophication impacts than conventional fuel; only four of the studies evaluated ecotoxicity, three of which determined that biofuel production was associated with worsened ecotoxicity and/or downstream carcinogenic effects compared to conventional fuels. The study was largely inconclusive, with the researchers suggesting a more unified approach and

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[205] Zhou, Wei, Mengmeng Li, and Varenyam Achal. "A Comprehensive Review on Environmental and Human Health Impacts of Chemical Pesticide Usage." *Emerging Contaminants* 11, no. 1 (August 26, 2024): 100410. https://doi.org/10.1016/j.emcon.2024.100410.
[206] Johnson, David R., Nathan B. Geldner, Jing Liu, Uris Lantz Baldos, and Thomas Hertel. "Reducing US Biofuels Requirements Mitigates Short-term Impacts of Global Population and Income Growth on Agricultural Environmental Outcomes." *Energy Policy* 175 (February 24, 2023): 113497. https://doi.org/10.1016/j.enpol.2023.113497.
[207] Bamber, Nicole, Ian Turner, Baishali Dutta, Mohammed Davoud Heidari, and Nathan Pelletier. "Consequential Life Cycle Assessment of Grain and Oilseed Crops: Review and Recommendations." *Sustainability* 15, no. 7 (April 4, 2023): 6201. https://doi.org/10.3390/su15076201.

more specific focus on a select group of crops to ensure similar production methods are implemented to make comparison across studies more useful (Bamber et al. 2023).

4.3.3 Potential Soil and Water Quality Impacts From This Rule

As was done in Section 4.2.3 for potential natural land conversion effects, we can look at the volume changes expected from this rule relative to the No RFS and 2025 Baselines, for both BBD and conventional renewable fuels, to understand potential soil and water quality effects. EPA completed these analyses for the Volume Scenarios and Proposed Volumes. The projected BBD volume changes (Table 4.2-1) relative to both baselines suggest that this rule would increase demand for BBD. If BBD supply were to come from crop-based feedstocks such as soybean and canola, then this rule could contribute to further declines in soil and water quality.

Similarly, we would see higher conventional renewable fuel volumes attributable to this rule relative to the No RFS Baseline, but to a smaller degree compared to BBD volumes as indicated by smaller values in Table 4.2-2 compared to Table 4.2-1. However, relative to the 2025 Baseline, we would not see additional conventional volumes attributable to this rule. As such, this rule would not lead to additional demands for conventional fuel as things currently stand and would likely not contribute to further domestic land use changes that impact soil and water quality.

Of course, the true impacts on land use change and subsequent soil and water quality impacts from this rule would also depend on imports and exports of BBD supplies in the coming years. Decreasing exportation of whole soybeans and crushing more soybeans domestically would allow for greater U.S. soybean oil production. FOG supplies have been imported at greater quantities in recent years, and their continued importation, as well as decreased exportation of whole soybeans, could also provide greater BBD supplies in the domestic market. If BBD is largely supplied by these changing import and export dynamics, then it could mean fewer land use impacts may be expected, and minimal soil and water quality effects from this rule.

It is difficult to say for certain what will occur in the future, and it is still possible that land use changes could occur from increased BBD volumes attributable to this rule. If so, some soil and water quality effects would likely occur. Based on results from the EPIC modeling work done in the RtC3 that was summarized previously, if past is prologue the volume increases from this rule could continue to contribute to small percentage increases in erosion, nutrient loss, and soil organic carbon loss.

In considering these potential impacts, is important to consider the baseline nutrients, sediment, and pesticide runoff from existing land uses. Even forests, which provide the highest water quality among all land cover types,[208] contribute to nutrient loadings in watersheds. As

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[208] Caldwell, Peter V., Katherine L. Martin, James M. Vose, Justin S. Baker, Travis W. Warziniack, Jennifer K. Costanza, Gregory E. Frey, Arpita Nehra, and Christopher M. Mihiar. "Forested Watersheds Provide the Highest Water Quality Among All Land Cover Types, but the Benefit of This Ecosystem Service Depends on Landscape Context." *The Science of the Total Environment* 882 (April 19, 2023): 163550. https://doi.org/10.1016/j.scitotenv.2023.163550.

another example, livestock grazing on pastureland can affect sediment runoff. Pastureland that is converted to cropland would still contribute to soil and water quality degradation, but likely to a lesser extent compared to natural grassland that is converted to cropland. As such, it is important to consider the loadings from any pre-extensification or pre-intensification scenarios to understand the potential net effect in pesticide, nutrient, and sediment loadings from the BBD volume increases in this rule. In some cases, the net effect may actually be a decrease in pollutants, as may be the case in crop conversion from corn to soy, a nitrogen fixer, leading to a decrease in nitrogen runoff assuming nitrogen fertilizer applications to the field decrease as well.

The magnitude of effects depends on feedstocks planted, the biogeophysical traits of the land being farmed on, the management practices in place, and many other factors that are not determined by the RFS standards. While past analyses can provide insight, the likely future effects of this rulemaking are not fully understood because it is not possible to understand the true effects at the local level due to such complexities. Further, for any potential effects, additional conservation measures—such as further adoption of conservation tillage and cover crops—would help reduce the impacts of biofuels and the RFS program.

As explained in Section 4.2.3, EPA plans to further explore the potential land use change effects from this rule in a Biological Evaluation. EPA is currently working with a contractor to update this econometric data to estimate maximum potential land use changes from the Proposed Volumes. These analyses will further contribute to our understanding of the potential soil and water quality effects from crop-based feedstocks.

Soil and water quality effects from other issues beyond agriculture could occur in connection to this rulemaking. This includes chemical leaks and spills from storage and transportation tanks. It is not possible at this time to attribute such leaks and spills to the RFS program. However, if any potential effects occur, EPA expects them to be minimal, and EPA is involved in a separate process outside of the Clean Air Act for taking corrective actions and completing remediation for any chemical releases.

There are also concerns regarding potential soil and water quality impacts from biogas production through manure collection and animal feeding operations on farms. However, the majority of biogas for cellulosic biofuel is sourced from landfills and not agricultural digesters. As such, we expect any potential impacts from agricultural digesters to be very minimal.

Lastly, palm oil production in Southeast Asia could lead to soil and water quality degradation abroad. At this time, however, EPA is unable to evaluate potential effects from this rule. As described in the RtC3, attribution of international effects to the RFS program remains challenging due to complex interrelationships among other major drivers of observed change.

4.4 Water Quantity and Availability

We have previously explored this topic in the Biofuels and the Environment Reports to Congress and Set 1 Rule RIA. We summarize major findings below.

4.4.1 Water and Biofuel Crop Growth

Growth of biofuel crops such as corn and soybeans is the primary use of water in the process of creating renewable fuels. Although there are several other "fuel crops" used in the RFS program, these are the two that will be the main focus of our evaluation on water quantity.

4.4.1.1 Corn

Historically, corn has been grown in mostly rain-fed locations such as in Iowa and Minnesota. Because of this, corn is considered to have a low to modest water footprint currently. However, with changes in cropland needs such as meat production and the RFS program, cropland usage has shifted. With increased production of corn for ethanol production, corn growth has expanded into locations where more irrigation is needed to produce this crop.

As discussed in the Set 1 Rule Biological Evaluation, several studies evaluated land use change as a result of volumes from the Set 1 Rule. More recently analyzed data concluded that corn acreage growth did not necessarily result in total crop land acreage growth. It was more likely that other crops were being displaced in order to plant additional corn. This could indicate the planting of corn in locations previously not thought to be ideal for the crops growth and requiring the need for additional irrigation.

4.4.1.2 Soybeans

Soybeans in general require less irrigation than corn. Corn and soybeans are typically grown in rotation and are therefore grown in the same regions, which typically receive higher rainfall.

Projections for biodiesel and renewable diesel volumes suggest an increase in production in the proposed years analyzed. However, imports of used cooking oil (UCO) have significantly increased in the past year. Access to UCO supply from China has increased drastically after European intake was paused in 2023. The majority of the projected increase in renewable fuel production is expected to be met mostly with this increased supply in UCO. The remainder of supply would then be meet with soybean oil. Although soybean oil demand will continue to increase with the anticipated fuel volumes, the impact to land use change could be minimal with implementation of other crop sustainability practices.

As stated above, the irrigation of corn, soybeans, and other biofuel crops is the predominant driver of water quantity impacts. Some studies show land use change over time coincided with areas experiencing groundwater depletion, but this correlation does not mean there is a direct, causal relationship between biofuel production and groundwater depletion. USDA data suggests that total irrigated acres have increased in the U.S. over time (2013-2018), however irrigation rates have declined on a per acre level over the same time period, for both corn and soybeans.[209]

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[209] USDA, "Irrigation and Water Use," January 8, 2025. https://www.ers.usda.gov/topics/farm-practices-management/irrigation-water-use.

4.4.2 Use of Water in Production Facilities

Production of biofuels requires water use for both the growth of crop feedstocks and the actual production of fuels at the biofuel facility. With increases in potential volumes in biofuel production, an increase in need for water can be assumed, not just for crop production but also in the fuel production process.

Similar to petroleum-based fuels, biofuel production requires the use of water to produce the fuel. At many biofuel facilities, consumption of water has declined over time through more efficient water use, water recycling and recovery processes and reuse of wastewater, for example. The biofuel production process itself requires less water consumption than the growth of the biofuel feed crops. That said, biofuel facility water use, even with the implementation of water saving techniques, may still be locally consequential in areas that are already experiencing stress on water availability.

Overall, while values will vary across states and counties, ethanol, biodiesel and renewable diesel made from vegetable oils are substantially more water intensive than the petroleum fuels they would displace.

In summary, based on the approaches above, there will likely be some increased irrigation pressure on water resources due to the Proposed Volumes. Specifically, the volume increases for 2026–2085 compared to the No RFS Baseline that is described in Section 4.2.3 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.

4.5 Ecosystem and Wildlife Habitat

The previous sections in this chapter discussed this rulemaking's potential impacts to air quality, wetland and other natural land loss, soil, and water quality, and water quantity. Changes to any of these environmental end points could subsequently impact ecosystems, defined as a biological community of interacting organisms and their physical environment. This may include impacts to habitat and threatened and endangered species that are in danger of becoming extinct in the future.

EPA has previously assessed the impacts of biofuel consumption and production on ecosystems and wildlife in the three Biofuels and the Environment: Triennial Reports to Congress. The RtC3, the Set 1 Rule RIA, and Biological Evaluation further evaluate impacts from the RFS program, of which the latter two examine potential impacts from the Set 1 Rule specifically. The Biological Evaluation examined impacts of the Set 1 Rule's 2023-2025 volumes on endangered and threatened (referred to as "listed" species), and found that the rule may affect, but is not likely to adversely affect (NLAA), any of the 810 populations or critical habitats found in a large action area comprising most of the U.S. where corn, soy, and canola can be grown.

In this section, we first explore the historical data and information contributing to our understanding of ecosystem and wildlife habitat effects from agriculture and biofuels broadly, as well as our understanding of potential effects from past RFS volumes specifically (Chapter 4.5.1). Because the Set 1 Rule's RIA and Biological Evaluation, finalized in 2023, included a literature review and information examining wildlife impacts, we also reviewed and discuss new literature from 2023–2024 related to this topic (Chapter 4.5.2). The last subsection explores the potential ecosystem and wildlife habitat impacts from this rule (Chapter 4.5.3).

4.5.1 Ecosystems and Wildlife Habitat Impacts

A summary of findings and EPA's current understanding of how agriculture, biofuel production, and the RFS program historically impacted ecosystems and wildlife habitat is included below.

Land conversion to cropland is generally associated with negative impacts to ecosystem health and biodiversity. Demand for crop-based feedstocks used for biofuel production (corn, soy, canola) can lead to further agricultural conversion which may affect species by contributing to habitat loss, for example. Because native grasslands have seen higher conversion rates to agriculture compared to wetlands and forests, it is likely that terrestrial wildlife species with the largest potential risk are grassland species, including bird species and various insect species that rely on those ecosystems. However, some impacts to species in wetland and forest ecosystems may still occur due to direct land conversion to agriculture.

Pesticide drift, or the movement of pesticide dust or droplets through the air, can affect nearby ecosystems and species after application to farm fields. In addition, nutrients, sediment, and pesticides carried by agriculture runoff affect the health of aquatic ecosystems and species that live or rely on such ecosystems. This pollution can impact water quality at nearby edge-of-field streams and rivers as well as at a significant distance from the location of the land use change as contaminants associated with crop production travel downstream and into major waterways. This is particularly true for contaminants with greater mobility and contaminants that persist for longer time periods in soil and aquatic environments.

Many species of fish, for example, rely on creeks and streams with low turbidity, well oxygenated and moderately clean water, and riffles, pools, and runs with differing substrates of gravel, pebble, and sand. They may also need riparian cover and cooler temperature of waters, an abundant source of food, geo-morphically stable river channels and banks, and sufficient water depth. Some or all of these features in creeks and streams could be affected by agricultural land conversion and runoff. For instance, increased sediment can alter the geomorphology of streams, and increased turbidity and nutrients could affect macroinvertebrate communities that provide sources of food for fish.

Furthermore, excess nutrients (eutrophication) and sediment in places like the Gulf of Mexico and Chesapeake Bay contribute to hypoxia and dead zone conditions in the summertime. Species that live in or rely on these estuarine and coastal ecosystems may therefore be impacted as well.

Potential air quality and water quantity effects could also occur due to production and consumption of biofuels, as discussed in greater detail in Sections 4.1 and 4.4, respectively. Such effects could subsequently impact the health of ecosystems and species that rely on clean air or adequate water supply.

To better understand potential impacts of land use change and biofuels on listed species, an analysis in the RtC3 found that shifts from perennial cover to corn and soybeans from 2008-2016 occurred in areas adjacent to or within critical habitat of 27 terrestrial threatened and endangered species across the contiguous U.S. Past RFS volume obligations during those years were just one factor out of many that could have played a role in these land use changes. The Report states that the range of possible impacts from the RFS program likely spanned from no impact to a negative impact on terrestrial biodiversity historically.

As stated previously, EPA also assessed the potential impacts to listed species from the Set 1 Rule volumes in the Set 1 Rule Biological Evaluation. EPA identified 810 populations or critical habitats found within a large action area that may be affected by the rulemaking. Ultimately, however, EPA found the Set 1 Rule is not likely to adversely affect listed species (NLAA) and their designated critical habitats. The 259-page Biological Evaluation document details the specific analyses and findings that led to this conclusion. In accordance with the Endangered Species Act (ESA), EPA submitted this Biological Evaluation and received letters of concurrence with this NLAA determination from NMFS on July 27, 2023, and from FWS on August 3, 2023, thereby concluding informal consultation.

To date, EPA's work to understand the impacts of past RFS volume obligations on habitats and listed species has fully relied on EPA's understanding of how the RFS, separate from other influencing factors, impacts land use change and intensification and extensification to agriculture. EPA has advanced this understanding in recent years by including an RFS attribution analysis in the RtC3, for example. Still, it has not been possible and is still not possible at this time to say which parcels of lands were converted in the past due to the RFS program alone, nor to project with confidence where land use change will occur in the future due to the RFS. With the currently available science, the finest grain possible for understanding the effect of biofuel production on cropland is at the county scale, though such analyses for the Set 1 Rule rendered limited information[210] and, further, are conservative estimates as they do not directly account for trends in imports and exports of crop-based feedstocks. These limitations make it even more challenging to fully understand how the RFS may affect unique habitats and wildlife that live and rely on location-specific ecosystems across the contiguous U.S.

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[210] In the Set 1 Rule, county-level estimates would have been possible by leveraging an econometric analysis for corn ethanol effects due to proximity to ethanol facilities, specifically, as opposed to corn ethanol crop price effects. However, the proximity to ethanol facility effects were estimated to be zero for total cropland in the Set 1 Rule Biological Evaluation, so EPA was not able to accomplish county-level estimates for this. See Li et al. (2019) and updated analyses by Madhu Khanna as described in the Set 1 Rule Biological Evaluation for more information.

Beyond our understanding of impacts from biofuels, the RFS, and land use change broadly, it is well known both in the scientific literature and environmental management field at large that conservation practices may help to mitigate any potential effects. These practices include protecting environmentally sensitive lands and increasing habitat heterogeneity to mitigate impacts from land conversion of habitat. Furthermore, the adoption and expansion of sustainable conservation practices on farmland can reduce impacts on aquatic ecosystems by restoring flow and decreasing loads of nutrients, sediment, and pesticides to levels that are less harmful to aquatic organisms.

4.5.2 New Literature on Ecosystem and Wildlife Habitat Impacts

Like in previous sections, EPA completed a literature review of research of articles to assess the current state of the science related to agriculture and biofuel production effects on habitat and species. Since the Set 1 Rule RIA included a literature review and was published in mid-2023, EPA searched for articles published in 2023-2024. EPA found only one study that directly linked potential effects to the RFS program.

The one article that related species and habitat impacts to the RFS program is from Lark (2023).[211] In this article, Lark explores how the RFS may have affected land use changes and critical habitat, illustrates example pathways of interaction between biofuels and endangered species, provides examples of potentially impacted species, and proposes solutions to mitigate harm. The article's examination of how land use change from biofuel crops relates to potential species impacts is in congruence with what EPA has written about in the three Biofuels and the Environment: Reports to Congress. Lark further acknowledged in the article that the "extent, duration, and magnitude of influence from the RFS specifically is unknown and remains a topic ripe for further research." Lark also encouraged EPA to complete consultation with the FWS and NMFS in accordance with the ESA, which EPA accomplished for the Set 1 Rule a few months after the article's publication.

Other studies did not look at the potential impacts from RFS program specifically but instead examined impacts from agriculture and biofuel crop-based feedstocks more broadly. The findings from these studies uphold a lot of our current understanding, for example that species that live and rely on grasslands are especially affected by agricultural conversion, and that there is a link between agricultural activity and declining fish populations.

In one study, van der Burg et al. (2023)[212] examined how biofuel crop production and oil and gas development impact grassland bird species in North Dakota. The researchers looked at four types of birds—Bobolink, Grasshopper Sparrow, Savannah Sparrow, and Western Meadowlark—between 1998 and 2021. They found that biofuel feedstocks, like corn and soybeans, had a more negative effect on grassland bird populations than oil and gas

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[211] Lark, Tyler J. "Interactions Between U.S. Biofuels Policy and the Endangered Species Act." *Biological Conservation* 279 (January 16, 2023): 109869. https://doi.org/10.1016/j.biocon.2022.109869.

[212] Van Der Burg, Max Post, Clint Otto, and Garrett MacDonald. "Trending Against the Grain: Bird Population Responses to Expanding Energy Portfolios in the US Northern Great Plains." *Ecological Applications* 33, no. 7 (July 7, 2023). https://doi.org/10.1002/eap.2904.

development. The authors observed that "all four species responded positively to the proportion of grasslands surrounding a point on the landscape. Likewise, [they] found that all four species responded negatively to the proportion of corn and soybeans on the landscape", meaning that birds were less likely to live in or use areas where biofuel crops dominated. They also found that small grain crops, like wheat and barley, had less of a negative effect, and in some cases, even a slight positive effect on the birds likely do to features on small grain fields that mimic the vegetation structure and phenology of grasslands.

In another study, Crawford and Alexander (2024)[213] investigated the relationship between historic fish kills and insecticide use, comparing data across 10 watersheds in Prince Edward Island, Canada, with varying degrees of agricultural activity (including corn and soybeans). Severely impacted watersheds—identified as those with greater than 50% of land being used for agriculture—generally exhibited nitrate levels in excess of the guidance levels, as well as elevated levels of other nutrients (e.g., total phosphorus) and insecticide concentrations. Though the researchers suggested a more targeted study be performed in the future, the results achieved point toward a link between industrial-scale pesticide use and detrimental impacts to downstream water quality.

4.5.3 Potential Ecosystem and Wildlife Habitat Impacts From This Rule

As was done in previous sections, as a first step we can look at the volume changes expected from this rule relative to the No RFS and 2025 Baselines, for both BBD and conventional renewable fuels, to assess potential impacts to ecosystems and wildlife. The projected BBD volume changes from the Volume Scenarios and Proposed Volumes (Table 4.2-1) suggest that this rule would increase demand for BBD. If BBD supply were to come from crop-based feedstocks such as soybean and canola, then this rule could contribute to additional land use change, declines in soil and water quality, and impacts to wildlife and habitat.

Similarly, we would see higher conventional renewable fuel volumes attributable to this rule relative to the No RFS Baseline, but to a smaller degree compared to BBD volumes as indicated by smaller values in Table 4.2-2 compared to Table 4.2-1. However, relative to the 2025 Baseline, we would not see additional conventional volumes attributable to this rule. As such, this rule would not lead to additional demands for conventional fuel as things currently stand and would likely not contribute to further domestic land use changes that impact wildlife and habitat.

Imports and exports of BBD supplies in the coming years will also play an important role. For example, decreasing soybean exportation and crushing more soybeans domestically would allow for greater U.S. soybean oil production without the need for increasing cropland for crop-based feedstocks. U.S. capacity for soybean crushing has increased in recent years. Further, as described in more detail in Chapter 7, FOG supplies have been imported at significantly greater quantities in recent years. Should this trend continue, this could provide greater BBD supplies in the domestic market. If BBD is largely supplied by these changing import and export

[213] Crawford, Miranda, and Alexa C. Alexander. "Fish Kills and Insecticides: Historical Water Quality Patterns in 10 Agricultural Watersheds in Prince Edward Island, Canada (2002–2022)." *Frontiers in Sustainable Food Systems* 8 (July 26, 2024). https://doi.org/10.3389/fsufs.2024.1356579.

dynamics, then it could mean fewer land use impacts may be expected, and minimal wildlife and ecosystem effects from this rule.

EPA is currently working to update econometric data used to estimate maximum potential land use changes from the Proposed Volumes. The results from this analysis will be included in a Biological Evaluation for this rule, in accordance with the ESA Section 7. As discussed in Chapters 4.2 and 4.3, this analysis will help contribute to our understanding of this rulemaking's potential impacts to land use conversion to agriculture as well as potential soil and water quality impacts, which consequently affect wildlife and habitat. Further, as was done for the Set 1 Rule Biological Evaluation, in the Biological Evaluation for this rule EPA will apply probabilistic analyses to select available lands for conversion and estimate the overlap between potential cropland changes and critical habitats or listed species' ranges. The probabilistic analyses will be repeated 100–500 times to generate an estimated probability of impact.

Impacts to air quality or water quantity from this rulemaking could also affect wildlife and ecosystems. However, any effects to water quantity and air quality impacts would likely be highly variable and dependent on what is going on at the local level. For example, as explained in Section 4.1 of this chapter, we would expect some localized increases in some air pollutant concentrations, particularly at locations near production and transport routes and in more rural areas. Overall, considering end use, transport, and production, emission changes are expected to have variable impacts on ambient concentrations of pollutants in specific locations across the U.S. With regard to water quantity, there remains great uncertainty in projecting changes at the local level as well; for example, with irrigation rates as decided by farmers for growth of corn, soybeans, and other crops.

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.[214] The United Nations Millennium Ecosystem Assessment[215] 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 Proposed Volumes in this rule specifically.

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[214] EPA, "Ecosystem Services." https://www.epa.gov/eco-research/ecosystem-services.
[215] Millennium Ecosystem Assessment, "Ecosystems and Human Well-being: Synthesis," 2005. https://www.millenniumassessment.org/documents/document.356.aspx.pdf.

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 quantity 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 on 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.

In recent years, humans have become more reliant upon these ecosystem services to the point where ecosystem have begun to rapidly change. These changes have been made to meet growing needs for food, water, and in the case of the RFS program, fuel. These changes, although beneficial to human well-being, have often been at the cost of the well-being to the environment. Water scarcity and land conversion are two of the most prominent consequences of a robust RFS biofuels program. As stated in previous sections, there are several ways to attempt to mitigate the effects of these volumes. Cropland is often able to have an increased harvest which allows for significantly less potential expansion to meet the volume needs. Additionally, the processing of biofuels has become increasingly more water efficient than previous methods.

Figure 4.6-1: Framework for Considering the Impact of the RFS Volumes on Ecosystem Services

Chapter 5: Climate Change Analysis

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." This chapter describes our analysis of the potential climate change impacts of this proposal. 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.

This chapter is organized as follows: Chapter 5.1 details the methodologies, models, scenarios and assumptions used to assess the potential climate change impacts of the Volume Scenarios assessed in this proposal. This section describes the methods for evaluating the GHG emissions associated with two different categories of biofuels (crop-based fuels and waste/byproduct-based fuels). Chapter 5.2 presents the results of modeling the Volume Scenarios relative to the No RFS Baseline. Results are presented in tons of GHG emissions changes. Chapter 5.3 describes how the analyses of the Volume Scenarios were used to assess the GHG impacts of the Proposed Volumes. This section also summarizes those impacts in tons of GHG emissions. Appendix 5-A discusses a sensitivity analysis which provides information on the sensitivity of the cumulative emissions estimates to uncertainty in model parameters.

5.1 Methodology

In this rule, our methodology for assessing climate change impacts advances the science of estimating climate impacts of biofuel policies in several key aspects discussed in the sections below. Our assessment of the climate impacts of the Volume Scenarios and Proposed Volumes includes: (1) new economic modeling of the combined impact of changes in volumes of fuels produced from crop-based feedstocks; and (2) new supply chain GHG emissions modeling for estimates for all fuels.

This section is organized as follows: Chapter 5.1.1 provides an overview of the methodology, including comparisons with past analyses of climate change impacts under the RFS program, the two categories of fuels and methods noted above, and the scenarios modeled in our analysis. Chapter 5.1.2 focuses on the methodology of assessing emissions impacts of volumes of biofuels produced from wastes and byproducts. Chapter 5.1.3 focuses on the methodology of assessing emissions impacts of volumes of fuels produced from crops.

5.1.1 Overview

Estimating the GHG emissions associated with the production and use of renewable fuels is an integral component of the Renewable Fuel Standard program. Multiple analyses requiring assessment of the GHGs associated with biofuels are prescribed in the Clean Air Act (CAA), including biofuel lifecycle assessments for the purpose of determining qualification of a fuel under the RFS program,[216] and, as required by CAA section 211(o)(2)(B)(ii), assessments of

[216] "Lifecycle greenhouse gas emissions" is defined under the RFS program in CAA section 211(o)(1)(H) and is applicable to the determinations of GHG reduction thresholds for different categories of fuels defined in CAA section 211(o)(1)(B)(i), (D), (E), and (o)(2)(A)(i).

climate change impacts of setting annual volume standards. These two analyses in particular serve different purposes under the statute. Thus, while there are many methodological similarities between the two, there are also important differences. This section describes our methods of assessing the potential climate change impacts of setting volume standards under various scenarios, as required by CAA section 211(o)(2)(B)(ii).

The Energy Independence and Security Act of 2007 (EISA) required substantial changes to the existing RFS program; the updated program also included statutorily established volumes of different categories of renewable fuels through 2022. The changes necessary to implement EISA's updates were implemented in the RFS2 Rule. In accordance with Executive Order 12866,[217] which provides guidance on conducting cost benefit analysis for significant regulatory actions, EPA developed and applied a methodology for assessing the climate impacts of volumes established under EISA in the RFS2 Rule.[218] EPA did not conduct a quantitative assessment of the potential climate change impacts of subsequent annual volume standards rules until the 2020-2022 Final Volume Standards Rule[219] in which EPA conducted an illustrative climate impacts analysis, again under the guidance of E.O. 12866. For continuation of the RFS program after 2022, the 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." Thus, for the Set 1 Rule, EPA assessed the potential climate change impacts of those volume standards. We again assess the potential climate impacts of proposed 2026 and 2027 standards under this rule, as required by the CAA.

The climate change assessment methodology under the RFS2 rule relied on combination of models and additional data sources to estimate potential global GHG emissions impacts of the RFS program from 2010–2022. This methodology was based on the best available models and science available at the time. While our 2010 approach represented a best-in-class approach at the time of publication, evidence from expert discussions, input from public stakeholders, and EPA's review of the available literature subsequently laid plain that this approach required updating. First and most critically, some of the tools which comprised our 2010 methodology were no longer maintained and ceased to be operational by the end of 2022. In addition, our 2010 methodology required the use of one model to represent impacts in the U.S. and another to represent the rest of the world. This was necessary in 2010 when no suitable modeling tool was available which integrated the global agricultural economy into a single framework. However, by 2022, several potentially suitable global models were available which integrated key economic sectors and global trade. In 2010, we estimated land use change emissions by stitching together individual sets of economic modeling results with satellite imagery and soil carbon datasets using elaborate and largely manual post-processing routines which had numerous opportunities for user error. By 2022, several models could integrate all these factors more accurately and consistently. Finally, in 2010 we were reliant on historical data and forward-looking projections from 2008 or earlier to estimate future impacts in 2022 and onward. By 2022, we had access to the most recent data on crop yields, trade flows, and other key factors which improved the

[217] Executive Order 12866: Regulatory Planning and Review. https://www.federalregister.gov/executive-order/12866.
[218] RFS2 Rule RIA, Chapter 2.7.
[219] 87 FR 39600 (July 1, 2022).

accuracy of our estimates of economic activity in that year and onward. All of these factors led to the conclusion not only that our 2010 methodology was out of date, but that better tools were available to meet our statutory obligations under the RFS program.

Recognizing that public input on models and methods available would be integral to incorporating the latest scientific advancements, EPA co-hosted a two-day public workshop with DOE and USDA, on February 28 and March 1, 2022, on biofuel GHG modeling. At this workshop, speakers within and outside of the federal government presented on available data, models, methods and uncertainties related to the assessment of GHG impacts of land-based biofuels. EPA also opened a public docket for the workshop (86 FR 73757) and requested that stakeholders submit any input or suggestions they might have regarding the best available scientific approaches for conducting biofuel GHG modeling under the RFS program, including, but not limited to, any suggested models, data sources, or interpretive methods. We received 29 public comments with 550 pages of technical input and recommendations in response to this request. The workshop proceedings and public comments showed that there continued to be substantial variation in estimates of the climate effects of biofuels, especially for emissions associated with biofuel-induced land use changes and other market-mediated effects.[220] A general theme that emerged from the workshop process was that, in support of a better understanding of the climate impacts of biofuels, it would be helpful to compare available models, identify how and why the modeled estimates differ, and evaluate which models and estimates align best with available science and data. Recognizing this need, EPA conducted a model comparison exercise ("MCE") to better understand these scientific questions.

The MCE effort started in May 2022 and culminated in the MCE Technical Report published in July 2023 along with the Set 1 Rule.[221] The goals of the MCE were to advance our scientific understanding of available models capable of assessing GHG impacts of biofuels and how differences between these models contributes to varying results. The MCE included five models:

- The Greenhouse gases, Regulated Emissions, and Energy use in Technologies Model (GREET)[222]
- The Global Change Analysis Model (GCAM)[223]
- The Global Biosphere Management Model (GLOBIOM)[224]

[220] See, e.g., Daioglou, Vassilis. "Review of Land Use Change Emission Estimates." *Workshop on Biofuel Greenhouse Gas Modeling*, March 1, 2022. https://www.epa.gov/system/files/documents/2022-03/biofuel-ghg-model-workshop-luc-emission-estiim-2022-03-01.pdf.
[221] EPA, "Model Comparison Exercise Technical Document," EPA-420-R-23-017, June 2023. https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1017P9B.pdf.
[222] Wang, Michael, Elgowainy, Amgad, Lee, Uisung, Baek, Kwang H., Bafana, Adarsh, Benavides, Pahola T., Burnham, Andrew, Cai, Hao, Cappello, Vincenzo, Chen, Peter, Gan, Yu, Gracida-Alvarez, Ulises R., Hawkins, Troy R., Iyer, Rakesh K., Kelly, Jarod C., Kim, Taemin, Kumar, Shishir, Kwon, Hoyoung, Lee, Kyuha, Liu, Xinyu, Lu, Zifeng, Masum, Farhad, Ng, Clarence, Ou, Longwen, Reddi, Krishna, Siddique, Nazib, Sun, Pingping, Vyawahare, Pradeep, Xu, Hui, and Zaimes, George. "Greenhouse gases, Regulated Emissions, and Energy use in Technologies Model ® (2022 Excel)." Computer software. October 10, 2022. https://doi.org/10.11578/GREET-Excel-2022/dc.20220908.1.
[223] JGCRI, "GCAM Documentation (Version 7.0)," September 13, 2024. https://doi.org/10.5281/zenodo.11377813.
[224] IIASA, "Global Biosphere Management Model (GLOBIOM) Documentation 2023 - Version 1.0," 2023. https://pure.iiasa.ac.at/id/eprint/18996/1/GLOBIOM_Documentation.pdf.

- The GTAP-BIO[225] model – an extension of the Global Trade Analysis Project (GTAP) model
- The Applied Dynamic Analysis of the Global Economy (ADAGE) model[226]

The MCE led to several findings which inform our analytical approach for this proposed rule, including the following conclusions:

- Economic models are best suited for estimating GHG emissions resulting from a change in biofuel consumption levels.
- Land use change estimates vary significantly among the models.
- Economic modeling of the energy sector provides important insights into the overall GHG impacts of a change in biofuel volumes.
- The MCE did not attempt to determine which of these economic models are more likely to be correct—doing so would require extensive validation tools that are not currently available. However, among the economic models included in the MCE, the GCAM, GLOBIOM, and GTAP-BIO models provide a strong level of detail in key sectors. The MCE observed that GCAM and GLOBIOM are dynamic models that can estimate impacts over time, whereas GTAP-BIO represents one historical year (i.e., 2014 in the version evaluated). Due to structural differences, these models estimate differing market-mediated effects.

During the same time period that EPA was conducting the technical work for the MCE, the National Academy of Sciences, Engineering and Medicine (NASEM) initiated a committee to write a report on lifecycle analysis (LCA) methods for low-carbon transportation fuel policies (hereafter the "the NASEM LCA Report").[227] The NASEM LCA Report, published in October 2022, did not reach a consensus on the best available model or any particular estimates, but it did include several recommendations that informed our analytical approach for this proposed rule climate change analysis, including:

- Regulatory impact analyses should evaluate market-mediated impacts to assess the extent to which a given policy design will result in reduced GHG emissions (Conclusion 3-1, Recommendations 2-2, 3-2).
- Policies should strive to reduce model uncertainties and compare results from multiple economic modeling approaches and transparently communicate the estimates (Recommendation 4-2).

[225] See, e.g., Taheripour, Farzad, Xin Zhao, and Wallace E. Tyner. "The Impact of Considering Land Intensification and Updated Data on Biofuels Land Use Change and Emissions Estimates." *Biotechnology for Biofuels* 10, no. 1 (July 20, 2017). https://doi.org/10.1186/s13068-017-0877-y. Model versions relying on the GTAP database are discussed in detail in the MCE technical report.
[226] Cai, Yongxia, Jared Woollacott, Robert H. Beach, Lauren E. Rafelski, Christopher Ramig, and Michael Shelby. "Insights From Adding Transportation Sector Detail Into an Economy-wide Model: The Case of the ADAGE CGE Model." *Energy Economics* 123 (May 8, 2023): 106710. https://doi.org/10.1016/j.eneco.2023.106710.
[227] National Academies of Sciences, Engineering, and Medicine ("NAS"). *Current Methods for Life Cycle Analyses of Low-Carbon Transportation Fuels in the United States*. *National Academies Press eBooks*, 2022. https://doi.org/10.17226/26402.

Given that the models used in the GHG impacts analysis conducted for the RFS2 Rule were no longer operational when technical work commenced on the Set 1 Rule and given that the MCE and NASEM investigation were still ongoing, EPA was unable to conduct new GHG impacts modeling for the volume scenarios for the Set 1 Rule. EPA instead relied on a literature review approach for the Set 1 Rule. In that analysis, we identified ranges of potential lifecycle GHG emissions associated with each individual fuel pathway (i.e., each unique combination of a feedstock, production process and fuel) from the available scientific literature. Lifecycle emissions estimates for each individual fuel pathway were then scaled to the projected change in the volume of that fuel to estimate a range of potential GHG impacts of the 2023–2025 RVO standards.

While the literature review-based approach was necessary to assess GHG impacts under the Set 1 Rule for the reasons outline above, it does have several deficiencies which are addressed in the climate impacts analysis in this rule. First, combining assessments of individual pathways of fuels, as EPA did in the Set 1 Rule literature review-based approach, fails to represent key interactions that are present when a policy is expected to simultaneously affect volumes of multiple fuels. For example, in simulations representing only an increase in corn ethanol, corn production may expand at the expense of soybean production via crop switching, while simulations representing increases in soybean biodiesel production may show the opposite; crop switching from corn to soybeans. Combining per-fuel effects to assess the overall impacts of simultaneous changes in fuel volumes introduces inconsistencies between simulations, and can substantially affect the overall emissions estimates, as was recognized in the RFS2 Rule.[228]

Second, for fuels produced from feedstocks with land use requirements (i.e., crop-based fuels), only a handful of the studies identified in the literature review produced emissions estimates that represented the temporal dynamics of land use change emissions; among these, only the pathway specific modeling from EPA's own RFS2 Rule analysis reported annual emissions impacts.[229] Thus, the illustrative GHG emissions scenarios presented in Set 1 Rule represented only the results of EPA's 2010 dated modeling, not the full breadth of impacts reported across more recent studies identified in the literature.

Finally, the literature review-based analysis did not attempt to weigh or rank the validity or robustness of the many different methods employed in studies it considered. Instead, the review-based approach presented a summary of the state of recent literature on biofuel lifecycle

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[228] In the RFS2 Rule EPA said: "…simply adding up the individual lifecycle results… multiplied by their respective volumes would yield a different assessment of the overall impacts. The two analyses [individual fuel scenarios and combined fuel scenarios] are separate in that the overall impacts capture interactions between the different fuels that can not be broken out into per fuels impacts, while the threshold values represent impacts of specific fuels but do not account for all the interactions… [W]hen looking at individual fuels there is some interaction between different crops (e.g., corn replacing soybeans), but with combined volume scenario when all mandates need to be met there is less opportunity for crop replacement (e.g., both corn and soybean acres needed) and therefore more land is required." 75 FR 14797-14798 (March 26, 2010).

[229] Most studies of GHG emissions impacts of individual biofuels present per-megajoule CI metrics that represent average emissions over an assumed period of analysis (30 years in EPA's methodology).

analysis and the wide breadth of potential impacts estimated therein.[230] For these reasons (analysis did not capture interactions between fuels and volumes, relied on outdated estimates, did not address differences in methods), the climate impacts assessment in the Set 1 Rule was presented as "illustrative" of the range of potential GHG impacts of the 2023–2025 volume standards.

For the GHG impacts assessment in this rule, we have developed a methodology based on information gathered through the biofuel modeling workshop, the MCE Technical Report, the NASEM LCA Report, and the literature review conducted for the Set 1 Rule. This methodology utilizes new modeling with separate approaches for two categories of fuels: crop-based fuels and waste- and byproduct-based fuels.

Based on our review of the available science referenced above, we continue to conclude that, because of interactions with complex global agricultural and feed systems and feedstock land use requirements, production and use of crop-based fuels has the potential for substantial market-mediated effects with significant implications for GHG emissions. As such, the GHG impacts of changes in volumes of these fuels are most appropriately assessed through simulation within global economic models with detailed representations of the key markets and biophysical processes associated with a change in biofuel production and use. For this analysis, we conduct new modeling of changes in crop-based fuels using two of the models considered in the 2023 MCE Technical Report: GCAM and GLOBIOM. This modeling incorporates several important advancements over past climate impacts assessments under the RFS program. First, whereas the modeling for crop-based fuels conducted under the RFS2 Rule analysis imperfectly combined results from different U.S. and international economic models and post-hoc land use change estimation methods, the models used in the analysis for this rule have globally integrated representations of relevant agricultural commodities, including trade, and endogenously represent land use change and land use change emissions. Second, these models have both benefitted from significant ongoing development over the last decade, incorporating the latest science and agricultural and energy system data into their simulations. Finally, use of these models allows for representation of important interactions under simultaneous changes in volumes of fuels produced from different agricultural feedstocks—a key deficiency, noted above, of the Set 1 Rule approach. The GCAM and GLOBIOM models, their relative strengths and reasons for selection, and implementation for the Volume Scenarios considered in this proposal are discussed in Chapter 5.1.3.

However, the MCE did not conclude which model(s) were most appropriate to use for the RFS nor does it conclude that crop-based biofuels have significant indirect emissions. Accordingly, we are soliciting public comment on the following issues:

- The methodologies and/or models that are most appropriate, accurate, and best-suited to be used to determine whether crop-based biofuels have significant indirect emissions,

[230] Chapter 4.2.2 of the Set 1 Rule RIA states: "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. Reflecting the many approaches to LCA and associated assumptions and uncertainties, our review is intentionally broad and inclusive of a wide range of estimates based on a variety of study types and assumptions."

- The most effective way to consider the uncertainties in quantifying indirect emissions. Are indirect emissions most appropriately characterized in the RFS with precise numerical values or with risk-based classification schemes?
- What are the system boundaries for the attribution of indirect emissions? Should emissions outside of the United States be considered? Indirect emissions assigned to biofuels in one region represent the direct emissions from other sectors and regions. Since the attribution of indirect emissions is not placed on the party that caused them, crop-based biofuels cannot mitigate indirect emissions.
- Should policies of foreign governments be considered in indirect emission determinations? Policies of foreign governments can significantly increase or decrease deforestation and land-use change.

Waste- and byproduct-based fuels are, by definition, not the primary driver of an economic activity; they are produced as secondary or tertiary outputs of a primary activity which is responsive to market pressures. For these fuels and feedstocks, our review of the best available science has led us to conclude that economic modeling of global markets is not necessary. NASEM recommendations, available studies examined through the Set 1 Rule literature review, and stakeholder input received through the 2023 LCA workshop all support the conclusion that assessment of the GHG impacts of these fuels can be adequately addressed using supply chain modeling. Additionally, global economic models as a class tend to lack detail on the supply chains for key non-crop-based fuels (e.g., waste fats, oils, and greases; biogas). This makes use of dedicated supply chain models the most appropriate choice given that they can represent supply chains for these fuels in significant detail. In the climate impacts assessment for the RFS2 Rule we used aspects of the GREET supply chain model to assess this category of fuels. In our climate impacts assessment for this rule, we rely more fully on a recent release of the R&D GREET model. More specifically, for this analysis we use the R&D GREET 2023 Revision 1 version of the model.[231] Although the 2024 version of the R&D GREET model is now available, the analytical work for this proposed rule was substantively completed before its release. Time permitting, we intend to update our estimates for the final rule based on the most recent version of the R&D GREET model available at that time. For the purposes of this proposal, we hereafter use the terms “the R&D GREET model” to specifically mean R&D GREET 2023 Revision 1, unless otherwise noted. Implementation and additional assumptions for our assessment of waste- and byproduct-based fuel pathways are detailed in Chapter 5.1.2.

Finally, while the methodology used in this rule represents significant progress in GHG emission impacts assessment modeling since 2010, the conclusions of the NASEM report, the MCE Technical Report, and stakeholder input all make clear that estimating the climate change impacts of biofuels is inherently difficult and significant uncertainties remain. A sensitivity

[231] Wang, Michael, Elgowainy, Amgad, Lee, Uisung, Baek, Kwang H., Balchandani, Sweta, Benavides, Pahola T., Burnham, Andrew, Cai, Hao, Chen, Peter, Gan, Yu, Gracida-Alvarez, Ulises R., Hawkins, Troy R., Huang, Tai-Yuan, Iyer, Rakesh K., Kar, Saurajyoti, Kelly, Jarod C., Kim, Taemin, Kolodziej, Christopher, Lee, Kyuha, Liu, Xinyu, Lu, Zifeng, Masum, Farhad, Morales, Michele, Ng, Clarence, Ou, Longwen, Poddar, Tuhin, Reddi, Krishna, Shukla, Siddharth, Singh, Udayan, Sun, Lili, Sun, Pingping, Sykora, Tom, Vyawahare, Pradeep, and Zhang, Jingyi. "Greenhouse gases, Regulated Emissions, and Energy use in Technologies Model ® (2023 Excel).” Computer software. October 09, 2023. https://doi.org/10.11578/GREET-Excel-2023/dc.20230907.1.

analysis considering uncertainty in this methodology is presented in Appendix 5-A at the end of this chapter.

5.1.1.1 Scenarios Assessed

Scenarios described in Section III and Section V of this proposal include estimates of volumes of different qualifying biofuels that would be expected to be consumed in the United States under alternative standards levels (i.e., the Low and High Volume Scenarios and the Proposed Volumes). The differences between the estimated future effects of these projected fuel volumes and the estimated future effects of the parallel volumes developed for the No RFS Baseline form the basis of our analysis of the GHG impacts of each of these scenarios.

5.1.1.1.1 Volumes Analyzed

Chapter 3 presents the renewable fuel volumes represented by each of the scenarios assessed for this proposed rule. For the Low and High Volume Scenarios, volumes by RIN category are presented in Tables 3.1-1 and 2 respectively. These RIN volumes are translated into projected volumes by fuel and feedstock and compared against projections of volumes by fuel and feedstock under the No RFS Baseline. The resulting differences between the projected volumes and No RFS Baseline are presented in Table 3.3-1 (Low Volume Scenario) and Table 3.3-2 (High Volume Scenario) and form the basis of our analysis of the potential climate change impacts of the analytical Volume Scenarios.

The volume differences specified in the tables in Chapter 3.3 include values for 2026–2030, i.e., volumes in these tables could be used to construct scenarios in which standards are set for anywhere between one and five years. However, the modeling necessary for climate impacts assessment would require separate simulations for each of the alternative durations (i.e., one year, two years, etc.) of standards under the Low Volume Scenario and High Volume Scenario. Completing the economic modeling described in Chapter 5.1.3 requires substantial lead time and resources. Additionally, based on findings in previous modeling efforts, we believe increasing the scope of this modeling to include scenarios representing multiple durations would yield limited additional insight.[232] For these reasons, we have only analyzed one duration for the Low and High Volume Scenarios; standards set for three years, 2026 through 2028. Additionally, at the time the technical specification of these scenario analyses was completed, the volumes proposed in this NPRM had not yet been determined, so assessing the three-year version of the scenarios provided analyses most applicable to the range of alternative durations. We acknowledge that this assumed three-year duration does not align perfectly with the two-year duration being proposed in this rule. However, for the reasons described above we nonetheless

[232] Chapter 8.1 of EPA's 2023 MCE Technical Report presented scenarios that investigated the sensitivity of per-megajoule CI results to the overall size of shock implemented. Based on these sensitivities, the MCE report conclude that "[the volume sensitivity scenario] results indicate a linear effect between shock size and most output values for ADAGE, GCAM, and GTAP results. GLOBIOM results show somewhat more nonlinearity with shock size for certain output parameters, which leads to differences in the GHG emissions. But the nonlinearities observed in the GLOBIOM results tend to be minor." Thus, we expect that emissions estimates form modeling scenarios that represent continued growth in volume standards through 2030 would scale roughly proportional to the marginal increase in fuel volumes over the 2028 volumes represented in our assessed scenarios.

believe this analysis is appropriate and provides useful information regarding the potential impacts of this proposal.

For the climate change analysis, we assess only volumes of the qualifying fuels which are estimated to have significant volume differences compared to the No RFS Baseline. This includes all fuel categories appearing in Table 3.3-1 and Table 3.3-2 with one exception: "Other Advanced Biofuels – Other" shows a relatively small volume (52 million RINs delta compared to the No RFS Baseline) and represents an unknown mix of various fuel types with smaller volumes. We have excluded this volume from our analysis because this mix is unknown and unpredictable. However, we would expect it to have only minor additional emissions impacts; we do not believe this exclusion meaningfully changes the results of our analysis, or the conclusions stakeholders may draw from them, in any way. Additionally, for the purposes of our climate change analysis we disaggregate estimated volumes of biofuels produced from waste fats oils and greases (FOG) into fuels produced from animal tallow, and fuels produced from used cooking oil. To do this, we assume 52% of fuels produced from waste FOG are produced from used cooking oil, and 48% are produced from tallow. This assumption is based on EIA data and is described in additional detail in Chapter 3.3. Finally, we note that biofuels produced from distillers corn oil are treated as byproduct-based fuels, following the convention established in the RFS2 Rule. In that rule, EPA determined that distillers corn oil should be treated as a byproduct of the dry mill process of producing ethanol from corn starch for the purposes of estimating the lifecycle GHG emissions of distillers corn oil-based fuels and corn starch based fuels. Consequently, these analyses attributed the indirect land use change emissions associated with using corn for ethanol production entirely to the corn starch ethanol; we continue to follow that established convention for the purposes of this analysis.

The volumes used in our assessment of the Low and High Volume Scenarios in our climate change analysis are presented in Table 5.1.1-1. Our assessment of the climate impacts under these scenarios is presented in Chapter 5.2.

Table 5.1.1-1: Difference in Consumption of Renewable Fuels (Trillion BTUs) in the Low Volume Scenario and High Volume Scenario Relative to the No RFS Baseline

Fuel	Assessed market-mediated GHG emissions?	Low Volume Scenario Minus No RFS Baseline			High Volume Scenario Minus No RFS Baseline		
		2026	2027	2028	2026	2027	2028
CNG/LNG from biogas	No	55	57	59	55	57	59
Biodiesel from Corn oil		4	7	4	4	7	4
Biodiesel from Used Cooking Oil		-3	-3	-3	-3	-3	-3
Biodiesel from Tallow		-3	-3	-3	-3	-3	-3
Renewable Diesel from Corn Oil		10	5	6	10	5	6
Renewable Diesel from Used Cooking Oil		61	74	87	61	74	87
Renewable Diesel from Tallow		57	69	80	57	69	80
Biodiesel from Soybean oil	Yes	138	137	138	138	137	138
Biodiesel from Canola oil		41	41	41	41	41	41
Renewable Diesel from Soybean oil		87	91	96	113	144	174
Renewable Diesel from Canola oil		16	16	16	28	41	53
Ethanol from Corn starch		16	18	18	16	18	18

In addition to the Low and High Volume Scenarios, Chapter 3 presents the volumes of specific fuels which are estimated to comprise the volume standards proposed in this rule. If these proposed standards are finalized, the actions of RIN generators and obligated parties will ultimately determine the exact volumes of each of these fuels which contribute to these standards in practice. However, Chapter 3 describes in detail that we believe these estimated volumes are appropriate for the purposes of estimating the impacts of these proposed standards. Parallelling the above discussion, volumes by RIN category are presented in Table 3.2-1 while projections of volumes by fuel and feedstock compared against similar estimates in the No RFS Baseline are presented in Table 3.3-5. The volumes used in our assessment of the climate change impacts of the Proposed Volumes are presented in Table 5.1.1-2.

Table 5.1.1-2: Difference in Consumption of Renewable Fuels (Trillion BTUs) in the Proposed Volumes Relative to the No RFS Baseline

Fuel	Assessed market-mediated GHG emissions?	Proposed Volumes Minus No RFS Baseline	
		2026	2027
CNG/LNG from biogas	No	55	57
Biodiesel from Corn oil		14	16
Biodiesel from Used Cooking Oil		-8	-8
Biodiesel from Tallow		-7	-8
Renewable Diesel from Corn Oil		59	55
Renewable Diesel from Used Cooking Oil		15	14
Renewable Diesel from Tallow		14	13
Biodiesel from Soybean oil	Yes	119	120
Biodiesel from Canola oil		19	19
Renewable Diesel from Soybean oil		153	184
Renewable Diesel from Canola oil		52	52
Ethanol from Corn starch		16	18

The Proposed Volumes are for years 2026 and 2027 only. The components of our analysis which rely on economic modeling have only been completed for the three-year analytical Volume Scenarios, as discussed above. See Chapter 5.3 for information on how the modeling for the analytical Volume Scenarios was used to estimate emissions impacts of the Proposed Volumes.

5.1.1.1.2 Period of Analysis

Any analysis of the GHG emissions impacts of biofuel policies must specify the time period considered in the analysis, i.e., the time period over which those emissions impacts will be assessed. This decision can have a substantial impact on the result of the analysis, particularly for renewable fuels produced from feedstocks with land use requirements (e.g., crops). If increased demand for biofuels leads to land conversion, an initial pulse of emissions from carbon sequestered in biomass and soils would likely take place when the land is converted. Over time, if production and use of biofuels continues, the GHG benefits of displacing fossil fuels may eventually “pay back” the initial increase in GHG emissions from the initial expansion of cropland. It is therefore important that an analysis of the GHG emissions impacts of biofuels formulate these assumptions intentionally and then describe these choices transparently, as we do in this subsection.

In the specific context of this proposal and EPA’s recurring responsibility to set RVOs under the RFS program, EPA must determine more specifically the appropriate timeframe over which to assess the GHG emissions impacts of setting only one or several years of RVO standards. Were EPA to use a scenario covering only the years for which volumes are set, e.g., only 2026 and 2027 in this proposal, our analyses of the climate impacts of setting RFS volumes would account for all of the near term emissions increases associated with expanding use of renewable fuels produced from crops, but would never account for the longer term emissions decreases associated with continued displacement of fossil fuel over time through continued production and use of those fuels. We believe it is not reasonable to limit our climate assessment to the impacts in the years in which we are proposing volume standards. Nor would this choice be the norm for assessing the impacts of a policy with effects that continue over time. When impacts of a proposed regulatory action are anticipated to occur over a longer period than the time horizon of the regulatory action itself, it is both appropriate and a well-established best practice to consider that longer period in the regulatory impact analysis. For example, the cost analysis for this proposal assumes a 15-year amortization period for capital expenses associated with increasing U.S. production capacity of affected fuels—also well beyond the time horizon covered by the proposed standards.

The example of EPA's LCA methodology under CAA section 211(o)(1)(H) provides an instructive illustration of the necessity of and the established scientific basis for considering this longer time horizon when estimating GHG impacts of renewable fuels. While this methodology serves a separate purpose in implementation of the RFS program, with statutory and analytical requirements that are distinct from our assessment of the climate impacts of setting RVO standards discussed in this section, the lifecycle analysis methodology similarly considered the question of the appropriate temporal scope of analysis. After considering public comments and the input of an expert peer review panel, in the RFS2 Rule, EPA determined that our lifecycle analysis for renewable fuels would quantify the GHG impacts over a 30-year period.[233] In 2010, EPA listed the following reasons supporting the 30-year temporal scope: 1) it aligns with the average life of a typical biofuel production facility; 2) extending the analysis further than 30 years would add uncertainty; 3) this relatively short temporal scope (e.g., relative to 100 years, which was supported by a number of stakeholders as an alternative to 30 years) is consistent with science indicating the benefits of reducing emissions in the near term.[234] Since our lifecycle analysis methodology is the approach through which we determine whether individual biofuels meet the statutory GHG reduction thresholds necessary to be included in the program,[235] and setting volumes standards is a key mechanism through which the RFS program promotes the use of those fuels, we believe that our accounting for the climate benefits of increasing volumes of those fuels should be consistent in temporal scope with the 30-year period of analysis.

Thus, the climate change analyses for this proposal consider a time horizon of 30 years of impacts of renewable fuel consumption. The Low and High Volume Scenarios assessed in Chapter 5.2 represent the volumes for 2026, 2027, and 2028 presented in Table 5.1.1-1, then hold constant volumes of U.S. renewable fuel consumption from 2028-2055. This comprises in total a 30-year period of analysis from 2026 to 2055. The Proposed Volumes assessed in Chapter 5.3 represents the volumes for 2026 and 2027 presented in Table 5.1.1-2, then hold constant volumes of U.S. renewable fuel consumption from 2027-2055, comprising an identical 30-year period of analysis to that analyzed for the Low and High Volume Scenarios.

For the reasons outlined above, we believe a 30-year period of analysis is both reasonable and has the benefit of being consistent with other analysis used in RFS program implementation.

[233] See discussion of the selection of the 30-year period of analysis in the RFS2 Rule DRIA Chapter 2.4.5.
[234] Id.
[235] GHG reduction thresholds for different categories of fuels under the RFS program are defined in CAA section 211(o)(1)(B)(i), (D), (E), and (o)(2)(A)(i).

However, we recognize that scenarios representing alternative renewable fuel consumption trajectories over the portion of the 30-year timeframe extending past the modeled standards years could be developed, and that such analysis could provide potentially useful sensitivities for the analysis of the potential climate impacts of volume standards.

5.1.2 Waste- and Byproduct-based Fuels

For the purposes of defining categories of renewable fuel feedstocks in this climate change analysis, waste and byproduct materials are considered to not be the primary driver of an economic activity; they are produced as secondary or tertiary output of a primary activity which is responsive to market pressures.[236] For the purposes of this analysis, we assume that the market-mediated emissions impacts for these materials and the fuels produced from them are negligible. That is, we assume that there are no significant emissions associated with diverting materials that are wastes, residues, and byproducts for use as feedstock to produce renewable fuels and we do not conduct any assessment of market-mediated impacts associated with these feedstocks and fuels. Provided that using these feedstocks for biofuel production does not cause significant market-mediated impacts, it is then appropriate to estimate the emissions associated with these fuels with a supply chain analysis. A supply chain analysis focuses on the direct emissions that result from procuring and processing the feedstock into fuel, as well as the emissions associated with transporting and using that fuel. For waste and residue-based fuels, this represents all the relevant categories of emissions that should be considered as this type of analysis estimates the emissions associated with all of the stages of the supply chain from the collection and transport of the feedstocks through to the production, transport and use of the finished fuel. Listed below are the fuels that are produced from feedstocks considered to be wastes and byproducts and which are assessed in our climate change analysis (i.e., fuels with significant volume differences between the assessed Volume Scenarios and the No RFS Baseline).

- CNG/LNG produced from biogas from landfills and waste digesters
- Biodiesel and renewable diesel produced from distillers corn oil
- Biodiesel and renewable diesel produced from animal tallow
- Biodiesel and renewable diesel produced from used cooking oil

For each of these waste- and byproduct-based fuel pathways, we estimate the emissions impacts associated with the use of these fuels based on an analysis of the supply chain lifecycle GHG emissions for each pathway, including all stages of fuel and feedstock production and distribution. Our estimates are based on modeling with the R&D GREET model developed and maintained by ANL. While our estimates rely on the R&D GREET model for data and emissions factors, we have made several adjustments and used a particular set of coproduct accounting methods as appropriate based on the purpose of our analysis. This section describes our analysis with the R&D GREET model and the resulting estimates.

To estimate the GHG emissions impacts associated with changes in the volumes of these fuels consumed in the U.S., we multiply the volume changes, converted to megajoules, with the

[236] See discussion of wastes and byproducts in the RFS2 Rule.

lifecycle GHG emissions factor for each fuel pathway generated in the R&D GREET model. We then compare these emissions with the lifecycle GHG emissions associated with the fossil-based fuels they displace; emissions from fossil-based fuels are also estimated using the R&D GREET model and then multiplied by the assumed number of megajoules being displaced by renewable fuels.[237] Emissions factors estimated using the R&D GREET model for each of the renewable and fossil-based fuel pathways included in this part of the analysis are presented in Table 5.1.2-1. Additional information about the assumptions used for each of these estimates is presented in the subsections below.

Table 5.1.2-1: Emissions Factors Used for Climate Impacts Analysis of Fuel Pathways Not Expected to Have Significant Market-Mediated Emissions Impacts (g/MJ fuel used)

Fuel Pathway	CO_2	CH_4	N_2O	CO_2e[a]
CNG/LNG: Biogas	11.0	0.50	0.001	26.3
Biodiesel: Distillers Corn Oil	16.3	0.07	0.032	26.8
Biodiesel: Used Cooking Oil	11.6	0.06	0.000	13.7
Biodiesel: Tallow	13.4	0.07	0.001	15.6
Renewable Diesel: Distillers Corn Oil	19.5	0.07	0.033	30.4
Renewable Diesel: Used Cooking Oil	15.2	0.07	0.001	17.4
Renewable Diesel: Tallow	16.1	0.07	0.001	18.3
Gasoline (E0)	88.9	0.11	0.001	92.5
Diesel (B0)	87.0	0.13	0.000	91.0
Natural Gas (CNG Vehicle)	65.3	0.27	0.002	74.1

[a] Estimates presented in CO_2e are calculated using 100-year global warming potentials from the IPCC Fifth Assessment Report (AR5) and are provided for informational purposes only. The climate change analysis in this chapter uses emissions factors for each individual GHG and applies social cost factors specific to emissions changes in each individual gas.

5.1.2.1 CNG/LNG from Biogas

To determine the lifecycle GHG intensity of CNG from biogas, we used the R&D GREET model for background and process data. We then applied technical adjustments based on a combination of available industry data, petition submission data, and other recent scientific literature to construct the CNG pathway in R&D GREET. Importantly, for this analysis we assume that biogas is a byproduct of landfilling and collected by the landfills to prevent the emission of methane gas, as required by regulation,[238] and flared. This assumption is consistent with the approach that EPA adopted for Pathways II Rule.[239] See in particular the technical memo to the docket for the 2014 rule explaining EPA's rationale for using a flaring baseline to evaluate biogas lifecycle emissions.[240]

[237] We assume use of renewable fuels displaces use of an equal amount of the relevant fossil fuel on an energy equivalent basis. We assume CNG/LNG derived from biogas displaces use of fossil natural gas and biodiesel and renewable diesel of all sources displaces use of diesel produced from petroleum.
[238] 61 FR 9905 (March 12, 1996).
[239] 79 FR 42128 (July 18, 2014).
[240] "Support for Classification of Biofuel Produced from Waste Derived Biogas as Cellulosic Biofuel and Summary of Lifecycle Analysis Assumptions and Calculations for Biofuels Produced from Waste Derived Biogas," Docket Item No. EPA-HQ-OAR-2012-0401-0243. https://www.regulations.gov/document/EPA-HQ-OAR-2012-0401-0243.

Our analysis of converting biogas to compressed natural gas (CNG) involves several key stages. First, biogas is generated at a landfill and collected using a gas collection system. The collected biogas then diverted to a purification process to be upgraded into renewable natural gas (RNG). The upgrading process requires electricity, which is supplied by the grid, based on the average U.S. energy mix. Once purified, the RNG is transported via pipelines to CNG stations, where it is compressed for vehicle fueling.

When considering the baseline emissions associated with diverting biogas from landfills for energy production, we assume that biogas is already being collected at landfills and sent to a flare. In this counterfactual, the carbon dioxide (CO_2) present in the flared biogas is emitted without conversion, while the methane (CH_4) is flared into CO_2 with a 99.96% CH_4 destruction efficiency. A small emission credit is applied to the biogas in the fuel production stage for avoiding unburned methane being released into the atmosphere when sent to a flare. During the upgrade process to RNG, we account for a 2% biomethane leakage. The process energy needed for the upgrading stage is supplied by the grid as electricity. For the RNG pipeline injection and delivery stages, we assume an RNG compression efficiency of 99.2% and that the RNG travels 680 miles[241] through pipelines, with a 0.31% leakage rate, before reaching off-site refueling stations. The delivered RNG is then compressed to CNG for vehicle fueling using the default values in R&D GREET.

Lastly, the tailpipe emissions associated with CNG use as a transportation fuel were modeled using a passenger vehicle from the 2017 model year that utilizes a spark ignition system in its internal combustion engine. Using the above methodology, we calculate that CNG from biogas has a lifecycle emission intensity of 26.3 g CO_2e/MJ. Our estimates of the supply chain GHG emissions associated with CNG Fuel produced from Landfill Biogas are summarized in Table 5.1.2.1-1.

Table 5.1.2.1-1: Supply Chain Emissions Associated with CNG Fuel from Landfill Biogas (gCO_2e/MJ)

Supply Chain Stage	Renewable CNG
Fuel Production	18.3
Fuel Transport and Distribution	6.9
Fuel Use	1.1
Total	26.3

5.1.2.2 Distillers Corn Oil-based Fuels

As part of the climate change analysis, we estimate the emissions associated with biodiesel and renewable diesel produced from distillers corn oil. For this analysis, we assume the feedstocks and fuels are produced and used in the U.S. using industry average production practices. Our analysis assumes that the biodiesel is produced through a standard

[241] The average natural gas transmission pipeline distance from the field to end-use is 680 miles. This value is based on the national ton-miles of natural gas freight via pipeline as reported by the US Bureau of Transportation Statistics in 2009 and tons of dry natural gas production in the same year as reported by EIA. Dunn JB, Elgowainy A, Vyas A, et al. "Update to Transportation Parameters in GREET," October 25, 2013.

transesterification process and that the renewable diesel is produced through a standard hydrotreating process.

Distillers corn oil is a byproduct of dry mill corn ethanol production that is used as a feedstock to produce biodiesel and renewable diesel. At dry mill ethanol plants, corn grain is ground and fermented to produce ethanol with coproduct distillers grains and solubles (hereafter "distillers grains"), a protein-rich livestock feed. Most dry mill ethanol plants extract distillers corn oil from the distillers grains. The distillers corn oil is used as feedstock to produce biomass-based diesel or added back to livestock feed as a source of fat and calories. Based on the data from the R&D GREET model, on an energy content basis (lower heating value), the outputs from an average U.S. dry mill ethanol plant with corn oil extraction are approximately 63% ethanol, 33% distillers grains, and 4% distillers corn oil.

Given that distillers corn oil is one of three outputs from a dry mill ethanol plant, coproduct accounting methods are required to estimate what quantity of the gross emissions associated with the ethanol supply chain are attributable to the ethanol production and what quantity of emissions are attributable to the distillers corn oil production. To make these estimates, we use a unit-process level energy allocation approach.[242] That is, we evaluate the emissions and outputs associated with each individual process in the supply chain and allocate the emissions among the outputs from each of these processes based on the energy content of each output and an assessment of the primary purpose of each process.

We allocate the supply chain emissions associated with corn farming and transport to all three coproducts on an energy basis. Thus, we allocate approximately 4% of the supply chain corn farming and transport emissions to the distillers corn oil.[243]

For all but one of the unit processes within the dry mill ethanol process, we allocate all the emissions associated with the process energy and chemical inputs to the ethanol output, as these processes are carried out for the specific purpose of ethanol production. The one exception is that we allocate emissions associated with distillers corn oil extraction to the corn oil. We make this choice because extracting corn oil does not contribute to the production of ethanol or distillers grains. The reason corn oil extraction is undertaken is not because of the decision to produce ethanol; instead, corn oil extraction is an additional step for the purpose of producing corn oil as a product distinct from distillers grains. Even if the corn had not been used to produce ethanol, a separate oil extraction process would still be needed to produce corn oil. That is, any extraction process to produce corn oil from corn would occur regardless of whether that corn was involved in ethanol production. For example, wet mill corn processing facilities which make high fructose corn syrup may engage in similar unit processes to also produce corn oil.

We recognize that that there are multiple methods for coproduct accounting. The NASEM LCA Report discusses the various coproduct accounting methods used in policy and the

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[242] ISO 14044 defines unit process as the "smallest element considered in the life cycle inventory analysis for which input and output data are quantified."

[243] This ensures that the supply chain emissions associated with distillers corn oil production are not double counted when we sum the GLOBIOM market-mediated emissions estimates associated with corn ethanol with the supply chain emissions estimates associated with distillers corn oil-based biodiesel and renewable diesel.

scientific literature. This report observes that "it is important to pair allocation methods with the policy objective," but it does not make any conclusions or recommendations about which methods are most appropriate. Overall, we observe that existing low-carbon fuel policies and models have taken various approaches to coproduct accounting, reflecting a lack of consensus on the most appropriate approach.

While there are many viable options for coproduct accounting, we believe that the unit process energy allocation approach is the most appropriate method for the supply chain emissions component of our analysis of biodiesel and renewable diesel produced from distillers corn oil. Energy allocation is an appropriate approach because the primary purpose of the biodiesel and renewable diesel production we are evaluating is to produce transportation fuel, which is an energy carrier. The energy allocation method is based on the physical properties of the coproducts, which are stable characteristics in the sense that they do not depend on context or market value fluctuations. In contrast, both the system expansion approach and the market-based allocation approaches are subject to fluctuations due to changing markets, policies, technologies, and other factors. Using these other allocation methods therefore requires a substantial number of additional assumptions to account for these considerations, many of which are highly uncertain and difficult to parameterize, and which can also significantly influence the results of the analysis. This makes LCA using these approaches more complex, more difficult to adequately document, explain, and understand, and more uncertain. Thus, relative to other options, energy allocation is a more transparent and stable methodology based on physical properties rather than fluctuating market dynamics.

To estimate the supply chain emissions associated with growing and harvesting corn, we use data from the R&D GREET model on the average inputs and yields associated with U.S. corn production. The R&D GREET model sources these data from USDA's major survey programs, the National Agricultural Statistics Service (NASS), the Economic Research Service (ERS), and the Office of the Chief Economist (OCE) reports.[244] For our analysis of the supply chain lifecycle emissions, we assume average corn yield of 177 bushels per harvested acre. Our analysis considers average inputs to corn farming, such as fertilizer, pesticide, diesel fuel to run tractors, and electricity to run irrigation pumps. Based on the R&D GREET model background data, we assume that the harvested corn is transported 10 miles by medium-duty truck to a collection point and then 40 miles by heavy-duty truck to an ethanol plant.

We estimate the emissions associated with extracting corn oil from the distillers grains based on data from the R&D GREET model representing an average U.S. dry mill ethanol plant with corn oil extraction. Based on the R&D GREET model data, we assume that the oil extraction equipment consumes 183 Btu of electricity per pound of distillers corn oil output (we assume the extraction equipment does not consume natural gas or other thermal process energy).

Our analysis includes the emissions associated with transporting the distillers corn oil feedstock to biodiesel or renewable diesel production facilities. Based on data from R&D GREET model, we assume that 20% of distillers corn oil used as biofuel feedstock is transported

[244] For further information, see Lee, Uisung, Hoyoung Kwon, May Wu, and Michael Wang. "Retrospective Analysis of the U.S. Corn Ethanol Industry for 2005–2019: Implications for Greenhouse Gas Emission Reductions." *Biofuels Bioproducts and Biorefining* 15, no. 5 (May 4, 2021): 1318–31. https://doi.org/10.1002/bbb.2225.

by rail 400 miles, and 80% of this oil is transported by heavy-duty truck 100 miles. We assume that these feedstock transport modes and distances are the same for biodiesel and renewable diesel production.

Our estimates include the emissions associated with biodiesel and renewable diesel production. We use operational data from the R&D GREET model and the energy allocation approach discussed above to account for coproducts. For biodiesel production, we assume the process inputs per pound of biodiesel output are 1.003 pounds of distillers corn oil, 1,137 Btu of natural gas, 147 Btu of electricity and 896 Btu of methanol. The other biodiesel inputs considered in our analysis are nitrogen gas, sodium methoxide, hydrochloric acid, and phosphoric acid. We assume that 0.97 dry pounds of byproduct glycerin is produced per pound of biodiesel output. For renewable diesel production, we assume the process inputs per pound of renewable diesel output are 1.26 pounds of distillers corn oil, 352 Btu of natural gas, 185 Btu of electricity and 2,071 Btu of hydrogen. We assume that 0.099 pounds of propane fuel mix is coproduced per pound of renewable output.

We estimate the emissions associated with biodiesel and renewable diesel transportation and distribution based on data and emissions factors from the R&D GREET model. We assume that biodiesel is transported from the production facility to a bulk terminal with the following modes and distances: 49% by barge for 200 miles, 46% by pipeline for 110 miles, and 5% by rail for 490 miles. We assume that renewable diesel is transported from the production facility to a bulk terminal with the following modes and distances: 8% by barge for 520 miles, 29% by rail for 800 miles, and 63% by truck for 50 miles. We assume that both biodiesel and renewable diesel are distributed from bulk terminals to refueling stations 30 miles via heavy-duty tanker truck. Consistent with the R&D GREET model, we assume 0.004% of biodiesel is lost during transportation, distribution and refueling.

Finally, based on emissions factors from the R&D GREET model, we include the emissions associated with using the biodiesel and renewable diesel in a diesel engine car. We include the non-CO_2 emissions associated with biodiesel combustion. Consistent with the methodology developed for the RFS2 Rule, we do not include the biodiesel combustion CO_2 emissions as we treat the carbon in the finished fuel derived from renewable biomass as biologically derived carbon recently originating from the atmosphere. In the context of a full lifecycle analysis, the uptake of this carbon from the atmosphere by the renewable biomass and the carbon dioxide emissions from combusting it cancel each other out. Therefore, instead of evaluating both the carbon uptake and tailpipe carbon dioxide emissions, we leave both values out of our estimates. Note that when applicable our analysis also accounts for all significant supply chain and market-mediated emissions, such as from land use changes, meaning that we do not simply assume that the ethanol or other biofuels are "carbon neutral."

For this analysis, we do not include the CO_2 emissions from combustion of the non-biogenic methanol portion of the biodiesel, because the purpose of this analysis is to estimate the emissions associated RIN generating volumes of fuel. Only the biogenic portion of biodiesel generates RINs as the equivalence value for biodiesel, 1.5 RINs per gallon, accounts for the renewable content of the fuel.

For this analysis we use emissions factors from the R&D GREET model representing current average U.S. industry operations. To evaluate the emissions associated with electricity, we use the emissions factor from the R&D GREET model for U.S. grid average electricity (128 $gCO_2e/mmBtu$). For natural gas, we use the emissions factor for conventional North American natural gas used at a biofuel plant (13,413 $gCO_2e/mmBtu$ well-to-gate plus 59,587 $gCO_2e/mmBtu$ from combustion). We assume that the methanol used for biodiesel production is produced from conventional natural gas (25,560 $gCO_2e/mmBtu$), and that hydrogen for renewable diesel production is produced by steam methane reforming of conventional natural gas (9,449 $kgCO_2e/kg$). The emissions associated with fuel produced at specific facilities that use other types of inputs (e.g., renewable electricity, renewable natural gas, electrolytic hydrogen) would be associated with lower supply chain emissions.

Our estimates of the supply chain GHG emissions associated with U.S. average biodiesel and renewable diesel produced from distillers corn oil are summarized in Table 5.1.2.2-1. Although our climate analysis uses estimates broken out by gas, for brevity this table presents the estimates in carbon dioxide-equivalent emissions (CO_2e) using global warming potential values from the IPCC Fifth Assessment Report (AR5).[245] The calculations upon which these estimates are based are contained in spreadsheets that are available in the public docket for this proposed rule.

Table 5.1.2.2-1: Supply Chain Emissions Associated with Corn Oil-based Fuels (gCO_2e/MJ)

Supply Chain Stage	Biodiesel	Renewable Diesel
Corn Production and Transport	17	17
Corn Oil Extraction	1	1
Corn Oil Transport	0.3	0.3
Fuel Production	7	10
Fuel Transport	0.3	0.3
Fuel Use	1	1
Total	27	30

5.1.2.3 Tallow and Used Cooking Oil-based Fuels

As part of the climate change analysis, we estimate the emissions associated with biodiesel and renewable diesel produced from animal tallow and used cooking oil (UCO). For this analysis, we assume the feedstocks and fuels are produced and used in the U.S., using industry average production practices. To the extent that feedstocks are imported, the estimates for some supply chain stages are likely underestimates. For example, imported UCO would likely have higher emissions associated with transportation than domestic UCO. Our analysis assumes that the biodiesel is produced through a standard transesterification process and that the renewable diesel is produced through a standard hydrotreating process.

[245] IPCC, "Climate Change 2013: The Physical Science Basis," *Working Group I Contribution to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change*, 2014. https://doi.org/10.1017/cbo9781107415324.

Tallow is produced through rendering of the animal by-products from cattle slaughtering.[246] While edible tallow is used as shortening for baked goods, we assume that only inedible tallow is used as a feedstock for biofuel production. Inedible tallow is a byproduct that, when not used as biofuel feedstock, can be used in animal feed, soap production and lubricants.

UCO is collected from commercial kitchens and restaurants. The collected UCO is brought to rendering facilities where excess water is removed. The result of UCO rendering is sometimes referred to as yellow grease, but for simplicity here we use the term UCO to refer to the UCO before and after rendering. When not used as a biofuel feedstock, UCO can be used an additive in pet food and animal feed.

To estimate the supply chain emissions associated with collecting rendering and transport tallow and UCO, we use data and emissions factors from the R&D GREET model representing average U.S. practices. The R&D GREET model data are based on industry surveys and data from the literature. For tallow rendering, we assume 1,052 Btu of natural gas and 307 Btu of electricity is used per pound of rendered tallow. R&D GREET assumes the follow average transportation modes and distances for transporting tallow from rendering facilities to biofuel plants: 20% by rail for 400 miles, and 80% by truck for 100 miles.

For UCO collection, we assume UCO is collected at restaurants and commercial kitchens and trucked 150 miles by heavy-duty truck to rendering facilities. We assume that 23% of the collected UCO is transported to a transfer station and then trucked an additional 200 miles by heavy-duty truck to the rendering facilities. We assume that on average, 908 Btu of natural gas and 107 Btu of electricity are used to render each pound of resulting dewatered UCO. The rendered UCO is then transported to biofuel plants using the following modes and distances: 95% by truck for 130 miles, and 5% by rail for 500 miles.

Our estimates include the emissions associated with biodiesel and renewable diesel production. We use operational data from the R&D GREET model and the energy allocation approach discussed above to account for coproducts. For tallow biodiesel production, we assume the process inputs per pound of biodiesel output are 1.05 pounds of tallow, 1,137 Btu of natural gas, 147 Btu of electricity and 896 Btu of methanol. For UCO biodiesel production, we assume the process inputs per pound of biodiesel output are 1.05 pounds of UCO, 1,075 Btu of natural gas, 138 Btu of electricity and 847 Btu of methanol. We assume that 0.071 dry pounds of glycerin are coproduced with each pound of biodiesel output.

For renewable diesel production, we assume the process inputs and outputs are the same when either tallow or UCO are used as feedstock. Per pound of renewable diesel output, the process inputs are 1.3 pounds of feedstock, 352 Btu of natural gas, 185 Btu of electricity, and 2,071 Btu of hydrogen. We assume that 0.099 pounds of propone fuel mix is coproduced per pound of renewable output.

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[246] Seber, Gonca, Robert Malina, Matthew N. Pearlson, Hakan Olcay, James I. Hileman, and Steven R.H. Barrett. "Environmental and economic assessment of producing hydroprocessed jet and diesel fuel from waste oils and tallow." *Biomass and Bioenergy* 67 (May 20, 2014): 108–18. https://doi.org/10.1016/j.biombioe.2014.04.024.

To evaluate the emissions associated with biodiesel and renewable diesel transportation, distribution, and use, we use the same methods and data for corn oil-based fuels as described in Chapter 5.1.2.2. For this analysis we use emissions factors from the R&D GREET model representing current average U.S. industry operations (see Chapter 5.1.2.2 for further description of these emissions factors).

Our estimates of the supply chain GHG emissions associated with U.S. average biodiesel and renewable diesel produced from tallow and UCO are summarized in Table 5.1.2.3-1. The calculations upon which these estimates are based are contained in spreadsheets that are available in the public docket for this proposed rule.

Table 5.1.2.3-1: Supply Chain Emissions Associated with Tallow and UCO-Based Fuels (gCO_2e/MJ)

	Tallow-based Fuels		UCO-based Fuels	
Supply Chain Stage	**Biodiesel**	**Renewable Diesel**	**Biodiesel**	**Renewable Diesel**
Collection, Rendering and Transport	7	7	7	6
Fuel Production	7	10	6	10
Fuel Transport	0.3	0.4	0.3	0.4
Fuel Use	1	1	1	1
Total	16	18	14	18

5.1.2.4 Fossil Fuel Baselines

For this climate change analysis, we assume that waste and byproduct-based fuels displace conventional fuels one-for-one on an energy-equivalent basis. We recognize this is likely an oversimplification as market prices can affect the overall level of transportation fuel consumption. However, given the lack of a robust model or methodology for estimating the market-mediated transportation sector effects of these particular biofuels, we believe that the energy-equivalent displacement assumption is appropriate for the purposes of this analysis.

For this analysis, we assume that biodiesel and renewable diesel replace conventional diesel fuel and that renewable CNG displaces conventional CNG. For the GLOBIOM-based analysis described in Chapter 5.2.2, we assume that ethanol displaces conventional gasoline. In this section we describe our estimates of the GHG emissions associated with these conventional fuels.

We use the R&D GREET model to evaluate the emissions associated with these conventional fossil fuels. The GREET model has been used for many years to estimate the emissions associated with conventional transportation fuels. This model includes all the stages in conventional fuel production and use, from raw material extraction through refining, fuel transport and use in vehicles. It is widely used for this purpose, including for peer reviewed publications and regulatory programs. The R&D GREET model analysis of petroleum leverages site specific data for crude oil extraction from the Oil Production Greenhouse Gas Emissions

Estimator (OPGEE) model,[247,248,249] and a detailed assessment of the energy intensities of 27 oil sands projects.[250] Furthermore, the R&D GREET model uses unit-process level analysis with linear programming models with data from 43 refineries that process approximately 70% of total crude input to U.S. refineries.[251,252] For these reasons, we believe the R&D GREET model is an appropriate method for evaluating the emissions associated with fossil fuels for the purpose of this analysis.

Given that we are estimating the emissions associated with the conventional fuels that would be displaced by additional renewable fuel blending, we estimate the emissions associated with conventional fuels containing 0% biofuel blends. Thus, we evaluate gasoline with 0% ethanol (E0), diesel with 0% biodiesel (B0) and 100% conventional CNG. For gasoline, we use the lifecycle emissions estimates for fuel used in a spark ignition passenger car. For conventional diesel, we use the lifecycle emissions estimates for B0 used in a compression ignition direct injection passenger car. For CNG we evaluate fuel used in a medium-duty spark ignition CNG vehicle. Given that we do not include the vehicle cycle emissions in our estimates (e.g., emissions associated with vehicle manufacturing), our estimates on a per MJ of fuel basis would not be significantly different if we evaluated fuel used in a different type of typical vehicle, such as spark ignition direct injection passenger car or a sport utility vehicle.

Other than selecting these fuel parameters and vehicle types, we make no other adjustments to the R&D GREET model to produce the emissions estimates summarized in Table 5.1.2.4-1.

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[247] Brandt, Adam R., Tim Yeskoo, Michael S. McNally, Kourosh Vafi, Sonia Yeh, Hao Cai, and Michael Q. Wang. "Energy Intensity and Greenhouse Gas Emissions From Tight Oil Production in the Bakken Formation." *Energy & Fuels* 30, no. 11 (October 20, 2016): 9613–21. https://doi.org/10.1021/acs.energyfuels.6b01907.

[248] Yeh, Sonia, Abbas Ghandi, Bridget R. Scanlon, Adam R. Brandt, Hao Cai, Michael Q. Wang, Kourosh Vafi, and Robert C. Reedy. "Energy Intensity and Greenhouse Gas Emissions From Oil Production in the Eagle Ford Shale." *Energy & Fuels* 31, no. 2 (January 8, 2017): 1440–49. https://doi.org/10.1021/acs.energyfuels.6b02916.

[249] Eker, Ilkay, Basak Kurtoglu, and Hossein Kazemi. "Multiphase Rate Transient Analysis in Unconventional Reservoirs: Theory and Applications." *SPE/CSUR Unconventional Resources Conference*, September 25, 2014. https://doi.org/10.2118/171657-ms.

[250] Cai, Hao, Adam R. Brandt, Sonia Yeh, Jacob G. Englander, Jeongwoo Han, Amgad Elgowainy, and Michael Q. Wang. "Well-to-Wheels Greenhouse Gas Emissions of Canadian Oil Sands Products: Implications for U.S. Petroleum Fuels." *Environmental Science & Technology* 49, no. 13 (June 9, 2015): 8219–27. https://doi.org/10.1021/acs.est.5b01255.

[251] Elgowainy, Amgad, Jeongwoo Han, Hao Cai, Michael Wang, Grant S. Forman, and Vincent B. DiVita. "Energy Efficiency and Greenhouse Gas Emission Intensity of Petroleum Products at U.S. Refineries." *Environmental Science & Technology* 48, no. 13 (May 28, 2014): 7612–24. https://doi.org/10.1021/es5010347.

[252] Forman, Grant S., Vincent B. Divita, Jeongwoo Han, Hao Cai, Amgad Elgowainy, and Michael Wang. "U.S. Refinery Efficiency: Impacts Analysis And Implications For Fuel Carbon Policy Implementation." *Environmental Science & Technology* 48, no. 13 (May 28, 2014): 7625–33. https://doi.org/10.1021/es501035a.

Table 5.1.2.4-1: Supply Chain Emissions Associated with Conventional Fuels (gCO_2e/MJ)

Supply Chain Stage	Gasoline	Diesel	CNG
Feedstock	6	8	14
Fuel	13	8	3
Vehicle Operation	73	76	57
Total	93	91	74

5.1.3 Crop-based Fuels

As discussed in Chapter 5.1.1, our analysis of the climate change impacts of crop-based fuels is based on new economic modeling that represents the specific fuel volumes under consideration in this proposal. The use of economic modeling for this assessment is well aligned with the recommendations of the 2022 NASEM LCA report, which concluded that regulatory impact analyses should evaluate market-mediated impacts to assess the extent to which a given policy design will result in reduced GHG emissions (Conclusion 3-1, Recommendations 2-2, 3-2).

5.1.3.1 Models Used

EPA's review of available models capable of biofuel GHG emissions modeling in the 2023 MCE Technical Document included five models: ADAGE, GCAM, GLOBIOM, GREET, and GTAP-BIO. Of these models, GREET is a supply chain model that does not endogenously represent market-mediated impacts of biofuel consumption, and therefore does not satisfy the NASEM recommendation to use consequential modeling for the purposes of regulatory impact analyses.

Estimating impacts of changes in GHG emissions over the 30-year scenarios assessed in this climate change analysis requires estimates of changes in emissions of each GHG between 2026 and 2055. GTAP-BIO is a static comparative model; biofuel modeling using the GTAP-BIO model represents alternative versions of the world under different assumed volumes of biofuel consumption in a single year—2014 for the version of GTAP-BIO assessed in the MCE, 2017 in more recent work.[253] Thus, GTAP-BIO does not provide estimates that are suitable for use in an RIA climate change analysis.

Next, while ADAGE does provide dynamic over time results that could be used to estimate emissions impacts in individual years over the period of analysis for this proposal, the analytical work undertaken as part of the MCE identified several model updates that we believe would be necessary before results from ADAGE could be included in this analysis. These included numerous updates to historical data which parameterize the model, including a major overhaul to represent a more recent model base year, significant updates to the model's representation of non-commercial forests and grasslands, and significant updates to the model's representation of soil carbon pools. We were not able to complete those model updates for the analyses undertaken for this proposed rule.

[253] See, e.g., DOE, "Guidelines To Determine Life Cycle Greenhouse Gas Emissions of Clean Transportation Fuel Production Pathways Using 45ZCF-GREET," January 2025. https://www.energy.gov/sites/default/files/2025-01/45zcf-greet_user-manual.pdf.

Finally, undertaking analyses with each model discussed in this section requires significant effort and resources. We believe that representing two models appropriately balances the NASEM recommendations to consider framework uncertainty by comparing results using multiple models, with the goal of having a flexible and responsive approach that allows updating analyses as appropriate for each proposed and final volume rule within given timing and resource constraints. For these reasons, we use the GLOBIOM and GCAM models in our assessment of the climate change impacts of volumes of crop-based biofuels under this proposal. The GLOBIOM and GCAM models are described in detail in the subsections below. Considerations for scenario implementation specific to each of GLOBIOM and GCAM follow in Chapters 5.1.3.2 and 5.1.3.3 respectively.

5.1.3.1.1 GLOBIOM

The Global Biosphere Management Model (GLOBIOM) is a partial equilibrium, recursive dynamic model with detailed grid cell land representation that captures the agricultural, forest and bioenergy sectors. It was developed by and continues to be managed by the International Institute for Applied Systems Analysis (IIASA). A sample of GLOBIOM code is available to the public, and an open-source version is under development.[254]

The climate change analysis undertaken in this proposal uses a version of GLOBIOM which is nearly identical to the version of GLOBIOM reviewed in EPA's 2023 MCE. The most notable difference is that, while the modeling in the MCE considered GLOBIOM scenarios that ran in ten-year timesteps though 2050, the version of GLOBIOM used in this analysis has been extended to run through model year 2060.[255]

As a partial equilibrium model, GLOBIOM does not have feedback from labor, capital or other parts of the economy. The model finds market equilibria that maximize the sum of producer and consumer surplus subject to resource, technological, demand and policy constraints at a country/regional level. Producer surplus is defined as the difference between market prices at a regional level and the product's supply curve at the regional level. The supply curve accounts for labor, land, capital and other purchased input. Consumer surplus is based on the level of consumption of each market and is arrived at by integrating the difference between the demand function of a good and its market price. The model uses linear programming to solve, although it also contains some non-linear functions that have been linearized using stepwise approximation.[256]

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

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[254] GLOBIOM, "Model Code." https://iiasa.github.io/GLOBIOM/model_code.html.
[255] Scaling of GLOBIOM results to the analytical timeframe is discussed in Chapter 5.1.3.2.
[256] Documentation of GLOBIOM's economic principles, sectors, and representation can be found in: IIASA, "Global Biosphere Management Model (GLOBIUM) Documentation 2023 - Version 1.0," 2023. https://pure.iiasa.ac.at/id/eprint/18996/1/GLOBIOM_Documentation.pdf.

GLOBIOM also features highly detailed livestock representation based on FAOSTAT data and represented at the grid cell level. For ruminants there are 8 production system possibilities, including grazing systems in different climatic locations such as arid and humid, mixed crop-livestock systems, and others. Pigs and poultry are classified under either small holder or industrial systems. Based on the production system, animal species, and region, GLOBIOM differentiates diets, yields, and GHG emissions.[257] Livestock production is allowed to intensify or extensify, thereby altering the amount of feed or grass consumed.[258] Since for ruminants this is modeled spatially, any changes in grassland consumed due to changes in production systems, animal type, yield, and GHGs is captured in the spatially-relevant areas.

Forestry in GLOBIOM is captured through the G4M module[259] and includes detailed representation of the sector and its supply chain and a differentiation between managed and unmanaged forest areas. GLOBIOM includes bilateral trade for agricultural and wood products.

The model also includes a bioenergy sector with first- and second-generation biofuels and biomass power plants. GLOBIOM represents biofuel coproducts including distillers grains, oilseed meals, and sugar beet fibers. These coproducts can be traded either in their processed or whole forms. Coproducts that can be used for livestock feed can substitute other forms of feed depending on protein and metabolizable energy content.[260]

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

Land use in GLOBIOM allows for both intensification and extensification.[261] Land conversion is endogenously determined based on conversion costs and the profitability of primary products, coproducts and final products. Costs increase as the area converted expands.

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[257] For instance, dairy and meat herds are modeled separately, and their diets are differentiated. Poultry in industrial systems is split into laying hens and broilers, again with different dietary needs.
[258] Intensifying involves increasing livestock output without expanding the area of pasture land by grazing more livestock per area of land, increasing feed relative to grazing, or using feedlots. Extensifying is the opposite—it involves expanding pasture area in order to increase livestock production.
[259] IIASA, "Global Forest Model (G4M)." https://iiasa.ac.at/models-tools-data/g4m.
[260] Valin, Hugo, et al. "Improvements to GLOBIOM for Modelling of Biofuels Indirect Land Use Change," *ILUC Quantification Consortium*, September 17, 2014.
[261] We define intensification as an increase in the amount of crop production on a given area of land, and extensification as an increase in the total area used to grow the crop of interest. Where we use the term extensification, we are including both non-cropland that was converted to cropland and shifting of cropland from one type of crop to another. However, our discussion of the results shows cropland shifting and land conversion to cropland separately.

Additionally, there are biophysical land suitability and production potential restrictions. Land use change is determined at the grid cell level.[262] There is a land transition matrix that sets the options for land conversion for each cell and is based on land conversion patterns specific to that region and conversion costs depending on the type of land converted. In the U.S. and EU regions, GLOBIOM, by default, does not allow forest conversion and restricts natural land conversion though these assumptions can be changed.

5.1.3.1.2 GCAM

The Global Change Analysis Model (GCAM) is a partial equilibrium, dynamic recursive, multi-sector dynamic model that represents human and Earth system dynamics. The core GCAM is developed and maintained at the Joint Global Change Research Institute, a partnership between Pacific Northwest National Laboratory (PNNL) and the University of Maryland (UMD) in College Park, Maryland. PNNL is the primary steward of the model, though members of a larger GCAM Community also contribute to its development.[263] GCAM is an open-source community model that can be downloaded from a public repository.[264] The model documentation is also publicly available[265] and includes a partial list of GCAM publications.[266]

The climate change analysis undertaken in this proposal uses a version of GCAM which is nearly identical to the version of GCAM reviewed in EPA's 2023 MCE technical document. That version of GCAM, referred to as "GCAM-T" in the MCE, was based on the GCAM core model version 5.3,[267] with a number of enhancements to better capture the energy, land, and atmospheric impacts of biofuel production. Additional documentation for the version of GCAM-T used in the MCE is included as a memorandum to the docket.[268] One revision has been made to the version of GCAM-T described above in the version of GCAM used in the climate change analysis for this proposal: parameters governing the effective elasticity of land use transitions have been updated to align with previous updates to GCAM's representation of land suitability.[269] The rest of this section describes the GCAM modeling framework broadly, including recent core versions of GCAM and the specific version of GCAM used in this proposal.

GCAM represents five systems—energy, economy, agriculture and land use, water, and atmosphere—and structurally represents key interactions between these systems through a fully

[262] GLOBIOM represents most land in the world using 5 arcminutes by 5 arcminutes grid. At the equator, this is roughly 9 km by 9 km.
[263] For more information, see GCIMS, "Community." https://gcims.pnnl.gov/community.
[264] See https://doi.org/10.5281/zenodo.1042788
[265] See https://jgcri.github.io/gcam-doc/index.html.
[266] See, more specifically, https://jgcri.github.io/gcam-doc/references.html.
[267] GCAM version 5.3 is available at: https://doi.org/10.5281/zenodo.3908600.
[268] See "GCAM-T 2022.0 Documentation," available in the docket for this action.
[269] These land transition parameter updates were released in core model version 7.1. While GCAM-T is built off of a prior core version of GCAM (v5.3), land transitions are a central component of biofuel modeling and, for this reason, we have included this isolated update in the version of GCAM used in the analyses in this proposal. These updates are described in Section 2.1 of JGCRI, "GCAM Core Model Proposal #393: Update AgLU parameters for land-based mitigation measures," March 20, 2024. https://jgcri.github.io/gcam-doc/cmp/393-AgLU_Parameters_Update.pdf.

integrated computational system.[270] It encompasses all human systems and economic sectors that produce or consume energy or emit GHGs. The model operates at a global level, with differing levels of spatial resolution across the different systems; there are 32 socioeconomic (market) regions, 235 water basins, and 384 distinct land use regions globally which are generated as the intersection of socioeconomic and water basin regions.

GCAM operates as a dynamic recursive model, solving for market equilibria in 5-year time steps, such that the information from one time period is passed forward to subsequent time periods. In practice, the model is often run from a base year in the recent past through the years 2050 or 2100. In our analysis for this proposal, it is run through 2060. However, time step and scenario length are flexible input assumptions to GCAM, and the framework can support scenario analysis across a wide range of time scales. For each modeled time period, GCAM iterates until it finds a vector of prices that clears all markets and satisfies all consistency conditions.

The energy and agricultural systems in GCAM are represented as distinct, interacting sectors, wherein the output of one sector can be an input to other sectors. Within each sector, specific production technologies compete for market share using a multi-level nesting approach that allows competition between different nodes at each level, and any number of levels. This nested competition follows a discrete logit[271] or modified logit model,[272] depending on the object. The market share of each discrete technology is determined by: (1) Relative costs, which include exogenous and endogenous components; (2) Calibration-derived "share-weight" parameters and capital carryover from prior time periods; and (3) An exogenous logit exponent that determines the price responsiveness of the competition. Additionally, technologies that are introduced in future time periods are assigned exogenous share-weights in each model time period. In the end, market shares of competing technologies are influenced by a number of both endogenous and exogenous parameters—including fuel and non-fuel costs, efficiency or input-output coefficients, share-weights, and logit exponents.

Inter-regional trade of energy and agricultural commodities in GCAM is specified using a hybrid of the Armington approach[273] and the Heckscher Ohlin theorem.[274] Traded commodities include crop and livestock products, forestry products, primary energy goods such as coal and oil, and selected secondary energy and industrial commodities such as refined fuels and nitrogenous fertilizers. Trade of each commodity is represented using a pooled global market; the inter-regional allocation of exports is based on relative costs of production and base-year

[270] https://jgcri.github.io/gcam-doc/overview.html.
[271] McFadden Daniel. "Conditional logit analysis of qualitative choice behavior." 1973. https://eml.berkeley.edu/reprints/mcfadden/zarembka.pdf.
[272] Clarke, John F., and J.A. Edmonds. "Modelling Energy Technologies in a Competitive Market." *Energy Economics* 15, no. 2 (April 1, 1993): 123–29. https://doi.org/10.1016/0140-9883(93)90031-l.
[273] The Armington approach to modeling international trade is based on the premise that products traded internationally are differentiated by country of origin. This is in contrast to models that assume perfect substitution between products produced in different countries. Armington, Paul S. "A Theory of Demand for Products Distinguished by Place of Production." *IMF Staff Papers*, 1969 (001). https://doi.org/10.5089/9781451956245.024.
[274] Note that the most recent public version of GCAM trades all energy goods through the Armington-like approach, rather than through homogenous markets. This version of the model was not released in time for inclusion in this exercise.

calibration, and on the consumption side, each region's choice of imports versus domestic sourcing is similarly determined by relative costs and calibrated base-year decisions.

The energy system in GCAM is detailed and consists of depletable and renewable resources (including primary biomass), energy transformation and distribution sectors (electricity, refining, gas processing, hydrogen production, and district services), and final energy demand sectors (buildings, industry, and transportation). For transportation biofuels specifically (referred to in the GCAM documentation as "biomass liquids"), the default model includes a total of 11 biofuel production technologies. These include four "first generation" technologies, representing ethanol and biodiesel products produced from agricultural commodity crops, and seven "second generation" technologies representing fuels produced from a variety of feedstocks, including energy crops and residues. By default, the technology assumptions for second generation represent the inputs and outputs of cellulosic ethanol and Fischer-Tropsch fuels. However, the input assumptions for these technologies can be modified to represent other fuel production pathways. Further description of these technological representations is available in the online GCAM documentation.[275]

The agriculture and land use module differentiates 384 land use regions globally, generated as the intersection of 32 socioeconomic regions with 235 water basins. Within each land use region, up to 25 land use types compete for land share based on the relative profitability of each use, using a nested land allocator tree structure.[276,277] Land use conversion in GCAM is driven by the logit structure of the model coupled with the land nesting structure. Further, GCAM land categories are structured in sub-nests, with easier conversion between land types within a sub-nest than across sub-nests. Land use types include exogenous land types (tundra, desert, urban), commercial and non-commercial pasture and forest lands, grasslands and shrublands, and a detailed set of agricultural crop commodities, including bioenergy crops, classified by irrigation type and management intensity.[278] Major global commodity crops, such as corn, rice, soybeans and wheat are modeled individually, while all other crops are modeled as a series of thematic aggregations.

Within this nesting structure, the allocations of land to each land use type are calibrated in the model base year, and in the future, changes from the base-year allocations are driven by changes in the relative profitability of each land use type, including both commercial and natural lands. Profitability of lands in agricultural and forestry production changes over time as a function of future commodity prices, yields, and costs of production (including endogenous costs of fertilizer, fuel, and irrigation water). The intrinsic profitability or value of natural lands is

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[275] See https://jgcri.github.io/gcam-doc/supply_energy.html.
[276] Wise, Marshall, Kate Calvin, Page Kyle, Patrick Luckow, and Jae Edmonds. "Economic and physical modeling of land use in GCAM 3.0 and an application to agricultural productivity, land, and terrestrial carbon." *Climate Change Economics* 05, no. 02 (May 1, 2014): 1450003. https://doi.org/10.1142/s2010007814500031.
[277] Zhao, Xin, Katherine V. Calvin, and Marshall A. Wise. "The critical role of conversion cost and comparative advantage in modeling agricultural land use change." *Climate Change Economics* 11, no. 01 (January 30, 2020): 2050004. https://doi.org/10.1142/s2010007820500049.
[278] A complete description of the land use module can be found in the online documentation (https://jgcri.github.io/gcam-doc/land.html) and in Kyle, G. Page, Patrick Luckow, Katherine V. Calvin, William R. Emanuel, Mayda Nathan, and Yuyu Zhou. "GCAM 3.0 Agriculture and Land Use: Data Sources and Methods," December 12, 2011. https://doi.org/10.2172/1036082.

inferred from the base year profitability of proximate land used for agriculture and forestry in each region. The logit competition for land is non-linear and exhibits diminishing marginal returns to expansion of each use as well as non-constant elasticities.[279] This nonlinear nature allows the land shares to be solved based on equal value at the margin without need for the explicit constraints used in linear models.

GCAM also uses land suitability and land protection assumptions to determine what land is available for expansion. All versions of GCAM divide land into arable and non-arable categories and, by default, protect some portion of the arable land from conversion to agricultural or silvicultural use. In the version of GCAM used for this exercise, GCAM-T, other assumptions limit the suitability of arable lands for crop production based on biophysical limitations (e.g., slope, annual rainfall) and human-imposed limitations such as land protection policies. The latter are parameterized using the International Union for Conservation of Nature's (IUCN) World Database of Protected Areas.[280]

5.1.3.2 Scenario Implementation: GLOBIOM

Because GLOBIOM represents decadal timesteps (i.e., model outputs are given for modeled years 2020, 2030, 2040, 2050, and 2060), representing biofuel volume changes in only a few consecutive years—three years (2026, 2027, and 2028) in the case of the Low and High Volume Scenarios and in only two years (2026 and 2027) in the case of the Proposed Volumes—requires making post-hoc translations, adjustments and interpretations of the native model outputs.

For model year 2020, we specify volumes of U.S. consumption for each of the five biofuels represented in GLOBIOM using RFS administrative data by taking a five-year average (2018–2022) of RINs generated for that fuel and feedstock. Because GLOBIOM does not represent the year 2028 specifically, in order to represent the 2028 volumes in the three-year Low and High Volume Scenarios and the accompanying No RFS Baseline, we specify volumes in model year 2030 to match the corresponding values for each scenario in 2028 (see Table 5.1.1-1 for volumes differences compared to No RFS).[281] We then assume that all effects in the model results are lagged by two years from the analytical scenario year (e.g., GLOBIOM outputs for model year 2050 represent analytical scenario year 2048, interpolated GLOBIOM outputs for year 2036 represent analytical scenario year 2034).

We use GLOBIOM model outputs to estimate five different categories of emissions, either directly or using post hoc adjustments or assumptions to supplement components which are not represented endogenously in GLOBIOM. These categories are summarized in Table 5.1.3.2-1.

[279] See Wise et al (2020).
[280] For more information, see documentation provided at: https://github.com/gcamt/gcam-core/tree/GCAM-T-2020.
[281] All volume specifications for GCAM and GLOBIOM scenarios are contained in "Set 2 NPRM Climate Change - Economic Model Scenario Specifications," available in the docket for this action.

Table 5.1.3.2-1: Summary of Emissions Categories and Adjustments for GHG Emissions Estimates Using GLOBIOM

Emissions Category	Interpolation Notes	Adjustments
Land Use Change	Linear interpolation of area of land use change between model years. This results in constant LUC emissions between model years.	N/A
Crop Production	Linear interpolation of crop production emissions between model years.	Model outputs supplemented with estimates for several components of crop production emissions using externally developed emissions factors.
Livestock Production	Linear interpolation of livestock production emissions between model years.	N/A
Fuel Production, Transport, Distribution &Use	Emissions calculated external to model outputs using the R&D GREET model based on volume assumptions.	Calculated using R&D GREET model-based emissions factors.
Fossil Fuel Use	Emissions calculated external to model outputs using the R&D GREET model based on volume assumptions.	Use of fossil fuels is not represented in GLOBIOM. We assume biofuels displace use of fossil fuels on a one-for-one energy equivalent basis.

GLOBIOM model outputs for land use change (LUC) emissions represent cumulative emissions over the prior decade (e.g., the GLOBIOM output in 2040 represents emissions from 2031–2040). To estimate LUC emissions for unrepresented years, we assume a constant rate of change in land use area over each decade, i.e., we use a linear interpolation assumption for total area of each land type. Since emissions are determined based on the area of annual land transitions, and we assume the amount and types of land changing in each individual year throughout a decade are the same, LUC emissions estimates are constant for each decade, with one exception. For the decade 2021–2030, we make alternative assumptions to represent the specific volume changes in 2026, 2027, and 2028. The model year 2030 outputs represent analytical year 2028 fuel volumes and their associated land use requirements. Thus, differences in land use change emissions outputs between the Volume Scenarios and the No RFS Baseline represent the LUC emissions associated with the difference in land use requirements to produce the specified 2028 fuel volumes. To allocate those emissions to individual years, we scale the 2030 LUC emissions estimate by the year-over-year volume difference for each year as percentage of 2028 volume difference. In other words, we allocate the LUC emissions proportionally to the three years 2026, 2027, and 2028 based on how much of the total change (relative to the No RFS Baseline) in volumes happens in those years. These scalar factors are presented in the top row of Table 5.1.3.2-2.

Table 5.1.3.2-2: Emissions Adjustment Scalars for Economic Modeling of the Low and High Volume Scenarios Compared to the No RFS Baseline

	Low Volume Minus No RFS			High Volume Minus No RFS		
	2026	2027	2028	2026	2027	2028
Year-over-year volume difference as percentage of 2028 volume difference	96.3%	1.6%	2.1%	79.2%	10.2%	10.6%
Cumulative volume difference as percentage of 2028 volume difference	96.3%	97.9%	100.0%	79.2%	89.4%	100.0%

For livestock production emissions and those crop production emissions components that are endogenously represented in GLOBIOM, we linearly interpolate emissions estimates for non-modeled years. This represents an assumption of linear change in crop production and livestock production activity between modeled years. For 2026, 2027, and 2028 we follow a similar approach to allocation of LUC emissions estimates, with one key difference: we scale the 2030 crop / livestock production emissions estimates by the cumulative volume difference for each year as percentage of 2028 volume difference rather than the year-over-year difference. These emissions correspond with ongoing activity (crop / livestock production), rather than one-time releases of stored carbon as is the case for LUC emissions, so we adjust by the cumulative total change in that activity. These scalar factors are presented in the bottom row of Table 5.1.3.2-2.

Components of crop production emissions that are endogenously represented in GLOBIOM outputs are limited to non-CO_2 emissions associated with application of manure and fertilizer, and CH_4 emissions associated with the cultivation of rice. Other components of crop production emissions that are not represented in GLOBIOM include non-CO2 emissions from burning or decomposition of crop residues, pesticide use and on-farm energy use (e.g., use of diesel fuel to operate farm equipment). We estimate crop production emissions from these unrepresented components using emissions factors developed for Argonne National Laboratory and for use in implementation of the 45Z tax credits.[282] These factors are defined by region and by crop as emissions by GHG per metric ton of production. These emissions factors and necessary region mappings are contained in an Excel workbook in the docket for this proposal.[283]

As discussed above, GLOBIOM does not endogenously represent the production, transport, distribution, or use of fuels, including biofuels. To represent emissions associated with those lifecycle stages for the assessed volumes in the GLOBIOM scenarios, we use estimated emissions factors for those stages of the assessed crop-based fuels to make post-hoc adjustments. The emissions factors used for these adjustments are presented in Table 5.1.3.2-3.

[282] Crop production emissions estimates under the 45Z tax credits are documented in: DOE, "Guidelines To Determine Life Cycle Greenhouse Gas Emissions of Clean Transportation Fuel Production Pathways Using 45ZCF-GREET," January 2025. https://www.energy.gov/sites/default/files/2025-01/45zcf-greet_user-manual.pdf.

[283] Factors are defined using the GTAP region definitions. In order to apply factors, we aggregate crop production outputs by GLOBIOM region to regions consistent with GTAP definitions. See details in "Set 2 NPRM Climate Change - Crop Production Emissions Factors," available in the docket for this action.

Table 5.1.3.2-3: Emissions Factors (gCO_2e/ MJ fuel used) Associated With Fuel Production and Downstream Emissions for Crop-Based Fuels

	Fuel Production	Transport, Distribution & Use	Subtotal
Biodiesel: Soybean Oil	3.8	1.1	4.9
Biodiesel: Canola Oil	3.8	1.1	4.9
Renewable Diesel: Soybean Oil	10.1	1.2	11.3
Renewable Diesel: Canola Oil	10.1	1.2	11.3
Ethanol: Corn Starch	25.5	1.4	26.9

We estimated all these emissions factors using data and emissions factors from the R&D GREET model. The fuel production emissions include the emissions associated with converting the feedstock to the finished fuel. The fuel production emissions do not include emissions associated with feedstock production or delivering the feedstocks to the biofuel plant, as those emissions are estimated with GLOBIOM. The fuel production emissions estimates use energy allocation to account for coproducts (see Chapter 5.1.2.2 for further discussion on the choice of energy allocation). For biodiesel and renewable diesel production, we use the simple system-level allocation method whereby the total fuel production emissions are allocated among the coproducts on an energy basis. For ethanol production, we allocate all the fuel production emissions to the ethanol, except that we allocate all of the emissions associated with corn oil extraction to the distillers corn oil (see Chapter 5.1.2.2 for further discussion on ethanol production allocation methods).

The transportation, distribution and use emissions include all the emissions downstream of the fuel production facility all the way to ultimate use of the fuel. As discussed above in Chapter 5.1.2.2, we exclude the biogenic CO_2 emissions from fuel combustion as we treat this as biogenic carbon recently removed from the atmosphere. Note that the GLOBIOM analysis estimates all the significant emissions associated with producing the feedstocks for these biofuels (including market-mediated land use changes). For these reasons, it would not be accurate to characterize our analysis as assuming that these fuels are "carbon neutral". Rather, we account explicitly for uptake of carbon in biomass and the release of that carbon as biomass degrades, is transformed into other states, and/or is consumed, along with all other relevant emissions and sinks associated with the production and use of these fuel products.

Finally, GLOBIOM does not represent energy sector impacts or emissions associated with biofuels displacing use of fossil fuels. We assume a straightforward one-for-one energy equivalent displacement of fossil gasoline (for ethanol volumes) and fossil diesel (for BBD volumes) in the United States and apply emissions factors representing process energy inputs for renewable fuel production as estimated in R&D GREET (See Chapter 5.1.2.4). These emissions factors are similarly used in our assessment of waste- and byproduct-based fuels.

5.1.3.3 Scenario Implementation: GCAM

While GCAM operates in five-year model timesteps instead of the 10-year steps that GLOBIOM uses, the scaling, translating, and interpolation necessary for implementing the Low Volume Scenario, High Volume Scenario, and No RFS Baseline is broadly similar. Differently from GLOBIOM, the version of GCAM used in this analysis represents production, trade and consumption of biodiesel produced from various vegetable oils. However, it does not represent renewable diesel produced from vegetable oils separately from biodiesel. To implement the volumes specified in the Volume Scenarios and Proposed Volumes in GCAM, we assume that all volumes (by energy content) of renewable diesel are instead biodiesel. This assumption ensures that roughly similar demands for feedstock vegetable oils are represented in our GCAM simulations and that an equivalent amount of biofuel on an energy equivalent basis enters the market to displaced fossil-based alternatives.

For GCAM model year 2020, we specify volumes of U.S. consumption for each of the represented biofuels using RFS administrative data by taking a five-year average (2018–2022) of RINs generated for that fuel and feedstock. For GCAM model year 2025, U.S. biofuel consumption levels we specify volumes of corn ethanol and biomass-based diesel (represented as biodiesel in GCAM) using the updated projections for 2025 biofuel consumption levels discussed in Chapter 2.2 and presented in Table 2.2-3. Because GCAM does not represent the year 2028 specifically, in order to represent the 2028 volumes in the three-year Low and High Volume Scenarios and the accompanying No RFS Baseline, we specify volumes in model year 2030 to match the corresponding values for each scenario in 2028 (see Table 5.1.1-1 for volumes differences compared to No RFS).[284] We then assume that all effects in the model results are lagged by two years from the analytical scenario year (e.g., GCAM outputs for model year 2045 represent analytical scenario year 2043, interpolated GCAM outputs for year 2036 represent analytical scenario year 2034).

We use GCAM model outputs to estimate five different categories of emissions, either as is or using post hoc adjustments or assumptions to supplement components which are not represented endogenously in GCAM. These categories are summarized in Table 5.1.3.3-1.

[284] All volume specifications for GCAM and GLOBIOM scenarios are contained in “Set 2 NPRM Climate Change - Economic Model Scenario Specifications,” available in the docket for this action.

Table 5.1.3.3-1: Summary of Emissions Categories and Adjustments for GHG Emissions Estimates Using GCAM

Emissions Category	Interpolation Notes	Adjustments
Land Use Change	Annual emissions reported from GCAM based on an assumed linear interpolation of area of land use change between model years.	N/A
Crop Production	Linear interpolation of crop production emissions between model years.	N/A
Livestock Production	Linear interpolation of livestock production emissions between model years.	N/A
Other Industrial[a]	Linear interpolation of other industrial emissions between model years.	N/A
Fossil Fuel Use	Linear interpolation of emissions from fossil fuel use between model years.	Adjustment using emissions factor from the R&D GREET model accounting for difference between biodiesel and renewable diesel in production & downstream emissions.

[a] "Other Industrial" emissions in GCAM represent changes in emissions from other industrial processes that are impacted by market-mediated effects in biofuel scenarios. These effects are very small relative to the other categories of emissions. For this reason, these emissions are aggregated with other energy sector emissions in our presentation of scenario results in Chapters 5.2 and 5.3.

While GCAM operates in five-year timesteps, LUC emissions are estimated within a land allocation module that results in annual emissions estimates, including for non-modeled years. These annual estimates implicitly assume a linear interpolation of land area change between model years, but account for non-linear processes affecting CO_2 emissions, including vegetative carbon uptake and soil carbon loss after land transitions.[285] Because GCAM outputs provide annual estimates of LUC emissions, no interpolation is needed: we instead simply translate the stream of emissions outputs by two years (i.e., analytical year 2029 corresponds with GCAM model year 2031 outputs). However, for analytical years 2026, 2027, and 2028 we need to make similar adjustments as were done in the GLOBIOM modeling to account for the specific biofuel consumption volumes in those years which are unable to be represented in GCAM. Because GCAM's LUC emissions reporting implicitly assumes linear changes in land area between non-modeled years, the emissions reported for 2026 represents emissions associated with roughly one fifth of the land area change that takes place between the 2025 and 2030 model time steps.[286] We assume the total land area change in 2030 represents the area change necessary to meet the 2028 volume specifications implemented as 2030 targets in these scenarios. Thus, we estimate the total LUC emissions between analytical years 2026 and 2028 to be five times the LUC emissions reported in model year 2026. We then allocate those LUC emissions between 2026, 2027, and

[285] GCAM's land allocation module and land use change emissions are documented in the GCAM online documentation at: https://jgcri.github.io/gcam-doc/land.html.

[286] This assumption ignores the non-linear effects accounted for in the GCAM land allocation and emissions accounting module, but is necessary for estimating three years of scaled emissions from emissions reporting for a five-year modeled timestep.

2028 using the same scalars used in the GLOBIOM modeling, presented in the top row of Table 5.1.3.2-2.

For livestock production emissions, crop production emissions, other industrial emissions, and emissions from fossil fuel use, we linearly interpolate emissions estimates for non-modeled years. For 2026, 2027, and 2028 we follow the same emissions allocation approach as was used in the GLOBIOM modeling for interpolated emissions categories; we scale the 2030 emissions estimates by the cumulative volume difference for each year as percentage of 2028 volume difference. These scalar factors are presented in the bottom row of Table 5.1.3.2-2.

Note that, because detailed energy demands are endogenously represented in GCAM, the emissions estimates for differences in fossil fuel use in GCAM represent displacement of use of fossil-based fuels with use of biofuels, market-mediated impacts on global energy use (e.g., "oil rebound"), and the additional energy and other inputs necessary for biofuel production. Thus, while in the GLOBIOM modeling we include additional biofuel production and downstream emissions estimates, these categories are represented within the fossil fuel use category in GCAM results. However, using biodiesel volumes as a proxy for renewable diesel production in our scenarios does not account for the different input and energy requirements between biodiesel and renewable diesel production. Given the substantial volumes of renewable diesel in the scenarios we are assessing, this is a necessary source of emissions to represent in our assessment. We account for these emissions by comparing estimates from GREET of the emissions of producing, distributing, and using renewable diesel versus the emissions from the same lifecycle stages for biodiesel. We then apply factors developed using the R&D GREET model representing the marginal additional emissions associated with producing renewable diesel rather than biodiesel to the volume of renewable diesel in the assessed scenarios. These factors are calculated simply as the difference between emissions factors for renewable diesel and biodiesel produced from a given feedstock in Table 5.1.3-3.

5.2 Assessment of Analytical Volume Scenarios

This section presents results of the climate change analysis for the Low and High Volume Scenarios relative to the No RFS Baseline under an assumed three-year standards rule (i.e., setting volumes for 2026, 2027, and 2028). Modeling methods, assumptions and scenario implementation are described in Chapter 5.1. Chapter 5.2.1 provides a summary of the emissions impacts of waste- and byproduct-based fuels under these scenarios. Chapter 5.2.2 provides an extensive description of the modeling undertaken to assess the emissions impacts of crop-based fuels.

5.2.1 Waste- and Byproduct-based Fuels

As discussed in Chapter 5.1.2, estimates of changes in emissions between scenarios for fuels produced from waste and byproduct feedstocks are calculated by comparing emissions intensity estimates from R&D GREET for the biofuel to emissions intensity estimates for the fossil fuel their use is assumed to displace. This results in a per-megajoule emissions impact factor for each renewable fuel product assessed in this manner, which is then multiplied by the difference in volumes of those renewable fuels for the scenario under consideration. However, volumes of all the waste- and byproduct-based fuels are identical under the Low and High Volume Scenarios, so the emissions impacts of these fuel volumes relative to the No RFS Baseline are identical under either scenario. These emissions impacts, assuming 30 years of continued volumes as described in Chapter 5.1.1.1, are presented in CO_2e[287] in Table 5.2.1-1.

Table 5.2.1-1: GHG Emissions (Million Metric Tons CO_2e) for Waste- and Byproduct-Based Fuels in the Low and High Volume Scenarios (2026–2028 Standards) Estimated Using R&D GREET

Year	CNG/LNG: Biogas	Biodiesel: Corn Oil	Biodiesel: UCO	Biodiesel: Tallow	Renewable Diesel: Corn Oil	Renewable Diesel: UCO	Renewable Diesel: Tallow	Total
2026	-2.8	-0.3	0.2	0.2	-0.6	-4.8	-4.3	-12.3
2027	-2.9	-0.4	0.3	0.2	-0.3	-5.8	-5.3	-14.2
2028	-3.0	-0.3	0.2	0.2	-0.4	-6.8	-6.2	-16.2
2029	-3.0	-0.3	0.2	0.2	-0.4	-6.8	-6.2	-16.2
2030	-3.0	-0.3	0.2	0.2	-0.4	-6.8	-6.2	-16.2
2031	-3.0	-0.3	0.2	0.2	-0.4	-6.8	-6.2	-16.2
2032	-3.0	-0.3	0.2	0.2	-0.4	-6.8	-6.2	-16.2
2033	-3.0	-0.3	0.2	0.2	-0.4	-6.8	-6.2	-16.2
2034	-3.0	-0.3	0.2	0.2	-0.4	-6.8	-6.2	-16.2
2035	-3.0	-0.3	0.2	0.2	-0.4	-6.8	-6.2	-16.2
2036	-3.0	-0.3	0.2	0.2	-0.4	-6.8	-6.2	-16.2
2037	-3.0	-0.3	0.2	0.2	-0.4	-6.8	-6.2	-16.2
2038	-3.0	-0.3	0.2	0.2	-0.4	-6.8	-6.2	-16.2
2039	-3.0	-0.3	0.2	0.2	-0.4	-6.8	-6.2	-16.2
2040	-3.0	-0.3	0.2	0.2	-0.4	-6.8	-6.2	-16.2
2041	-3.0	-0.3	0.2	0.2	-0.4	-6.8	-6.2	-16.2
2042	-3.0	-0.3	0.2	0.2	-0.4	-6.8	-6.2	-16.2
2043	-3.0	-0.3	0.2	0.2	-0.4	-6.8	-6.2	-16.2
2044	-3.0	-0.3	0.2	0.2	-0.4	-6.8	-6.2	-16.2
2045	-3.0	-0.3	0.2	0.2	-0.4	-6.8	-6.2	-16.2
2046	-3.0	-0.3	0.2	0.2	-0.4	-6.8	-6.2	-16.2
2047	-3.0	-0.3	0.2	0.2	-0.4	-6.8	-6.2	-16.2
2048	-3.0	-0.3	0.2	0.2	-0.4	-6.8	-6.2	-16.2
2049	-3.0	-0.3	0.2	0.2	-0.4	-6.8	-6.2	-16.2
2050	-3.0	-0.3	0.2	0.2	-0.4	-6.8	-6.2	-16.2
2051	-3.0	-0.3	0.2	0.2	-0.4	-6.8	-6.2	-16.2
2052	-3.0	-0.3	0.2	0.2	-0.4	-6.8	-6.2	-16.2
2053	-3.0	-0.3	0.2	0.2	-0.4	-6.8	-6.2	-16.2
2054	-3.0	-0.3	0.2	0.2	-0.4	-6.8	-6.2	-16.2
2055	-3.0	-0.3	0.2	0.2	-0.4	-6.8	-6.2	-16.2

5.2.2 Crop-based Fuels

In this section we discuss results of the scenarios described above when modeled in the GCAM and GLOBIOM frameworks. Based on the differing scopes, designs, strengths and

[287] For simplicity, we report all emissions in this chapter in terms of CO_2 equivalence using GWPs published in AR5. However, emissions estimates within these analyses are calculated for three major GHGs: CO_2, CH_4 and N_2O. Estimates disaggregated by gas are provided, where available, in "Set 2 NPRM Climate Change Analyses," available in the docket for this action.

limitations of these frameworks, GCAM and GLOBIOM scenario results provide a range of potential effects of the assessed volume changes on the energy, agriculture, land use, and livestock sectors, with corresponding differences in GHG emissions associated with those effects. While the sections below compare and discuss the model results in detail for each of these sectors, it is useful for understanding the intertwined effects to start from a narrative summary comparison of the scenario results in each model.

At a high level, in the GCAM simulations, the additional demand for biofuels is met through a combination of expansion of cropland both within and outside the U.S., some "swapping out" of soybean oil for other vegetable oils from food usage, some increased imports[288] of fuels currently produced in non-U.S. regions, and decreased net exports of feedstock crops. In the GLOBIOM simulations the additional demand for biofuels is met by producing additional feedstock crops through crop switching in the U.S. and cropland expansion outside the U.S., and through diversion of soybean and canola oil from food and other uses which are subsequently backfilled with expanded meat and dairy consumption and greater consumption of other vegetable oils.

Energy sector impacts (Chapter 5.2.2.1) illustrate a significant distinction between the scope of these two modeling frameworks. Energy demands and trade in energy commodities are not represented within GLOBIOM, so the entirety of the increased biofuel demand represented in the scenarios must be met by increasing U.S. production of those fuels. In contrast, GCAM represents global energy demands and trade, thus allowing a portion of the additional demand for biofuels to be met through increased U.S. net imports, effectively lowering the overall global increase in biofuel usage. In terms of crop production (Chapter 5.2.2.2) and land use (Chapter 5.2.2.3), GCAM tells a story primarily of cropland expansion, and to a lesser extent, crop switching and substitution between vegetable oils, while GLOBIOM results emphasize greater crop switching and substitution between vegetable oils, with cropland expansion playing a lesser but still substantial role outside the U.S. Finally, impacts on livestock production (Chapter 5.2.2.4) are minimal in GCAM, with additional oilseed meals replacing other feed commodities while overall livestock production remains relatively unchanged. In contrast, in GLOBIOM simulates livestock production increases in response to the availability of additional oilseed meal for feed use. This shift towards more meat and dairy consumption for food partially offsets the decrease in consumption of vegetable oils for food.

The sections below present figures and data describing these observations in detail. Unless otherwise noted, figures and values discussed in this section represent unadjusted model outputs from the GCAM and GLOBIOM simulations. This discussion of model outputs describes estimated tradeoffs and responses associated with the modeled scenarios and should be understood within the boundaries of each respective model. Additionally, the GCAM and GLOBIOM simulations discussed in this section do not explicitly represent the "import RIN reduction" discussed in Preamble Section VIII. Trade in fuels and feedstock commodities may be expected to differ from the results shown if we were able to represent the "import RIN reduction" proposal in the simulations discussed in this section.

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[288] Note that the GCAM and GLOBIOM simulations undertaken for this analysis do not explicitly represent the proposed "import RIN reduction" discussed in Preamble Section VIII.

In some cases, model outputs provide incomplete accounting of all categories of GHG impacts associated with the volumes of renewable fuels under assessment. For example, emissions associated with fossil fuel use and emissions associated with some categories of crop production are not endogenously represented in GLOBIOM; these results are instead accounted for in post-hoc adjustments to model outputs. These adjustments are described where relevant in the sections below and in Chapters 5.1.3.2 and 5.1.3.3.

Additionally, model outputs are reported in model years which approximate the analytical year for which the volumes in the Low and High Volume Scenarios are defined. For example, GCAM and GLOBIOM provide outputs for a 2030 time step, which are then translated to correspond with analytical year 2028. See Chapter 5.1.3 for additional explanation of this adjustment.

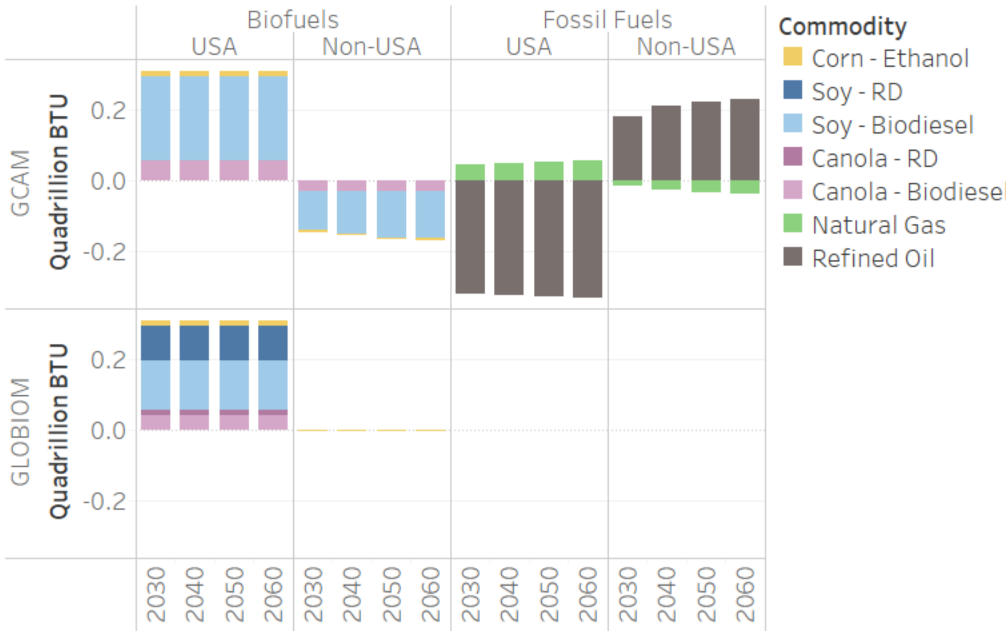
Unless otherwise indicated, figures below represent the Low Volume Scenario for standards that would apply to three years: 2026, 2027, and 2028, and assume 2028 volumes are held constant in future years. Results from modeling the High Volume Scenario show similar directional effects, with magnitudes roughly proportional to the greater volumes. Emissions impact estimates for both scenarios are presented Chapter 5.2.3. Importantly, the volumes and years modeled in the scenarios discussed in this section do not match the Proposed Volumes and years. Due to the significant lead time required to complete complex global economic simulation modeling, this analysis was completed before the Proposed Volumes were determined. While we were unable to complete additional modeling in the economic modeling frameworks used to assess the impacts of crop-based fuels, we have used the completed simulations described in this section to derive an estimate of the impacts of the Proposed Volumes. That derivation and resulting emissions estimates are described in Chapter 5.3. We intend to revise this analysis for a final rule to reflect finalized volume standards.

5.2.2.1 Energy Use

Figure 5.2.2.1-1 illustrates how the Low Volume Scenario and the No RFS Baseline are implemented in GCAM and GLOBIOM, along with several key differences between these models and how they represent energy commodities. The left-most panes of Figure 5.2.2.1-1 show the difference between the Low Volume Scenario and the No RFS Baseline in consumption of corn starch ethanol and soy- and canola-based diesel products—roughly 0.31 quadrillion BTUs combined in 2028, which is represented in model year 2030. The version of GCAM used in this analysis represents biodiesel but not renewable diesel,[289] so all volumes of soy- and canola-based biomass-based diesel are represented as biodiesel in GCAM.[290] In GLOBIOM, biodiesel and renewable diesel are differentiated, as indicated in the figure.

[289] See Chapter 5.1.3.1 for a description GCAM and the specific version used in this analysis.
[290] Renewable diesel and biodiesel have different process input requirements, which is accounted for in the final emissions estimates. This is described in more detail in Chapter 5.1.3.2.

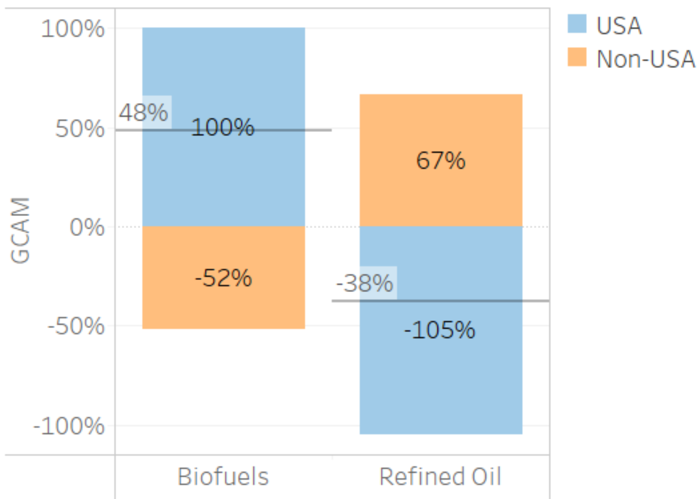
Figure 5.2.2.1-1: Difference in Consumption of Energy Commodities (Quadrillion BTUs) in the Low Volume Scenario Relative to the No RFS Baseline



A key difference between the GCAM and GLOBIOM models is that GCAM endogenously represents energy demands, production, trade and use of fuels, and GHG emissions associated with producing and using fuels, and GLBOIOM does not. This difference in scope results in several important differences in modeled outcomes which are apparent in Figure 5.2.2.1-1. First, because GLOBIOM does not represent energy commodities within its economic logic—the model includes only exogenously defined additional demand for agricultural feedstocks to produce bioenergy products—GLOBIOM outputs do not include any displacement or other economic effects associated with use of fossil fuels, nor do GLOBIOM simulations allow for any changes in renewable fuel production and use in the non-U.S. regions as market-mediated responses to the exogenously defined consumption shock within the U.S. This boundary in the scope of GLOBIOM is apparent in the absence of effects depicted in the bottom three rightmost panels in Figure 5.2.2.1-1. Because these effects are not represented in the GLOBIOM results, we exogenously account for displacement of refined oil and process energy requirements in our emissions accounting for the GLOBIOM scenarios. We assume a straightforward one-for-one energy equivalent displacement of fossil gasoline (for ethanol volumes) and fossil diesel (for BBD volumes) in the U.S. and apply emissions factors representing process energy inputs for renewable fuel production as estimated in R&D GREET (see Chapter 5.1.3.2 for explanation of these emissions factors). In contrast, GCAM endogenously represents effects on fossil fuel consumption and markets in the U.S. and non-U.S. regions and effects on renewable fuel use in non-U.S. regions in its economic logic. The remainder of the discussion in this section focuses on these effects in the GCAM scenarios.

Within the GCAM simulations, the primary effect of greater use of biofuels in the U.S. is displacement of petroleum-based fuel consumption. This is seen in the significant decline in use of refined oil[291] in the U.S. in Figure 5.2.2.1-1 (top middle-right panel). Outside of the U.S., there is a substantial decline in consumption of soy- and canola-based biodiesel (top middle-left panel). This decline represents biofuels that were produced and consumed in non-U.S. regions in the No RFS Baseline, but which were instead traded and consumed in the U.S. to meet the higher consumption targets under the Low Volume Scenario.[292] The decline in consumption of these biofuels in non-U.S. regions corresponds with a similar increase in use of refined oil to meet energy demand (top right panel). Observed changes in natural gas consumption in the U.S. and non-U.S. correspond with changes in natural gas demand for biofuel production in the regions respectively.

Figure 5.2.2.1-2: Difference in Liquid Fuel Consumption Relative to the Total Cumulative Difference in U.S. Biofuel Consumption for the Low Volume Scenario in GCAM



In addition to the first order displacement and backfilling effects observed above, subtler demand shifts responding to market signals also affect consumption of refined oil in the GCAM simulations. Figure 5.2.2.1-2 illustrates the cumulative differences in consumption of biofuels and refined oil in the U.S. and non-U.S., expressed as a percentage of the cumulative difference in U.S. biofuel consumption, i.e., the "shock." Note that the difference in consumption of "Biofuels" in the U.S. in the figure is, by definition, 100%. First, the cumulative decline in refined oil consumption within the U.S. is 105% of the full cumulative shock—i.e., 5% greater than one-for-one energy equivalent displacement. The decline in fuel consumption is greater than one-for-one because the additional renewable fuels being blended into the U.S. fuel supply in the assessed Volume Scenarios are estimated by GCAM to be costlier on a per-unit-of-energy-basis than the petroleum gasoline and diesel they displace. This estimate generally comports with our analysis and findings regarding the costs of these fuels presented in Chapter 10 of the DRIA. As these fuels displace less costly fuels in the domestic transportation fuel pool, the average cost of

[291] "Refined oil" is an aggregated commodity in GCAM representing gasoline, diesel, jet fuel, and other fuels produced from crude oil. End use sectors, including transportation, residential, and industrial sectors, represent different energy demands that can be met with refined oil, biofuels, and other sources of energy.
[292] Note that the GCAM and GLOBIOM simulations undertaken for this analysis do not explicitly represent the proposed "import RIN reduction" discussed in Preamble Section VIII.

transportation fuel increases, which in turn causes transportation fuel demand to decline on the margin.

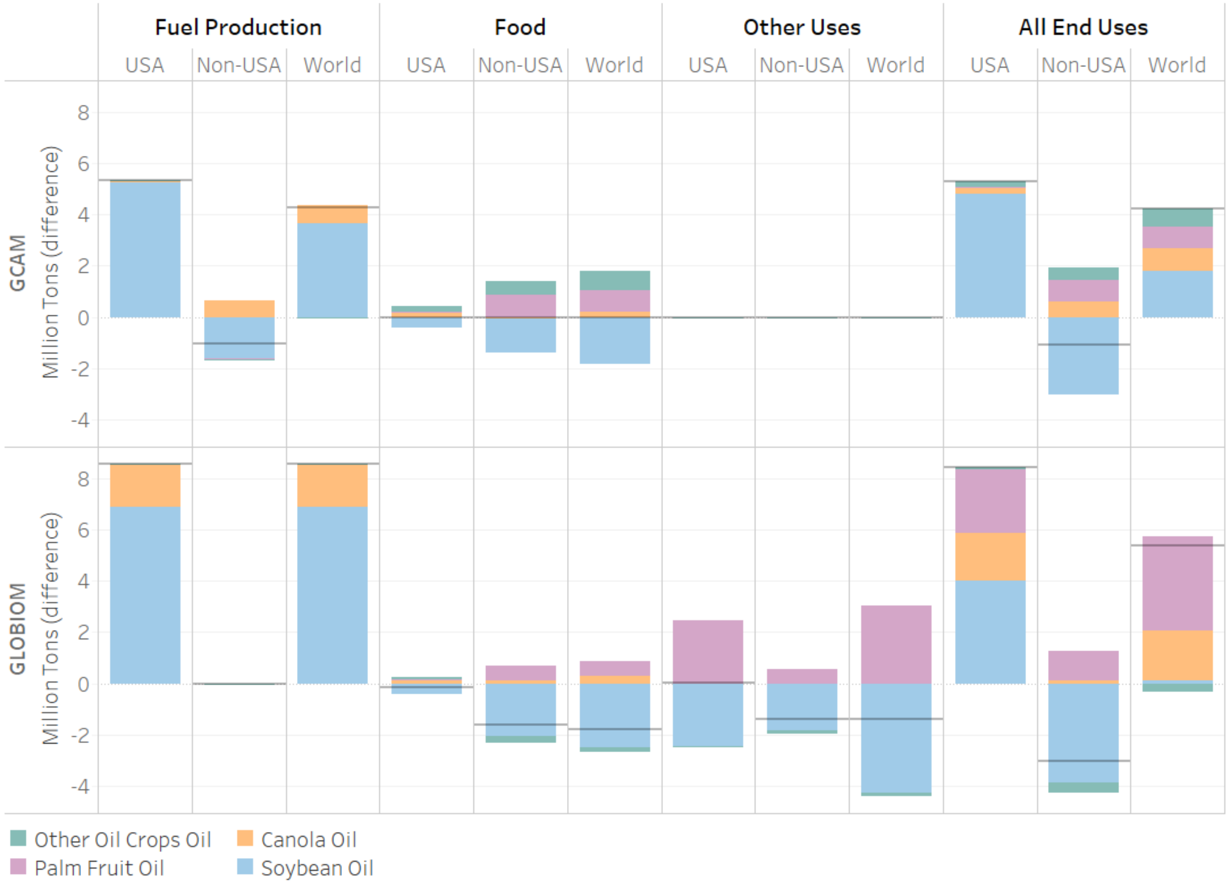
Additionally, Figure 5.2.2.1-2 shows that, over the full analytical timeframe (2026–2055), the decline in consumption of biofuels in non-U.S. regions is equivalent to 52% of the increase in U.S. consumption of biofuels. In other words, the total global cumulative change in biofuel consumption is 48% of the cumulative U.S. volume shock. Furthermore, we see that the increase in use of refined oil in non-U.S. regions exceeds the decrease in use of biofuels in those regions—67% vs 52% respectively. In other words, the increase in refined oil use outside of the U.S. goes beyond backfilling for the decrease in biofuel use by an additional 15% of the shock. This effect—often described in the literature as oil rebound—represents increased demand for refined oil outside the U.S. because of lower oil and refined oil consumption in the U.S. and consequently, lower global prices for those commodities. As the U.S. decreases its consumption of refined petroleum, this increases the supply of petroleum to the rest of the global market. This increase in supply in turn depresses prices, which stimulates additional petroleum demand on the margin.

5.2.2.2 Crop Production

The impacts of differing biofuel volumes on agricultural commodity demand are predominantly driven through additional demand for vegetable oils because oilseed oil-based biofuels represent the substantial majority of the difference in consumption of crop-based biofuels between the Low Volume Scenario and the No RFS Baseline. Thus, we begin our consideration of effects on crop production and use with an examination of changes in vegetable oil consumption. Figure 5.2.2.2-1 illustrates shifts in consumption in model year 2030 of the four categories of vegetable oils represented in GCAM and GLOBIOM (soybean oil, canola oil, palm fruit oil, and oil from other oil crops) across three end uses—fuel production, food, and "other uses" which represents non-fuel industrial uses and use in other commercial products such as cosmetics.

First, we observe that use of soybean oil and canola oil to produce biofuels aligns with the observations in Chapter 5.2.2.1; because GLOBIOM does not represent trade in fuels, all the additional biofuel consumption in the U.S. must be met through fuel production using soybean oil and canola oil in the U.S., and no shifts in non-U.S. biofuel production are possible. In GCAM, non-U.S. production of soybean oil- and canola-based biofuels is affected, with canola BBD volumes being met almost entirely through imports of fuels—sourced from both existing and expanded production—and soybean oil-based BBD volumes being met through increased imports of oil that is refined into BBD in the U.S. rather than in non-U.S. regions.

Figure 5.2.2.2-1: Difference in Consumption of Oilseed Oils (Million Metric Tons) by End Use in the Low Volume Scenario Relative to the No RFS Baseline in Model Year 2030 [a]



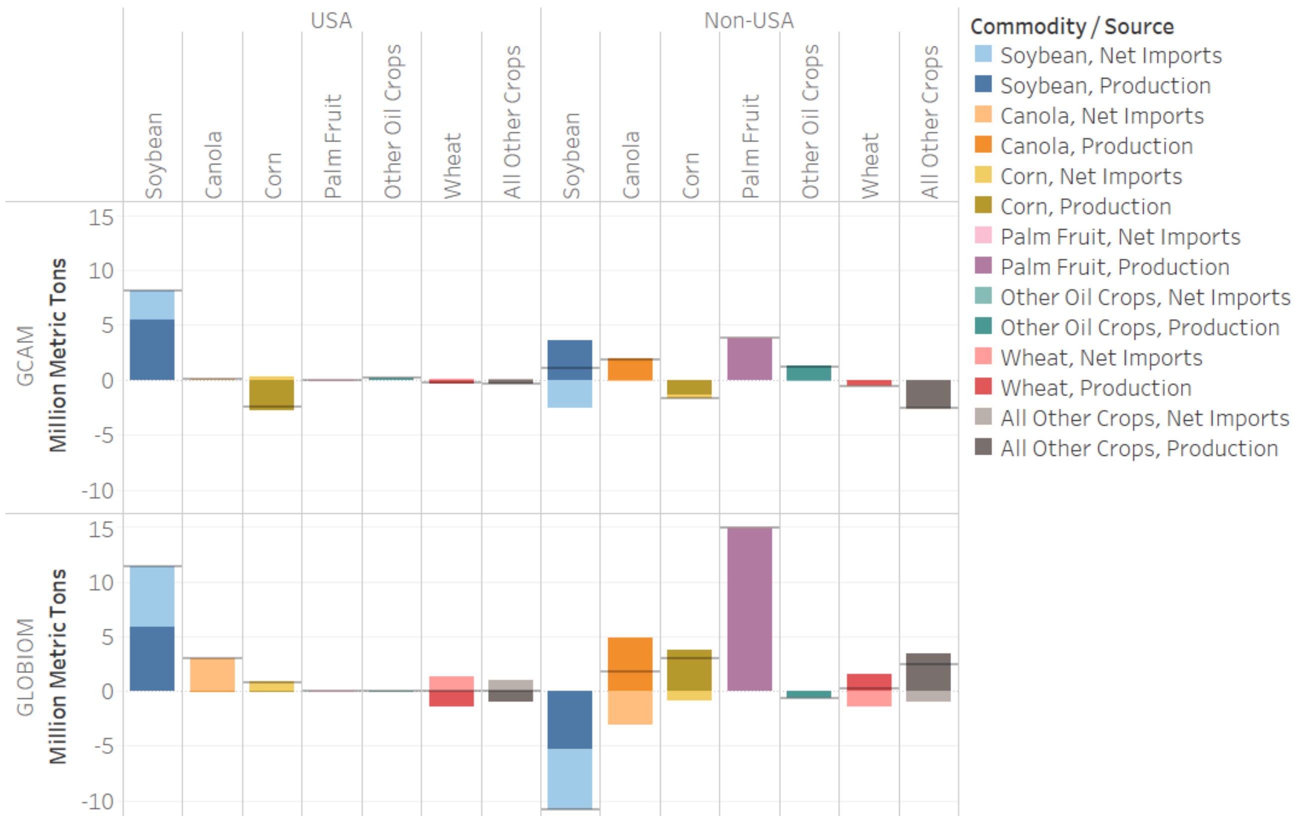
[a] Reference lines represent the net difference in consumption of a oilseed oils for a given end use and region.

Consumption of vegetable oils for food shows shifts in both models. In GCAM simulations, in both the U.S. and non-U.S. more soybean oil is used to produce fuel rather than consumed as food. That food consumption is replaced with consumption of the other three represented categories of vegetable oils, but with total net consumption of vegetable oils for food remaining roughly the same in all regions. In GLOBIOM simulations, however, while some backfilling does occur, overall consumption of vegetable oils for food decreases as soybean oil is shifted towards fuel production. This decrease in human consumption of vegetable oils represents a shift in caloric intake away from vegetable oils and towards greater meat and dairy consumption. This shift is discussed in greater detail in Chapter 5.2.2.4. Finally, GLOBIOM simulations show much greater substitutability between vegetable oils used for "other uses," with no significant substitution in GCAM, but a substantial shift from soybean oil to palm oil in GLBOIOM in this use category. Based on the scale of the difference between the two models, we believe the representation of substitutability of vegetable oils in this category warrants further review in the future.

Next, we consider how the shifts in consumption of vegetable oils and the greater demand for corn to produce corn ethanol impact production and trade of key commodity crops. Figure 5.2.2.2-2 illustrates production, trade, and consumption differences for key crops in the

Low Volume Scenario relative to the No RFS Baseline in model year 2030, which represents the analytical scenario volumes in 2028. For each of the crop categories depicted, the darker color represents changes in production in a region (U.S. on the left, non-U.S. on the right), while the lighter color represents changes in net imports of that crop for the given region. Because neither GCAM nor GLOBIOM depict inter-year storage or spoilage of commodities, all of a commodity available after trade must be consumed. In other words, the difference in consumption in a region is the sum of the differences in production and net imports, which is depicted in the figure with reference lines in each column.

Figure 5.2.2.2-2: Difference in Production and Net Imports of Crops (Million Metric Tons) in the Low Volume Scenario Relative to the No RFS Baseline in Model Year 2030[a]



[a] Reference lines represent differences in consumption. Neither GCAM nor GLOBIOM represent inter-year storage or spoilage of commodities, so consumption is, by definition, equal to production plus net import.

Several important aspects of each model's respective response to the shock are illustrated in this figure. First, oilseed oils—primarily soybean oil—represent a significant majority of the additional feedstocks required to meet renewable fuel volume targets in the Low Volume Scenario relative to the No RFS Baseline. Consequently, both models show substantial increases in soybean crushing in the U.S., with roughly one third of the additional soybeans being sourced from changes in reduced U.S. exports (depicted as increased net imports in Figure 5.2.2.2-2) in GCAM and roughly one half in GLOBIOM. However, as noted in Chapter 5.2.2.1, a portion of the additional biodiesel consumed in the U.S. in the Low Volume Scenario in GCAM is imported from non-U.S. regions. Thus, the total additional demand for soybean oil and for soybeans to crush in the U.S. is lower in GCAM than in GLOBIOM. Additionally, the increase in soybean production and imports in the U.S. has notably differing impacts in the two models. In GCAM, increased U.S. soybean production comes from: 1) Cropland expansion, which is discussed in Chapter 5.2.2.3, and 2) Switching from corn to soybean production, as some use of corn in feed can be replaced with additional soybean meal available from increased crushing. In GLOBIOM, increased U.S. production of soybeans is achieved almost entirely from crop switching, primarily away from wheat and "other crops." Outside of the U.S., GCAM simulations show greater production of soybeans to make up for reduced exports from the U.S., with a marginal net increase in use of soybeans in non-U.S. regions reflecting increased crushing for exporting soybean oil rather than soybeans. In GLOBIOM, there is both a substantial decrease in imports of soybeans in non-U.S. regions, and a decrease in production of soybeans in those regions, roughly commensurate with the increase in soy production in the U.S. As shown in Figure 5.2.2.2-2, the GLOBIOM simulations show a more pronounced substitution effect of palm and other vegetable oils for soybean and canola oil to meet global food and other industrial demand, which is reflected in greater production of those crops in non-U.S. regions.

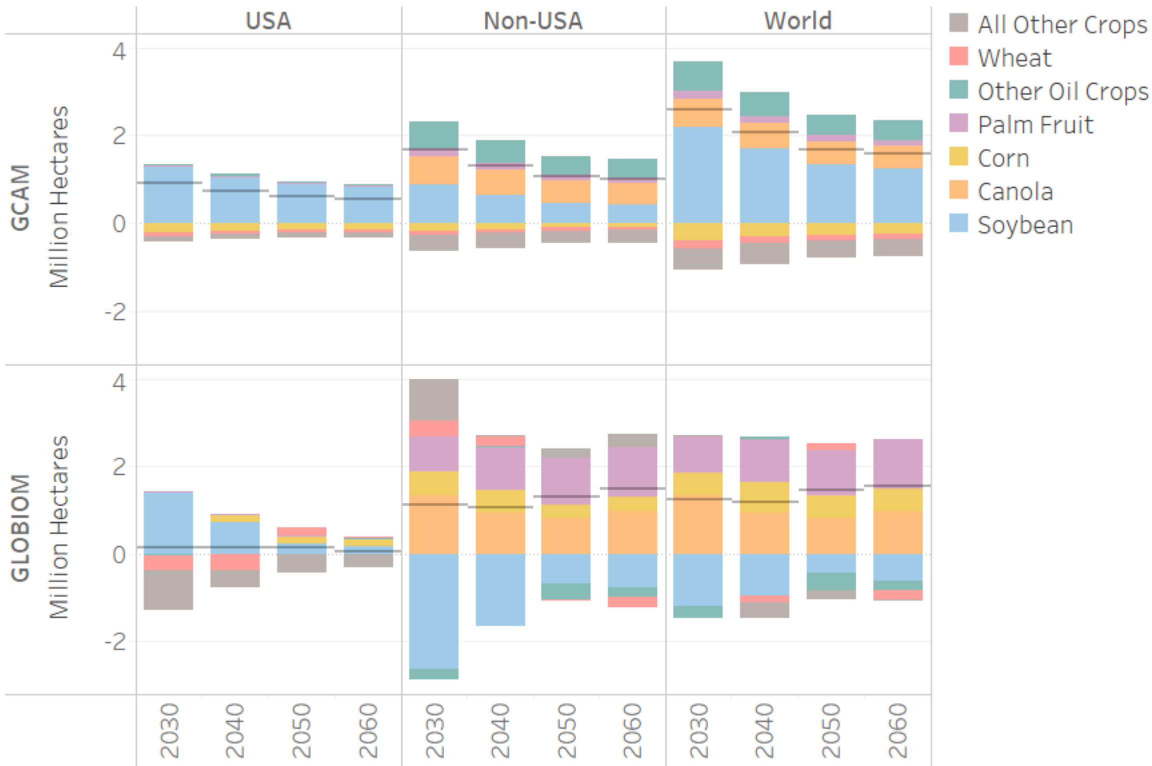
In order to meet increasing demand for canola-based diesel products, simulations in both models show increased canola production in non-U.S. regions, primarily in Canada. Results related to canola differ between the models largely from differences in the stage at which trade takes place; GCAM's structure allows for more flexibility, since canola-based fuels can be sourced from imported canola seeds (rapeseed), imported canola oil, or imported finished biofuels, whereas in GLOBIOM, the biofuel required to meet the shock must be produced in the U.S. so can be sourced from imported canola seeds or canola oil only.

GCAM and GLOBIOM each include estimates of GHG emissions associated with the changes in crop production observed above. However, the categories of crop production emissions represented in GLOBIOM are incomplete, excluding important categories such as emissions from on farm energy use (e.g., emissions associated with using diesel fuel to run tractors). For those categories of emissions, we use external estimates of emissions factors associated with production of crops in different regions. Those adjustments are presented in greater detail in Chapter 5.1.3.2.

5.2.2.3 Land Use

Changes in cropland area correspond with the production changes discussed in Chapter 5.2.2.2. Differences in cropland area between the Low Volume Scenario and the No RFS Baseline are illustrated in Figure 5.2.2.3-1. In GCAM simulations, extensification (i.e., expansion of cropland area) is the most significant trend, with expansion in the harvested area of soybeans in the U.S. and expansion of soybeans, canola and other oil crops in non-U.S. regions being the predominant effects. Switching cropland from cultivation of corn and other crops to accommodate expanded oilseed production is a notable but less prominent impact in the GCAM simulations. In GLOBIOM simulations, there is substantially more crop switching and less expansion of new cropland when compared to the GCAM results. Expansion of soybean cultivation in the U.S. replaces primarily cultivation of wheat and other crops. In non-U.S. regions, the substitution of non-soy vegetable oils for soybean oil in food and other end uses corresponds with significant crop switching away from soybeans and towards palm and canola cultivation. Displaced production of wheat and other crops in the U.S. is also made up for through increasing cultivation of these crops in non-U.S. regions, which have more elastic land transition assumptions in GLOBIOM.[293]

Figure 5.2.2.3-1: Difference in Cropland Area (Million Hectares) in the Low Volume Scenario Relative to the No RFS Baseline Over Time[a]

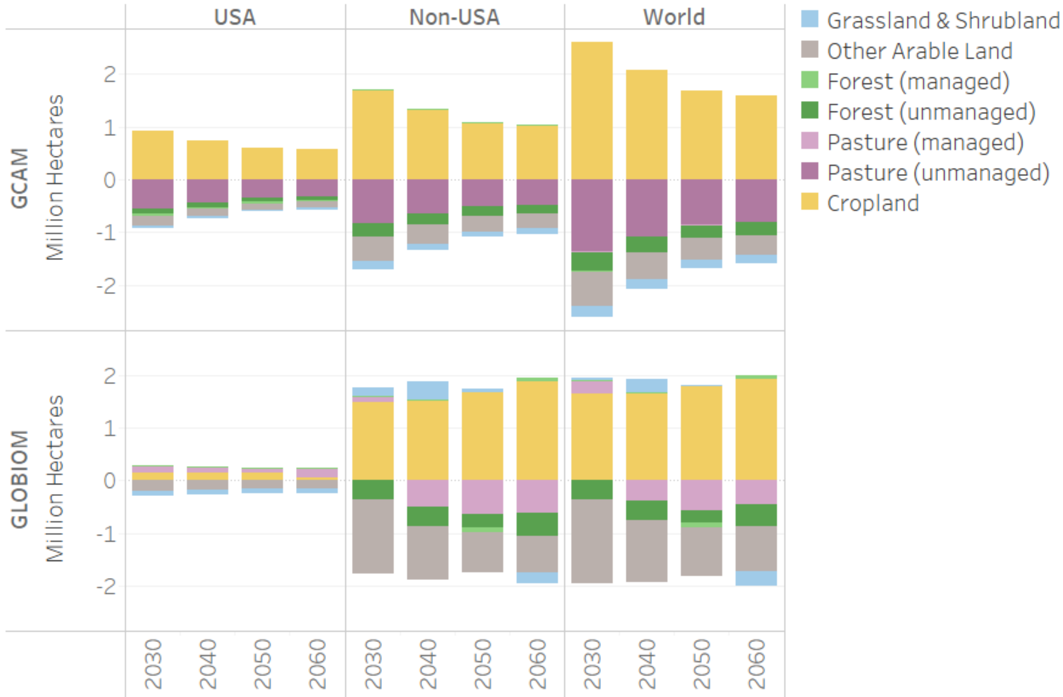


[a] Reference lines represent the net difference in cropland area in a given region and time period.

Cropland expansion differs in magnitude between simulations in the two models, as noted above, but also in which land types are replaced. Differences in land cover area between the Low Volume Scenario and the No RFS Baseline are illustrated in Figure 5.2.2.3-2. In GCAM, expansion of cropland replaces substantial quantities of less intensively used or natural lands, including unmanaged forest, unmanaged pasture, grassland and shrubland. While vegetative and soil carbon sequestered in the landscape differs greatly across climates, regions and land cover types, in general natural lands, and especially unmanaged (i.e., not commercially productive) forests, hold more carbon than other land cover categories. Consequently, the expansion of cropland into these natural land types results in substantial carbon releases in the GCAM simulations (Figure 5.2.2.3-3), with emissions taking place across most regions.

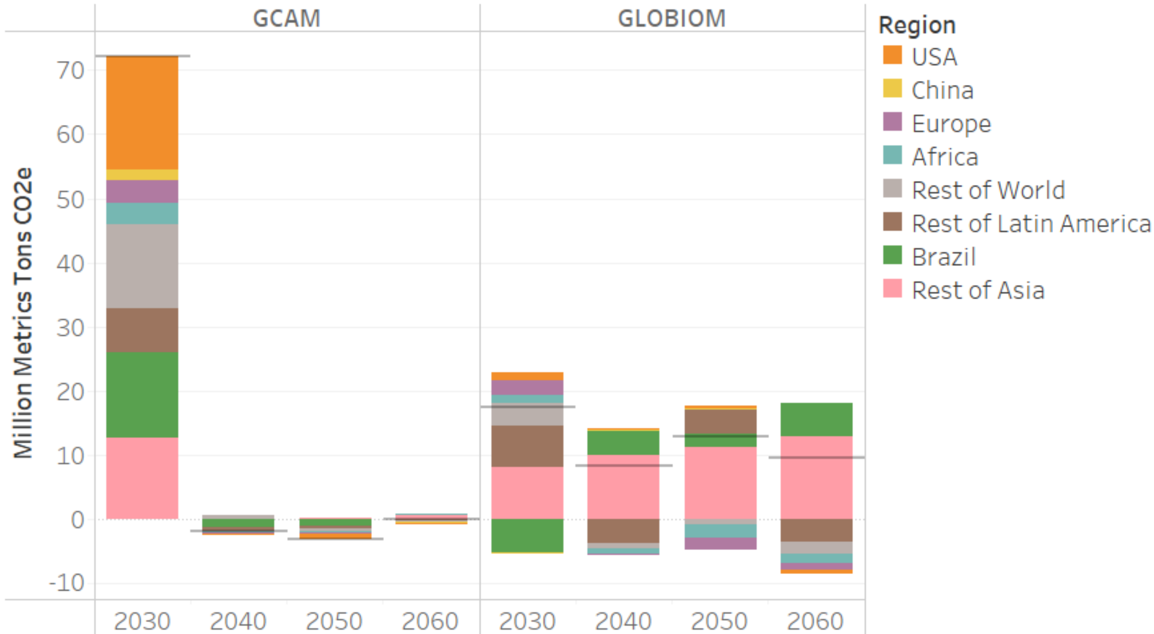
[293] GLOBIOM includes assumptions that preclude expansion of cropland and other commercially productive land cover types into natural areas in the USA, including into natural forest and grassland. This is an important assumption that we believe warrants further investigation and consideration of alternative implementation methods in future analyses. A consequence of this assumption is that most changes in crop production in the U.S. are achieved through switching cropland from one crop to another (i.e., "crop switching"), rather than through expanding cropland into other land cover types.

Figure 5.2.2.3-2: Difference in Land Area (Million Hectares) in the Low Volume Scenario Relative to the No RFS Baseline Over Time



As discussed above, in GLOBIOM simulations cropland expansion is constrained within the U.S., with most of the expansion seen happening at the expense of "other arable land"—a category that includes cropland pasture and other unused cropland, with lower carbon densities compared with other unmanaged land cover types. Most cropland expansion in GLOBIOM simulations occurs in non-U.S. regions, replacing unmanaged forest, other arable land and, increasingly, managed pasture. Additionally, GLOBIOM simulations include greater substitution between vegetable oils compared with GCAM, with this substitution effect increasing over time. As a result, the difference in cropland area between the Low Volume Scenario and the No RFS Baseline increases gradually over time, resulting in additional land use change emissions in future years (Figure 5.2.2.3-3). Additionally, this vegetable oil substitution effect results in a greater production of palm oil which primarily takes place in Southeast Asia (included in "Rest of Asia" in the regional aggregation in Figure 5.2.2.3-3). Regions with the highest levels of oil palm production—Indonesia and Malaysia—also have high concentrations of peat soils. When peat lands are developed for crop cultivation, e.g., for oil palm cultivation, carbon within the peat can continue to oxidize (be released into the atmosphere as CO_2) for several decades. This phenomenon is represented in both GCAM and GLOBIOM, and can be seen in the continued land use change emissions in the Rest of Asia region through 2060 in Figure 5.2.2.3-3.

Figure 5.2.2.3-3: Difference in GHG Emissions (Million Metric Tons of CO_2e) From Land Use Change (LUC) in the Low Volume Scenario Relative to the No RFS Baseline Over Time, and by Region in Which the Emissions Take Place [a]

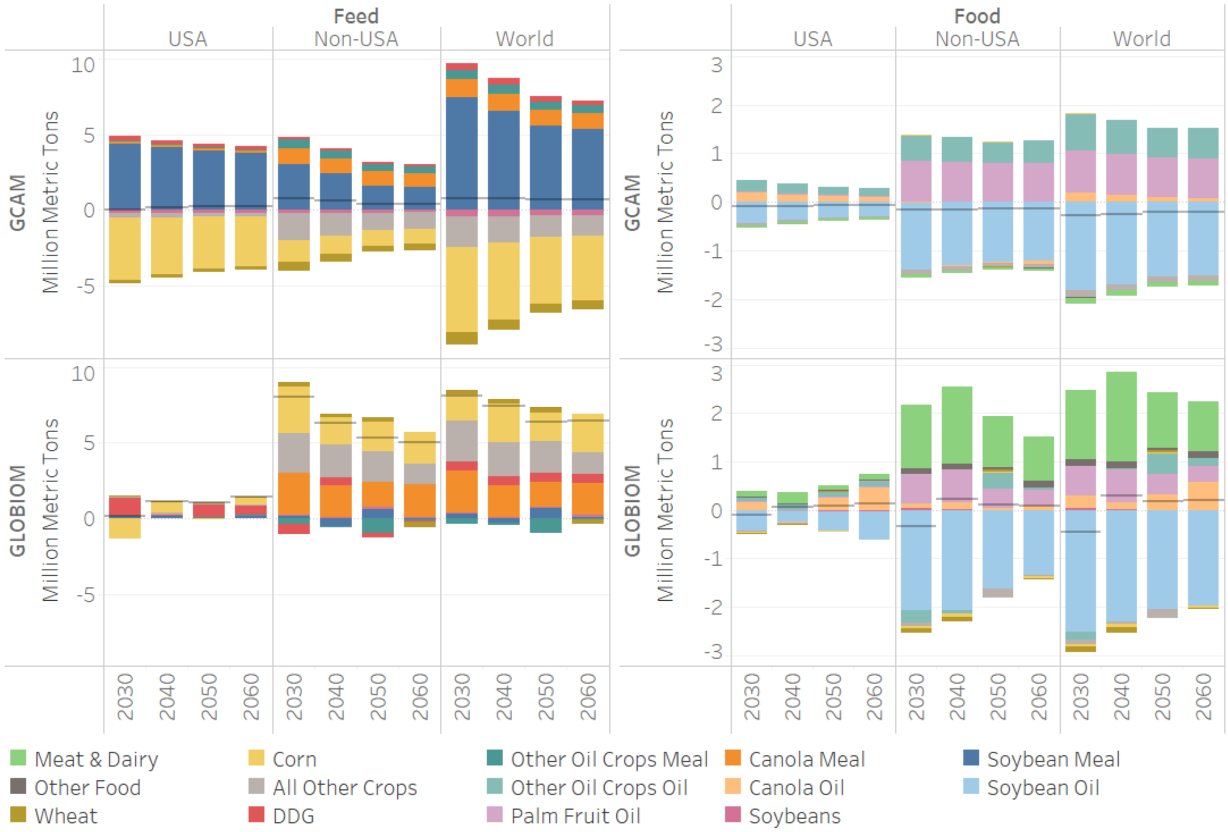


[a] Reference lines represent the net difference in LUC emissions in a given region and time period.

5.2.2.4 Livestock Production

Impacts of the Low Volume Scenario relative to the No RFS Baseline on livestock production can be understood through examination of use of agricultural commodities for livestock feed and for human food consumption. This is illustrated in Figure 5.2.2.4-1, with consumption for feed displayed in the left pane and consumption for food in the right pane.

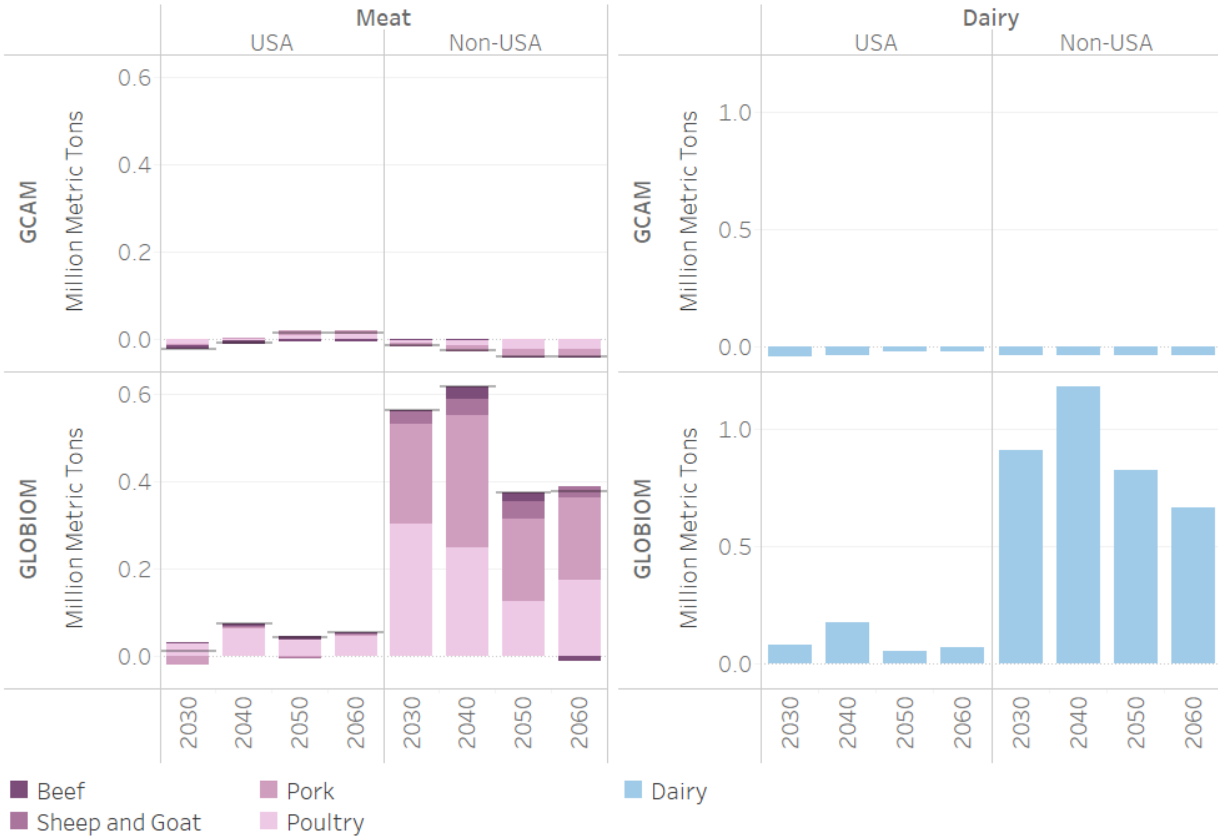
Figure 5.2.2.4-1: Difference in Commodities Used for Livestock Feed and Food Consumption (Million Metric Tons) in the Low Volume Scenario Relative to the No RFS Baseline Over Time [a]



[a] Reference lines represent the net difference in total (by weight) commodity usage for livestock feed or food in a given region and time period.

First, we observe that in the GCAM simulations the primary effect in livestock feed markets is to use less corn and to use the additional available oilseed meals—primarily soybean meal but also canola meal and other oil crops meal in non-U.S. regions—for feeding livestock. The effect on the total amount of feed supplied (by weight), however, is limited; the story told by the GCAM simulations is largely one of substitution of feed commodities, while overall meat and dairy production is relatively unaffected. In GLOBIOM simulations, however, there are notably different livestock production impacts; as discussed in the sections above, the additional soybean oil needed to meet the volume requirements is met almost entirely by shifting where and how existing soybean oil capacity is produced and consumed. Thus, there is limited additional soybean meal entering livestock feed markets. At the same time, soybean oil is shifted away from human food consumption—a deficit that requires alternative food sources to meet human caloric intake requirements. This decrease in soybean oil food consumption is balanced by an increase in use of other vegetable oils—notably palm oil—and in consumption of meat and dairy, i.e., an expansion in livestock production which requires additional feed. That additional feed is sourced primarily from 1) newly available canola meal (unlike soybean oil BBD, canola oil for increased production of BBD is supplied almost entirely by new rapeseed production and crush in GLOBIOM), and 2) expanded production of commodity crops for use as feed.

Figure 5.2.2.4-2: Difference in Meat and Dairy Production (Million Metric Tons) in the Low Volume Scenario Relative to the No RFS Baseline Over Time [a]



[a] Reference lines in the "Meat" panel represent the net difference in meat production across all categories of livestock for a given region and time period.

The differences in meat and dairy consumption noted above are also illustrated in Figure 5.2.2.4-2, which shows differences between the Low Volume Scenario and No RFS Baseline in meat and dairy production over time. Again, we observe relatively small changes in meat and dairy production in the GCAM simulations. In the GLOBIOM simulations, meat and dairy production expands to meet food demand as vegetable oils are shifted from food to biofuel consumption. However, over time additional demand for soybean oil to meet U.S. BBD production targets is increasingly met by shifting soybean oil out of "other uses" rather than away from food usage, so less meat and dairy is needed by 2060 to meet human food demand.

5.2.2.5 Emissions

Because emissions outputs from GCAM and GLOBIOM are not comparable without first performing the post-hoc adjustments, interpolation, scaling and translation described in Chapter 5.1.3.2 and Chapter 5.1.3.3, in this section we provide the *adjusted* model results. This differs from the unadjusted model outputs presented and discussed in Chapters 5.2.2.1 through 5.2.2.4.

Tables 5.2.2.5-1 through 4 provide 30-year annual GHG emissions estimates, reported in CO_2e,[294] for the Low and High Volume Scenarios relative to the No RFS Baseline.

For GCAM results, emissions reported under Fossil Fuel Use include all endogenously determined impacts on energy consumption, an adjustment for emissions associated with renewable diesel versus biodiesel production, and relatively small emissions impacts reported under the "other industrial" category in GCAM. For GLOBIOM results, emissions reported under Fossil Fuel Use include assumed one-for-one displacement of fossil fuels using emissions factors derived from R&D GREET and biofuel production and downstream emissions estimated using factors derived from R&D GREET. Additionally, Crop Production emissions results for the GLOBIOM modeling have been supplemented with estimated emissions factors for categories of crop production emissions that are not represented in GLOBIOM. All of these adjustments are described in detail in Chapter 5.1.3.3.

[294] For simplicity we report all emissions in this chapter in terms of CO_2 equivalence using GWPs published in AR5. However, emissions estimates within these analyses are calculated for three major GHGs: CO_2, CH_4 and N_2O. Estimates disaggregated by gas are provided, where available, in "Set 2 NPRM Climate Change Analyses," available in the docket for this action.

Table 5.2.2.5-1: GHG Emissions (Million Metric Tons CO_2e) for the Low Volume Scenario (2026–2028 Standards) Estimated Using GCAM

Year	Land Use Change	Crop Production	Livestock Production	Fossil Fuel Use[a]	Total
2026	287.4	4.7	-0.4	-10.0	281.7
2027	4.9	4.8	-0.4	-10.2	-0.8
2028	6.2	4.9	-0.4	-10.4	0.4
2029	8.1	4.9	-0.4	-10.2	2.3
2030	5.8	4.8	-0.4	-10.1	0.2
2031	4.0	4.8	-0.4	-10.0	-1.6
2032	2.3	4.7	-0.3	-9.9	-3.2
2033	0.9	4.7	-0.3	-9.8	-4.6
2034	0.7	4.6	-0.3	-9.6	-4.6
2035	-0.1	4.6	-0.3	-9.5	-5.3
2036	-0.8	4.6	-0.3	-9.3	-5.9
2037	-1.4	4.5	-0.3	-9.2	-6.4
2038	-2.0	4.5	-0.3	-9.0	-6.8
2039	-2.0	4.4	-0.3	-8.9	-6.7
2040	-2.4	4.4	-0.3	-8.8	-7.1
2041	-2.7	4.4	-0.3	-8.7	-7.4
2042	-3.0	4.3	-0.3	-8.6	-7.6
2043	-3.3	4.3	-0.3	-8.5	-7.8
2044	-2.6	4.3	-0.3	-8.5	-7.1
2045	-2.7	4.3	-0.3	-8.5	-7.3
2046	-2.9	4.2	-0.3	-8.5	-7.4
2047	-3.1	4.2	-0.3	-8.4	-7.6
2048	-3.2	4.2	-0.3	-8.4	-7.7
2049	-0.2	4.2	-0.3	-8.4	-4.7
2050	-0.2	4.2	-0.3	-8.4	-4.7
2051	-0.1	4.1	-0.3	-8.4	-4.6
2052	-0.1	4.1	-0.3	-8.4	-4.6
2053	-0.1	4.1	-0.3	-8.4	-4.6
2054	0.0	4.1	-0.3	-8.4	-4.5
2055	0.0	4.1	-0.3	-8.4	-4.6

[a] Emissions reported under Fossil Fuel Use include all endogenously determined impacts on energy consumption, an adjustment for emissions associated with renewable diesel versus biodiesel production, and relatively small emissions impacts reported under the "other industrial" category in GCAM.

Table 5.2.2.5-2: GHG Emissions (Million Metric Tons CO_2e) for the High Volume Scenario (2026–2028 Standards) Estimated Using GCAM

Year	Land Use Change	Crop Production	Livestock Production	Fossil Fuel Use[a]	Total
2026	334.0	5.5	-0.4	-11.2	327.9
2027	43.2	6.2	-0.4	-12.5	36.5
2028	44.5	6.9	-0.5	-13.8	37.2
2029	11.7	6.9	-0.5	-13.6	4.4
2030	8.5	6.8	-0.5	-13.5	1.3
2031	5.8	6.7	-0.5	-13.3	-1.3
2032	3.4	6.7	-0.5	-13.1	-3.5
2033	1.4	6.6	-0.5	-12.9	-5.4
2034	1.4	6.6	-0.5	-12.7	-5.3
2035	0.2	6.5	-0.4	-12.5	-6.3
2036	-0.9	6.4	-0.4	-12.2	-7.1
2037	-1.8	6.4	-0.4	-12.0	-7.9
2038	-2.6	6.3	-0.4	-11.8	-8.5
2039	-2.5	6.3	-0.4	-11.7	-8.3
2040	-3.1	6.2	-0.4	-11.5	-8.8
2041	-3.6	6.2	-0.4	-11.4	-9.2
2042	-4.1	6.2	-0.4	-11.3	-9.6
2043	-4.5	6.1	-0.4	-11.1	-9.9
2044	-3.5	6.1	-0.4	-11.1	-8.9
2045	-3.8	6.1	-0.4	-11.0	-9.1
2046	-4.0	6.0	-0.4	-11.0	-9.3
2047	-4.2	6.0	-0.4	-10.9	-9.5
2048	-4.4	6.0	-0.4	-10.9	-9.7
2049	-0.3	5.9	-0.4	-10.8	-5.6
2050	-0.2	5.9	-0.4	-10.8	-5.5
2051	-0.2	5.9	-0.4	-10.8	-5.4
2052	-0.1	5.9	-0.4	-10.8	-5.4
2053	-0.1	5.9	-0.4	-10.8	-5.4
2054	-0.1	5.8	-0.4	-10.7	-5.3
2055	-0.1	5.8	-0.4	-10.6	-5.3

[a] Emissions reported under Fossil Fuel Use include all endogenously determined impacts on energy consumption, an adjustment for emissions associated with renewable diesel versus biodiesel production, and relatively small emissions impacts reported under the “other industrial” category in GCAM.

Table 5.2.2.5-3: GHG Emissions (Million Metric Tons CO_2e) for the Low Volume Scenario (2026–2028 Standards) Estimated Using GLOBIOM

Year	Land Use Change	Crop Production	Livestock Production	Fossil Fuel Use[a]	Total
2026	168.1	5.8	1.4	-26.0	149.3
2027	2.8	5.9	1.5	-26.4	-16.3
2028	3.6	6.0	1.5	-27.0	-15.9
2029	8.3	5.8	1.4	-27.0	-11.5
2030	8.3	5.7	1.3	-27.0	-11.7
2031	8.3	5.6	1.2	-27.0	-11.9
2032	8.3	5.4	1.1	-27.0	-12.1
2033	8.3	5.3	1.0	-27.0	-12.4
2034	8.3	5.2	0.9	-27.0	-12.6
2035	8.3	5.0	0.8	-27.0	-12.8
2036	8.3	4.9	0.7	-27.0	-13.0
2037	8.3	4.8	0.6	-27.0	-13.3
2038	8.3	4.6	0.5	-27.0	-13.5
2039	12.7	4.5	0.5	-27.0	-9.2
2040	12.7	4.4	0.4	-27.0	-9.4
2041	12.7	4.4	0.3	-27.0	-9.5
2042	12.7	4.3	0.3	-27.0	-9.7
2043	12.7	4.2	0.2	-27.0	-9.9
2044	12.7	4.1	0.1	-27.0	-10.1
2045	12.7	4.0	0.1	-27.0	-10.2
2046	12.7	3.9	0.0	-27.0	-10.4
2047	12.7	3.8	-0.1	-27.0	-10.6
2048	12.7	3.7	-0.2	-27.0	-10.7
2049	9.5	4.4	-0.4	-27.0	-13.5
2050	9.5	5.1	-0.7	-27.0	-13.1
2051	9.5	5.8	-1.0	-27.0	-12.7
2052	9.5	6.5	-1.3	-27.0	-12.3
2053	9.5	7.2	-1.6	-27.0	-11.8
2054	9.5	7.9	-1.9	-27.0	-11.4
2055	9.5	8.6	-2.2	-27.0	-11.0

[a] Emissions reported under Fossil Fuel Use in GLOBIOM results include assumed one-for-one displacement of fossil fuels using emissions factors derived from R&D GREET and biofuel production and downstream emissions estimated using factors derived from R&D GREET.

Table 5.2.2.5-4: GHG Emissions (Million Metric Tons CO_2e) for the High Volume Scenario (2026–2028 Standards) Estimated Using GLOBIOM

Year	Land Use Change	Crop Production	Livestock Production	Fossil Fuel Use[a]	Total
2026	177.6	6.5	2.0	-29.3	156.9
2027	23.0	7.3	2.1	-32.9	-0.5
2028	23.7	8.2	2.1	-36.7	-2.7
2029	11.1	8.1	2.1	-36.7	-15.3
2030	11.1	8.0	2.1	-36.7	-15.4
2031	11.1	8.0	2.1	-36.7	-15.5
2032	11.1	7.9	2.1	-36.7	-15.6
2033	11.1	7.8	2.1	-36.7	-15.6
2034	11.1	7.7	2.2	-36.7	-15.7
2035	11.1	7.7	2.2	-36.7	-15.8
2036	11.1	7.6	2.2	-36.7	-15.8
2037	11.1	7.5	2.2	-36.7	-15.9
2038	11.1	7.4	2.2	-36.7	-16.0
2039	8.2	7.3	2.1	-36.7	-19.1
2040	8.2	7.1	2.1	-36.7	-19.3
2041	8.2	6.9	2.0	-36.7	-19.5
2042	8.2	6.8	2.0	-36.7	-19.7
2043	8.2	6.6	1.9	-36.7	-19.9
2044	8.2	6.4	1.9	-36.7	-20.2
2045	8.2	6.3	1.8	-36.7	-20.4
2046	8.2	6.1	1.7	-36.7	-20.6
2047	8.2	6.0	1.7	-36.7	-20.8
2048	8.2	5.8	1.6	-36.7	-21.0
2049	15.7	6.7	1.4	-36.7	-12.9
2050	15.7	7.6	1.1	-36.7	-12.3
2051	15.7	8.6	0.8	-36.7	-11.6
2052	15.7	9.5	0.5	-36.7	-11.0
2053	15.7	10.4	0.3	-36.7	-10.4
2054	15.7	11.3	0.0	-36.7	-9.7
2055	15.7	12.2	-0.3	-36.7	-9.1

[a] Emissions reported under Fossil Fuel Use in GLOBIOM results include assumed one-for-one displacement of fossil fuels using emissions factors derived from R&D GREET and biofuel production and downstream emissions estimated using factors derived from R&D GREET.

5.2.3 Summary of GHG Emission Impacts Estimates

In this section we summarize combined emissions impacts estimates for both waste- and byproduct-based biofuels and crop-based fuels for the Low and High Volume Scenarios relative to the No RFS Baseline. Tables 5.2.3-1 and 2 label these combined net emissions estimates as "Estimate A," which uses the GCAM model to assess market-mediated emissions for crop-based fuels, and "Estimate B," which uses the GLOBIOM model to assess market-mediated emissions for crop-based fuels. Neither estimate should be interpreted as EPA's central or favored assessment of the likely GHG impacts of these scenarios. Rather, it is EPA's assessment that each of the two economic models provides plausible projections of the potential impacts of the analytical Volume Scenarios. As described in the section above, the two economic models used in this analysis each have relative strengths for assessing the GHG impacts of increased use of biofuels. Consistent with recommendations found in the 2022 NASEM technical report, we provide results using both methodologies, reflecting alternative complex mathematical representations of earth and human systems and recognizing the uncertainty that is inherent in any modeling exercise or comparison of model results (i.e., "model uncertainty").[295] All emissions are presented in million metric tons CO_2e.[296]

[295] See, for example, Recommendation 4-3: "LCA studies used to inform policy should explicitly consider parameter uncertainty, scenario uncertainty, and model uncertainty." NASEM Report at 58. The NASEM Report explains: "Ideally, model structural uncertainty would be assessed through comparisons between models with fundamentally different approaches, such that there would not be common errors made by both approaches. In reality it is often not possible to estimate LCA model outputs through approaches that do not share many of the same assumptions." Id. at 57. It therefore provides that, "in some cases, it is more informative to simply compare discrete model runs with different assumptions, rather than parsing the average output of multiple models." Id. at 56.

[296] For simplicity we report all emissions in this chapter in terms of CO_2 equivalence using GWPs published in AR5. However, emissions estimates within these analyses are calculated for three major GHGs: CO_2, CH_4 and N_2O. Estimates disaggregated by gas are provided, where available, in "Set 2 NPRM Climate Change Analyses," available in the docket for this action.

Table 5.2.3-1: Summary of GHG Emissions Estimates (Million Metric Tons CO_2e) for the Low Volume Scenario (2026–2028 Standards) Relative to the No RFS Baseline[a]

Year	Crop-based Fuels (GCAM)	Crop-based Fuels (GLOBIOM)	Waste- and Byproduct-based Fuels	Estimate A		Estimate B	
				Annual Total	Cumulative Total	Annual Total	Cumulative Total
2026	281.7	149.3	-12.3	269.4	269.4	137.0	137.0
2027	-0.8	-16.3	-14.2	-15.1	254.4	-30.5	106.5
2028	0.4	-15.9	-16.2	-15.8	238.6	-32.0	74.5
2029	2.3	-11.5	-16.2	-13.8	224.8	-27.6	46.9
2030	0.2	-11.7	-16.2	-16.0	208.8	-27.8	19.0
2031	-1.6	-11.9	-16.2	-17.8	191.0	-28.1	-9.0
2032	-3.2	-12.1	-16.2	-19.4	171.7	-28.3	-37.3
2033	-4.6	-12.4	-16.2	-20.7	151.0	-28.5	-65.8
2034	-4.6	-12.6	-16.2	-20.7	130.2	-28.7	-94.6
2035	-5.3	-12.8	-16.2	-21.5	108.8	-29.0	-123.6
2036	-5.9	-13.0	-16.2	-22.0	86.7	-29.2	-152.8
2037	-6.4	-13.3	-16.2	-22.5	64.2	-29.4	-182.2
2038	-6.8	-13.5	-16.2	-23.0	41.2	-29.7	-211.8
2039	-6.7	-9.2	-16.2	-22.9	18.4	-25.4	-237.2
2040	-7.1	-9.4	-16.2	-23.2	-4.9	-25.5	-262.7
2041	-7.4	-9.5	-16.2	-23.5	-28.4	-25.7	-288.4
2042	-7.6	-9.7	-16.2	-23.8	-52.1	-25.9	-314.3
2043	-7.8	-9.9	-16.2	-24.0	-76.1	-26.0	-340.3
2044	-7.1	-10.1	-16.2	-23.2	-99.4	-26.2	-366.5
2045	-7.3	-10.2	-16.2	-23.4	-122.8	-26.4	-392.9
2046	-7.4	-10.4	-16.2	-23.6	-146.3	-26.5	-419.5
2047	-7.6	-10.6	-16.2	-23.7	-170.0	-26.7	-446.2
2048	-7.7	-10.7	-16.2	-23.8	-193.9	-26.9	-473.1
2049	-4.7	-13.5	-16.2	-20.9	-214.8	-29.7	-502.7
2050	-4.7	-13.1	-16.2	-20.8	-235.6	-29.3	-532.0
2051	-4.6	-12.7	-16.2	-20.8	-256.4	-28.8	-560.8
2052	-4.6	-12.3	-16.2	-20.8	-277.2	-28.4	-589.2
2053	-4.6	-11.8	-16.2	-20.7	-297.9	-28.0	-617.2
2054	-4.5	-11.4	-16.2	-20.7	-318.6	-27.6	-644.8
2055	-4.6	-11.0	-16.2	-20.7	-339.3	-27.1	-671.9

[a] "Estimate A" represents the estimates using the GCAM model. "Estimate B" represents estimates using the GLOBIOM model.

Table 5.2.3-2: Summary of GHG Emissions Estimates (Million Metric Tons CO_2e) for the High Volume Scenario (2026–2028 Standards) Relative to the No RFS Baseline[a]

Year	Crop-based Fuels (GCAM)	Crop-based Fuels (GLOBIOM)	Waste- and Byproduct-based Fuels	Estimate A		Estimate B	
				Annual Total	Cumulative Total	Annual Total	Cumulative Total
2026	327.9	156.9	-12.3	315.6	315.6	144.6	144.6
2027	36.5	-0.5	-14.2	22.3	337.9	-14.8	129.8
2028	37.2	-2.7	-16.2	21.0	358.9	-18.8	111.0
2029	4.4	-15.3	-16.2	-11.7	347.2	-31.5	79.5
2030	1.3	-15.4	-16.2	-14.8	332.4	-31.6	47.9
2031	-1.3	-15.5	-16.2	-17.4	315.0	-31.6	16.3
2032	-3.5	-15.6	-16.2	-19.6	295.3	-31.7	-15.4
2033	-5.4	-15.6	-16.2	-21.6	273.8	-31.8	-47.2
2034	-5.3	-15.7	-16.2	-21.4	252.4	-31.8	-79.0
2035	-6.3	-15.8	-16.2	-22.4	229.9	-31.9	-110.9
2036	-7.1	-15.8	-16.2	-23.3	206.6	-32.0	-142.9
2037	-7.9	-15.9	-16.2	-24.0	182.6	-32.1	-175.0
2038	-8.5	-16.0	-16.2	-24.6	158.0	-32.1	-207.1
2039	-8.3	-19.1	-16.2	-24.5	133.6	-35.2	-242.4
2040	-8.8	-19.3	-16.2	-24.9	108.6	-35.4	-277.8
2041	-9.2	-19.5	-16.2	-25.4	83.3	-35.7	-313.5
2042	-9.6	-19.7	-16.2	-25.7	57.6	-35.9	-349.3
2043	-9.9	-19.9	-16.2	-26.0	31.5	-36.1	-385.4
2044	-8.9	-20.2	-16.2	-25.0	6.5	-36.3	-421.7
2045	-9.1	-20.4	-16.2	-25.3	-18.8	-36.5	-458.2
2046	-9.3	-20.6	-16.2	-25.5	-44.2	-36.7	-495.0
2047	-9.5	-20.8	-16.2	-25.7	-69.9	-36.9	-531.9
2048	-9.7	-21.0	-16.2	-25.8	-95.8	-37.2	-569.1
2049	-5.6	-12.9	-16.2	-21.7	-117.5	-29.1	-598.2
2050	-5.5	-12.3	-16.2	-21.6	-139.1	-28.4	-626.6
2051	-5.4	-11.6	-16.2	-21.6	-160.7	-27.8	-654.4
2052	-5.4	-11.0	-16.2	-21.5	-182.3	-27.1	-681.5
2053	-5.4	-10.4	-16.2	-21.5	-203.8	-26.5	-708.0
2054	-5.3	-9.7	-16.2	-21.4	-225.2	-25.9	-733.9
2055	-5.3	-9.1	-16.2	-21.5	-246.7	-25.2	-759.1

[a] "Estimate A" represents the estimates using the GCAM model. "Estimate B" represents estimates using the GLOBIOM model.

In both estimates for both scenarios, a similar pattern is present in the emissions estimates: an immediate pulse of emissions in 2026, driven by land use change emissions impacts from the difference in volumes of crop-based fuels relative to the No RFS Baseline, followed by continual emissions benefits as biofuels produced on the additional acreage of cropland continue to accrue emissions benefits by displacing use of fossil fuels. One way of comparing these estimates is through the consideration the "payback period" —measured as the year in which net emissions become negative. Under the Low Volume Scenario with 2026–2028 standards, net negative cumulative GHG emissions are achieved in 2040 under Estimate A and in 2031 under Estimate B. Under the High Volume Scenario with 2026–2028 standards, net negative cumulative GHG emissions are achieved in 2045 under Estimate A and in 2032 under Estimate B.

5.3 Assessment of Proposed Volumes

Table 5.1.1-1 presents the volume differences between the Proposed Volumes for 2026 and 2027 and the volume in the No RFS Baseline. For waste- and byproduct-based fuels, we follow the same methodology described in the sections above; we apply emissions factors developed using the R&D GREET model for the difference in volumes of renewable fuels in each year and compare those emissions with similar estimates of displaced fossil fuels. Descriptions of these factors can be found in Chapter 5.1.2.

Because of the lead time required to specify and complete economic modeling of volumes of crop-based fuels using GCAM and GLOBIOM, we were unable to complete simulations representing the 2026 and 2027 Proposed Volumes in either of the economic models. However, the simulations used to assess the Low and High Volume Scenarios relative to the No RFS Baseline can be adjusted to approximate the results under the proposed volumes by scaling all impacts proportionally based on the total net difference in modeled biofuel volumes (assessed in energy equivalence) that would be implemented in model year 2030 in the GCAM and GLOBIOM simulations. For the Low and High Volume Scenarios, that is the difference in crop-based biofuels from No RFS Baseline levels in analytical year 2028; 310 trillion BTUs in the Low Volume Scenario and 425 trillion BTUs in the High Volume Scenario. For the Proposed Volumes, we consider the difference in crop-based biofuels from No RFS Baseline levels in analytical year 2027; 392 trillion BTUs. Because the total volume difference that would have been modeled for the Proposed Volumes is closer to the High Volume Scenario than to the Low Volume Scenario, we use scaled High Volume Scenario modeling results to approximate the effects under the Proposed Volumes. However, neither the Low Volume Scenario nor the High Volume Scenario represents the same ratio of volumes of fuels as the Proposed Volumes, so the scaling is a necessary, if imperfect representation of what a more specific analysis of the Proposed Volumes might estimate. We also note that the total magnitude of the Proposed Volumes is in between those of the Low and High Volume Scenarios, so considering the full range of potential results estimated across the Low and High Scenarios may therefore provide a more fulsome sense for the potential impacts of this proposal, across the many attendant uncertainties that exist when modeling future GHG emissions impacts of renewable fuels.[297] To the extent possible, we intend to align our simulations with the volumes in the final rule.

Scaling of the High Volume Scenario results to estimate the impacts of the Proposed Volumes largely follows the methodology described in Chapter 5.1.3, with a few exceptions of note. First, all model results are translated by three years instead of two (e.g., model year 2030 corresponds with analytical year 2027 instead of 2028). All interpolation between model years after 2030 is identical to the methods described in Chapters 5.1.3.2 and 5.1.3.3. In order to

[297] Additionally, the economic modeling of crop-based fuels undertaken for this proposal does not explicitly represent the proposed "import RIN reduction" discussed in Preamble Section VIII, nor do these simulations endogenously determine the mix of fuels expected to be used to meet the volume standards. Rather, volumes of crop-based fuels expected to be used to meet the standards are projected external to the models (see Chapter 5.1.1.1.1) and used as exogenously specified consumption targets.

represent the specific volumes in 2026 and 2027, we use scalar factors calculated using the same methods as described in Chapters 5.1.3.2 and 5.1.3.3, but using the 2026 and 2027 Proposed Volumes relative to the No RFS Baseline. These factors are presented in Table 5.3-1.

Table 5.3.1-1: Emissions Adjustment Scalars for Economic Modeling of the Proposed Volumes Relative to the No RFS Baseline

	Proposed Volumes Minus No RFS	
	2026	**2027**
Year-over-year volume difference as percentage of 2027 volume difference	91.6%	8.4%
Cumulative volume difference as percentage of 2027 volume difference	91.6%	100.0%

Finally, all impacts are scaled by the ratio of the total volume difference in 2027 in the Proposed Volumes to the total volume difference in 2028 in the High Volume Scenario—a factor of approximately 0.92 (392 trillion BTUs / 425 trillion BTUs). All calculations are provided in an Excel workbook in the docket for this proposal.[298] Table 5.3.1-2 provides the stream of estimated emissions impacts reported in CO_2e.[299] Under the Proposed Volumes for 2026 and 2027, net negative cumulative GHG emissions are achieved in 2053 under Estimate A and in 2034 under Estimate B.

[298] See "Set 2 NPRM Climate Change Analyses," available in the docket for this action.
[299] For simplicity, we report all emissions in this chapter in terms of CO_2 equivalence using GWPs published in AR5. However, emissions estimates within these analyses are calculated for three major GHGs: CO_2, CH_4 and N_2O. Estimates disaggregated by gas are provided, where available, in "Set 2 NPRM Climate Change Analyses," available in the docket for this action.

Table 5.3-2: Summary of GHG Emissions Estimates (Million Metric Tons CO_2e) for the Proposed Volumes (2026–2027 Standards)[a]

Year	Crop-based Fuels (GCAM)	Crop-based Fuels (GLOBIOM)	Waste- and Byproduct-based Fuels	Estimate A		Estimate B	
				Annual Total	Cumulative Total	Annual Total	Cumulative Total
2026	350.1	167.3	-8.5	341.6	341.6	158.8	158.8
2027	25.9	-6.8	-8.3	17.6	359.2	-15.1	143.6
2028	4.2	-13.9	-8.3	-4.0	355.2	-22.2	121.4
2029	1.4	-14.0	-8.3	-6.9	348.3	-22.3	99.1
2030	-1.0	-14.1	-8.3	-9.3	339.0	-22.4	76.7
2031	-3.0	-14.1	-8.3	-11.3	327.7	-22.4	54.3
2032	-4.8	-14.2	-8.3	-13.1	314.6	-22.5	31.8
2033	-4.7	-14.3	-8.3	-13.0	301.6	-22.6	9.2
2034	-5.6	-14.3	-8.3	-13.9	287.7	-22.6	-13.4
2035	-6.4	-14.4	-8.3	-14.7	273.1	-22.7	-36.1
2036	-7.1	-14.5	-8.3	-15.3	257.7	-22.8	-58.8
2037	-7.6	-14.5	-8.3	-15.9	241.8	-22.8	-81.7
2038	-7.5	-17.4	-8.3	-15.8	226.0	-25.7	-107.3
2039	-7.9	-17.6	-8.3	-16.2	209.8	-25.9	-133.2
2040	-8.3	-17.8	-8.3	-16.6	193.2	-26.1	-159.3
2041	-8.6	-18.0	-8.3	-16.9	176.3	-26.3	-185.6
2042	-8.9	-18.2	-8.3	-17.2	159.1	-26.5	-212.1
2043	-8.0	-18.4	-8.3	-16.3	142.8	-26.7	-238.7
2044	-8.2	-18.6	-8.3	-16.5	126.3	-26.9	-265.6
2045	-8.4	-18.8	-8.3	-16.7	109.6	-27.1	-292.7
2046	-8.6	-19.0	-8.3	-16.9	92.7	-27.3	-319.9
2047	-8.8	-19.2	-8.3	-17.0	75.6	-27.5	-347.4
2048	-5.0	-11.7	-8.3	-13.3	62.4	-20.0	-367.4
2049	-4.9	-11.1	-8.3	-13.2	49.2	-19.4	-386.8
2050	-4.8	-10.5	-8.3	-13.1	36.1	-18.8	-405.6
2051	-4.8	-9.9	-8.3	-13.1	23.0	-18.2	-423.8
2052	-4.8	-9.3	-8.3	-13.0	10.0	-17.6	-441.5
2053	-4.7	-8.8	-8.3	-13.0	-3.0	-17.0	-458.5
2054	-4.7	-8.2	-8.3	-13.0	-16.0	-16.5	-475.0
2055	-4.7	-7.6	-8.3	-13.0	-29.0	-15.9	-490.8

[a] "Estimate A" represents the estimates using the GCAM model. "Estimate B" represents estimates using the GLOBIOM model.

For this proposed rule we are not monetizing the estimated GHG emissions. There are significant uncertainties related to monetization of greenhouse gases that include, but are not limited to:

- The magnitude of the change in climate;
- The relationship between changes in climate and the impacts and resulting economic impacts;
- Climate-economic interactions;
- Future economic growth across all countries of the world;
- Future population growth;

- Future technological advancements;
- Impact from emissions on the regulated entities in the United States; and
- Appropriate discount rates.

Due to the orders of magnitude of uncertainties related to monetization of emissions from GHGs, it would result in the following if EPA continued to monetize GHG impacts:

- Misleading the publc that the federal government has a better understanding of monetized climate impacts from these actions.
- Reduce confidence in the federal government and confuse the public on why the federal government is taking actions.
- Potentially result in flawed decision making due to overreliance on highly uncertain values.

Appendix 5-A: Sensitivity Analysis for Economic Modeling

We simulated a Monte Carlo simulation (MCS) with GCAM to explore the influence of a range of parameters on the estimates. The goals of the MCS are to test the behavior of the model, evaluate the overall sensitivity of the estimates to variations in the input parameters, and to test which parameters tend to have the largest influence on the results for this specific model.[300]

We conducted this analysis using methods and software consistent with the MCS described in Plevin et al. (2022).[301] We ran the MCS by applying random values drawn from distributions across 37 parameters. In this case, we use the term parameter to refer to a set of related values in GCAM's input files. For example, for this analysis we call "biomass carbon density of cropland" one parameter, even though GCAM uses independent cropland biomass carbon input values for each water basin region. For each of the three MCE scenarios (i.e., reference, low-growth biofuel shock, high-growth biofuel shock), we ran 1,000 trials (3,000 total model simulations). The same set of randomly drawn parameter values were used for each of the three scenarios. We consulted with the GCAM developers to determine the likely range of legitimate values for each parameter and then set selected distributions for each parameter based on our own judgements. In some cases, we were able to leverage previous research to determine empirically based distribution shapes. Table 5.A-1 describes the parameters and distributions used in our MCS.

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[300] The NASEM LCA Report highlights the importance of investigating and transparently communicating uncertainty in impacts modeling of renewable fuels (see recommendation 4-2, page 57). Use of MCS methods for characterizing variance in GHG impacts of biofuels based on parametric uncertainty are discussed on pages 55-56 in the NASEM LCA Report.

[301] Plevin, Richard J., Jason Jones, Page Kyle, Aaron W. Levy, Michael J. Shell, and Daniel J. Tanner. "Choices in Land Representation Materially Affect Modeled Biofuel Carbon Intensity Estimates." *Journal of Cleaner Production* 349 (March 22, 2022): 131477. https://doi.org/10.1016/j.jclepro.2022.131477. Section 2.5 describes the MCS.

Table 5.A-1: GCAM Monte Carlo Simulation Parameter Distributions

Name	Distribution	Description
corn-etoh-corn-coef	Triangle(0.98, 1, 1.02)	Million metric tons of corn required to produce an exajoule of corn ethanol.
cropland-soil-c	Uniform(0.5, 0.99)	Defines a distribution for percentiles to draw from the Beta distribution implied by the statistics gleaned from the moirai data.
cropland-veg-c	Uniform(0.5, 0.99)	Defines a distribution for percentiles to draw from the Beta distribution implied by the statistics gleaned from the moirai data.
forest-soil-c	Uniform(0.5, 0.99)	Defines a distribution for percentiles to draw from the Beta distribution implied by the statistics gleaned from the moirai data.
forest-veg-c	Uniform(0.5, 0.99)	Defines a distribution for percentiles to draw from the Beta distribution implied by the statistics gleaned from the moirai data.
grass-shrub-soil-c	Uniform(0.5, 0.99)	Defines a distribution for percentiles to draw from the Beta distribution implied by the statistics gleaned from the moirai data.
grass-shrub-veg-c	Uniform(0.5, 0.99)	Defines a distribution for percentiles to draw from the Beta distribution implied by the statistics gleaned from the moirai data.
pasture-soil-c	Uniform(0.5, 0.99)	Defines a distribution for percentiles to draw from the Beta distribution implied by the statistics gleaned from the moirai data.
pasture-veg-c	Uniform(0.5, 0.99)	Defines a distribution for percentiles to draw from the Beta distribution implied by the statistics gleaned from the moirai data.
peat-CO2-emissions	Uniform(0.31, 1.75)	CO2 emissions from peatland conversion.
peat-CO2-emissions-linked	Linked(peat-CO2-emissions)	CO2 emissions from peatland conversion on unmanaged land.
N-fertilizer-rate	Triangle(0.7, 1, 1.3)	Quantity of N fertilizer required per mass of crop harvested.
crop-productivity	Triangle(0.7, 1, 1.3)	Annual change in agricultural productivity (yield).
irrig-rainfed-logit-exp	Triangle(0.333, 1, 3.0)	Logit exponent controlling competition between irrigated and rainfed land.
mgmt-level-logit-exp	Triangle(0.333, 1, 3.0)	Logit exponent controlling competition between high and low crop management levels.
n2o-emissions	Triangle(0.5, 1, 2.0)	N2O emissions intensity of agricultural production.
veg-oil-demand-logit-exp	Triangle(0.333, 1.0, 2.0)	Controls substitution among types of vegetable oil
water-wd-price	Triangle(0.333, 1, 3.0)	The price of withdrawn water.
agro-forest-logit-exp	Triangle(0.333, 1, 3.0)	Logit exponent controlling competition between forest-grass-crop and pasture.
cow-sheepgoat-feed-logit	Triangle(0.5, 1, 2.0)	Logit exponent controlling competition between Beef, Dairy, and SheepGoat, which determines the sharing between Mixed and Pastoral subsectors.
crop-logit-exp	Triangle(0.333, 1, 3.0)	Logit exponent controlling competition among crops.
forest-grass-crop-logit-exp	Triangle(0.1, 1.0, 3.0)	Logit exponent controlling competition among forest, grassland, and cropland.
forest-logit-exp	Triangle(0.333, 1, 3.0)	Logit exponent controlling competition between managed and unmanaged forest.
pasture-logit-exp	Triangle(0.333, 1, 3.0)	Logit exponent controlling competition between managed and unmanaged pasture.

Name	Distribution	Description
regional-crop-logit-exp	Triangle(0.333, 1.0, 2.0)	Logit exponent controlling competition between imports and domestic ag products. (10/3/22 - Reduced upper end to try to reduce the number of model failures.)
traded-commodity-logit-exp	Triangle(0.333, 1.0, 2.0)	Logit exponent controlling competition in traded ag commodities. (10/3/22 - Reduced upper end to try to reduce the number of model failures.)
traded-commodity-subsector-logit-exp	Triangle(0.333, 1.0, 2.0)	Logit exponent controlling competition among exports in each traded commodity sector. (10/3/22 - Reduced upper end to try to reduce the number of model failures.)
ng-upstream-ch4	Uniform(0.9, 1.3)	CH4 emissions upstream from natural gas production processes and transport.
population-factor	Triangle(0.0, 0.5, 1.0)	Defines a path between the lower and higher bounds of the UNDP 95% confidence interval around population projections.
biodiesel-competition-logit-exp	Triangle(0.5, 1, 2.0)	Controls substitution among types of biodiesel
pass-road-ldv-4W-logit-exp	Triangle(0.5, 1, 2.0)	Logit exponent controlling substitution among Compact Car, Midsize Car, Large Car, Light Truck and SUV.
pass-road-ldv-4W-vehicle-logit-exp	Triangle(0.5, 1, 2.0)	Logit exponent controlling substitution among 4WD vehicle fuel technology options include BEV, FCEV, Hybrid liquids, Liquids, and NG.
pass-road-ldv-logit-exp	Triangle(0.5, 1, 2.0)	Logit exponent controlling substitution between 2- and 4-wheel light-duty vehicles.
ref-fuel-enduse-ex-US	Triangle(0.333, 1, 3.0)	Controls substitution in supplies of refined fuel for "end use" outside the U.S.
staples-price-elast	empirical	Price elasticity of demand for staple foods
non-staples-price-elast	empirical	Own price elasticity of non-staple food demand.
non-staples-income-elast	empirical	Income elasticity of non-staple food demand.

[a] Unless the parameter name includes an asterisk, the draws from the given distributions were multiplied by the GCAM default values to produce values for each trial. For parameter names with an asterisk, values from the distribution were used directly, replacing the default values.

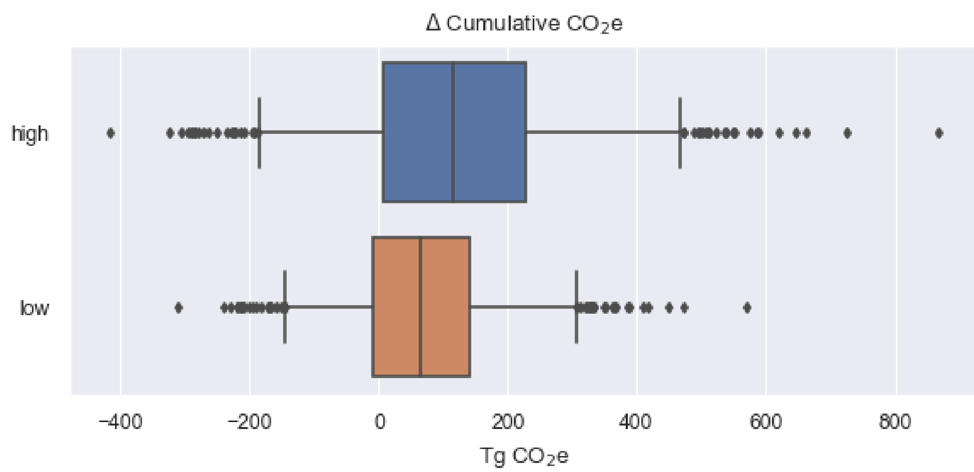
Most of the parameters above are applied directly to values in GCAM's extensible markup language (XML) input files. Parameters for vegetative and soil carbon are handled differently though, as these distributions are applied to the comma-separated value (CSV) data in the GCAM data system, which is then run to regenerate consistent XML files with values reflecting the distributions.[302]

In some cases, combinations of parameters push the model beyond its ability to match supply and demand in all markets simultaneously, in which case the model fails to solve. As shown in Table 5.A-1, we primarily used triangular distributions to reduce the likelihood, relative to normal distributions, of outlier parameter draws, thus reducing the number of model failures. Nonetheless, some of the trials failed to solve; the actual number of trials completed for each model version was 938 for the No RFS Baseline (93.8%), 919 for the High Volume Scenario (91.9%), and 916 for the Low Volume Scenario (91.6%).

[302] Additional documentation of the software and methods used in this analysis are available at: pygcam, "Running the GCAM data system." https://pygcam.readthedocs.io/en/master/mcs/datasystem.html.

The following figure presents the results of our MCS experiment with GCAM as distributions of cumulative GHG estimates from 2026–2055. Although the figure presents the MCS results in probabilistic terms, the actual probability of any given GHG emissions impact cannot be determined from this analysis. Our sensitivity analysis only reveals the likelihood of an outcome given all the inputs into our analysis, such as the version of GCAM, the reference parameter values, the solution technique, the definitions chosen for the parameters evaluated, and the distributions for the parameters evaluated. Although the figure does not tell us the actual probability of a given outcome, it provides information about the general tendency of the model and the variance of results due to parametric uncertainty.

Figure 5.A-1: Distribution of Cumulative (2026–2055) GHG Emissions (Million Metric Tons CO_2e) Difference Estimates from GCAM Modeling of Crop-Based Fuels Using Monte-Carlo Analysis



"low" indicates estimates from the Low Volume Scenario relative to the No RFS Baseline. "high" indicates estimates from the High Volume Scenario relative to the No RFS Baseline. Boxes indicate interquartile range; whiskers indicate 5th and 95th percentiles; vertical line indicates median value.

Based on Figure 5.A-1, we observe that GCAM tends to estimate a net increase in cumulative GHG emissions for both the High and Low Volume Scenarios relative to the No RFS Baseline. However, for both sets of scenarios there are a minority of parameters values that cause GCAM to estimate net decreases in the cumulative emissions.

As part of the MCS experiment, we identified the parameters most strongly influencing the variance in GHG emissions results. We did this by computing the rank correlations between the values for each random variable and the resulting GHG emissions across all MCS trials. The rank correlations are squared and normalized to sum to one to produce an approximate "contribution to variance." In Figure 5.A-2, the sign of the correlation is applied after normalization. This figure shows the strength of the influence of the 15 most influential input parameters on the variance in the output (cumulative GHG emissions), in descending order, with the magnitude and direction corresponding to the strength and direction of the correlation respectively. A contribution to variance further from zero indicates that the parameter is more influential. A positive contribution to variance indicates that as the parameter value increases or decreases, the cumulative GHG estimates tend to move in the same direction. A negative contribution to variance indicates the opposite. Following the figure, we discuss our interpretation of the findings. We only present the figure associated with the High Volume Scenario relative to the baseline, as the same figure or the Low Volume Scenario is nearly identical.

Figure 5.A-2: Tornado Chart of Most the Influential Parameters on Cumulative (2026–2055) GHG Emissions (Million Metric Tons CO_2e) Difference Estimates from GCAM Modeling of Crop-based Fuels Using Monte-Carlo Analysis

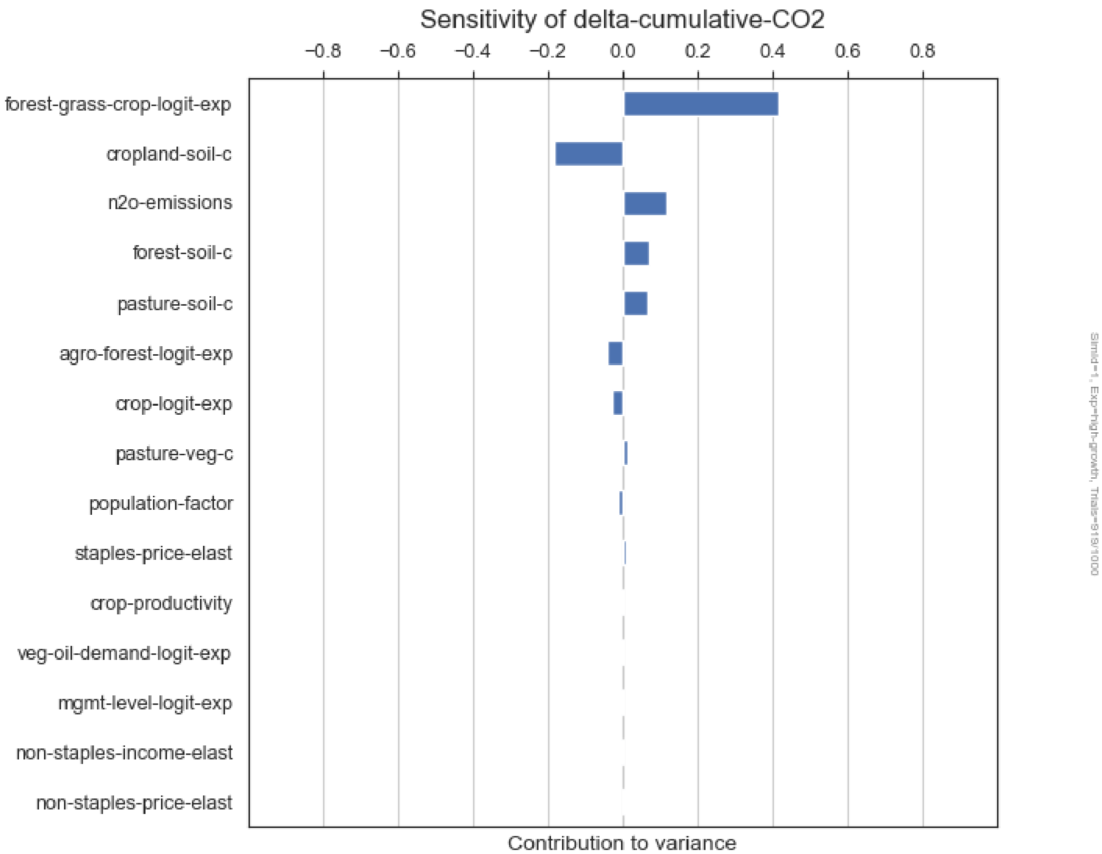


Figure 5.A-2 shows that, for this MCS experiment, about 5 parameters have an outsized influence on the estimates. This does not mean the other parameters have no effect, but rather that their influence is much smaller than that of the 5 most influential parameters. The most influential parameter is *forest-grass-crop-logit-exp*, the parameter controlling the flexibility of competition among forest, grassland, and cropland. Higher values for this parameter mean more flexibility for price-driven land use changes among these land categories. For example, given an increase in crop prices, higher values for this parameter will translate to larger increases in crop area at the expense of grassland and forest area. The other most influential parameters are: (1) *cropland-soil-c*, the soil carbon density of cropland, (2) *n2o-emissions*, the N_2O emissions intensity of agriculture, (3) *forest-soil-c*, the soil carbon density of forestland, and (4) *pasture-soil-c*, the soil carbon density of pastureland. All the most influential parameters appear to be primarily related to land use change and land use change emissions.

Chapter 6: Energy Security Impact

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. This chapter describes our analysis of the energy security impacts of the Volume Scenarios relative to the No RFS Baseline. In addition, this chapter provides energy security estimates of the Proposed Volumes.

U.S. energy security is broadly defined as the uninterrupted availability of energy sources at an acceptable price.[303] Most discussions of U.S. energy security have historically revolved around the topic of the economic costs of U.S. dependence on oil imports.[304] However, all exposures to global energy supply disruptions and price spikes—including those related to renewable fuels and renewable fuel feedstocks—create risks to energy security. A related but separate consideration is U.S. energy independence, which is achieved by reducing the sensitivity of the U.S. economy to energy imports and foreign energy markets to the point where the costs of depending on foreign energy (fossil fuels, biofuels, electricity, etc.) are so small that they have minimal effects on the U.S.'s economic, military, or foreign policies.[305] In this definition of U.S. energy independence, it is necessary to reduce, but not eliminate, all energy imports to the U.S. to achieve independence.

Reducing oil imports and, thus, becoming more independent from foreign suppliers of oil has been a central goal of U.S. energy security policy for decades. Similarly, as described in Preamble Section VIII, we are also proposing to reduce the number of RINs generated for imported renewable fuel and renewable fuel produced from foreign feedstocks, which is intended to reduce America's reliance on such fuels in future years consistent with the statutory goals of energy security and independence. In addition to evaluating impacts on energy security, we have also considered the impacts of the Volume Scenarios on U.S. energy independence in this analysis. 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.[306] As stated above, energy independence and energy security are distinct but related concepts, implying that an analysis of energy independence also helps to inform our analysis of energy security.

Given the historical focus in the U.S. on reducing oil imports, the discussion and analysis in this chapter largely focuses on the role of oil imports in energy security and energy independence. The growing role of imported renewable fuels and renewable fuel feedstocks, and the interplay between reductions in imports of oil, renewable fuels, and renewable fuel

303 IEA, "Energy Security." https://www.iea.org/topics/energy-security.
304 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. Sanger, David E., Clifford Krauss, and Nicole Perlroth. "Cyberattack Forces a Shutdown of a Top U.S. Pipeline," *New York Times*, May 8, 2021. https://www.nytimes.com/2021/05/08/us/politics/cyberattack-colonial-pipeline.html.
305 Greene, David L. "Measuring Energy Security: Can the United States Achieve Oil Independence?" *Energy Policy* 38, no. 4 (March 7, 2009): 1614–21. https://doi.org/10.1016/j.enpol.2009.01.041.
306 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).

feedstocks on U.S. energy security and independence, is also a significant factor to consider. However, we currently lack the tools to assess these impacts.

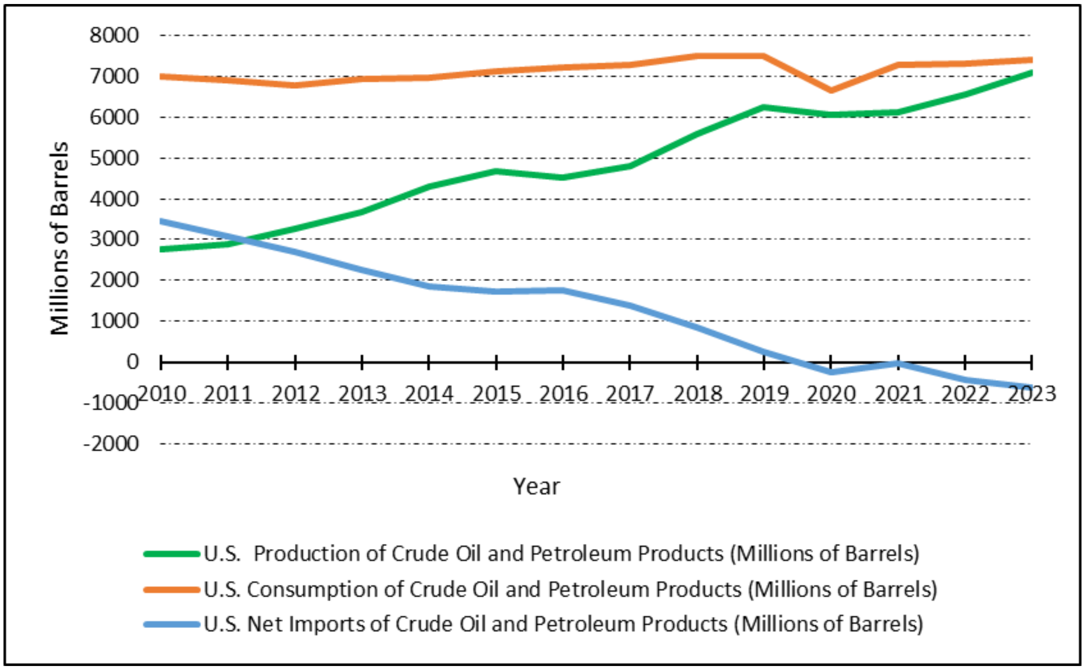
The U.S. has witnessed a significant change in its exposure to the world oil market since initial implementation of the RFS2 Rule in 2010. This shift in exposure has implications for U.S. energy security. Between 2010 and 2023, U.S. production of crude oil and petroleum products grew at an average annual rate of approximately 7.4%, as shown in Figure 6-1. The growth rate in U.S. oil production was largely due to significant increases in U.S. tight (i.e., shale) oil production.[307] As of 2023, as a result of growing oil production, the U.S. was the largest producer of oil in the world, producing 12.9 million barrels per day (MMBD), followed by Russia producing 10.1 MMBD and Saudi Arabia producing 9.7 MMBD.[308]

During this same time frame, U.S. consumption of crude oil and petroleum products remained fairly flat, with an average annual growth rate of 0.6%, as shown in Figure 6.1. The significant increase in U.S. oil production and relatively flat U.S. oil consumption resulted in a significant reversal in the U.S.'s petroleum trade balance position. Prior to 2020, the U.S. had been a net importer of crude oil and petroleum products (i.e., net petroleum importer) since the early 1950s.[309] However, as also depicted in Figure 6.1, the U.S. became a net exporter of crude oil and petroleum products (i.e., a net petroleum exporter) starting in 2020. Thus, the U.S. has achieved a greater degree of energy independence with respect to petroleum by reducing dependence on imports.

From 2026–2030, EIA estimates that U.S. oil consumption will gradually decline from 18.6 to 18.4 MMBD, roughly similar to the amount of oil that the U.S. consumed in 2010. However, in 2010, the U.S. imported roughly 9.4 MMBD of petroleum.[310] In contrast, the U.S. is now anticipated to be a modest net petroleum exporter of roughly 2.3 MMBD in 2030.[311]

[307] EIA, "Tight oil production estimates by play," *Petroleum & Other Liquids*, May 2025. https://www.eia.gov/petroleum/data.php.
[308] EIA, "United States produces more crude oil than any country, ever," *Today in Energy*, March 11, 2024. https://www.eia.gov/todayinenergy/detail.php?id=61545. Oil production estimates for the U.S. include crude oil and lease condensate.
[309] EIA, "Oil imports and exports," *Oil and petroleum products explained*, January 19, 2024. https://www.eia.gov/energyexplained/oil-and-petroleum-products/imports-and-exports.php.
[310] Id.
[311] Calculated from AEO2023, Table 11 as Total Net Exports minus Ethanol, Biodiesel, Renewable Diesel, and Other Biomass-derived Liquid Net Exports.

Figure 6-1: U.S. Consumption, Production, and Net Imports of Crude Oil and Petroleum Products



Source: EIA, "Supply and Disposition," Petroleum & Other Liquids, April 30, 2025. https://www.eia.gov/dnav/pet/pet_sum_snd_d_nus_mbbl_a_cur.htm.

The Volume Scenarios represent net increases in renewable fuels in comparison to previous years and, also, net increases in comparison to the No RFS Baseline. Increasing the use of renewable fuels in the U.S. displaces domestic consumption of petroleum-based fuels. Given the U.S.'s projected pattern of petroleum trade with other countries, reductions in U.S. oil consumption will result in increases in U.S. gross petroleum exports as well as a reduction in U.S. gross petroleum imports. A reduction in U.S. net petroleum imports (i.e., from the combined increase in U.S. gross petroleum exports and reductions in U.S. gross petroleum imports) reduces both financial and strategic risks caused by potential sudden disruptions in the supply of petroleum to the U.S., increasing U.S. energy security.

In recent years, a substantial quantity of imports of renewable fuels and renewable fuel feedstocks have been used to meet the RFS volume obligations. Trade balances for some renewable fuels and renewable fuel feedstocks have been moving in different directions than the historical oil import trends discussed above. In particular, there has been a recent expansion of imports of BBD feedstocks since 2021, which can be seen in Preamble Figure III.B.2.d-2. This shift, which has been driven by a confluence of factors discussed elsewhere (e.g., Preamble Section III.B.2), have implications for energy security and energy independence.

Increasing reliance on renewable fuels and renewable fuel feedstocks, and imports of both, to meet the RFS volume obligations will likely influence the U.S.'s energy security and independence. For example, the supply of renewable fuels and renewable fuel feedstocks could be subject to market supply disruptions such as weather-related events (e.g., droughts) in the U.S. or abroad. To the extent that renewable fuel and renewable fuel feedstock prices are subject to only modest price shocks, and the price shocks are not strongly correlated with oil price shocks, blending renewable fuels with petroleum fuels will likely provide energy security benefits. The use of renewable fuels, therefore, may dampen the impacts of oil price shocks but expose fuel markets to new shocks. From the standpoint of U.S. energy independence, reducing imported renewable fuels and renewable fuel feedstocks moves the U.S. towards the goal of energy independence. However, the energy security risks of using renewable fuels/feedstocks are not well understood, nor well studied. As a result, this chapter focuses on the literature on energy security impacts associated with U.S. petroleum consumption and U.S. net oil imports and summarizes EPA's estimates of the benefits of reduced petroleum consumption/net imports that would result from this proposal.

After considering recent changes in the U.S. trade balances of oil, renewable fuels, and renewable fuel feedstocks and the greater degree of independence from foreign oil, energy security risks still remain. There are three main reasons why energy security is still a concern, despite the reduction in U.S. net imports of petroleum. First, oil, renewable fuels, and renewable fuel feedstocks are globally traded commodities and, as a result, a price shock to any of these commodities is transmitted globally even if a country is a net exporter of a commodity. For example, were U.S. oil producers to attempt to keep their prices low in the face of a global oil price shock, foreign consumers would attempt to buy up that cheaper oil, bidding up the price. In this way, U.S. consumers of oil would become equally exposed to oil price shocks, even when purchasing oil produced in the U.S. As a result, an oil price shock would raise the price of oil and oil products that U.S. households and businesses pay for petroleum products, which could adversely affect the U.S. economy as a whole. Additional use of renewable fuels and renewable fuel feedstocks can dampen price impacts from oil price shocks, if these prices are largely uncorrelated, but will result in new exposure in the renewable fuel markets.

Second, U.S. refineries rely on significant imports of heavy crude oil which could be subject to direct supply disruptions. These refiners are unable to consume the lighter crude oil produced by U.S. tight oil operations without expensive and time-consuming changes to their refinery configurations and supply chain logistics. They therefore lack the agility to make such changes in the face of acute short- or medium-term oil supply disruptions. While U.S. petroleum exports now exceed imports, the volume of gross imports remains quite significant. In 2024, gross petroleum imports totaled roughly 8.4 MMBD.[312] Likewise, there has been an expansion in imported BBD feedstocks in recent years.

Third, oil exporters with a large share of global production have the ability to raise or lower the price of oil by exerting their market power through the Organization of Petroleum Exporting Countries (OPEC) to alter oil supply relative to demand. It is somewhat uncertain how much market power OPEC will have in the time frame of this proposed rule. But in the face of such uncertainty, OPEC's market power must be considered a significant risk to U.S. energy security. All three of the factors listed above contribute to the vulnerability of the U.S. economy to episodic energy supply shocks and price spikes, even though the U.S. is projected to be a net petroleum exporter for the foreseeable future.

[312] EIA, "U.S. Imports from All Countries," *Petroleum & Other Liquids*, May, 2025. https://www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_ep00_im0_mbblpd_a.htm

To summarize, we recognize that because the U.S. is a participant in the world market for oil, renewable fuels, and renewable fuel feedstocks, its economy cannot be shielded from worldwide price shocks from these commodities.[313] But the potential for petroleum supply disruptions due to supply shocks has been diminished due to the increase in U.S. tight oil production and due to increased consumption of renewable fuels, among other factors. These factors have collectively shifted the U.S. to being a modest net petroleum exporter in the world petroleum market in 2026–2027.[314] At the same time, a trend of increasing imports of renewable fuel feedstocks has emerged, raising concerns about the impacts of renewable fuels and renewable fuel feedstocks on energy security and independence. The potential for petroleum supply disruptions has also 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.[315]

6.1 Review of Historical Energy Security Literature (1981 to 2014)

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 or 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.

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),[316] EMF (1982),[317] and Plummer (1982)[318]). Bohi and Montgomery detailed the theoretical foundations of the oil import premium and established many of the critical analytic relationships that can be used to estimate the magnitude of the oil import premium. Hogan (1981)[319] and Broadman and Hogan (1986,[320] 1988[321]) revised and extended the established analytical framework to estimate optimal oil import premia with a more detailed accounting of macroeconomic effects. Since the original

[313] Bordoff, Jason. "The Myth of U.S. 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.
[314] Krupnick, Alan, Richard Morgenstern, Nathan Balke, Stephen P.A. Brown, Ana María Herrera, and Shashank Mohan. "Oil Supply Shocks, US Gross Domestic Product, and the Oil Security Premium." *Resources for the Future*. November 2017. https://media.rff.org/documents/RFF-Rpt-OilSecurity.pdf.
[315] Foreman, Dean. "Why the US must Import and Export Oil," *American Petroleum Institute*, June 14, 2018.
[316] Bohi, D.R. and W.D. Montgomery. "Social Cost of Imported Oil and US Import Policy." *Annual Review of Energy* 7, no. 1 (November 1, 1982): 37–60. https://doi.org/10.1146/annurev.eg.07.110182.000345.
[317] "World Oil: Summary Report." *Energy Policy* 10, no. 4 (December 1, 1982): 367. https://doi.org/10.1016/0301-4215(82)90059-3.
[318] Plummer, James L. *Energy Vulnerability*. Ballinger Publishing Company, 1982.
[319] Hogan, W. "Import Management and Oil Emergencies," Chapter 9 in D. Deese and J. Nye, eds. *Energy and Security*, Cambridge: Ballinger Press, 1981.
[320] Broadman, Harry G. "The Social Cost of Imported Oil." *Energy Policy* 14, no. 3 (June 1, 1986): 242–52. https://doi.org/10.1016/0301-4215(86)90146-1.
[321] Broadman, Harry G., and William W. Hogan. "The numbers say yes." *The Energy Journal* 9, no. 3 (July 1, 1988): 7–30. https://doi.org/10.1177/01956574198809031.

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).[322,323]

The economics literature on whether oil shocks have continued to present the same level of threat to economic stability as they were when this literature emerged in the 1980s has been mixed over time. Hamilton (2012) reviewed the empirical literature on oil shocks and suggested that the results were mixed, noting that some work (e.g., Rasmussen and Roitman (2011)) found less evidence for economic effects of oil shocks or declining effects of shocks (Blanchard and Gali (2010)), while other work found more evidence regarding the economic importance of oil shocks.[324] For example, Baumeister and Peersman (2012) found 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."[325] Ramey and Vine (2010) found "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."[326]

Some of the literature on oil price shocks has emphasized 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. 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)).[327] A paper by Kilian and Vigfusson (2014), for example, assigned a more prominent role to the effects of price increases that are unusual, in the sense of being beyond the range of recent experience.[328] Kilian and Vigfusson also concluded 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)."[329]

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[322] Leiby, Paul N., Donald W. Jones, T. Randall Curlee, and Russell Lee. "Oil Imports: An Assessment of Benefits and Costs." *Oak Ridge National Laboratory*, ORNL-6851. November 1, 1997.
[323] Parry, Ian W.H., Joel Darmstadter. "The Costs of U.S. Oil Dependency." Resources for the Future, December 2003. https://media.rff.org/documents/RFF-DP-03-59.pdf.
[324] Rasmussen, Tobias N., and Agustin Roitman. "Oil Shocks in a Global Perspective: Are They Really That Bad?" *IMF Working Paper* 11, no. 194 (January 1, 2011): 1. https://doi.org/10.5089/9781462305254.001.
325 Baumeister, Christiane, and Gert Peersman. "The Role of Time-Varying Price Elasticities in Accounting for Volatility Changes in the Crude Oil Market." *Journal of Applied Econometrics* 28, no. 7 (June 26, 2012): 1087–1109. https://doi.org/10.1002/jae.2283.
[326] Ramey, Valerie A., and Daniel J. Vine. "Oil, Automobiles, and the U.S. Economy: How Much Have Things Really Changed?" *NBER Macroeconomics Annual* 25, no. 1 (January 1, 2011): 333–68. https://doi.org/10.1086/657541.
[327] Baumeister Christiane, Gert Peersman and Ine Van Robays. "The Economic Consequences of Oil Shocks: Differences across Countries and Time," Reserve Bank of Australia Annual Conference – 2009. https://www.rba.gov.au/publications/confs/2009/baumeister-peersman-vanrobays.html.
[328] Kilian, Lutz, and Robert J. Vigfusson. "The Role of Oil Price Shocks in Causing U.S. Recessions." *Journal of Money Credit and Banking* 49, no. 8 (November 16, 2017): 1747–76. https://doi.org/10.1111/jmcb.12430.
[329] Kilian, Lutz. "Not All Oil Price Shocks Are Alike: Disentangling Demand and Supply Shocks in the Crude Oil Market." *American Economic Review* 99, no. 3 (May 1, 2009): 1053–69. https://doi.org/10.1257/aer.99.3.1053.

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.[330] They state: "The results indicate that the economic consequences of a supply-driven oil-price shock are very different from those of an oil-demand shock driven by global economic activity, and vary for oil-importing countries compared to energy exporters." Cashin et al. continues "…oil importers (including the U.S.) typically face a long-lived fall in economic activity in response to a supply-driven surge in oil prices." But almost all countries see an increase in real output caused by an oil-demand disturbance.

Considering all of the energy security literature from the 1981–2014 timeframe, EPA's assessment concludes that there are benefits to the U.S. from reductions of its net oil imports. There is some debate as to the magnitude 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 6.4) 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 an increase in imported feedstocks to make renewable fuels due to this proposed rule, the rule would result in an overall reduction in the combined total of imported fossil and renewable fuel feedstocks used to make transportation fuels, moving the U.S. modestly towards the goal of energy independence while enhancing the U.S.'s energy security.

6.2 Review of Energy Security Literature from the Last Decade

There have also been a handful of studies from the last decade (i.e., since 2015) that are relevant for the issue of energy security. We provide a brief review and high-level summary of each of these studies below.

6.2.1 Oil Energy Security Studies from the Last Decade

The first studies on the energy security impacts of oil we reviewed are by Resources for the Future (RFF), a study by Brown and two studies by Oak Ridge National Laboratory (ORNL). The RFF study (2017) attempted 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.[331] In a follow-on study, Brown summarized the RFF study results as well.[332] The RFF argued that there have been major changes that have occurred over the last two decades which have reduced the impacts of oil shocks on the U.S. economy. First, the U.S. became less dependent on imported oil in the 2010s due in part to the "fracking revolution" (i.e., tight/shale

[330] Cashin, Paul, Kamiar Mohaddes, Maziar Raissi, and Mehdi Raissi. "The Differential Effects of Oil Demand and Supply Shocks on the Global Economy." *Energy Economics* 44 (April 6, 2014): 113–34. https://doi.org/10.1016/j.eneco.2014.03.014.
[331] Krupnick, Alan, Richard Morgenstern, Nathan Balke, Stephen P.A. Brown, Ana María Herrera, and Shashank Mohan. "Oil Supply Shocks, US Gross Domestic Product, and the Oil Security Premium." *Resources for the Future*. November 2017. https://media.rff.org/documents/RFF-Rpt-OilSecurity.pdf.
[332] Brown, Stephen P.A. "New Estimates of the Security Costs of U.S. Oil Consumption." *Energy Policy* 113 (November 22, 2017): 171–92. https://doi.org/10.1016/j.enpol.2017.11.003.

oil), and to a lesser extent, increased production of renewable fuels. In addition, RFF argued that the U.S. economy became more resilient to oil shocks in the 2010s compared to an early 2000s time frame. Some of the factors that made 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).

In the RFF effort, a number of comparative modeling scenario exercises were 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 framework involved was a dynamic stochastic general equilibrium model developed by Balke and Brown.[333] The second set of modeling frameworks used alternative structural vector autoregressive models of the global crude oil market.[334] The last of the models utilized was the National Energy Modeling System (NEMS).[335]

Two key parameters were 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 reported 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 examined 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 was that the large variations in oil

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[333] Balke, Nathan S., and Stephen P.A. Brown. "Oil Supply Shocks and the U.S. Economy: An Estimated DSGE Model." *Energy Policy* 116 (February 28, 2018): 357–72. https://doi.org/10.1016/j.enpol.2018.02.027.
[334] These models include:
Kilian, Lutz. "Not All Oil Price Shocks Are Alike: Disentangling Demand and Supply Shocks in the Crude Oil Market." *American Economic Review* 99, no. 3 (May 1, 2009): 1053–69. https://doi.org/10.1257/aer.99.3.1053.
Kilian, Lutz, and Daniel P. Murphy. "The Role of Inventories and Speculative Trading in the Global Market for Crude Oil." *Journal of Applied Econometrics* 29, no. 3 (April 10, 2013): 454–78. https://doi.org/10.1002/jae.2322.
Baumeister, Christiane, and James D. Hamilton. "Structural Interpretation of Vector Autoregressions With Incomplete Identification: Revisiting the Role of Oil Supply and Demand Shocks." *American Economic Review* 109, no. 5 (May 1, 2019): 1873–1910. https://doi.org/10.1257/aer.20151569.
[335] Mohan, Shashank. "Oil Price Shocks and the US Economy: An Application of the National Energy Modeling System." *Resources for the Future*. November 2017. https://media.rff.org/documents/RFF-Rpt-OilSecurity-Appendix.pdf.

price over the last 15 years are believed to be predominantly “demand shocks” (e.g., for example, a rapid growth in global oil demand followed by the Great Recession and then the post-recession recovery).

There have only been two situations where events have led to a potentially significant supply-side oil shock in the last decade. 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 was the largest crude oil processing and stabilization plant in the world, with a capacity of roughly 7 million barrels of oil a day (MMBD) or about 7% of global crude oil production capacity.[336] On September 16th, the first full day of commodity trading after the attack, both Brent and WTI crude oil prices surged by $7.17/barrel and $8.34/barrel, 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.[337] Tanker loading estimates from third-party data sources indicated that loadings at two Saudi Arabian export facilities were restored to the pre-attack levels.[338] 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 was 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 3, 2022, the WTI crude oil price was roughly $76/barrel.[339] The WTI oil price increased to roughly $124/barrel on March 8th, 2022, a 63% increase.[340] 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.[341] 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.[342] More recently, as of September 9, 2024, the WTI crude oil price was $70/barrel, a somewhat lower price than before the Russian invasion of Ukraine.[343]

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[336] EIA, “Saudi Arabia crude oil production outage affects global crude oil and gasoline prices,” *Today in Energy*, September 23, 2019. https://www.eia.gov/todayinenergy/detail.php?id=41413.
[337] Id.
[338] Id.
[339] EIA, “Spot Prices,” *Petroleum & Other Liquids*, May 14, 2025. https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm.
[340] Id.
[341] EIA, “Crude oil prices increased in the first half of 2022 and declined in the second half of 2022,” *Today in Energy*, January 4, 2023. https://www.eia.gov/todayinenergy/detail.php?id=55079.
[342] Id.
[343] EIA, “Spot Prices,” *Petroleum & Other Liquids*, May 14, 2025. https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm.

Oil prices at present are relatively low mainly because of projected slowdown in world oil demand growth, particularly in China.[344] Crude oil prices (i.e., the WTI crude oil price) are expected to be flat in the 2026–2027 time frame of this proposed rule, in the $85–86 per barrel (2022$) range.[345]

Geopolitical disruptions that occurred in 2022 are likely to continue to affect global trade of crude oil and refined 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.[346] For the 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 refined petroleum products starting in February 2023.[347] In light of this geopolitical environment and other market factors, the U.S. has seen its refined petroleum product exports grow steadily since 2021. It is anticipated that the U.S. will continue to witness a modest increase in refined petroleum product exports in the time frame of this proposed rule, 2026–2027.[348]

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 the Abqaiq oil processing facility in Saudi Arabia and the events in the world oil market in 2022 and 2023 in response to the Russian invasion of Ukraine 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.[349]

A second set of studies related to energy security were from ORNL. In the first study, ORNL (2018) undertook a quantitative meta-analysis of world oil demand elasticities based upon the recent economics literature.[350] 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 undertook 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 found 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.

[344] EIA, "Short-Term Energy Outlook," September 2024. https://www.eia.gov/outlooks/steo/archives/sep24.pdf.
[345] AEO2023, Table 12 – Petroleum and Other Liquids Prices. https://www.eia.gov/outlooks/archive/aeo23.
[346] EIA, "U.S. petroleum product exports set a record high in 2022," *Today in Energy*, March 20, 2023. https://www.eia.gov/todayinenergy/detail.php?id=55880.
[347] Id.
[348] AEO2023, Table 11 – Petroleum and Other Liquids Supply and Disposition.
[349] 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 Energy Modeling Forum (EMF) risk analysis framework, which provides the oil disruption probabilities than ORNL is using.
[350] Uria-Martinez, Rocio, Paul Leiby, Gbadebo Oladosu, David Bowman, and Megan Johnson. "Using Meta-Analysis to Estimate World Oil Demand Elasticity," *Oak Ridge National Laboratory* ORNL/TM-2018/1070, December 10, 2018. https://doi.org/10.2172/1491306.

The second relevant ORNL (2018) study from the standpoint of energy security was 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.[351] Nineteen 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 found 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.

6.2.2 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 affected U.S. energy security; two of the ways this might occur are discussed here.[352] 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.[353] According to the GAO, the ban was lifted in part due to increases in tight (i.e., shale) oil.[354] Second, due to differences in development cycle characteristics and average well productivity, tight oil producers could be more price responsive than most other oil producers. However, the oil price level that triggers a substantial increase in tight oil production appears to be higher in 2021–2023 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.[355]

U.S. crude oil production increased from 5.0 MMBD in 2008 to 13.2 MMBD in 2024 and tight oil wells have been responsible for most of the increase.[356] Figure 6.2.2-1 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 6.2.2-1, one can see that the annual average U.S. tight oil production grew from 0.5 MMBD in 2008 to 8.9 MMBD in 2024.[357]

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351 Oladosu, Gbadebo A., Paul N. Leiby, David C. Bowman, Rocio Uría-Martínez, and Megan M. Johnson. "Impacts of Oil Price Shocks on the United States Economy: A Meta-analysis of the Oil Price Elasticity of GDP for Net Oil-importing Economies." *Energy Policy* 115 (February 3, 2018): 523–44. https://doi.org/10.1016/j.enpol.2018.01.032.

352 "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.'" Union of Concerned Scientists, "What Is Tight Oil?" March 3, 2015. https://www.ucs.org/resources/what-tight-oil.

353 Pub. L. 114-113 (December 18, 2015).

354 GAO, "Crude Oil Markets: Effects of the Repeal of the Crude Oil Export Ban," GAO-21-118, October 2020. https://www.gao.gov/assets/gao-21-118.pdf. According to the GAO, "Between 1975 and the end of 2015, the Energy Policy and Conservation Act directed a ban on nearly all exports of U.S. crude oil. This ban was not considered a significant policy issue when U.S. oil production was declining and import volumes were increasing. However, U.S. crude oil production roughly doubled from 2009 to 2015, due in part to a boom in shale oil production made possible by advancements in drilling technologies. In December 2015, Congress effectively repealed the ban, allowing the free export of U.S. crude oil worldwide."

355 Kemp, John. "U.S. shale restraint pushes oil prices to multi-year high," *Reuters*, June 4, 2021. https://www.reuters.com/business/energy/us-shale-restraint-pushes-oil-prices-multi-year-high-kemp-2021-06-04.

356 EIA, "Crude Oil Production," *Petroleum & Other Liquids*, April 30, 2025. https://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbblpd_a.htm.

357 EIA, "Short Term Energy Outlook," May 2025, Table 10b – Crude Oil and Natural Gas Production from Shale and Tight Formations. https://www.eia.gov/outlooks/steo/tables/pdf/10btab.pdf.

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 26% decrease in tight oil production in the period from December 2019 to May 2020. U.S. tight oil production averaged 7.2 MMBD in 2020–2021 and resumed growth in 2022–2024. The 2024 average production (8.9 MMBD) is the new all-time peak for U.S. tight oil production. It represents a relatively modest share (less than 10% in 2024) of global liquid fuel supply.[358]

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.[359] 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.[360]

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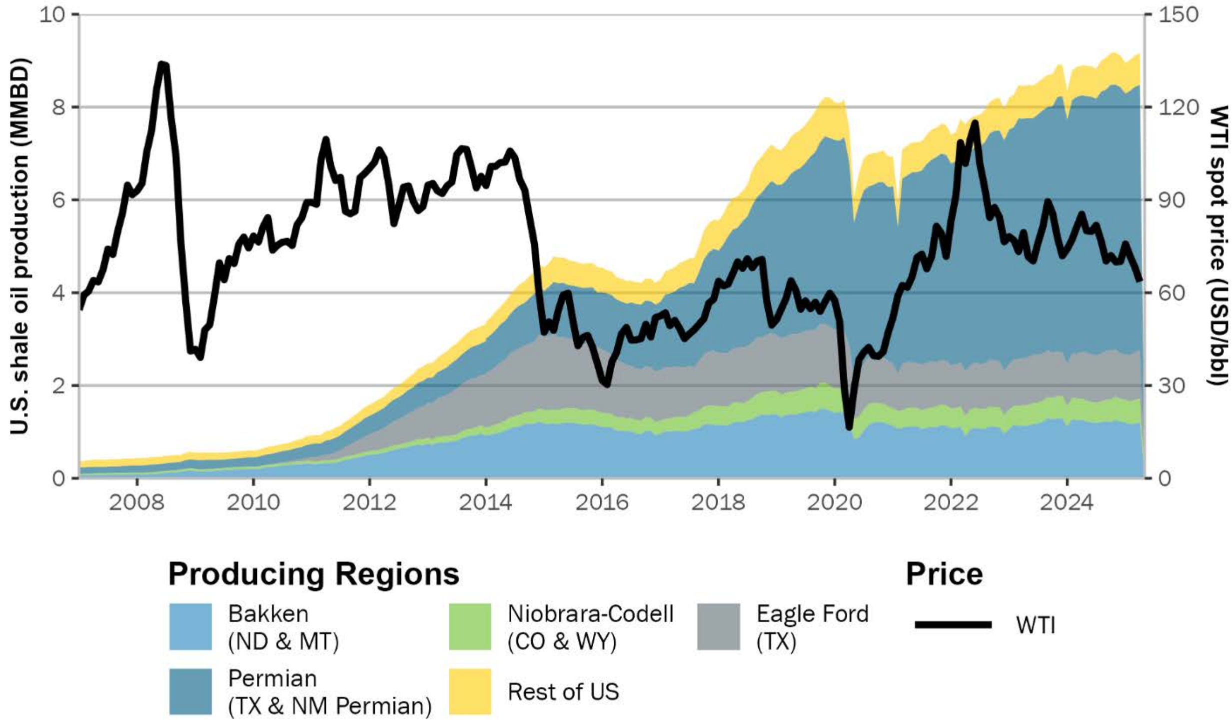
[358] The 2024 global crude oil production value used to compute the U.S. tight oil share (102.8 mb/d) is from EIA, "Petroleum and other liquids (production)," *International*, May 15, 2025. https://www.eia.gov/international/data/world/petroleum-and-other-liquids/annual-petroleum-and-other-liquids-production.

[359] 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.

[360] Bjørnland, Hilde C., Frode Martin Nordvik, and Maximilian Rohrer. "Supply Flexibility in the Shale Patch: Evidence From North Dakota." *Journal of Applied Econometrics* 36, no. 3 (February 5, 2021): 273–92. https://doi.org/10.1002/jae.2808.

Figure 6.2.2-1: U.S. Tight Oil Production (by Producing Regions) and WTI Crude Oil Spot Price



Source: EIA, "Tight oil production estimates by play," *Petroleum & Other Liquids*, May 2025. https://www.eia.gov/petroleum/data.php. EIA, "Spot Prices," *Petroleum & Other Liquids*, May 14, 2025. https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm.

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. 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, recent literature has considered the question of whether tight oil might be able to respond to an oil price shock more quickly and substantially than conventional oil.[361] 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.

[361] "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.'" Union of Concerned Scientists, "What Is Tight Oil?" March 3, 2015. https://www.ucs.org/resources/what-tight-oil.

Newell and Prest (2019) looked 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.[362] For both conventional oil wells and shale oil wells (i.e., unconventional oil wells), Newell and Prest estimated 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 concluded that U.S. oil supply responsiveness to prices increased more than tenfold from 2006 to 2017. They found that tight/shale oil wells were more price responsive than conventional oil wells, mostly due to their much higher productivity, but the estimated oil supply elasticity was still small. Newell and Prest noted 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), used 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.[363] They found 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 was not statistically different from zero. It should be noted that the elasticity value estimated by Bjornland et al. combined 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) explored 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.[364] They conducted 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 found 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 ranged 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 used data sets that end in 2019 or earlier. The responsiveness of U.S. tight oil production to recent price increases in the

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[362] Newell, Richard, and Brian Prest. "The Unconventional Oil Supply Boom: Aggregate Price Response From Microdata," October 1, 2017. https://doi.org/10.3386/w23973.
[363] Bjørnland, Hilde C., Frode Martin Nordvik, and Maximilian Rohrer. "Supply Flexibility in the Shale Patch: Evidence From North Dakota." *Journal of Applied Econometrics* 36, no. 3 (February 5, 2021): 273–92. https://doi.org/10.1002/jae.2808.
[364] Walls, W.D., and Xiaoli Zheng. "Fracking and Structural Shifts in Oil Supply." *The Energy Journal* 43, no. 3 (April 21, 2021): 1–32. https://doi.org/10.5547/01956574.43.3.wwal.

2020s 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 6.2.2-1 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.[365] Most U.S. tight oil producers did not generate positive cashflow.[366] As of 2021, U.S. shale oil producers have pledged to repay their debt and reward shareholders through dividends and stock buybacks.[367] 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/barrel. To profitably drill new wells, the required average WTI prices ranged from $48–69/barrel. 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/barrel, 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.[368] Given the recent behavior of tight oil producers, we do not believe that tight oil will provide additional significant energy security benefits in 2026–2027 due to its lack of price responsiveness. The ORNL model still accounts for U.S. tight oil production increases on U.S. net 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 6.4 focuses on those incremental social costs that follow from the resulting changes in net imports, employing the usual oil import premium measure.

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[365] McLean, Bethany. "The Next Financial Crisis Lurks Underground," *New York Times*, September 1, 2018. https://www.nytimes.com/2018/09/01/opinion/the-next-financial-crisis-lurks-underground.html.
[366] Id.
[367] Crowley, Kevin and David Wethe. "Shale Bets on Dividends to Match Supermajors, Revive Sector," *Bloomberg*, August 2, 2021. https://www.bloomberg.com/news/articles/2021-08-02/shale-heavyweights-shower-investors-with-dividends-on-oil-rally.
[368] Federal Reserve Bank of Dallas, "Oil and Gas Expansion Accelerates as Outlooks Improve Significantly," *Dallas Fed Energy Survey*, First Quarter, March 23, 2022. https://www.dallasfed.org/research/surveys/des/2022/2201.

6.3 Cost of Existing U.S. Energy Security Policies

An additional often-identified component of the full economic costs of U.S. oil imports is the costs to the U.S. taxpayers of existing U.S. energy security policies. The two primary examples are maintaining the Strategic Petroleum Reserve (SPR) and maintaining a military presence to help secure a stable oil supply from potentially vulnerable regions of the world.

The SPR is the largest stockpile of government-owned emergency crude oil in the world. Established in the aftermath of the 1973/1974 oil embargo, the SPR provides the U.S. with a response option should a disruption in commercial oil supplies threaten the U.S. economy.[369] 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.[370] 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.[371] In 2023, the DOE sold 26 million barrels of oil between April and June.[372] A total of 246.6 million barrels were released from the SPR from January 2022 to July 2023. By the end of July 2023, the SPR stock level was 346.8 million barrels (the lowest level since August 1983). To start replenishing the stock, the SPR office purchased 60.5 million barrels through competitive solicitations conducted between May 2023 and November 2024, for deliveries from August 2023 to May 2025. 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

[369] Energy Policy and Conservation Act, 42 U.S.C. § 6241(d) (1975).

[370] DOE, "DOE Announces Emergency Notice of Sale of Crude Oil from the Strategic Petroleum Reserve to Address Oil Supply Disruptions," March 2, 2022. https://www.energy.gov/ceser/articles/doe-announces-emergency-notice-sale-crude-oil-strategic-petroleum-reserve-address.

[371] DOE, "DOE Announces Second Emergency Notice of Sale of Crude Oil From The Strategic Petroleum Reserve to Address Putin's Energy Price Hike," April 4, 2022. https://www.energy.gov/articles/doe-announces-second-emergency-notice-sale-crude-oil-strategic-petroleum-reserve-address.

[372] DOE, "DOE Issues Notice of Congressionally Mandated Sale to Purchase Crude Oil from the Strategic Petroleum Reserve," February 13, 2023. https://www.energy.gov/ceser/articles/doe-issues-notice-congressionally-mandated-sale-purchase-crude-oil-strategic.

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 accounts rather than by mission, the allocation to particular missions is not always clear.[373] 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).[374]

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).[375] Stern (2010), on the other hand, argued 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.[376] Stern presented an estimate of military cost for Persian Gulf force projection, addressing the challenge of cost allocation with an activity-based cost method. He used 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.

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373 Crane, Keith, Andreas Goldthau, Michael Toman, Thomas Light, Stuart Johnson, Alireza Nader, Angel Rabasa, and Harun Dogo. "Imported Oil and U.S. National Security." *RAND Corporation*, 2009. https://doi.org/10.7249/mg838.
374 Koplow, Douglas, and Aaron Martin. "Fueling Global Warming: Federal Subsidies to Oil in the United States." *Greenpeace*, 1998. https://www.earthtrack.net/sites/default/files/fdsuboil.pdf.
375 Moore, John L., Carl E. Behrens, and John E. Blodgett. "Oil Imports: An Overview and Update of Economic and Security Effects," *CRS Environment and Natural Resources Policy Division* 98, no. 1 (December 12, 1997): 1-14.
376 Stern, Roger J. "United States Cost of Military Force Projection in the Persian Gulf, 1976–2007." *Energy Policy* 38, no. 6 (February 25, 2010): 2816–25. https://doi.org/10.1016/j.enpol.2010.01.013.

Delucchi and Murphy (2008) sought 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.[377] 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 assumed that military costs from oil import reductions can be scaled proportionally, attempting to address the incremental issue.

Crane et al. considered force reductions and cost savings that could be achieved if oil security were no longer a consideration. Taking two approaches and guided by post-Cold War force draw downs and by a top-down look at the current U.S. allocation of defense resources, they concluded that $75–91 billion, or 12–15% of the current U.S. defense budget, could be reduced.

Finally, an Issue Brief by Securing America's Future Energy (SAFE) (2018) found a conservative estimate of approximately $81 billion per year spent by the U.S. military protecting global oil supplies.[378] 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 concluded that the implicit subsidy for all petroleum consumers is approximately $11.25/barrel of crude oil, or $0.28/gallon. According to SAFE, a more comprehensive estimate suggests the costs could be greater than $30/barrel, or over $0.70/gallon.[379]

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.[380] We are unaware of a robust methodology for assessing the effect on military costs of a partial reduction in U.S. oil use. Therefore, we are unable to quantify this effect resulting from the projected reduction in U.S. oil use attributable to this rule.

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[377] Delucchi, Mark A., and James J. Murphy. "US Military Expenditures to Protect the Use of Persian Gulf Oil for Motor Vehicles." *Energy Policy* 36, no. 6 (April 23, 2008): 2253–64. https://doi.org/10.1016/j.enpol.2008.03.006.
[378] Securing America's Future Energy, "Issue Brief – The Military Cost of Defending the Global Oil Supply," September 21, 2018. https://secureenergy.org/wp-content/uploads/2020/03/Military-Cost-of-Defending-the-Global-Oil-Supply.-Sep.-18.-2018.pdf.
[379] Id.
[380] Crane, Keith, Andreas Goldthau, Michael Toman, Thomas Light, Stuart Johnson, Alireza Nader, Angel Rabasa, and Harun Dogo. "Imported Oil and U.S. National Security." *RAND Corporation*, 2009. https://doi.org/10.7249/mg838.

6.4 Energy Security Impacts

6.4.1 U.S. Oil Import Reductions

From 2026–2030, the time frame of the analysis of this proposed rule, the AEO2023 Reference Case projects that the U.S. will be a net exporter of petroleum, both an exporter and an importer of crude oil and petroleum products.[381] 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 3.2 MMBD in 2026 and 3.4 MMBD in 2030. U.S. crude oil imports, meanwhile, are projected to range between 6.8 MMBD and 7.1 MMBD over the 2026–2030 time period. AEO2023 also projects that net U.S. exports of petroleum products will increase from 5.7 MMBD in 2026 to 6.0 MMBD in 2030. Given the pattern of stable U.S. crude oil imports, and the projected growth in the U.S.'s net petroleum product exports, the U.S. is projected to have constant net petroleum exports of 2.3 MMBD for both 2026 and 2027.

Currently, the U.S. is the largest oil consumer in the world, consuming 20.3 MMBD of oil.[382] U.S. oil consumption is anticipated to gradually decline during the time frame of this proposed rule from 18.6 MMBD in 2026 to 18.4 MMBD in 2030.[383] It is not just U.S. crude oil imports alone, but both imports and consumption of petroleum from all sources and their role in economic activity, that exposes the U.S. to risk from price shocks in the world oil price. In 2026–2027, 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.

EPA estimates changes in U.S. petroleum consumption as a result of this proposed rule. EPA uses an oil import reduction factor to estimate how changes in U.S. refined product demand from this rule (i.e., changes in U.S. oil consumption) influences U.S. net oil imports (i.e., changes in U.S. oil imports). In Chapter 10, EPA is estimating an oil import reduction factor of 98.3%. See Chapter 10.4.2.1.1 for how the 98.3% is estimated.

We also estimate how lower U.S. petroleum demand would affect U.S. refinery production, partially due to its impact on imports, but also to understand how lower petroleum demand would impact U.S. refinery's production capacity for energy security reasons. Based on an industry study, EPA believes that U.S. refinery output would decline by half (50%) of that reduced oil demand (it is likely that much of this decline would be due to U.S. refineries converting from refining crude oil to instead produce renewable diesel fuel), while increases in refined product net exports (i.e., equivalently a decline in net refined product imports) would account for the other half (50%) of that reduced oil demand. See Chapter 10 and a Memorandum

[381] AEO2023, Table 11 – Petroleum and Other Liquids Supply and Disposition.
[382] EIA, "Petroleum and other liquids (consumption)," *International*, May 15, 2025. https://www.eia.gov/international/data/world/petroleum-and-other-liquids/annual-refined-petroleum-products-consumption.
[383] AEO2023, Table 11 – Petroleum and Other Liquids Supply and Disposition.

to the Docket for more discussion on this topic.[384] There are good economic reasons why U.S. refineries might continue to operate despite reduced U.S. product demand as a result of this proposed rule. Principally due to lower natural gas and crude oil prices available in the U.S., U.S. refineries generally have lower production costs compared to other refinery regions around the world. Lower refinery production costs are attributed to the lower feedstock costs in the U.S.[385] Even with a decrease in the U.S. product demand from this proposed rule, we anticipate that U.S. refineries would be quite economically competitive compared to refineries operating around the world. Thus, U.S. refineries would largely continue to operate and export refined products to the rest of the world.

Based upon the changes in oil consumption estimated by EPA and the 98.3% oil import reduction factor, the reductions in U.S. net oil imports as a result of the Low and High Volume Scenarios and the renewable fuel volumes for the proposed RFS Set 2 Rule are estimated in Table 6.4.1-1 for the 2026–2030 timeframe. 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 the years 2026–2030, the time frame of the analysis of this proposed rule, based on the AEO2023.

Table 6.4.1-1: 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 Volume Scenarios and Proposed Volumes (MMBD)

	2026	2027	2028	2029	2030
U.S. Crude Oil Exports	3.2	3.3	3.3	3.3	3.4
U.S. Crude Oil Imports	6.8	6.9	6.9	7.0	7.1
U.S. Net Petroleum Refined Product Exports[a]	5.7	5.8	5.8	5.9	6.0
U.S. Net Crude Oil and Refined Petroleum Product Exports[b]	2.1	2.1	2.2	2.2	2.3
U.S. Oil Consumption[c]	18.6	18.6	18.6	18.5	18.4
Reduction in U.S. Net Oil Imports from:					
Low Volume Scenario	0.10	0.11	0.12	0.12	0.13
High Volume Scenario	0.11	0.13	0.15	0.16	0.18
Proposed Volumes	0.15	0.15			

[a] Calculated from AEO2023, Table 11 as Net Product Exports minus Ethanol, Biodiesel, Renewable Diesel, and Other Biomass-derived Liquid Net Exports.
[b] Calculated from AEO2023, Table 11 as Total Net Exports minus Ethanol, Biodiesel, Renewable Diesel, and Other Biomass-derived Liquid Net Exports.
[c] Calculated from AEO2023, Table 11 as Total Primary Supply minus Biofuels.

Of course, the impact on crude oil and refined petroleum product exports does not tell the whole story. The proposed RFS Set 2 Rule will likely result in substantial imports of feedstocks that are used to produce renewable fuels to meet the RFS renewable fuel volume requirements.

[384] Ding, Cherry, Alexandre Ferro, Tim Fitzgibbon, and Piotr Szabat. "Refining in the Energy Transition Through 2040," *McKinsey & Company*, November 3, 2022. https://www.mckinsey.com/industries/oil-and-gas/our-insights/refining-in-the-energy-transition-through-2040.
[385] EIA, "Lower crude feedstock costs contribute to North American refinery profitability," *Today in Energy*, June 5, 2014. https://www.eia.gov/todayinenergy/detail.php?id=16571.

As discussed in Chapter 10.4.2.1, we expect that up to 40% of the renewable fuels used to meet the renewable fuel volumes will be derived from imported feedstocks.

While imported feedstocks will move the U.S. away from the goal of energy independence, it is not clear how imported feedstocks will influence U.S. energy security. The energy security implications of using imported feedstocks to make renewable fuels used in the U.S. are not well understood or studied. To estimate the energy security impacts of imported feedstocks on the U.S.'s energy security, one would need to have information on the variability of imported feedstock prices. In addition, one would need to know how prices of imported feedstocks and the biofuels produced from them are correlated with world oil prices. For example, consider canola oil. Price variability in canola oil is likely related to weather-related events, while price increases in world oil markets are influenced largely by geopolitical events such as wars that cause disruptions in the world oil markets. From an overall perspective, however, imported feedstocks will provide fuel supply diversity to the U.S., which may bring some modest energy security benefits.

6.4.2 Oil Import Premiums Used for This Proposed Rule

In order to understand the energy security implications of reducing U.S. net oil imports, EPA has worked with ORNL, which has developed approaches for evaluating the social costs and energy security implications of U.S. oil imports. The energy security estimates provided below are based upon a methodology first developed in a peer-reviewed 2008 ORNL study.[386] This 2008 ORNL study was an updated version of the approach used for estimating the energy security benefits of U.S. oil import reductions developed in an earlier 1997 ORNL Report.[387] Since 2008, 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 proposed rule, EPA has updated the ORNL methodology using the AEO2023.

The ORNL methodology is used to compute the oil import security premium per barrel of imported oil.[388] The values of U.S. oil import security 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. Each of these simulations inform the estimates of the marginal changes in economic welfare with respect to changes in U.S. oil import levels. ORNL then summarizes the results from the individual simulations into a mean and 90% confidence interval for the import premium.

EPA only considers 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 oil imports are considered transfer payments. In

[386] Leiby, Paul. "Estimating the Energy Security Benefits of Reduced U.S. Oil Imports." *Oak Ridge National Laboratory*, ORNL/TM-2007/028. March 2008. https://cfpub.epa.gov/si/si_public_file_download.cfm?p_download_id=504469.

[387] Leiby, Paul N., Donald W. Jones, T. Randall Curlee, and Russell Lee. "Oil Imports: An Assessment of Benefits and Costs." *Oak Ridge National Laboratory*, ORNL-6851. November 1, 1997. https://www.esd.ornl.gov/eess/energy_analysis/files/ORNL6851.pdf.

[388] The oil import premium concept is defined in Chapter 6.1.

previous EPA rules when the U.S. was projected by EIA to be a net petroleum importer, 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 its 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.[389]

In the context of this proposed rule, the U.S.'s oil trade balance position has shifted notably from the position it held when we assessed energy security impacts for most previous RFS rules. As discussed above (see Figure 6-1), the U.S. became a net petroleum exporter for the first time in several decades in 2020, and these net exports have continued to grow since that time. As also observed above, the EIA projects the U.S. will continue to be a net petroleum exporter in the 2026–2030 time frame of analysis of this proposed rule. As a result, reductions in U.S. oil consumption and, in turn, U.S. net oil imports, lower the world oil price, albeit 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 therefore 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 proposed rule on the costs associated with existing energy security policies (e.g., maintaining the Strategic Petroleum Reserve or strategic military deployments), which are discussed in Chapter 6.3.

The macroeconomic oil security premiums arise from the effect of U.S. oil imports on the expected cost of supply disruptions and accompanying price increases. A sudden increase in oil prices triggered by a disruption in world oil supplies has two main effects: (1) it increases the costs of oil imports in the short-run, and (2) it leads 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 the on-going, updated energy security literature. Based on EPA and ORNL's review of the energy security literature, EPA is using updated macroeconomic oil security premiums for this proposed rule. The recent economics literature (discussed in Chapter 6.2) focuses on three factors that can influence the macroeconomic oil security premiums: (1) price elasticity of oil

[389] We also discuss monopsony oil import premiums in previous EPA GHG vehicle rules. See, e.g., EPA, "Revised 2023 and Later Model Year Light Duty Vehicle GHG Emissions Standards: Regulatory Impact Analysis," EPA-420-R-21-028, December 2021, Section 3.2.5. https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1013ORN.pdf.

demand, (2) GDP elasticity in response to oil price shocks, and (3) the impacts of the tight (i.e., shale) oil boom. We discuss each factor below and provide a rationale for how we are developing new estimates of the macroeconomic oil security premiums.

First, we assess the price elasticity of demand for oil. In RFS rules prior to the 2020–2022 RFS Rule, EPA used a short-run elasticity of demand for oil of –0.045.[390] From the RFF study (2017) discussed previously in Chapter 6.2.1, 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 in the 2026–2027 timeframe of this proposed rule. According to IEA, the share of global oil consumption attributed to the transportation sector grew from 60% in 2000 to 66% in 2019.[391] 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 2026–2027 timeframe. Thus, we believe it would be surprising if short-run oil demand responsiveness has changed in the dramatic fashion implied by the RFF "new literature" estimates.

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 proposed rule, and consistent with the 2020–2022 RFS Rule and the Set 1 Rule, we have increased the short-run price elasticity of demand for oil from –0.045 to –0.07, a 56% increase.[392] 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 RFS Rule, a GDP elasticity to an oil price shock of –0.032 was used.[393] 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 economics literature on this topic since it considers a wide 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 proposed rule and consistent with the 2020–2022 RFS Rule and 2023–2025 Set 1 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).[394] 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 in the GDP elasticity has the effect of lowering the macroeconomic oil security

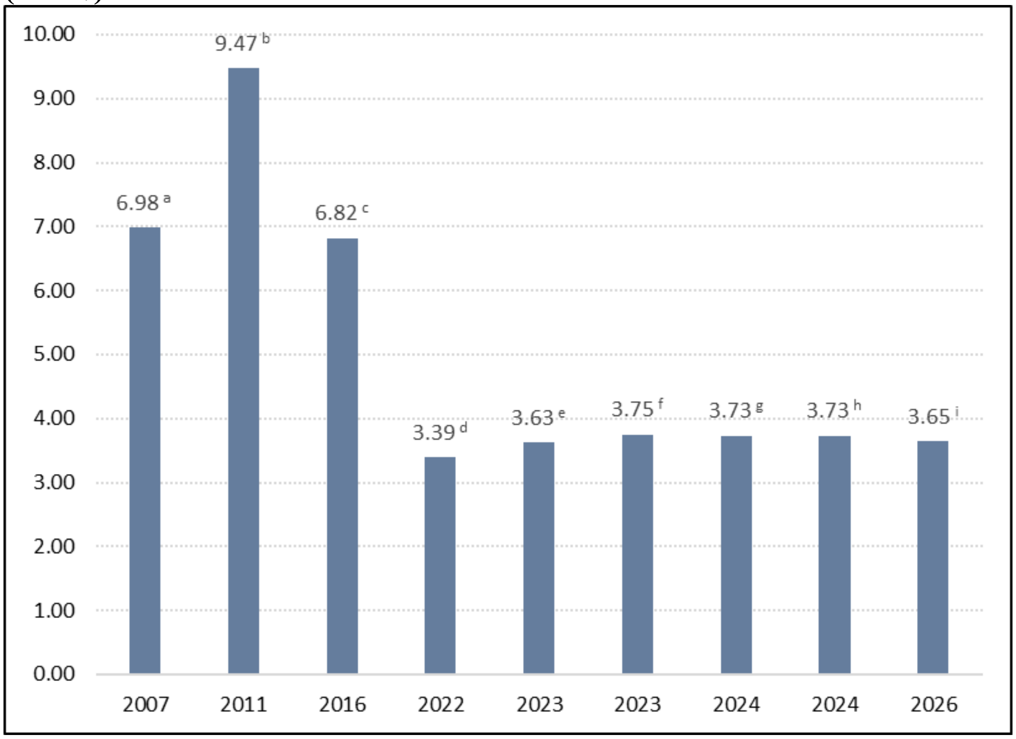
[390] See, e.g., 75 FR 26049, May 10, 2010.
[391] IEA, "World Energy Statistics and Balances." https://www.iea.org/data-and-statistics/data-product/world-energy-statistics-and-balances.
[392] EPA and ORNL worked together to develop an updated estimate of the short-run elasticity of demand for oil for use in the ORNL model.
[393] See, e.g., 75 FR 26049 (May 10, 2010).
[394] 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.

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 since 2020.[395] Increased tight oil production still results in energy security benefits through its impact of reducing U.S. oil imports in the ORNL model.

Figure 6.4.2-1 shows the evolution of oil security premiums for this rule in comparison with oil security premiums for previous EPA final rules from 2007–2024. For each rulemaking, the estimated oil security premium value is computed using the ORNL oil security premium model, which is based upon oil market and economic conditions projected by each relevant AEO. The premiums are all computed following the same methodology, but under changing oil market balances and conditions, with some parameters evolving to reflect changing understanding of oil market flexibility and declining macroeconomic sensitivity to oil price shocks. Each bar corresponds to the first year for which the premium was estimated in each specific proposed/final rule. Oil security premiums are estimated to be approximately $7/barrel in 2007 and increased to $9.47 in 2011. Then, the oil security premiums decreased markedly through the 2010s, landing at $3.39/barrel in 2021. Values estimated for 2022 through 2026 have all been approximately $3.7/barrel.

[395] 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.

Figure 6.4.2-1: Comparison of Oil Security Premiums of This Rule and Previous Rules (2022$)



a. RFS1: Final Rule. (2007). Based on AEO2006.
b. Final Rule for Phase 1 Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles (2011). Based on AEO2011.
c. Final Rule for Phase 2 Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles (2016). Based on AEO2015.
d. 2020–2022 RFS Rule (2022). Based on AEO2021.
e. Final Rule to Revise Existing National GHG Emissions Standards for Passenger Cars and Light Trucks Through Model Year 2026 (2023). Based on AEO2021.
f. Set 1 Rule (2023). Based on AEO2023.
g. Greenhouse Gas Emissions Standards for Heavy-Duty Vehicles - Phase 3 (2024). Based on AEO2023.
h. Final Rule: Multi-Pollutant Emissions Standards for Model Years 2027 and Later Light-Duty and Medium-Duty Vehicles (2024). Based on AEO2023.
i. RFS Set 2 Rule 2026-2027; Proposal. Based on AEO2023.

Multiple factors drive the change in magnitude of the U.S. oil security premiums over time. First, the U.S. oil trade balance is a key component in the calculation of premiums. The marginal change in expected net oil import costs during disruption events depends directly on the magnitude of net oil imports. The U.S. went from being a net importer of crude oil and petroleum products of roughly 12 million barrels per day in 2007 to becoming a next exporter in 2020. This trend reversal is mirrored in the evolution of the oil import premium from 2011 to 2021 in Figure 6.4.2-1. Second, in the calculation of premiums, OPEC's share of global oil production is modelled to influence the size of potential supply disruptions. OPEC is the main production region that is assumed to have an insecure supply and is subject to the disruption events considered in the premium calculation. A larger share of OPEC production implies more oil supply is at risk and potentially higher price shocks from oil market disruptions. Third, all else equal, the oil import premium varies with oil price levels, with higher price levels presenting a risk of even larger price shocks during a disruption, with a greater effect on GDP and the net trade balance in oil.

Fourth, two important parameters going into the oil security premium calculation (the elasticity of demand for oil with respect to oil prices and the U.S. elasticity of U.S. GDP with respect to oil prices) have been updated over time to reflect the U.S. economy's evolving market structure. See the discussion above for more details about how the short-run price elasticity of demand for oil increased, indicating greater short-run flexibility. In addition, the central value used for elasticity of GDP in response to oil price shocks has been updated based upon the most recent estimations in the economics literature.

The combined effect of all these factors aligns directionally with the evolution of oil security premium values shown in Figure 6.4.2-1. From 2007 to 2011, despite U.S. net oil imports trending downward, the oil security premium value increased due to higher oil prices and higher OPEC market share. The decreasing trend from 2011 to 2021 resulted from a combination of decreases in U.S. net oil imports and oil prices. Additionally, the premiums for year 2021 and later are based on calculations with more price elastic oil demand and less elastic U.S. GDP to price shocks. Small increases in the premium estimates for 2023 and 2024 relative to 2021 can be mostly explained by modest changes in expected market conditions, including higher oil prices projections.

Table 6.4.2-1 provides EPA's estimates of the macroeconomic oil security premiums for 2026–2030 for this RFS proposed rulemaking, showing that they are gradually increasing over this time period. The macroeconomic oil security premiums range from \$3.65/barrel in 2026 to \$3.92/barrel in 2030. In terms of cents per gallon, the macroeconomic oil security premiums range from 8.6 cents per gallon in 2026 to 9.3 cents per gallon in 2030. These estimates of the macroeconomic oil security premiums are actual values as opposed to discounted values, implying that they do not reflect the time value of money.

Table 6.4.2-1: Macroeconomic Oil Security Premiums (2022\$/barrel)[a]

Year	Macroeconomic Oil Security Premiums (2022\$/Barrel of Reduced Oil Imports)
2026	\$3.65 (\$0.47–\$6.89)
2027	\$3.73 (\$0.51-\$7.02)
2028	\$3.78 (\$0.51-\$7.15)
2029	\$3.87 (\$0.54-\$7.31)
2030	\$3.92 (\$0.51-\$7.46)

[a] Top-values in each cell are mean values. Values in parentheses are 90 percent confidence intervals.

6.4.3 Energy Security Benefits

Estimates of the total annual energy security benefits of the Low and High Volume Scenarios and the proposed RFS renewable fuel volumes are based on the ORNL oil import premium methodology with updated oil import premium estimates reflecting the energy security literature and using AEO2023. To calculate total energy security benefits, annual macroeconomic oil security premiums (Table 6.4.2-1) are multiplied by the annual reduction in U.S. net oil imports (Table 6.4.1-1). The total annual energy security benefits are presented in Tables 6.4.3-1 and 2. We do not consider military cost impacts or the monopsony effect of U.S. crude oil and refined petroleum product import changes. These benefit estimates are actual values as opposed to discounted values, implying that they do not reflect the time value of money.

Table 6.4.3-1: Total Annual Energy Security Benefits of the Low and High Volume Scenarios (millions 2022$, undiscounted)[a,b]

Year	Total Energy Security Benefits Low Volume Scenario	Total Energy Security Benefits High Volume Scenario
2026	$138 ($18–$261)	$151 ($19–$284)
2027	$150 ($21–$283)	$176 ($24–$331)
2028	$162 ($22–$307)	$201 ($27–$380)
2029	$175 ($24–$331)	$228 ($32–$430)
2030	$187 ($24–$357)	$254 ($33–$484)

[a] Top-values in each cell are the mean values, while the values in parentheses define 90 percent confidence intervals.
[b] U.S. net 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 Chapter 10.4.2.1.1 converted to crude oil-equivalent barrels.

In Table 6.4.3-2, we present the energy security benefits for the proposed RFS renewable fuel volumes. These benefit estimates are actual values as opposed to discounted values, implying that they do not reflect the time value of money. The present value and annualized value of estimated energy security impacts of the Proposed Volumes using 3% and 7% discount rates are presented in Preamble Section V.H.

Table 6.4.3-2: Total Annual Energy Security Benefits of the Proposed Renewable Fuel Volumes for 2026-2027 (millions 2022$, undiscounted)[a,b]

Year	Total Energy Security Benefits Proposed Volumes
2026	\$196 (\$25–\$369)
2027	\$210 (\$29–\$395)

[a] Top-values in each cell are the mean values, while the values in parentheses define 90 percent confidence intervals.
[b] U.S. net 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 Chapter 10.4.2.1.1 converted to crude oil-equivalent barrels.

Chapter 7: Rate of Production and Consumption of Renewable Fuel

This chapter outlines the anticipated annual rate of future commercial production for renewable fuels, including advanced biofuels in categories such as cellulosic biofuel and biomass-based diesel. While we are proposing to establish RFS standards for a two-year period, we are presenting projections of the rate of production and consumption of renewable fuels through 2030, consistent with the Low and High Volume Scenarios. Consequently, we evaluated production trends for each year from 2026 to 2030. Our projections for this period are based on historical data and other relevant factors, considering both domestically produced biofuels and imported biofuels available for use in the United States.[396]

We also project the use (i.e., consumption) of qualifying renewable fuels in the U.S. While not an explicit factor that we must consider under the statute, domestic consumption of qualifying renewable fuels as transportation fuel is the primary basis for compliance with our RFS standards. It is also inherent in the requisite consideration of infrastructure which is addressed in Chapter 8, and in the cost to consumers of transportation fuel which is addressed in Chapter 11. For 2026–2030, 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 2030.

We discuss the production and use of each major type of biofuel in turn: cellulosic biofuel (Chapter 7.1), biomass-based diesel (biodiesel and renewable diesel) (Chapter 7.2), imported sugarcane ethanol (Chapter 7.3), other advanced biofuels (besides ethanol, biodiesel, and renewable diesel) (Chapter 7.4), total ethanol (Chapter 7.5), corn ethanol (Chapter 7.6), and conventional biodiesel and renewable diesel (Chapter 7.7).

7.1 Cellulosic Biofuel

Over the past few years, cellulosic biofuel production has steadily increased, reaching record levels in 2024. This growth has been primarily driven by biogas-derived compressed natural gas (CNG) and liquified natural gas (LNG).[397] However, small volumes of liquid cellulosic biofuels, particularly ethanol produced from corn kernel fiber (CKF), have also played a contributing role (see Figure 7.1-1). This section describes our assessment of the expected production rate and consumption of qualifying cellulosic biofuel for 2025–2030, along with some of the uncertainties associated with the projected volume for these years.

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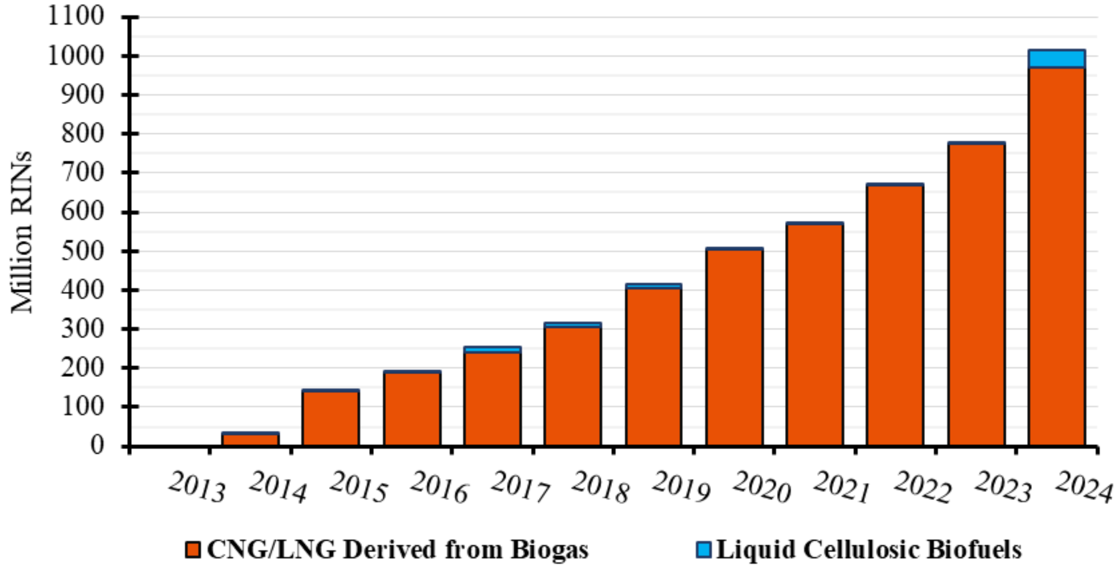
[396] This is what we generally mean when we use the term biofuel "production" in this chapter and do not specify whether we are discussing domestic production or imports.

[397] 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 7.1-1: Cellulosic RINs Generated (2013-2024)



Source: EMTS.

To project the volume of cellulosic biofuel production in 2025-2030, we evaluated several key factors. These include assessing the accuracy of previous methodologies used to estimate cellulosic biofuel production, data reported to EPA through EMTS, the projected use of CNG/LNG as transportation fuel, and insights gathered from meetings with representatives of facilities that have recently produced or have the potential to produce qualifying volumes of cellulosic biofuel by 2030.

This section of Chapter 7 is organized as follows: Chapter 7.1.1 provides an industry-wide assessment of the cellulosic biofuel sector to understand its current state. Chapter 7.1.2 reviews and analyzes EPA's previous cellulosic biofuel projections. Chapter 7.1.3 addresses the projected volume of cellulosic biofuel for 2025. Chapter 7.1.4 addresses the projected volume of RNG used as CNG/LNG from 2026-2030. Chapter 7.1.5 focuses on the projected production of liquid cellulosic biofuels from 2026-2030. Finally, Chapter 7.1.6 summarizes the overall projected rate of cellulosic biofuel production for 2026-2030.

7.1.1 Cellulosic Biofuel Industry Assessment

This section evaluates the cellulosic biofuel producers expected to generate qualifying cellulosic biofuel between 2026 and 2030. This includes producers of both D3 RIN-generating cellulosic biofuels and D7 RIN-generating cellulosic diesel. Analysis of existing RIN generation data shows two primary contributors: biogas-derived compressed natural gas (CNG) and liquified natural gas (LNG), as well as ethanol produced from corn kernel fiber (CKF). Beyond these main sources, we have also looked at other potential contributors that could impact the future of cellulosic biofuel production.

7.1.1.1 Biogas-derived Compressed Natural Gas and Liquefied Natural Gas

In July 2014, EPA approved cellulosic biofuel pathways under the "Pathways II" Rule, allowing CNG and LNG derived from biogas to generate cellulosic biofuel (D3) RINs when used as transportation fuel. Eligible biogas sources include landfills, separated municipal solid waste digesters, municipal wastewater treatment facilities, agricultural digesters, and the cellulosic components of biomass processed in other waste digesters. Since the implementation of the Pathways II Rule, cellulosic biofuel production has grown significantly, increasing from approximately 33 million RINs in 2014 to over 1,013 million RINs in 2024. Notably, about 95% of all cellulosic RINs generated in 2024 were attributed to CNG/LNG derived from biogas (see Figure 7.1-1). Biogas-derived CNG/LNG is expected to remain the primary source of cellulosic RIN generation through 2030.

7.1.1.2 Ethanol from Corn Kernel Fiber

Outside of biogas-derived CNG/LNG, few additional sources of cellulosic biofuel exist. One notable exception is ethanol produced from corn kernel fiber (CKF). During the corn ethanol production process, a fraction of the cellulosic component of corn kernel fiber can be co-processed with the corn starch to produce cellulosic ethanol. Thus, with minimal additional processing or modifications, meaningful volumes of cellulosic ethanol could be co-produced alongside starch ethanol production. However, facilities must accurately determine the amount of ethanol specifically derived from the cellulosic portion to qualify for generating cellulosic biofuel (D3) RINs. This requires reliable and precise methods to distinguish ethanol produced from the cellulosic component from that derived from the starch portion of the corn kernel. In September 2022, EPA issued updated guidance on analytical methods that could be used to quantify the amount of ethanol produced when co-processing corn kernel fiber and corn starch.[398] EPA has also engaged with facility owners registered as cellulosic biofuel producers. As a result of these efforts, EPA anticipates that most facilities currently producing corn starch ethanol will generate D3 RINs for cellulosic ethanol during the years analyzed in this proposed rule. Given the significant volume of corn starch ethanol production, ethanol from CKF is expected to make a meaningful contribution to future cellulosic biofuel volumes.

7.1.1.3 Other Cellulosic Biofuels

Between 2026 and 2030, EPA expects that commercial-scale production of cellulosic biofuel—beyond CNG/LNG derived from biogas and ethanol produced from CKF—to remain very limited. In the past, small volumes of D7 RINs have been generated from foreign facilities producing cellulosic heating oil/diesel. While this production is worth noting, the total volume has remained consistently low,[399] making it almost indistinguishable from the background uncertainty of any future projections. Outside of these sources, there are several cellulosic biofuel production facilities in various stages of development, construction, and commissioning that may be capable of producing commercial scale volumes of cellulosic biofuel by 2030. These facilities primarily focus on producing cellulosic hydrocarbons from feedstocks such as

[398] EPA, "Guidance on Qualifying an Analytical Method for Determining the Cellulosic Converted Fraction of Corn Kernel Fiber Co-Processed with Starch," EPA-420-B-22-041, September 2022.
[399] EMTS data reports that from 2020 to 2024, annual D7 RIN generation varied from 55,892 to 283,259 RINs.

separated municipal solid waste (MSW), precommercial thinnings, and tree residues, which can be blended into gasoline, diesel, and jet fuel. Several of these facilities are currently registered with EPA and have the potential to generate RINs for qualifying cellulosic biofuel by 2030. However, according to data from EMTS, none of these facilities have generated cellulosic RINs for liquid cellulosic biofuel since March 2019. As a result, while these facilities have been considered potential sources of cellulosic biofuel, we do not project any volume of other cellulosic biofuel through 2030.

7.1.2 Review of EPA's Projection of Cellulosic Biofuel in Previous Years

Before estimating future cellulosic biofuel volumes, we first review and evaluate the accuracy of EPA's past projections to identify potential improvements to past methodologies. Table 7.1.2-1 provides a comparison of actual cellulosic biofuel volumes—including cellulosic biofuel (which generate D3 RINs) and cellulosic diesel (which generate D7 RINs)—against EPA's projections from 2015 to 2025. These data show that EPA projections underestimated RIN availability in 2015, 2018, and 2022, while overestimating it in 2016, 2017, 2019, 2020,[400] 2023, and 2024. This variability highlights the inherent challenges in forecasting cellulosic biofuel production and emphasizes the need to continue refining our projection methods to improve accuracy in the future.

[400] Cellulosic biofuel production in 2020 was affected by the Covid-19 pandemic. Since the projections were made before the pandemic, the resulting overestimates are attributed to the pandemic's impact, rather than to any issues in EPA's projection methodology.

Table 7.1.2-1: Projected and Actual Cellulosic Biofuel Production (million ethanol-equivalent gallons)

Year	Source	Projected Volume: Liquid Cellulosic Biofuel	Projected Volume: RNG used as CNG/LNG	Projected Volume: Total Cellulosic Biofuel[b]	Actual Volume[a]: Liquid Cellulosic Biofuel	Actual Volume[a]: RNG used as CNG/LNG	Actual Volume[a]: Total Cellulosic Biofuel[b]
2015	c,d	2	33	35	<1	53	53
2016	d	23	207	230	4	186	190
2017	e	13	298	311	12	239	251
2018	f	14	274	288	11	304	315
2019	g	20	399	418	11	403	414
2020	h,i	16	577	593	2	503	505
2021	j	N/A	N/A	N/A	1	562	563
2022	k	0	632	632	1	662	663
2023	l	7	831	840	1	772	773
2024	l	51	1,039	1,090	43	971	1,014
2025	l,m	77	1,299	1,380	-	-	-

[a] 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.
[b] Total cellulosic biofuel may not be precisely equal to the sum of liquid cellulosic biofuel and RNG used as CNG/LNG due to rounding.
[c] 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.
[d] 2014–2016 RFS Rule (80 FR 77506; December 14, 2015).
[e] 2017 RFS Rule (81 FR 89760; December 12, 2016).
[f] 2018 RFS Rule (82 FR 58486; December 12, 2017).
[g] 2019 RFS Rule (83 FR 63704; December 11, 2018).
[h] 2020 RFS Rule (85 FR 7016; February 6, 2020).
[i] Cellulosic biofuel production in 2020 was affected by the Covid-19 pandemic, likely causing the actual volumes to fall short of the projections.
[j] The 2021 cellulosic volume requirement was retroactively established at the actual volume of cellulosic biofuel produced in 2021. 2020–2022 RFS Rule (87 FR 39600; July 1, 2022).
[k] 2020–2022 RFS Rule (87 FR 39600; July 1, 2022).
[l] Set 1 Rule (88 FR 44468; July 12, 2023).
[m] As discussed in Preamble Section VII and Chapter 7.1.3, EPA is proposing to revise the 2025 cellulosic biofuel volume requirement in this rule.

Examining the data in this table, we find that EPA projections for liquid cellulosic biofuel were consistently higher than actual production volumes each year from 2015 to 2017. In response to the over-projections in 2015-2017, EPA revised our methodology in the 2018 final rule to incorporate the most recent data and improve the accuracy of our projections. This updated approach involves first categorizing potential liquid cellulosic biofuel producers into two groups: those with a proven track record of commercial-scale production ("consistent producers") and those still working toward it ("new producers"). For each group, we defined a likely production range and then applied a percentile value to estimate a single projected production volume based on each group's historical performance relative to its projected range.

Despite these adjustments, EPA continued to overestimate liquid cellulosic biofuel production from 2018-2020. The year 2020, however, posed particular challenges due to the impacts of Covid-19—an unexpected disruption that could not be predicted in our projections. In

2022, EPA under-projected liquid cellulosic biofuel volumes using the revised 2018 methodology. For the 2023-2025 rule, EPA once again used the 2018 projection methodology. While only two full years of data (2023 and 2024) are available as of this proposal, this information shows that EPA overestimated liquid cellulosic biofuel production for both years.

Next, we turn to the projection of RNG used as CNG/LNG. From 2015 to 2017, EPA applied a facility-by-facility approach to project CNG/LNG production from RNG, estimating volumes for individual companies or facilities. However, this methodology also significantly overestimated CNG/LNG production in 2016 and 2017, prompting EPA to develop a broader industry-wide projection method, first implemented in 2018.

This broader approach estimates future production by applying an industry-wide, year-over-year growth rate to current RNG production rate. Specifically, EPA analyzes RIN generation data from the most recent 24 months available at the time of each rulemaking and calculated a growth rate from that period. This growth rate is then applied to the latest full calendar year of data and compounded for each subsequent year to project future production. This updated approach reflects the maturity of the RNG industry used as CNG/LNG, which has a greater number of potential producers than the liquid cellulosic biofuel industry. In such mature markets, industry-wide projections tend to be more accurate than a facility-by-facility method, as broader economic trends generally outweigh the performance of individual facilities.

The industry-wide approach slightly under-projected RNG used as CNG/LNG in 2018, 2019, and 2022. Though, this approach overestimated production in 2020, likely due to the impacts of Covid-19. For the rulemaking that established volumes for 2023-2025, EPA again applied this methodology. However, unlike in the 2018-2022 rules, the growth rate for projections was calculated based on data from 2015-2022, rather than the previous 24 months. This adjustment was made to counteract the anticipated negative impacts of the Covid-19 pandemic on the 2020 and 2021 data, with pre-pandemic growth rates believed to reflect future biogas production potential more accurately. While only two full years of generation data (2023 and 2024) are available as of this proposal, this information shows that EPA overestimated RNG production for all years projected in the 2023-2025 rulemaking. For more details, refer to Chapter 7.1.3

Reflecting on these past projections highlights two key points. First, estimating these volumes is inherently challenging, underscoring the need to continually refine our methods for greater accuracy. Second, the production of RNG used as CNG/LNG has consistently exceeded that of liquid cellulosic biofuel. This difference likely results from several factors, including the maturity of RNG production technology relative to liquid cellulosic biofuel technologies, the lower production costs for RNG used as CNG/LNG (see Chapter 11), and the relatively high value of the cellulosic RIN. While we project liquid cellulosic biofuel and RNG volumes separately, the overall accuracy of the combined cellulosic biofuel volume projection is ultimately what matters for obligated parties.

7.1.3 Projection of the 2025 Cellulosic Biofuel Volumes

As discussed in the previous section, EPA overestimated total cellulosic RIN generation for 2023 and 2024. This overestimation was largely driven by an over projection of RNG production, which makes up a significant portion of the total cellulosic biofuel volumes. Specifically for 2023, RNG volumes were insufficient to meet the cellulosic volume requirement set by the prior RFS rulemaking. As a result, a deficit in cellulosic RINs was carried forward into 2024. Looking at 2024, RNG production—and, consequently, total cellulosic biofuel volumes—are again expected to fall short of the required volumes. Given this anticipated shortfall, the existing RIN deficit from 2023, and the limited availability of 2023 carryover RINs, the cellulosic RIN deficit in 2024 could be substantial. This shortfall may force some obligated parties that carried forward a deficit from 2023 into noncompliance with their 2024 obligations. In response, EPA proposed adjusting the 2024 cellulosic biofuel volume requirements.[401]

Given the shortfalls in projecting the 2023 and 2024 volumes, EPA has reason to believe that cellulosic biofuel volumes could also fall short in 2025. While the exact causes of past deficits remain unclear and may stem from multiple factors, EPA has long been aware that the RNG market could eventually reach a "saturation point"—where nearly all RFS-eligible CNG/LNG vehicles are fueled entirely with RNG. Since biogas-derived CNG/LNG can only generate RINs when it is used in CNG/LNG vehicles as a transportation fuel, RIN generation from biogas-derived CNG/LNG past this saturation point would be constrained by the expansion of the total CNG/LNG vehicle market. While EPA had anticipated this eventual limitation, we did not believe the market had reached this point when establishing the 2023-2025 volume targets. At the time of that rulemaking, EPA projected future volumes based on the assumption that RNG production capacity—not the RNG market consumption—would be the primary constraint on cellulosic RIN generation. Though, in that rulemaking EPA acknowledged that this methodology might become less appropriate as RNG usage in CNG/LNG vehicles approaches the total volume of CNG/LNG used as transportation.[402] With cellulosic biofuel volumes falling short of projections for both 2023 and 2024, there is now strong evidence to suggest that the market is, in fact, demand-limited. In light of this shift, EPA has reevaluated 2025 volume projections under both a supply-limited and a demand-limited scenario, using the most recent generation data available.

Under a demand-limited scenario—where RNG consumption is the limiting factor—EPA projects the 2025 volumes shown in Table 7.1.3-1. Additional details on how this volume was calculated can be found in Chapter 7.1.4.1. Conversely, under a supply-limited scenario—where RNG production capacity is the primary constraint—EPA estimates that 2025 RNG volumes will align with the data presented in Table 7.1.3-1. For details on how this estimate was determined, see Chapter 7.1.4.2.

[401] 89 FR 100442 (December 12, 2024).
[402] Set 1 Rule RIA Chapter 6.1.3.

Table 7.1.3-1: Projected 2025 Biogas-derived CNG/LNG Volumes (million ethanol-equivalent gallons)

	Volume
Biogas-derived CNG/LNG Volumes Under Demand-limited Scenario	1,113
Biogas-derived CNG/LNG Volumes Under Supply-limited Scenario	1,206

Combining this estimate for the future biogas-derived CNG/LNG volume with the estimate of the future volume of cellulosic ethanol from the previous rulemaking, (see Table 7.1.2-1), EPA estimates that 2025 total cellulosic volumes will align with the data presented in Table 7.1.3-2.

Table 7.1.3-2: Projected 2025 Cellulosic Volumes (million ethanol-equivalent gallons)

	Biogas-derived CNG/LNG	Ethanol from CKF	Total Cellulosic
Demand-limited Scenario	1,113	77	1,190
Supply-limited Scenario	1,206	77	1,283

Because the demand for biogas-derived CNG/LNG is lower than the projected supply, we believe that the market has effectively reached the above-mentioned saturation point, with nearly all RFS-eligible CNG/LNG vehicles being fueled primarily by biogas-derived CNG/LNG. Accordingly, we are proposing in this action to adjust the cellulosic fuel volume for 2025.[403]

Table 7.1.3-3: Projected 2025 Cellulosic Volumes (million ethanol-equivalent gallons)

	Biogas-derived CNG/LNG	Ethanol from CKF	Total Cellulosic
2025 Cellulosic Volumes	1,113	77	1,190

7.1.4 Projecting the Biogas-derived CNG and LNG Market

As discussed in the previous section, biogas-derived CNG/LNG can only qualify for RIN generation when it is used by CNG/LNG vehicles as a transportation fuel. To do so, raw biogas from eligible sources must first be collected and upgraded. This upgrading process involves removing contaminants and other undesirable components from the biogas. Biogas that has been upgraded and distributed through a closed, private distribution system is defined as "treated biogas," whereas biogas that has been upgraded to be suitable for injection into the commercial natural gas pipeline system is defined as renewable natural gas (RNG).[404] While treated biogas is typically used at the site of production, RNG is injected into the commercial natural gas pipeline system. Because RNG is upgraded to meet pipeline specifications, it is functionally identical to fossil-based natural gas. Once injected into pipelines, RNG can be used just like fossil-based natural gas—for fueling CNG/LNG vehicles, generating electricity, residential heating, and various industrial and commercial applications. Currently, large volumes of biogas are produced

[403] See Preamble Section VII.
[404] 40 CFR 80.2.

at landfills and wastewater treatment plants across the U.S., with further potential for biogas generation from manure and other agricultural residues.[405] Although the quantity of biogas from qualifying sources potentially far exceeds current CNG/LNG usage as transportation fuel,[406] much of this biogas is not being upgraded to RNG[407]—a necessary step for its use in CNG/LNG vehicles. Instead, due to the significant capital investment required for collection and treatment, much of this biogas is currently either flared or used for onsite electricity generation.[408]

Despite these challenges, the incentive created by the cellulosic biofuel RIN has led to rapid growth in RNG[409] use as CNG/LNG since 2014 (see Table 7.1.4-1). Considering this incentive, we believe that the volume of RNG used as CNG/LNG can continue to grow under the influence of the RFS through 2030. At the same time, however, there are several market factors that we expect could limit the rate of growth of this biofuel in future years. As initially discussed in Chapter 7.1.3, we believe the market is becoming increasingly demand-limited, a factor that must be considered when projecting future volumes. The following subsections further explore the supply and demand dynamics of RFS-qualifying RNG.

Table 7.1.4-1: RIN Generation (Million RINs) and Annual Growth Rate for RNG used as CNG/LNG

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
RIN Generation	140	189	240	304	404	504	567	667	773	971
Annual Growth Rate	-	35%	27%	27%	33%	25%	13%	18%	16%	26%

7.1.4.1 Projected Demand of Biogas-derived CNG and LNG

To estimate the future demand of RNG used in CNG/LNG vehicles, we first looked to identify an appropriate estimate for all CNG/LNG usage in transportation, including both fossil and biogas-derived sources. Because RINs under the RFS can only be generated for CNG/LNG used as transportation fuel, the maximum potential volume of CNG/LNG in transportation represents the upper limit for RNG volumes. Several projections exist for CNG/LNG usage in the 2026-2030 period. One key source is AEO2023, which projects nationwide CNG/LNG use as transportation fuel at: 1,752; 1,778; 1,845; 1,893; and 1,909 million ethanol-equivalent gallons for the years 2026, 2027, 2028, 2029, and 2030, respectively (see Table 7.1.4.1-1). However, these AEO projections include all transportation-related energy usage, including sectors like

405 American Biogas Council, "Biogas Market Snapshot," April 2025. https://americanbiogascouncil.org/biogas-market-snapshot.
406 A discussion of EPA's estimates for current and future CNG/LNG usage as transportation fuel is in Chapter 7.1.4.1.
407 EPA, "LFG Energy Project Development Handbook," January 2024. https://www.epa.gov/system/files/documents/2024-01/pdh_full.pdf.
408 EPA, "LMOP Landfill and Project Database." https://www.epa.gov/lmop/lmop-landfill-and-project-database.
409 We note that RNG is defined as biogas that has been upgraded to commercial pipeline quality and placed onto the natural gas commercial pipeline system. We also define the term "treated biogas" to refer to biogas that has undergone treatment for use as transportation fuel but that is not placed onto the natural gas commercial pipeline system (i.e., it is distributed via a closed, private distribution system). Although they are defined differently in the regulations, we use the term "RNG" to collectively refer to both treated biogas and RNG in this document.

international shipping, which are outside the RFS scope.[410] After adjusting the AEO estimates to exclude non-relevant CNG/LNG volumes,[411] the revised projections indicate more conservative estimates of: 1,131; 1,136; 1,141; 1,143; and 1,145 million ethanol-equivalent gallons for the years 2026-2030, as shown in Table 7.1.4.1-1.

Table 7.1.4.1-1: Projected CNG/LNG Transportation Usage from EIA's 2023 AEO[412] (million ethanol-equivalent gallons)

	2026	2027	2028	2029	2030
CNG/LNG Transportation Usage	1,752	1,778	1,845	1,893	1,909
Adjusted[a] CNG/LNG Transportation Usage	1,131	1,136	1,141	1,143	1,145

[a] Usage adjusted to exclude volumes attributed to international and domestic shipping.

Additionally, given the high likelihood of nationwide consumption limitations emerging by the mid-to-late 2020s, we believe it would be valuable to develop an alternative estimate of future CNG/LNG demand. This would allow for a more comprehensive assessment of potential saturation points by providing a basis for comparison with the AEO estimate. To achieve this, EPA created a separate estimate of future CNG/LNG demand entirely independent of the AEO estimate. Referred to in this section as the "EPA Estimate," this independent estimate was developed from a combination of data sources and modeling techniques specifically tailored to different vehicle categories.

The vehicle categories chosen were primarily based on the U.S. Department of Transportation (DOT) Highway Performance Monitoring System (HPMS) vehicle classifications, as outlined in Table VM-1 of the Federal Highway Administration's (FHWA) annual Highway Statistics report.[413] The HPMS classifications include light-duty vehicles with a short wheelbase, light-duty vehicles with a long wheelbase, motorcycles, buses, single unit trucks,[414] and combination trucks.

For this analysis, EPA consolidated short- and long- wheelbase light-duty vehicles into a single "light-duty vehicle" category. Motorcycles were excluded from EPA's estimates of CNG/LNG consumption, as historically, no motorcycles have been powered by these fuels. EPA further refined the bus category by distinguishing between "school buses" and "transit buses" based on the availability of data that allowed for a more detailed analysis of their fuel consumption. Additionally, refuse haulers were separated from other single-unit trucks because of the historically high usage rate of CNG/LNG for these vehicles, resulting in the refuse hauler

[410] Under the definition of transportation fuel in 40 CFR 80.2, fuel for use in ocean-going vessels is excluded as a transportation fuel.

[411] Volumes attributed to: Light-Duty Vehicle, Commercial Light Trucks, Freight Trucks, Freight Rail, Transit Buses, and School Buses were included. Volumes attributed to: International Shipping and Domestic Shipping were excluded.

[412] AEO2023, Table 36 – Transportation Sector Energy Use by Fuel Type Within a Mode.

[413] FHWA, Highway Statistics Series, Table VM-1: Annual Vehicle Distance Traveled in Miles and Related Data - 2022. https://www.fhwa.dot.gov/policyinformation/statistics/2022/vm1.cfm.

[414] Single-Unit: single frame trucks that have 2-axles and at least 6 tires or a gross vehicle weight rating exceeding 10,000 lbs.

category being a key sector in EPA's fuel consumption estimates. As a result of this additional refinement, EPA chose to estimate fuel consumption for the following vehicle categories: light-duty vehicles, public transit, school buses, refuse trucks, single unit trucks (excluding refuse haulers), and combination trucks.

To estimate fuel consumption from the light-duty vehicle category, EPA relied on data from the Department of Energy (DOE) as the primary source for vehicle count information.[415] This vehicle count data for natural gas vehicles was integrated with assumptions for average vehicle miles traveled (VMT)[416] and average fuel efficiency[417] in the light-duty vehicle sector. Using this methodology, EPA calculated a total estimate for CNG/LNG consumption among light-duty vehicles, which is shown in Table 7.1.4.1-2. Based on current trends, EPA does not anticipate significant growth in CNG/LNG volumes within the light-duty sector, given the limited introduction of new light-duty natural gas vehicles models. Notably, no new CNG light-duty vehicle models have been introduced since Model Year (MY) 2022.[418] Despite the lack of growth and the likely decrease in vehicle numbers due to future scrappage, EPA has opted to keep the vehicle count steady in this analysis for simplicity, given that consumption for the light-duty category is already minimal.

Table 7.1.4.1-2: CNG/LNG Usage from the Light-duty Vehicle Sector (million ethanol-equivalent gallons)[a]

Year	Data Type	Vehicle Count	CNG/LNG Usage
2022	Actual	24,700	23.4
2023–2030	Projected	24,700	23.4

[a] Calculated using an average efficiency of 17.8 miles per gasoline-equivalent gallon and an average VMT of 11,318 miles per vehicle.

To estimate consumption from public transit, EPA utilized data from the American Public Transportation Association's *2023 Public Transportation Fact Book*, which provides energy consumption data separated by fuel type.[419] Data from this source indicates significant variability in annual fuel usage, with no clear trend beyond a noticeable reduction in usage during the Covid-19 pandemic period. Given this volatility and the fact that the most recent data available are from 2021 (which would still reflect the impacts of Covid-19), EPA opted to calculate an average annual growth rate based on data from 2014 onward. This starting point aligns with the classification of RNG as a cellulosic biofuel under the RFS program. The resulting average growth rate of 0.9% per year was applied to each subsequent year to project

[415] AFDC, "Vehicle Registration Counts by State," 2022. https://afdc.energy.gov/vehicle-registration?year=2022.
[416] AFDC, "Average Annual Vehicle Miles Traveled by Major Vehicle Category," September 2024. https://afdc.energy.gov/data/10309.
[417] AFDC, "Average Fuel Economy by Major Vehicle Category," January 2024. https://afdc.energy.gov/data/10310.
[418] AFDC, "Fuel and Advanced Technology Vehicles," Model Year 2022 (https://afdc.energy.gov/vehicles/search/download.pdf?year=2022), Model Year 2023 (https://afdc.energy.gov/vehicles/search/download.pdf?year=2023), and Model Year 2024 (https://afdc.energy.gov/vehicles/search/download.pdf?year=2024).
[419] American Public Transportation Association, "2023 Public Transportation Fact Book," Appendix A: Historical Tables, Table 58 – Non-Diesel Fossil Fuel Consumption by Fuel Type. https://www.apta.com/research-technical-resources/transit-statistics/public-transportation-fact-book.

future CNG/LNG consumption in public transportation. The projected CNG/LNG usage data for public transportation are presented in Table 7.1.4.1-3.

Table 7.1.4.1-3: CNG/LNG Usage from the Public Transportation Sector (million ethanol-equivalent gallons)

Year	Data Type	CNG/LNG Usage	Year-over Year Growth
2014	Actual	284.2	N/A
2015	Actual	297.9	4.8%
2016	Actual	316.8	6.3%
2017	Actual	312.7	-1.3%
2018	Actual	323.4	3.4%
2019	Actual	342.2	5.8%
2020	Actual	310.1	-9.4%
2021	Actual	299.2	-3.5%
2022	Projected	301.8	0.9%
2023	Projected	304.5	0.9%
2024	Projected	307.2	0.9%
2025	Projected	309.9	0.9%
2026	Projected	312.7	0.9%
2027	Projected	315.5	0.9%
2028	Projected	318.3	0.9%
2029	Projected	321.1	0.9%
2030	Projected	323.9	0.9%

For school buses, EPA is using data from the World Resources Institute's *Dataset of U.S. School Bus Fleets,*[420] which provides information on the composition of school bus fleets across the U.S. This dataset includes data from 46 states and the District of Columbia. However, data for four states—Colorado, Hawaii, Louisiana, and New Hampshire—are not available. To address this limitation, EPA used state population data alongside state-level CNG bus counts to estimate the number of CNG school buses in the states with missing data. The vehicle count data for CNG buses was then combined with average VMT[421] and average fuel efficiency specific to school buses.[422] This approach resulted in an estimate of total CNG/LNG consumption for the school bus sector. Since this dataset does not reflect changes over time—data were collected between March and November 2022, capturing vehicle counts only for that period—EPA applied the same annual growth rate (0.9%) as used for the public transportation sector to estimate year-over-year growth in CNG/LNG usage. For simplicity, we have also chosen to exclude future scrappage from the analysis, as fuel consumption in the school bus category is already minimal. The estimated consumption data for the school bus sector are presented in Table 7.1.4.1-4.

[420] Lazer, Leah, Lydia Freehafer, and Jessica Wang. "Dataset of U.S. School Bus Fleets Version 2," *World Resources Institute*, February 17, 2023. https://datasets.wri.org/datasets/usa-school-bus-fleets.
[421] AFDC, "Average Annual Vehicle Miles Traveled by Major Vehicle Category," September 2024. https://afdc.energy.gov/data/10309.
[422] AFDC, "Average Fuel Economy by Major Vehicle Category," January 2024. https://afdc.energy.gov/data/10310.

Table 7.1.4.1-4: CNG/LNG Usage from the School Bus Sector (million ethanol-equivalent gallons)[a,b]

Year	Data Type	Vehicle Count	Year-over-Year Growth	CNG/LNG Usage
2022	Actual	5,564	N/A	18.1
2023	Projected	5,614	0.9%	18.3
2024	Projected	5,664	0.9%	18.4
2025	Projected	5,714	0.9%	18.6
2026	Projected	5,764	0.9%	18.8
2027	Projected	5,816	0.9%	18.9
2028	Projected	5,867	0.9%	19.1
2029	Projected	5,919	0.9%	19.3
2030	Projected	5,972	0.9%	19.4

[a] Calculated using an average efficiency of 6.46 miles per gasoline-equivalent gallon.

[b] Calculated using an average VMT of 14,084 miles per vehicle.

For refuse trucks, EPA derived vehicle count estimates from fleet information reported in the sustainability reports of the largest waste management companies in the U.S. For many companies, especially smaller ones, data were more limited, and historical data were unavailable for several of the years reviewed. In such cases, EPA applied average growth rates from companies with available data to estimate vehicle counts for periods with missing information. Following this approach, total vehicle counts from the analyzed companies were aggregated and are shown in Table 7.1.4.1-5. Using this aggregated dataset, EPA calculated an average annual growth rate, which was then applied to the most recent vehicle totals to project future vehicle counts. These projected vehicle counts, in conjunction with average VMT[423] and average fuel efficiency for refuse haulers,[424] were used to estimate total CNG/LNG consumption within the refuse hauler sector. In comparing this vehicle count to data from The Transportation Project, we note that The Transportation Project reports "Over 17,000 natural gas refuse trucks operate across the country and about 60% of new trucks on order are NGVs [Natural Gas Vehicles]."[425] This figure is lower than EPA's estimate of approximately 21,000 vehicles in 2023. However, given the rapid growth and adoption of CNG/LNG usage in this sector, EPA believes that its higher estimate may better represent future vehicle counts. The resulting data for refuse haulers are presented in Table 7.1.4.1-6.

[423] AFDC, "Average Annual Vehicle Miles Traveled by Major Vehicle Category," September 2024. https://afdc.energy.gov/data/10309.

[424] AFDC, "Average Fuel Economy by Major Vehicle Category," January 2024. https://afdc.energy.gov/data/10310.

[425] The Transport Project, "Vehicles for every route". https://transportproject.org/vehicles.

Table 7.1.4.1-5: Estimated Refuse Hauler Vehicle Counts[a]

Company	2018	2019	2020	2021	2022	2023
Waste Management	7,944	8,924	10,388	10,832	11,307	12,119
Republic Services	3,200	3,200	3,423	3,444	3,380	3,440
Waste Connections	1,070	1,119	1,166	1,090	1,070	1,134[b]
Clean Harbors	-	-	-	-	13	14[b]
GFL Environmental	-	776	983	1,179	1,238	1,312[b]
Recology	-	1,950	2,080	2,158	2,314	2,453[b]
Waste Pro USA	800	800[b]	800[b]	800[b]	800[b]	848[b]
Casella Waste Systems	-	-	-	30	44	47[b]

[a] Vehicle counts are estimated based on limited data, including information available only from earlier years.

[b] Data sources: WM Sustainability Reports (https://sustainability.wm.com/esg-data-center); Republic Services SASB Reports (https://investor.republicservices.com/financials/reports); Waste Connections Sustainability Reports (https://sustainability.wasteconnections.com/sustainability-data-hub.html); Clean Harbors Sustainability Reports (https://www.cleanharbors.com/sites/g/files/bdczcs356/files/2023-11/CLH%20Sustainability%20Supplement%20110323.pdf); GFL Environmental SASB Reports (https://investors.gflenv.com/English/esg/sustainability/default.aspx); Recology Sustainability Reports (https://www.recology.com/sustainability-at-recology); Waste Pro USA (https://www.wasteprousa.com/blog/waste-pro-recognized-for-eco-friendly-operations); Casella Waste Systems SASB Reports.

Table 7.1.4.1-6: CNG/LNG Usage from the Refuse Hauler Sector (million ethanol-equivalent gallons)[a]

Year	Data Type	Vehicle Count	Year-over Year Growth	CNG/LNG Usage
2019	Actual	16,769	N/A	252.5
2020	Actual	18,840	12.3%	283.7
2021	Actual	19,533	3.7%	294.1
2022	Actual	20,166	3.2%	303.7
2023	Actual[b]	21,367	6.0%	321.7
2024	Projected	22,715	6.3%	342.0
2025	Projected	24,147	6.3%	363.6
2026	Projected	25,670	6.3%	386.5
2027	Projected	27,288	6.3%	410.9
2028	Projected	29,009	6.3%	436.8
2029	Projected	30,838	6.3%	464.4
2030	Projected	32,783	6.3%	493.6

[a] Calculated using an average efficiency of 2.48 miles per gasoline-equivalent gallon and an average VMT of 25,000 miles per vehicle.

[b] Calculated using both projected and actual data.

For single-unit trucks (excluding refuse haulers) and combination trucks, EPA estimated CNG/LNG vehicle counts for each calendar year using national vehicle registration data from 2014, 2020, and 2023.[426] To fill in the gaps, data was linearly interpolated to estimate

[426] Vehicle count data shown in Tables 7.1.4.1-7 and 8 are from the Motor Vehicle Emission Simulator (MOVES5), (https://www.epa.gov/moves/latest-version-motor-vehicle-emission-simulator-moves). For information on how this data was derived, see EPA, "Population and Activity of Onroad Vehicles in MOVES5," EPA-420-R-24-019, November 2024, Chapters 4 and 5. https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P101CUN7.pdf.

registrations for all years between 2014 and 2022. In addition to registration data, EPA incorporated average VMT and fuel efficiency data from the Bureau of Transportation Statistics' *National Transportation Statistics* publication.[427] Using historic vehicle counts, along with average VMT and fuel efficiency for both single-unit and combination trucks, EPA estimated total CNG/LNG consumption in these sectors for each year from 2014 to 2022, shown in Tables 7.1.4.1-7 and 8. Based on this aggregated dataset, EPA calculated the average annual growth rate of total CNG/LNG usage and applied it to the most recent totals to project future fuel volumes, shown in Tables 7.1.4.1-9 and 10.

Table 7.1.4.1-7: CNG/LNG Usage from the Single Unit Truck Sector (miles; miles per diesel-equivalent gallon; million ethanol-equivalent gallons)[a]

Year	Single Unit Truck Vehicle Count	Single Unit Truck VMT	Single Unit Truck Fuel Economy	Single Unit Truck Fuel Consumption
2014	11,710	13,123	7.34	35.5
2015	14,286	12,960	7.38	42.5
2016	17,160	12,958	7.39	51.0
2017	19,025	12,435	7.44	53.9
2018	22,832	11,687	7.51	60.3
2019	25,335	12,278	7.49	70.4
2020	27,250	11,892	7.56	72.6
2021	29,899	12,287	7.67	81.2
2022	32,020	12,290	7.93	84.1

[a] Diesel-equivalent gallons (DGE) converted to ethanol-equivalent gallons (EGE) using 1 EGE = 0.59 DGE.

Table 7.1.4.1-8: CNG/LNG Usage from the Combination Truck Sector (miles; miles per diesel-equivalent gallon; million ethanol-equivalent gallons)[a]

Year	Combination Truck Vehicle Count	Combination Truck VMT	Combination Truck Fuel Economy	Combination Truck Fuel Consumption
2014	4,539	65,897	5.83	86.9
2015	6,908	61,978	5.89	123.1
2016	8,527	63,428	5.91	155.2
2017	9,667	62,751	5.98	172.0
2018	10,832	63,374	6.07	191.6
2019	11,420	59,929	6.05	191.8
2020	11,967	60,120	6.16	197.9
2021	14,048	62,169	6.42	230.6
2022	17,256	60,018	6.91	254.0

[a] Diesel-equivalent gallons (DGE) converted to ethanol-equivalent gallons (EGE) using 1 EGE = 0.59 DGE.

[427] Bureau of Transportation Statistics, National Transportation Statistics, Table 4-13 – Single-Unit 2-Axle 6-Tire or More Truck Fuel Consumption and Travel (https://www.bts.gov/content/single-unit-2-axle-6-tire-or-more-truck-fuel-consumption-and-travel) and Table 4-14 – Combination Truck Fuel Consumption and Travel. (https://www.bts.gov/content/combination-truck-fuel-consumption-and-travel).

Table 7.1.4.1-9: CNG/LNG Usage from the Single Unit Truck Sector (million ethanol-equivalent gallons)

Year	Data Type	CNG/LNG Usage	Year-over Year Growth
2017	Actual	53.9	N/A
2018	Actual	60.3	11.8%
2019	Actual	70.4	16.8%
2020	Actual	72.6	3.1%
2021	Actual	81.2	11.8%
2022	Actual	84.1	3.6%
2023	Projected	92.0	9.4%
2024	Projected	100.7	9.4%
2025	Projected	110.1	9.4%
2026	Projected	120.5	9.4%
2027	Projected	131.8	9.4%
2028	Projected	144.2	9.4%
2029	Projected	157.8	9.4%
2030	Projected	172.6	9.4%

Table 7.1.4.1-10: CNG/LNG Usage from the Combination Truck Sector (million ethanol-equivalent gallons)

Year	Data Type	CNG/LNG Usage	Year-over Year Growth
2017	Actual	172.0	N/A
2018	Actual	191.6	11.4%
2019	Actual	191.8	0.1%
2020	Actual	197.9	3.2%
2021	Actual	230.6	16.5%
2022	Actual	254.0	10.1%
2023	Projected	274.8	8.2%
2024	Projected	297.3	8.2%
2025	Projected	321.7	8.2%
2026	Projected	348.1	8.2%
2027	Projected	376.6	8.2%
2028	Projected	407.5	8.2%
2029	Projected	440.9	8.2%
2030	Projected	477.1	8.2%

In addition to the above scenario using a year-over-year growth projection for total CNG/LNG usage, EPA conducted an alternative analysis incorporating higher future CNG/LNG vehicle counts to account for potential accelerated adoption in this sector. In particular, this analysis focused on the potential market impact of the Cummins X15N engine,[428] assuming exponential growth in CNG engine adoption among freight trucks, with market penetration

[428] Cummins, "Engines – X15N (2024)." https://www.cummins.com/engines/x15n-2024.

potentially reaching 10% of new vehicles by 2030.[429] Under this scenario, estimated fuel volumes increased significantly (Table 7.1.4.1-11). This outcome highlights the challenges of accurately forecasting CNG/LNG consumption, particularly as emerging technologies shape market trends. While this aggressive growth scenario was not included in our final consumption estimate—given that we did not want to base RNG consumption potential on a single new engine technology—it is presented here for context. With that stated, stakeholder feedback has shown strong interest in this new engine, suggesting that future adoption rates may warrant revisions to these estimates as market dynamics evolve.

Table 7.1.4.1-11: CNG/LNG Usage from both Single Unit and Combination Trucking Sector Assuming Aggressive Growth (million ethanol-equivalent gallons)

Year	CNG/LNG Usage Under Standard Growth Scenario	CNG/LNG Usage Under High Penetration Scenario
2022	338.1	338.1
2023	366.8	421.6
2024	398.0	487.1
2025	431.8	568.8
2026	468.4	671.7
2027	508.2	802.5
2028	551.4	970.6
2029	598.2	1,188.9
2030	649.0	1,476.0

After estimating volumes for each vehicle category, we aggregated these individual totals to produce an overall "EPA Estimate" of future CNG/LNG consumption, shown in Table 7.1.4.1-12. This aggregated volume is generally consistent with, but slightly higher than, the AEO estimate, shown in Table 7.1.4.1-1.

Table 7.1.4.1-12: Total CNG/LNG Usage for the "EPA Estimate" (million ethanol-equivalent gallons)

	2025	2026	2027	2028	2029	2030
Light-duty Vehicles	23.4	23.4	23.4	23.4	23.4	23.4
Public Transportation	309.9	312.7	315.5	318.3	321.1	323.9
School Buses	18.6	18.8	18.9	19.1	19.3	19.4
Refuse Trucks	363.6	386.5	410.9	436.8	464.4	493.6
Single Unit Trucks	110.1	120.5	131.8	144.2	157.8	172.6
Combination Trucks	321.7	348.1	376.6	407.5	440.9	477.1
Total[a]	1,147	1,210	1,277	1,349	1,426	1,509

[a] Total may not be precisely equal to the sum of each vehicle sector due to rounding.

In addition to the EPA Estimate, we wanted to develop an alternative volume projection that considered a different potential market constraint: the limitation of existing CNG/LNG

[429] Cummins stated that their goal is for this engine to reach 10% of market sales by 2030. See: Patrick Campbell, Cummins Alternative Power Technologies - Regional Sales Manager, Fleets and Fuel Conference Presentation from BIOGAS AMERICAS 2024 (May 13-16, 2024). https://youtu.be/fOH6j1ccIkI (19:15 in video).

fueling infrastructure. Specifically, we examined how the growth of RNG used as CNG/LNG might be constrained by the existing CNG/LNG fueling infrastructure. While natural gas and natural gas pipelines are widely accessible, there are only around 1,400 public and private fueling stations in the U.S.[430] compared to roughly 145,000 gasoline stations.[431] Some fleets interested in using CNG/LNG invest in private fueling infrastructure so they can fuel onsite; however, this can be a significant investment that not all businesses can afford. To account for this potential constraint, EPA developed an additional projection based on fueling infrastructure capacity.

By analyzing California's CNG/LNG usage data and station numbers, EPA calculated an average fuel throughput per station. This throughput was then applied to the total number of CNG/LNG stations nationwide to estimate overall U.S. CNG/LNG throughput of CNG/LNG, as shown in Table 7.1.4.1-13. This "station throughput" method was not used to project future volumes, as it assumes every U.S. station would dispense fuel at California's rates, which would likely overestimate consumption due to California's outsized market. It also is heavily based on the number of CNG/LNG refueling stations, an estimate which experiences a reasonable amount of volatility year-to-year. However, comparing this throughput estimate to actual RIN data for each corresponding year shows an interesting insight: although this volume exceeds the total RINs generated in each year, even if every U.S. station dispensed fuel at California's rates, the estimated volume totals over the past five years still only ranges between 1,186 and 1,558 million EGE.

Table 7.1.4.1-13: Projected Consumption of CNG/LNG Used as Transportation Fuel Using "Station Throughput" Method

	Units	2019	2020	2021	2022	2023
CNG/LNG used as transportation fuel in California[a]	Million EGE	305	278	303	335	356
CNG/LNG refueling stations in California[b]	Station Count	365	363	364	352	341
Average annual throughput per station in California	Million EGE per Station	0.84	0.77	0.83	0.95	1.04
CNG/LNG refueling stations in the U.S.	Station Count	1576	1549	1510	1399	1492
Projected CNG/LNG used as transportation fuel in the U.S.	Million EGE	1,317	1,186	1,257	1,331	1,558
RIN Generation for RNG used as CNG/LNG	Million RINs	404	504	568	667	773

[a] California LCFS Reporting Tool Quarterly Summaries. https://ww2.arb.ca.gov/resources/documents/low-carbon-fuel-standard-reporting-tool-quarterly-summaries.
[b] AFDC, "Alternative Fueling Station Locator". https://afdc.energy.gov/stations#/analyze?country=US&region=US-CA&tab=location&fuel=CNG&fuel=LNG&access=public&access=private.

[430] AFDC, "Alternative Fueling Station Locator." https://afdc.energy.gov/stations#/analyze?fuel=LNG&fuel=CNG&access=public&access=private&country=US&tab=fuel.
[431] API, "Service Station FAQs." https://www.api.org/oil-and-natural-gas/consumer-information/consumer-resources/service-station-faqs.

Because we are not using the station throughput method, we return to the previous estimates of total CNG/LNG consumption, specifically EIA's AEO estimate (Table 7.1.4.1-1) and the EPA estimate (Table 7.1.4.1-12). To develop a single projection for future CNG/LNG consumption, we have chosen to rely solely on the EPA estimate for the demand side of the market. This was done due to the similarity of the values and our level of understanding of their derivation.

With the consumption estimate selected, we next looked to determine how much of the total CNG/LNG market could be met with RNG. In a model scenario where all fossil-based CNG/LNG could be fully replaced by RNG, this total CNG/LNG estimates would serve as the maximum potential RNG volumes, with no further adjustment needed. However, due to practical facility-level constraints like infrastructure limitations, costs, and other variables, it's unlikely the market would achieve 100% replacement efficiency, and some fossil-based CNG/LNG would likely remain in use. Thus, to better estimate realistic RNG consumption in a saturated market, we applied an efficiency factor based on observed market conditions. Specifically, we looked at California's LCFS program to better understand RNG consumption in a saturated market. Since its inception in 2011, California's LCFS program has awarded credits for both renewable and fossil-based natural gas used as transportation fuel within the state. In 2014, when RNG used as CNG/LNG was classified as a cellulosic biofuel under the RFS program, the utilization of RNG surged significantly due to the ability to generate lucrative credits under both programs for displacing existing fossil CNG/LNG demand. This aggressive growth under both the LCFS and RFS has resulted in RNG-based CNG/LNG dominating the market in California. As seen in Table 7.1.4.1-14, the California CNG/LNG market has shifted to be almost entirely RNG-based, with volumes accounting for an average of 97% of the total market from 2021 through 2023. Thus, we assumed that California represents a mature, fully saturated market.

Table 7.1.4.1-14: California Low Carbon Fuel Standard Program Data (million ethanol-equivalent gallons)[432]

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
RNG-based CNG/LNG	49	113	151	181	203	236	257	296	323	344
Fossil-based CNG/LNG	164	122	95	87	82	69	21	7	12	12
Total CNG/LNG	213	234	247	268	285	305	278	303	335	356
Year-over-year Growth of Total	-	10%	5%	8%	6%	7%	-9%	9%	11%	6%
RNG Blend Rate	23%	48%	61%	68%	71%	77%	92%	98%	96%	97%

Subsequently, we assume that any fully saturated CNG/LNG market would consist of approximately 97% RNG. Using this approach, we applied a 97% efficiency factor to the EPA projections for future CNG/LNG volumes to estimate the potential RNG consumption under saturated market conditions. These consumption estimates for RNG are detailed in Table 7.1.4.1-15.

432 Id.

Table 7.1.4.1-15: Projected Maximum Amount of RNG That Could Be Used As CNG/LNG Due to Market Replacement Efficiency (million ethanol-equivalent gallons)

	2025	2026	2027	2028	2029	2030
EPA CNG/LNG Consumption Estimate	1,147	1,210	1,277	1,349	1,426	1,509
Potential RNG Usage Assuming 97% Replacement Efficiency	1,113	1,174	1,239	1,309	1,384	1,464

7.1.4.2 Projected Supply of Biogas-derived CNG and LNG

In addition to projecting future demand for biogas-derived CNG/LNG, EPA also analyzed the potential production capacity of biogas-derived CNG/LNG under unrestricted market conditions, assuming no consumption limitations. This analysis was conducted to assess whether the market is genuinely constrained by consumption rather than production capacity. To do so, we utilized the same industry-wide projection methodology that has been employed in the RFS standard-setting rules since 2018. This methodology is based on applying an industry-wide year-over-year growth rate to the current production rate of biogas (see Chapter 7.1.2 for more information on this methodology). Specifically, EPA used RIN generation data from the most recent 24 months and multiplied the observed growth rate during that period with the most recent full calendar year of data available. This growth rate was then repeatedly applied to each progressive year to project future production. Using this method, the growth rate calculated is 24.2%, shown in Table 7.1.4.2-1.

Table 7.1.4.2-1: RIN Generation for D3 RNG (million ethanol-equivalent gallons)

Volume Generated Between Feb. 2023 – Jan. 2024	Volume Generated Between Feb. 2024 – Jan. 2025[a]	Year-Over-Year Increase
778	966	24.2%

[a] This was the most recent 12 months for which data were available at the time of this analysis.

EPA then applied this 24.2% year-over-year growth rate to the total number of 2024 cellulosic RINs generated and available for compliance for CNG/LNG. That is, in this proposed 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 supplied in the most recent calendar year for which data is available (in this case 2024), considering actual RIN generation. The ethanol equivalent RNG volume potential projected using this methodology are shown in Table 7.1.4.2-2.

Table 7.1.4.2-2: Projected Production Potential of RNG (million ethanol-equivalent gallons)

Year	Date Type	Growth Rate	Volume
2024	Actual	N/A	971
2025	Projected	24.2%	1,206
2026	Projected	24.2%	1,497
2027	Projected	24.2%	1,859
2028	Projected	24.2%	2,308
2029	Projected	24.2%	2,866
2030	Projected	24.2%	3,559

The projected production shown in Table 7.1.4.2-2 serves as the estimated volume of RNG that could be produced absent any constraint on demand for use as transportation fuel.

7.1.4.3 Projected Volume of Biogas-derived CNG and LNG

With the consumption estimate selected from Chapter 7.1.4.1, we combined it with the production estimates from Chapter 7.1.4.2, with this combination shown in Table 7.1.4.3-1.

Table 7.1.4.3-1: Estimated Production of RNG and Estimated Consumption of RNG By CNG/LNG Vehicles (million ethanol-equivalent gallons)

	2026	2027	2028	2029	2030
RNG Production	1,497	1,859	2,308	2,866	3,559
RNG Consumption	1,174	1,239	1,309	1,384	1,464

Analyzing both the consumption and production estimates shows that for 2026–2030, potential RNG production exceeds the likely theoretical maximum for RNG consumption over this period. Therefore, we expect the RNG market to be limited by the overall CNG/LNG market size. Thus, EPA is projecting future RNG volumes based on the estimated future consumption of RNG. These estimated volumes are shown in in Table 7.1.4.3-2.

Table 7.1.4.3-2: Projected Volume Biogas-derived CNG and LNG (million ethanol-equivalent gallons)

	2026	2027	2028	2029	2030
Volume of RNG	1,174	1,239	1,309	1,384	1,464

7.1.5 Projected Supply of Liquid Cellulosic Biofuels

Several technologies are currently being developed to produce liquid fuels from cellulosic biomass. However, most of these technologies are unlikely to yield significant volumes by 2030. One notable exception is the production of ethanol from corn kernel fiber (CKF), for which several companies have developed processes. Many of these processes involve simultaneously co-processing of both the starch and cellulosic components of the corn kernel. However, to be eligible for generating cellulosic RINs, facilities must accurately determine the amount of ethanol produced specifically from the cellulosic portion. This requires the ability to reliably and precisely calculate the ethanol derived from the cellulosic component, distinct from the starch portion of the corn kernel. In September 2022, EPA issued updated guidance on analytical methods that could be used to quantify the amount of ethanol produced when co-processing corn kernel fiber and corn starch.[433]

EPA has also had substantive discussions with technology providers intending to use analytical methods consistent with this guidance, as well as with owners of facilities registered as cellulosic biofuel producers using these methods. Based on information from these technology providers, EPA believes that cellulosic ethanol production from CKF might be feasible at all existing corn ethanol facilities with minimal additional processing units or modifications. However, for the purposes of this analysis, we assume that only 90% of facilities will actually be able to produce cellulosic ethanol during the years analyzed for this proposed rule due to potential facility-specific challenges that may prevent 100% adoption.

Additionally, while technology providers have indicated that the use of analytical methods consistent with EPA's guidance allows for demonstrating that approximately 1.5% of the ethanol produced at existing corn ethanol facilities comes from cellulosic biomass, the current industry-wide average for registered facilities is closer to 1%. Therefore, for the purposes of this analysis, we are using a 1% conversion rate.

The projected production of cellulosic ethanol form CKF, as shown in Table 7.1.4-1, is based on projections of total corn ethanol production (see Chapter 7.1.6 for more information on our total corn ethanol projections), with a 90% facility participation rate and a 1% conversion efficiency applied.

Table 7.1.4-1: Projected Production of Ethanol from CKF (ethanol-equivalent gallons)

Year	Volume
2026	124
2027	123
2028	122
2029	120
2030	119

7.1.6 Projected Rate of Cellulosic Biofuel Production for 2026–2030

After projecting production of cellulosic biofuel from liquid cellulosic biofuels and CNG/LNG derived from biogas, EPA combined these estimates to project total cellulosic biofuel production for 2026–2030. These projections are shown in Table 7.1.6-1.

[433] EPA, "Guidance on Qualifying an Analytical Method for Determining the Cellulosic Converted Fraction of Corn Kernel Fiber Co-Processed with Starch," EPA-420-B-22-041, September 2022.

Table 7.1.6-1: Projected Production of Cellulosic Biofuel in 2026–2030 (million ethanol-equivalent gallons)

	2026	2027	2028	2029	2030
CNG/LNG Derived from Biogas	1,174	1,239	1,309	1,384	1,464
Ethanol from CKF	124	123	122	120	119
Total Cellulosic Biofuel	1,298	1,362	1,431	1,504	1,583

7.2 Biomass-Based Diesel

Since 2010 when the 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. Since 2015, increasing volumes of renewable diesel have also been supplied. In 2023, the quantity of renewable diesel supplied to the U.S. surpassed the supply of biodiesel for the first time. Production and import of renewable diesel are expected to continue to increase in future years. Along with biodiesel and renewable diesel, 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 the factors we consider in projecting the domestic production and net imports of BBD in 2026–2030. First, we present the available data on biodiesel and renewable diesel production, import, and use in previous years (Chapter 7.2.1). Next, we provide an updated projection of the supply of BBD through 2025 based on recent data (Chapter 7.2.2) and assess the current and projected future production capacity for biodiesel and renewable diesel (Chapter 7.2.3). The availability of qualifying feedstocks for biodiesel and renewable diesel production (Chapter 7.2.4) and potential imports and exports of BBD (Chapter 7.2.5) are in the following sections. Finally, we describe our assessment of the rate of production and use of qualifying biomass-based diesel biofuel in 2026–2030 based on this information (Chapter 7.2.6) and discuss some of the uncertainties associated with those volumes. This section addresses the projected rate of production and consumption of all BBD projected to be produced and used in the U.S. in 2026-2030, regardless of whether the production and use of the BBD is driven by the BBD, advanced, or total renewable fuel volume requirements. An analysis of the projected rate of production and consumption of advanced (D5) biodiesel and renewable diesel and conventional (D6) biodiesel and renewable diesel can be found in Chapters 7.4 and 7.7, respectively.

7.2.1 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 many complex and inter-related factors beyond simple total production capacity that could affect the supply of BBD. 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 BBD feedstocks,[434] demand for those feedstocks in other markets and internationally, the federal tax credits available to biodiesel and renewable diesel producers, tariffs on imported biodiesel and renewable diesel (and the feedstocks used to produce these fuels), biofuel policies in other countries, import and distribution infrastructure, and other market-based factors. Thus, 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 point in considering future volumes. Production, import, export, and total volumes of BBD are shown in Table 7.2.1-1.

Table 7.2.1-1: BBD (D4) Production, Imports, and Exports from 2012 to 2022 (million gallons)[a]

	2016	2017	2018	2019	2020	2021	2022	2023
Domestic Biodiesel (Annual Change)	1,581 (+336)	1,552 (–29)	1,841 (+289)	1,706 (–135)	1,802 (+96)	1,701 (-101)	1,614 (-87)	1,661 (+47)
Imported Biodiesel (Annual Change)	562 (+301)	462 (–100)	175 (–287)	185 (+10)	209 (+24)	208 (-1)	240 (+32)	501 (+261)
Exported Biodiesel (Annual Change)	89 (+16)	129 (+40)	74 (–55)	76 (+2)	88 (+12)	91 (+3)	117 (+26)	97 (-20)
Total Biodiesel (Annual Change)[c]	2,054 (+621)	1,885 (–169)	1,942 (+57)	1,815 (–127)	1,924 (+109)	1,817 (-107)	1,738 (-79)	2,065 (+327)
Domestic Renewable Diesel (Annual Change)	231 (+62)	252 (+21)	282 (+30)	454 (+172)	472 (+18)	777 (+305)	1,369 (+592)	2,345 (+976)
Imported Renewable Diesel (Annual Change)	165 (+45)	191 (+26)	176 (–15)	267 (+91)	280 (+13)	362 (+82)	311 (-51)	361 (+50)
Exported Renewable Diesel (Annual Change)	40 (+19)	37 (–3)	80 (+43)	145 (+65)	223 (+78)	241 (+18)	326 (+85)	414 (+88)
Total Renewable Diesel (Annual Change)[c]	356 (+88)	406 (+50)	378 (–28)	576 (+198)	529 (–47)	897 (+368)	1,354 (+457)	2,292 (+938)
Total BBD[d] (Annual Change)	2,412 (+711)	2,293 (–119)	2,322 (+29)	2,393 (+71)	2,457 (+64)	2,717 (+260)	3,106 (+389)	4,378 (+1,272)

[a] All data from EMTS. EPA reviewed all BBD 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. 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 does not include D5 or D6 biodiesel and renewable diesel. These fuels are discussed in Chapters 7.4 and 7.7, respectively.
[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.

[434] Throughout this chapter we refer to BBD as well as BBD feedstocks. In this context, BBD refers to any biodiesel or renewable diesel for which RINs can be generated that satisfy an obligated party's BBD biofuel obligation (i.e., D4 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, but are not limited to: 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 Rows F, G, and H of Table 1 to 80.1426).

Since 2016, the year-over-year changes in the volume of BBD used in the U.S. have varied greatly, from a low of 119 million fewer gallons from 2016 to 2017 to a high of 1.27 billion additional gallons from 2022 to 2023. 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 1.27 billion gallons of BBD 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, 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 2016 approximately 15% of all BBD was renewable diesel, and the remaining 85% was biodiesel. However, since 2016 nearly all the net growth in the BBD category has been in renewable diesel volume. By 2023 production and net imports of renewable diesel had increased not only in absolute terms (from 365 million gallons in 2016 to 2.29 billion gallons in 2023), but also as a percentage of the BBD pool. In 2023 approximately 52% of all BBD was renewable diesel, while the remaining 48% 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 has also provided biodiesel and renewable diesel with a competitive advantage relative to other biofuels that do not qualify for the tax credit. This is likely one of the factors that has contributed to the high growth of BBD relative to other advanced biofuels over the years.

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 2020–2025, 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, 2020–2023) 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,[435] 260 million gallons, 389 million gallons, and 1,272 million gallons respectively). However, following the large increases in 2013 and 2016, there was little to no growth in the use of BBD 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.

Beginning in 2025, the structure of the federal tax credit available to biodiesel and renewable diesel producers is scheduled to change significantly. Prior to 2025 all qualifying biodiesel and renewable diesel (including biodiesel and renewable diesel co-processed with petroleum) was eligible for a $1 per gallon tax credit. This tax credit was available for biodiesel

[435] This is the volume increase in 2020, which was impacted by the Covid-19 pandemic.

and renewable diesel produced in the U.S. as well as biodiesel or renewable diesel produced in foreign countries and used in the U.S. In 2025, the 45Z credit will come into effect. This credit consolidates and replaces the previous $1 per gallon credit for blending biodiesel and renewable diesel into diesel fuel under 40A, and also provides a production credit for alternative fuels and sustainable aviation fuel. This credit differs from the biodiesel blenders tax credit in several significant ways. First, it is available to other forms of transportation fuel, potentially including ethanol. Second, the tax credit is available only for transportation fuel produced in the United States. Finally, and perhaps more importantly, the magnitude of the tax credit is a function of the CI of the transportation fuel. This means that fuels must have lifecycle GHG emissions lower than 50 kilograms CO_2 equivalent per mmBTU to qualify for the tax credit, and fuels with lower GHG emissions are eligible for a higher tax credit than fuels with higher GHG emissions. The tax credit amount rises based on the CI of the transportation fuel up to $1.00 per gallon for non-aviation fuel and up to $1.75 per gallon for aviation fuel, provided certain wage and labor requirements are met. The structure of the 45Z tax credit therefore has a significant impact on the relative competitiveness of biofuels produced from different feedstocks in the U.S. market.

Another important factor highlighted by the historic data is the impact of changing renewable fuel and trade policies in other countries on the supply of biodiesel and renewable diesel to the U.S. In December 2017, the U.S. International Trade Commission adopted tariffs on biodiesel imported from Argentina and Indonesia.[436] According to data from EIA, 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.[437] 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 BBD supplied to the U.S. in 2018. Instead, higher domestic production of BBD, in combination with lower exported volumes of domestically produced biodiesel, resulted in an overall increase in the volume of BBD supplied in 2018 and subsequent years.

More recently changes in demand for biodiesel in the EU resulted in significant increased imports to the U.S. from the EU. Through 2021 biodiesel imports from the EU had never exceeded 100 million gallons in any single year.[438] Biodiesel imports from the EU increased to approximately 114 million gallons in 2022 and then quite dramatically to approximately 320 million gallons in 2023.[439] In these same years, imports of feedstocks used by domestic biodiesel and renewable diesel producers, such as tallow from Brazil and used cooking oil from China, increased significantly. These countries had historically exported biofuel feedstocks to the EU, and increased exports to the U.S. were likely impacted by declining demand for these feedstocks by biofuel producers in the EU. These impacts are discussed in greater detail in Chapters 7.2.4 and 7.2.3 respectively.

[436] USITC, "Biodiesel from Argentina and Indonesia Injures U.S. Industry, says USITC," December 5, 2017. https://www.usitc.gov/press_room/news_release/2017/er1205ll876.htm.
[437] EIA, "U.S. Imports by Country of Origin – Biodiesel," *Petroleum & Other Liquids*, April 30, 2025. https://www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_epoordb_im0_mbbl_a.htm.
[438] Id. Total reported biodiesel imports from the EU include imports from Belgium, Finland, France, Germany, Italy, the Netherlands, Norway, Portugal, and Spain.
[439] Id.

7.2.2 Biomass-Based Diesel Supply in 2024 and 2025

In addition to the data on BBD production, imports and exports discussed in Chapter 7.2.1, we also considered more recent data from 2024 in projecting the production and consumption of BBD in 2024, 2025, and beyond. At the time the analyses for this rulemaking were completed EPA had RIN generation data for the first five months of 2024 (January – May). While RIN generation and retirement data for the first five months of 2024 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 2024. The simplest way to project BBD RIN supply in 2024 using this data is to assume the average monthly RIN generation observed in the first five months of the year continues through the end of 2024. This projection methodology, however, ignores the observed seasonality in BBD RIN generation. To better account for the observed seasonality in BBD RIN generation we compared RIN generation in the first 5 months of 2024 to RIN generation during the first 5 months of 2023. From this data we can calculate a percentage increase (or decrease) that can be applied to the total BBD RIN supply in 2023 to project the total BBD RIN supply in 2024. Because the recent trends in the supply of BBD are significantly different for biodiesel and renewable diesel we calculated percentage increases separately for these fuels. We included the small volume of renewable jet fuel produced in 2024 in the renewable diesel total. These calculations, and the resulting projecting of BBD RIN supply in 2024 are shown in Table 7.2.2-1.

Table 7.2.2-1: Projected BBD Supply for 2023 Based on 2024 Data Through May 2024 (Million RINs)

	RIN Generation (Jan. – May 2023)	RIN Generation (Jan. – May 2024)	Percent Change	2023 RIN Supply	2024 RIN Supply (Projected)
Biodiesel	1,271	1,292	+1.7%	3,097	3,150
Renewable Diesel[a]	1,746	2,236	+28.7%	3,891	5,008

[a] Includes a small volume of renewable jet fuel.

At the time this analysis was completed we did not have sufficient data to determine the feedstocks used to produce BBD in 2024, nor do we have sufficient data to determine whether there is any seasonality in the feedstocks used to produce BBD. We therefore applied the projected percent changes in biodiesel and renewable diesel production from 2023 to 2024 equally to each of the feedstocks used to produce BBD in 2023. At the time this analysis was completed we did not have any RIN generation data for 2025 to use to further project BBD growth from 2024 to 2025. We considered using the same percentage growth rates we used to project the BBD supply in 2024 based on data through May 2024 to project further growth in 2025. There are several factors that suggest this may over-estimate the BBD supply in 2025. First, the overall growth rate for BBD through May 2024 (17.3%), while significant, is notably lower than the observed increase in the supply of BBD from 2022 to 2023 (42%). Second, the switch from the biodiesel blenders tax credit to the CFPC is expected to reduce the federal tax incentives available to BBD producers, particularly for fuels produced from virgin vegetable oils, and eliminate the incentives available for imported BBD. In light of these anticipated changes, we have projected that the BBD supply in 2025 will be equal to the projected BBD supply in 2024. This projection reflects both the incentives provided by the RFS program and the reduced incentives provided by the CFPC relative to the biodiesel blenders tax credit it replaces. The projected supply of BBD for 2024 and 2025 using this methodology is shown in Table 7.2.2-2.

Table 7.2.2-2: Projected BBD Supply for 2024 and 2025 (Million RINs)

Fuel Type	2023 Supply	Growth Rate	2024 and 2025 Projected Supply
BBD (total)	**6,988**	**+17.3%**	**8,157**
Biodiesel (total)	**3,097**	**+1.7%**	**3,150**
Soybean Oil	1,883	+1.7%	1,915
FOG	505	+1.7%	514
Corn Oil	183	+1.7%	186
Canola Oil	526	+1.7%	535
Renewable Diesel/Jet Fuel (total)	**3,891**	**+28.7%**	**5,008**
Soybean Oil	870	+28.7%	1,120
FOG	2,489	+28.7%	3,203
Corn Oil	362	+28.7%	466
Canola Oil	170	+28.7%	219

7.2.3 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. This section focuses on current and projected future BBD production capacity. While many of the biodiesel and renewable diesel production facilities considered in this section are also capable of producing conventional biodiesel and renewable diesel, very low volumes of conventional biodiesel and renewable diesel have been supplied to the U.S. in recent years.[440] Domestic biodiesel production capacity, domestic biodiesel production, and the utilization rate of the existing biodiesel production capacity each year is shown in Figure 7.2.3-1. Active biodiesel production capacity in the U.S. has experienced modest growth in recent years, from approximately 2.1 billion gallons in 2012 to just over 2.5 billion gallons in 2019.[441] As of August 2024, active biodiesel production capacity has decreased to approximately 2.0 billion gallons.[442] While production of biodiesel has generally increased during this time period, excess production capacity remains. Facility utilization was below 75% for each year through 2022, but increased to 82% in 2023 due in part to decreases in the operating biodiesel capacity since 2019. 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

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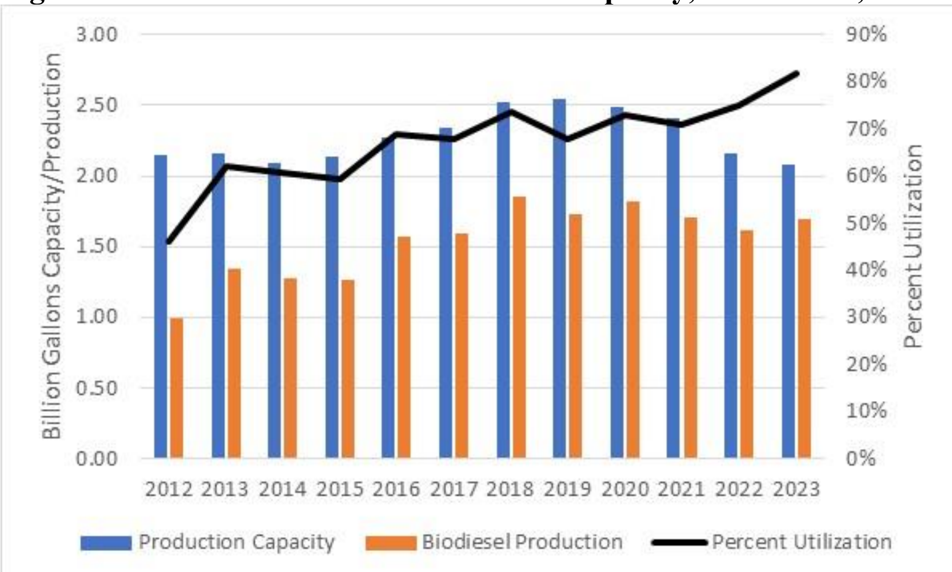
[440] EMTS data indicates that from 2018–2022, no conventional biodiesel or renewable diesel was supplied to the U.S. In 2023, 10 million gallons of conventional biodiesel and renewable diesel were supplied. As there are currently no approved pathway for generating RINs for conventional biodiesel and renewable diesel, conventional biodiesel and renewable diesel can only generate RINs if produced at grandfathered facilities that are exempt from the 20% GHG emission reduction requirements per 40 CFR 80.1403.

[441] EIA, "Monthly Biodiesel Production Report," February 2021. https://www.eia.gov/biofuels/biodiesel/production/archive/2020/2020_12/biodiesel.pdf.

[442] EIA, "U.S. Total Biofuels Operable Production Capacity," *Petroleum & Other Liquids*, April 30, 2025. https://www.eia.gov/dnav/pet/pet_pnp_capbio_dcu_nus_m.htm.

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 limit domestic biodiesel production.

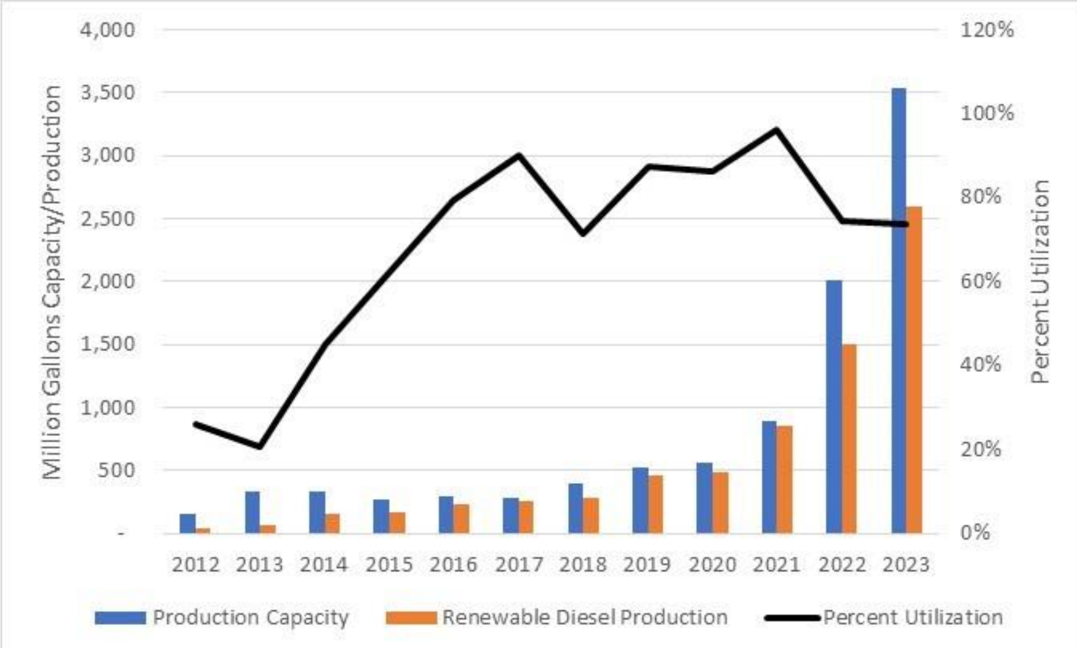
Figure 7.2.3-1: U.S. Biodiesel Production Capacity, Production, and Capacity Utilization



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 4.6 billion gallons in August 2024 (Figure 7.2.3-2).[443] Domestic 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 has consistently neared or exceeded the production capacity from the previous year. As renewable diesel production capacity continues to expand aggressively, it is unclear if this trend will continue in future years, particularly as affordable feedstocks may become more scarce with increasing renewable diesel production (see Chapter 7.2.4 for further discussion of available feedstocks).

[443] RFS facility registration data and EIA, "U.S. Total Biofuels Operable Production Capacity," *Petroleum & Other Liquids*, April 30, 2025. https://www.eia.gov/dnav/pet/pet_pnp_capbio_dcu_nus_m.htm.

Figure 7.2.3-2: U.S. Renewable Diesel Production Capacity, Production, and Capacity Utilization



Source: Renewable diesel production volumes are from EIA, "Monthly Energy Review," March 2025, Table 10.4b. https://www.eia.gov/totalenergy/data/monthly/archive/00352503.pdf. Renewable diesel production capacity for 2012–2020 is from EMTS. Renewable diesel production capacity for 2021–2023 is from EIA, "U.S. Total Biofuels Operable Production Capacity," Petroleum & Other Liquids, April 30, 2025. https://www.eia.gov/dnav/pet/pet_pnp_capbio_dcu_nus_m.htm. EIA first reported renewable diesel production capacity in 2021. Production capacity shown for 2021–2023 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 and/or jet fuel through 2030. 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. EIA currently projects that renewable diesel production capacity will continue to expand and could reach nearly 6 billion gallons by 2025.[444] A recent report published by the National Renewable Energy Laboratory (NREL) found that by 2028 the domestic production capacity for renewable diesel and jet fuel could increase to 9.6 billion gallons per year.[445] A map of the facilities expected to begin producing renewable diesel and/or jet fuel by 2028 from the NREL study is shown in Figure 7.2.3-3.

We note, however, that despite the potential for rapidly increasing production capacity through 2028, feedstock limitations (discussed in Chapter 7.2.4) are not expected to support all of these facilities. It is also possible that some of these projects may be delayed or cancelled.

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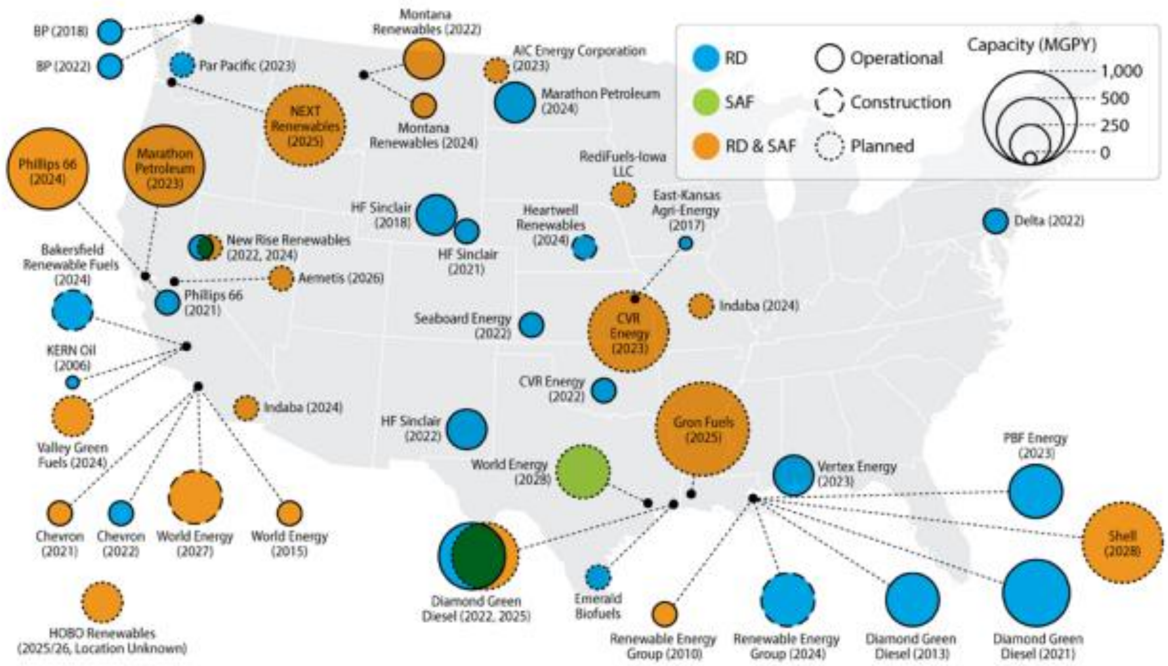
[444] EIA, "Domestic renewable diesel capacity could more than double through 2025,". *Today in Energy*, February 2, 2023. https://www.eia.gov/todayinenergy/detail.php?id=55399.

[445] Calderon, Oscar Rosales, Ling Tao, Zia Abdullah, Michael Talmadge, Anelia Milbrandt, Sharon Smolinski, Kristi Moriarty, et al. "Sustainable Aviation Fuel State-of-Industry Report: Hydroprocessed Esters and Fatty Acids Pathway," *National Renewable Energy Laboratory*, NREL/TP-5100-87803, July 30, 2024. https://doi.org/10.2172/2426563.

Thus, it is likely that the domestic renewable diesel production will fall short of the 9.6 billion gallons implied by the sum current production capacity and announced new and expanded facilities. Nevertheless, it appears unlikely that domestic production capacity will limit renewable diesel production through 2030. Rather, it is more likely that the feedstock limitations may limit production.

Figure 7.2.3-3: New or Expanded Renewable Diesel and Jet Fuel Production Capacity in the U.S. Through 2028

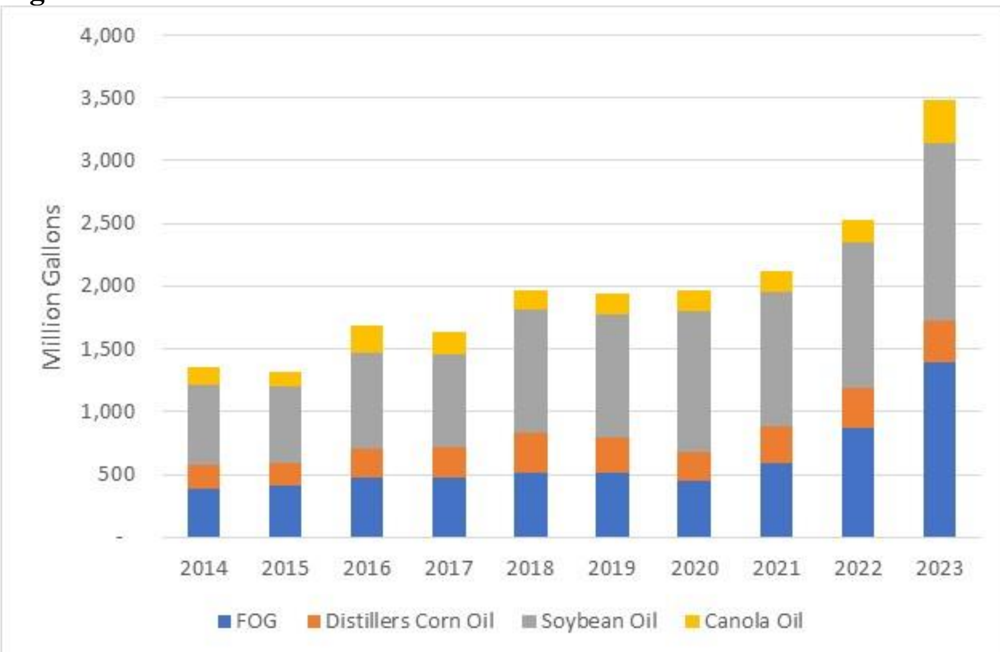


Source: Calderon, Oscar Rosales, Ling Tao, Zia Abdullah, Michael Talmadge, Anelia Milbrandt, Sharon Smolinski, Kristi Moriarty, et al. "Sustainable Aviation Fuel State-of-Industry Report: Hydroprocessed Esters and Fatty Acids Pathway," *National Renewable Energy Laboratory*, NREL/TP-5100-87803, July 30, 2024. https://doi.org/10.2172/2426563.

7.2.4 Biomass-Based Diesel Feedstock Availability to Domestic Biofuel Producers

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 2030, we first reviewed the feedstocks used by domestic BBD producers (including both domestically produced and imported feedstocks) in previous years. This review of feedstocks used by domestic BBD producers in previous years can provide information about the feedstocks most likely to be used by domestic BBD producers 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 2023 is shown in Figure 7.2.4-1.

Figure 7.2.4-1: Feedstocks Used to Produce BBD in the U.S.



Source: EMTS.

Historically the largest sources of feedstock used by domestic BBD producers have been FOG (which includes both used cooking oil and animal fats) and soybean oil, with smaller volumes of distillers corn oil and canola oil. Through 2021, FOG was primarily sourced domestically and the total supply to BBD producers was relatively stable. Beginning in 2021, the quantity of FOG used for domestic BBD production increased significantly, primarily as the result of increasing imports of these feedstocks. The soybean oil and distillers corn oil used by domestic BBD producers have also historically been primarily sourced domestically. Use of soybean oil and distillers corn oil by BBD producers has generally increased with the increased domestic production of these feedstocks. Finally, relatively small quantities of canola oil have been used by domestic BBD producers historically; however, the use of canola oil increased notably in 2023. This increase was likely the result of EPA's approval of a RIN generating pathway for renewable diesel produced from canola oil. Most canola oil used in the U.S. is imported from Canada, but smaller volumes of canola oil are also produced domestically.

Projecting the availability of feedstocks to domestic BBD producers requires a consideration of a wide range of factors including the total production and/or collection of these feedstocks (both in the U.S. and foreign countries) and competition for these feedstocks from both non-biofuel markets and biofuel producers in other countries. Each of these factors are in turn impacted by a variety of technical and political issues that are very difficult to project with certainty in future years. To illustrate these complex dynamics, consider the potential growth in soybean oil and FOG to U.S. biofuel producers. Increasing U.S. soybean oil production in future years will require investment to increase the domestic soybean crushing capacity. Domestic soybean crushers that have made these investments in the past are able to do so in the future but are unlikely to do so unless they have a reasonable expectation of increasing demand for soybean oil to provide a return on their investments. The recent observed increase of imported FOG to domestic BBD producers is the result of increased global collection of these feedstocks and changes to biofuel policies in both the U.S. and other countries, such that the U.S. has become a preferred destination for these feedstocks. If these market conditions continue in future years we would expect to see increasing imports of FOG for biofuel production. However, any number of factors, such as other countries adopting more stringent biofuel mandates, providing higher incentives for biofuels produced from FOG, or restricting FOG exports, could quickly change these market dynamics.

The remainder of Chapter 7.2.4 provides more detail on the historic and projected future supply of these feedstocks to domestic BBD producers. In general, these sections focus on projecting the total quantity of feedstocks that could be provided to domestic producers if there are sufficient economic incentives to increase the production and/or collection of these feedstocks and if the U.S. remains a preferred destination for these feedstocks. A further discussion of the uncertainties related to these projections, and how these uncertainties impact the Proposed Volumes, can be found in Chapter 7.2.6 and Preamble Section V.C, respectively. In our discussion of available feedstocks we have differentiated between domestically sourced feedstocks and imported feedstocks, as both the historic trends and factors that are expected to impact future supplies to BBD producers differ significantly depending on the source of the feedstock. While this section considers the availability of imported feedstocks to domestic BBD producers, it does not consider BBD imported from foreign producers, which is covered in Chapter 7.2.5.

7.2.4.1 Domestic BBD Feedstocks

Domestic feedstocks used for BBD production have historically come from three different sources: FOG (including UCO and animal fats), distillers corn oil, and soybean oil. Domestic BBD producers generally do not report whether the feedstock they use to produce biofuel is sourced domestically or imported. In many cases EPA had to infer the quantity of BBD feedstock from domestic sources based on total reported feedstock use records of the quantity of BBD feedstocks imported to the U.S. from UN Comtrade. While this data has its own limitations (for example, it only reports total import quantities of various products and does not identify the importers or the industries using the imported feedstock), we have been able to reasonably estimate the quantities of domestic and imported feedstocks used by BBD producers using a combination of EMTS data on domestic biofuel production by feedstock, domestic feedstock production from USDA and other sources, and import data from UN Comtrade.

Domestic BBD production from fats, oils, and greases (FOG) in the U.S. was mostly from domestically sourced feedstocks and was relatively stable from 2014 through 2020. However, beginning in 2022 it increased rapidly, driven primarily by FOG imports (see Chapter 7.2.4.2 for more information on FOG imports). These feedstocks are generally by-products of other industries. Their historical growth prior to 2014 domestically was driven by the greater economic incentive provided by the RFS and LCFS programs, increasing collection rates, reducing disposal, and shifting them from other uses. Once the majority of FOG that could economically be collected in the U.S. had been used productively, the subsequent growth in the collection of these feedstocks has tended to follow population growth. We expect this trend to continue in future years and that any significant increases in the availability of FOG to domestic biofuel producers will primarily be the result of increased imports of these feedstocks (see

Chapter 7.2.4.2 for a discussion of the availability of imported FOG to domestic BBD producers).

To project increases in the supply of FOG from the U.S. to domestic BBD producers we relied primarily on historical data. Table 7.2.4.1-1 shows the total quantity of FOG used by domestic BBD producers each year from 2014 – 2023. Prior to the significant increase in imported FOG in 2021 the general trend in the production of BBD from FOG was relatively small but predictable growth. From 2014 through 2021 the average annual increase in the domestic production of BBD from FOG was approximately 25 million gallons per year. A study conducted by Global Data similarly projected that the domestic supply of UCO would increase by approximately 30 million gallons per year from 2022 through 2030.[446] Based on this data we project that the domestic supply of FOG to BBD producers will increase at a rate of approximately 25 million gallons per year through 2030.

Table 7.2.4.1-1: Domestic BBD production from FOG (million gallons)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
391	406	477	469	518	516	455	587	869	1,395

Production of BBD from distillers corn oil has also generally increased through 2023. 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 (see Table 7.2.4.1-2). 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 2023 was approximately 2.15 million tons,[447] or enough corn oil to produce about 540 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.[448] It is also possible that domestic production of distillers corn oil could increase or decrease in future years for a variety of reasons, including new varieties of corn with higher oil content, greater extraction rates, or changes in U.S. ethanol production for domestic or international markets. While it is possible that the use of distillers corn oil by domestic BBD producers will increase in future years through the diversion of this feedstock from other markets or increased production, we project that there will not be any increase (or decrease) in the supply of distillers corn oil to domestic BBD producers through 2030.

Table 7.2.4.1-2: Domestic BBD production from Distillers Corn Oil (million gallons)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
187	183	224	245	308	278	226	299	325	332

[446] Global Data, "UCO Supply Outlook," August 2023. https://cleanfuels.org/wp-content/uploads/GlobalData_UCO-Supply-Outlook_Sep2023.pdf. Annual growth in UCO collection based on estimated growth in per capita UCO collection rates from 2022–2030.
[447] USDA, "Grain Crushings and Co-Products Production 2023 Summary," September 2024. https://downloads.usda.library.cornell.edu/usda-esmis/files/v979v304g/m326nt02n/r781z807m/cagcan24.pdf.
[448] For a discussion of backfilling when oil is removed from dried distillers grains, see 83 FR 37735 (August 2, 2018).

The remaining volume of domestic BBD has been produced from soybean oil and canola oil. The largest source of BBD production in the U.S. historically has been soybean oil. While there have been small quantities of soybean oil imported into the U.S. in previous years, the vast majority of soybean oil available in the U.S. is from domestic sources due to the large domestic soybean oil industry and significant tariffs on imported soybean oil.[449] Conversely, the domestic canola oil industry is relatively small, and most of the canola oil used in the U.S. is imported from Canada. Domestic production of canola oil has been relatively stable since 2013/2014,[450] and we are therefore not projecting any increase in the availability of domestic canola oil to U.S. biofuel producers through 2030. Our projections of potential increases in imported canola oil from Canada are covered in Chapter 7.2.4.2. However, there does hypothetically exist the potential for greater quantities of canola oil to be shifted away from other end uses to biofuel production. For the 2023/24 harvest year, domestic disappearance of canola oil was about 8.9 billion pounds across all industries and including exports.[451] Less than half of that volume was used as biofuel feedstock. In a hypothetical scenario where all canola oil was shifted to biofuel production, there would be sufficient supply to produce about 662 million gallons of BBD from canola oil.

Use of soybean oil to produce biodiesel increased from approximately 5.1 billion pounds in the 2013/2014 agricultural marketing year to approximately 12.5 billion pounds in the 2022/2023 agricultural marketing year.[452] This time period saw significant increases in total soybean oil production (through increased domestic soybean crushing) and the use of soybean oil for biofuel production, both in absolute terms and relative to other markets. Domestic soybean crushing increased by 27.5% from 2013/2014 (1,734 million bushels) to 2022/2023 (2,212 million bushels) with a corresponding 30% increase in soybean oil production over these years. At the same time that domestic soybean oil production was increasing, the percentage of all soybean oil produced in the U.S. for biodiesel also increased, from approximately 25% in 2013/2014 to approximately 47% in 2022/2023.

As a point of reference, if all the soybean oil produced in the U.S. in 2022/2023 (26.6 billion pounds) were used to produce BBD, this quantity of feedstock could be used to produce approximately 3.3 billion gallons of renewable diesel. If all soybeans grown in the U.S. in 2022/2023 were crushed domestically (rather than exported) we project that domestic soybean oil production would be approximately 50.6 billion pounds, enough feedstock to produce approximately 6.3 billion gallons of BBD. In the near term it is not possible to crush all the soybeans produced in the U.S. domestically due to crushing capacity limitations, nor is it possible to divert all soybean oil to biofuel production due to strong demand in other non-biofuel industries. These numbers illustrate, however, the theoretical maximum level of BBD production from the current U.S. soybean crop if recent trends toward increasing domestic soybean crushing and greater use of soybean oil for biofuel production relative to other markets were to continue indefinitely. We note, however, that shifting greater quantities of soybean oil from current

[449] USDA, "Oil Crops Yearbook," March 2025. https://www.ers.usda.gov/data-products/oil-crops-yearbook. The agricultural marketing year for soybeans runs from September to August.
[450] Id.
[451] Id.
[452] Id.

markets for increased biofuel production could result in these markets turning to other sources of vegetable oil such as palm oil, potentially impacting the GHG benefits.

Additional soybean oil production in future years is primarily expected to come from increased domestic soybean oil production. While additional quantities could be made available through shifting the use of soybean oil from other markets (discussed further below) this seems relatively unlikely as the total use of soybean oil in non-biofuel markets has remained relatively stable at approximately 14 billion pounds per year since the 2008/2009 agricultural marketing year even as the use of soybean oil for biofuel production has increased by approximately 10 billion pounds.[453] In contrast, U.S. soybean oil production could continue to increase in future with investments in expanding domestic soybean crush capacity, with increases in soybean crush likely resulting in reduced soybean exports. Since 2000/2001 the percentage of U.S. soybean production that has been crushed domestically has varied from a low of 44% in the 2016/2017 agricultural year to a high of 67% in the 2007/2008 marketing year.[454] 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 66.3 million tons (approximately 2.2 billion bushels) in the 2022/2023 agricultural marketing year and is expected to increase to 67 million tons (2.3 billion bushels in 2023/2024).[455] There have also been numerous investment announcements to increase domestic soybean crush capacity through the construction of new facilities as well as the expansion of existing facilities. Crush capacity expansion that is planned and/or currently under construction is expected to continue to add to domestic soybean crush capacity through 2027. Future crush expansion in 2028 and beyond is dependent on the expected demand for soybean oil in these years from the biofuel sector and other markets. 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. However, shifting soybean crushing to the U.S. and using the oil domestically would decrease soy oil supplies abroad. Foreign countries could respond to this reduction of soybean oil supply by increasing their consumption of other vegetable oils.

The USDA Agricultural Projections to 2033 project increasing domestic soybean oil production through 2030 as a result of an increased soybean crushing. USDA projects that domestic soybean oil production will increase by approximately 2 billion pounds from 2025 (28 billion pounds) to 2030 (30 billion pounds).[456] If this entire increase in soybean oil production were used to produce biodiesel or renewable diesel, it would result in an increase of approximately 250 million gallons of biofuel from 2025 to 2030, or an increase of approximately

[453] Id.
[454] Id.
[455] Id.
[456] USDA, "USDA Agricultural Projections to 2033," OCE-2024-1, February 2024. https://www.usda.gov/sites/default/files/documents/USDA-Agricultural-Projections-to-2033.pdf. For each year, we converted soybean oil production projections to calendar year prices by weighting production in the first agricultural marketing year (e.g., 2024/2025 for the 2025 price) by 0.75 and production in the second agricultural marketing year (e.g., 2025/2026 for the 2025 price) by 0.25.

50 million gallons per year.[457] These projections are based on macroeconomic forecasts and do not appear to account for the number of facilities that have recently begun construction or announced plans to build or expand soybean crushing facilities, which could significantly increase domestic soybean oil production through 2028. As such, they are better projections of domestic soybean oil production with static RFS volume requirements at 2025 levels rather than projections of potential domestic soybean oil production supported by strong and growing RFS volume requirements.

EMTS data on domestic BBD production from soybean oil (see Table 7.2.4.1-3) show that the use of soybean oil for BBD production has increased significantly since 2014. The average annual increase in domestic BBD produced from soybean oil from 2014–2023 was approximately 90 million gallons per year. More recent data, however, indicate that this rate of growth may be accelerating. From 2021 to 2023 the average annual growth rate increased to approximately 170 million gallons per year, and the increase from 2022 to 2023 was approximately 260 million gallons.

Table 7.2.4.1-3: Domestic BBD production from Soybean Oil (million gallons)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
641	616	774	745	984	987	1,123	1,072	1,159	1,418

Recent announcements of plans to invest in increasing the domestic soybean crush capacity suggest that the higher observed rates of growth in the supply of soybean oil to BBD producers may continue in future years. In the Set 1 Rule RIA, EPA projected the increase in the domestic production of soybean oil based on publicly available announcements of capacity expansion (including both new facilities and expanded facilities). In the Set 1 rule we projected that from 2022–2025 the production of renewable diesel from domestic soybean oil would increase by approximately 580 million gallons, or approximately 190 million gallons per year. In comments on that rule stakeholders identified several other similar estimates of growth in domestic soybean oil production. 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.[458] 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.[459] More recently a study conducted by S&P Global projected that U.S. soybean crushing expansion from 2024 through 2027 would increase crush capacity by 700 million bushels, producing enough soybean oil to produce approximately 1 billion gallons of renewable diesel.[460] These estimates are summarized in Table 7.2.4.1-4.

[457] These projections are based on the existing RFS volume requirements through 2025 and not any assumed increase in RFS volumes for 2026 and beyond. Future growth projections are therefore based on increases in future demand from non-biofuel sectors.
[458] Comment submitted by American Soybean Association (ASA), Docket Item No. EPA-HQ-OAR-2021-0427-0579. https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0427-0579.
[459] Comment submitted by Clean Fuels Alliance America, Docket Item No. EPA-HQ-OAR-2021-0427-0805. https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0427-0805.
[460] S&P Global, "Availability of Feedstocks for Biofuel Use – Key Highlights," July 2024. https://www.nopa.org/wp-content/uploads/2024/07/NOPA-SPGCI-Availability-of-Feedstocks-Key-Highlights.pdf.

Table 7.2.4.1-4: Summary of Projections of Soybean Oil Supply to BBD Producers (million gallons BBD)

Data Source	Estimated Increase	Timeframe	Annual Average Increase
USDA Agricultural Projections to 2033	250	2025-2030	50
EMTS Data	780	2014-2023	90
EMTS Data	350	2021-2023	170
Set1 RIA	580	2022-2025	190
American Soybean Association	700	2023-2025	350
LMC	750-800	2021-2025	200
S&P Global	1,000	2024-2027[a]	250

[a] Estimate includes expansion in 2024.

The higher observed and projected increases in domestic soybean oil production occurred following a period where soybean oil prices were historically high. From 2013/2014 through 2018/2019 the average price of soybean oil was approximately $0.31 per pound.[461] Starting in 2019/2020 soybean oil prices increased dramatically and remained high for several years, averaging $0.61 per pound from 2019/2020 through 2023/2024.[462] Industry data suggest that the construction timeline for a soybean crushing facility is approximately 2 years, aligning the observed and projected periods of significant growth in domestic soybean oil production with a two year lag of the observed price increase. Thus, the available data suggest that future increases in domestic soybean crushing are possible, but that future increases are dependent on increased demand for soybean oil, whether from BBD producers or other markets.

While there are some slight variations in these estimates, the data submitted by commenters demonstrates that domestic soybean oil production is likely to increase beyond 2025 levels. With the exception of the USDA estimate from the agricultural projections to 2033 and the EMTS data from 2014–2023, all of these estimates cover a time period during which high soybean oil prices lead to increased investment in soybean oil production. These estimates are therefore likely indicative of the level of increases in domestic soybean oil production that could be achieved with continued high demand for domestic soybean oil.

In addition to increasing U.S. soybean crushing, additional quantities of soybean oil could be made available for biofuel production from decreased exports of soybean oil itself. Prior to the ramp-up in biodiesel and renewable diesel use the U.S. exported significant quantities of soybean oil, with soybean oil exports peaking in 2009/2010 at approximately 3.4 billion pounds.[463] Since that time soybean oil exports have generally decreased as the quantity of soybean oil used for domestic biofuel production has increased. USDA estimates that in the 2022/2023 agricultural marketing year soybean oil exports decreased by approximately 90 percent to 0.4 billion pounds.[464] While it is possible that these soybean oil exports could be diverted to domestic biofuel production in future years, diverting all of the soybean oil exports

[461] USDA, "Oil Crops Yearbook," March 2025. https://www.ers.usda.gov/data-products/oil-crops-yearbook.
[462] Id.
[463] Id.
[464] Id.

from 2022/2023 to biofuel production would only increase BBD production by approximately 50 million gallons per year.

Based on our review of the historical data on the use of soybean oil for domestic BBD production and the available projections of increases in soybean crushing capacity in future years, we project that the production of BBD from domestic soybean oil could increase at a rate of approximately 250 million gallons per year through 2030 if supported by increases in demand. Conversely, absent increased demand from the BBD producers increases in domestic soybean production are likely to be much smaller, closer to 50 million gallons per year, driven by increased demand for soybean meal from the livestock industry and other markets.

7.2.4.2 Imported BBD Feedstocks

In recent years domestic BBD producers have used increasing quantities of imported feedstocks to produce BBD. The primary imported feedstocks used for BBD production are FOG (UCO and animal fats) and canola oil. While we do not have reliable information on the quantity of imported soybean oil used for BBD production, USDA estimates total soybean oil imports of approximately 380 million pounds in the agricultural marketing year 2022/2023.[465] Even if this entire volume were used for BBD production it would result in approximately 50 million gallons of renewable diesel per year. Similarly, we are not aware of any available data on imported distillers corn oil used for BBD production. While we do not project significant imports of distillers corn ethanol through 2030 it is possible that imported distillers corn ethanol may become a source of feedstock to domestic BBD producers as corn ethanol production in foreign countries such as Brazil increases.[466] This chapter focuses on projected imports of FOG and canola oil, which are projected to be the dominant sources if imported BBD feedstocks through 2030.

Imports of FOG to the U.S. have, historically, been relatively small. From 2014–2021 imports of FOG increased gradually, reaching a total of about 0.5 million metric tons in 2021.[467] Imports of these feedstocks increased significantly in 2022 and 2023 (see Table 7.2.4.2-1). This rapid rise in the imports of FOG is likely due to a number of factors, including the rapid increase in renewable diesel production capacity,[468] greater incentives from California's LCFS program and other state clean fuels programs for BBD produced from FOG, the changes to the federal tax credit in 2025 which is expected to further advantage biofuels produced from FOG relative to those produced from virgin vegetable oils, and biofuel policies internationally.

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[465] Id.
[466] Colussi, Joana, Nick Paulson, Gary Schnitkey, and Jim Baltz. "Brazil Emerges as Corn-Ethanol Producer with Expansion of Second Crop Corn." *farmdoc daily* (13):120, June 30, 2023. https://farmdocdaily.illinois.edu/2023/06/brazil-emerges-as-corn-ethanol-producer-with-expansion-of-second-crop-corn.html.
[467] Data on imports of FOG from UN Comtrade. Data for imports of UCO and animal fats are based on HS Codes 1518 and 1502.10 respectively.
[468] In general, renewable diesel production facilities are able to process FOG feedstocks, while only a subset of biodiesel production facilities can process these feedstocks. Additionally, many renewable diesel production facilities are located near ports and have easier access to imported feedstocks.

Table 7.2.4.2-1: U.S. Imports of FOG (million metric tons)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
UCO	0.02	0.02	0.02	0.04	0.06	0.09	0.08	0.13	0.40	1.41
Animal Fats	0.06	0.06	0.08	0.08	0.14	0.19	0.24	0.33	0.55	0.79
Total	0.08	0.09	0.10	0.12	0.20	0.28	0.33	0.46	0.95	2.20

Projecting the future supply of FOG to U.S. BBD producers is an inherently difficult task, as it requires projecting not only the global supply of these feedstocks but also making assumptions about future worldwide market conditions for these feedstocks. For example, the recent increase in UCO imports to the U.S. is largely a function of the U.S. surpassing the EU as the preferred destination for UCO exports from foreign countries. These types of market changes can dramatically impact the supply of imported feedstocks to the U.S., and it is not possible to project these changes with any degree of certainty. In this Chapter we have projected the potential available supply of imported FOG to the U.S. assuming that the U.S. remains the preferred destination for these feedstocks. In Chapter 7.2.6 we provide further discussion on some of the key uncertainties related to market conditions for imported feedstocks, and potential future scenarios if other countries increase their market share of imported FOG in future years.

To project potential future supplies of FOG, we first examined several data sets, including historical data on FOG imports and projections of future FOG imports from several sources. EPA considered both historical data on total FOG imports sourced from UN ComTrade and data on domestic BBD production from FOG from EMTS. The data considered are shown in Table 7.2.4.2-2. From 2021–2023 UCO imports increased at an annual average rate of approximately 175 million gallons per year and imports of animal fats increased at a rate of approximately 64 million gallons per year. In both cases the increase from 2022–2023 was higher than the increase from 2021–2022 demonstrating an ongoing trend of increasing FOG imports to the U.S. The total increase in FOG imports from 2021–2023 (478 million gallons) were lower than the total increase in domestic BBD production from FOG (808 million gallons). The fact that the increase in the quantity of BBD produced from FOG from 2021 to 2023 is larger than the total quantity of FOG imported suggests that very little, if any, FOG was used in markets other than biofuel production.

Table 7.2.4.2-2: FOG Imports and Domestic BBD Production from FOG (million gallons)

	2019	2020	2021	2022	2023
UCO Imports[a]	24	23	36	109	387
Animal Fat Imports[a]	53	67	91	152	218
Total FOG Imports[a]	77	90	127	261	605
BBD Produced from FOG[b]	516	455	587	869	1,395

[a] Import data from UN ComTrade (Data on FOG represents HS code 1518 and data on animal fats represents HS code 1502.10). Data from ComTrade was converted from kilograms to million gallons BBD assuming 8 lbs FOG per gallon of BBD.
[b] Data from EMTS.

EPA also considered available estimates of potential FOG imports. A study conducted by Global Data on behalf of the Clean Fuels Alliance America in August 2023 projected the potential increase in the supply of UCO to domestic BBD producers of approximately 0.9 billion gallons from 2025 to 2030 in their base case, an increase of approximately 180 million gallons per year.[469] This same study also estimated additional global potential beyond the base case. Global Data estimated that the additional global potential could increase the global supply of UCO available to biofuel producers to support an additional 4.7 billion gallons of BBD production from 2025 to 2030. Another study conducted by S&P Global projected that UCO imports to the U.S. could increase by about 5 billion pounds per year from 2023 – 2030 (enough to produce over 600 million gallons of BBD) and tallow imports could increase by about 3.25 billion pounds from 2023–2030 (enough to produce over 400 million gallons of BBD).[470] The estimates of the potential growth rate in the production of BBD from FOG from both the historic data and these studies are summarized in Table 7.2.4.2-3.

Table 7.2.4.2-3: Summary of Projections of FOG Supply to BBD Producers (million gallons BBD)

Data Source	Estimated Increase	Timeframe	Annual Average Increase
All FOG (undifferentiated)			
EMTS Data	808	2021-2023	404
UCO			
UN ComTrade Imports	351	2021-2023	176
Global Data (Base Case)	900	2025-2030	180
Global Data (Base + Potential)	5,600	2025-2030	1,120
S&P Global	600	2023-2030	86
Tallow			
UN ComTrade Imports	127	2021-2023	64
S&P Global	400	2023-2030	58

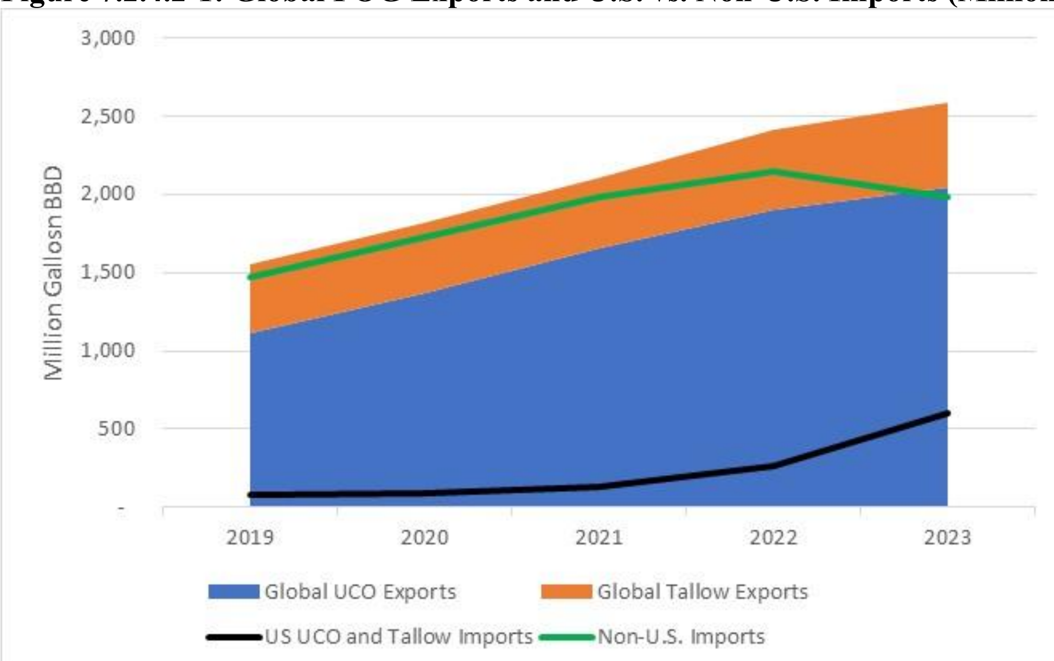
Based on our review of the historical data on the use of imported UCO and tallow for domestic BBD production and the available projections of increases in the imports of these feedstocks in future years, we project that the production of BBD from imported UCO could increase at a rate of 200 million gallons per year through 2030 and imported tallow could increase at a rate of 50 million gallons per year through 2030. These projections are slightly lower than the observed rate of increase in domestic BBD production from FOG from 2021–2023 when the U.S. became a more significant importer of these feedstocks. We note, however, that these numbers also include increases from domestic sources of FOG.

To assess the feasibility of increasing imports of FOG for biodiesel production we considered the global volumes of these feedstocks exported over the past five years for which data were available and the total quantity of these feedstocks imported by the U.S. This information is shown in Figure 7.2.4.2-1. During this time period, global exports of tallow have increased gradually, while UCO exports have increased more quickly. Total UCO exports in 2023 were more than 80% higher than in 2019. At the same time, U.S. imports of FOG increased significantly since 2021, both in absolute terms and as a percentage of total FOG market. The projected potential increases in U.S. FOG imports (250 million gallons per year) through 2030

[469] Global Data, "UCO Supply Outlook," August 2023. https://cleanfuels.org/wp-content/uploads/GlobalData_UCO-Supply-Outlook_Sep2023.pdf.
[470] S&P Global, "Availability of Feedstocks for Biofuel Use," July 2024. https://www.nopa.org/wp-content/uploads/2024/07/NOPA-SPGCI-Availability-of-Feedstocks-Key-Highlights.pdf.

are approximately equal to the observed average annual increases in total FOG exports from 2019–2023 (260 million gallons per year). If global FOG exports continue to increase at the observed rate from the past five years, the projected FOG imports could occur without diverting FOG from existing markets. Alternatively, if demand for these feedstocks from other markets increases this may limit the quantity of these feedstocks available to U.S. BBD producers. These projections therefore assume continued incentives for the production of BBD from FOG sufficient to ensure that the U.S. remains the preferred global destination for these feedstocks. Policy changes by the U.S. to discourage imports or by other countries to discourage the export of FOG to foreign markets, or to increase their domestic incentives offered for biofuels produced from these feedstocks, could have a significant impact on the available supply in future years.

Figure 7.2.4.2-1: Global FOG Exports and U.S. vs. Non-U.S. Imports (Million Gallons)



In addition to imported FOG, we also project significant quantities of imported canola oil could be made available to domestic BBD producers in future years. As with other potential sources of feedstock for domestic BBD producers, we used the historic BBD production and canola oil import data as a starting point for our future projections. Annual domestic BBD production and canola oil imports are shown in Table 7.2.4.2-4. From 2014 through 2022 production of BBD from canola oil fluctuated between 100 and 200 million gallons per year. Production of BBD from canola oil increased significantly in 2023, to approximately 340 million gallons likely as the result of increased canola crushing in Canada and the approval of the pathway for renewable diesel to generate BBD RINs for fuel produced from canola oil.[471] Since the 2010/2011 agricultural marketing year approximately 70% of all canola oil supplied to the U.S. has been imported,[472] and greater than 95% of the imported canola oil is imported from Canada.[473] We anticipate that through 2030 Canada will be the predominant source of any

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[471] 87 FR 73956 (December 2, 2022).
[472] USDA, "Oil Crops Yearbook," March 2025. https://www.ers.usda.gov/data-products/oil-crops-yearbook.
[473] Data from UN Comtrade.

increase in imports of canola oil to domestic BBD producers and have therefore primarily focused on potential imports from Canada in projecting the availability of canola oil for biofuel production.

Table 7.2.4.2-4: Domestic BBD Production from Canola Oil and Total Canola Oil Imports (Million Gallons BBD Equivalent)

	2014	2015	2106	2017	2018	2019	2020	2021	2022	2023
Domestic BBD Production from Canola Oil	141	115	207	177	159	157	159	166	174	344
Canola Oil Imports for All Uses	433	470	509	541	505	493	506	524	610	809

We also considered projections of increased canola oil production in Canada in future years and how much of that increased production would be made available to U.S. biofuel producers. In the Set 1 rule EPA used publicly available data to project increasing canola oil production in Canada from 2022–2025. We projected that total canola oil production in Canada would increase by approximately 1.1 million metric tons from 2022–2025, and that half of this increase in production would be available to U.S. BBD producers (enough canola oil to produce approximately 280 million gallons of BBD). The estimate that only half of the increased in Canadian canola oil production would be available to U.S. BBD producers reflects our expectation that there will continue to be strong demand for canola oil in both the food market and from Canadian biofuel producers.

More recently S&P Global estimated that canola oil production in Canada would increase by about 5.4 billion pounds from 2024–2027. This quantity of canola could be used to produce approximately 700 million gallons of BBD if it were all used for this purpose. To estimate how much of this biofuel could be available to U.S. BBD producers we considered projected BBD demand in Canada. Canada passed the Clean Fuels Regulations in 2022. These regulations require decreasing carbon intensities from transportation fuel used in Canada each year from 2023–2030. USDA FAS estimated BBD use in Canada in 2023 at approximately 370 million gallons.[474] A document published by Environment Canada in February 2024 projected that under a current measures scenario BBD consumption in Canada could increase to approximately 1.1 billion gallons in 2035.[475] Reaching 1.1 billion gallons of BBD consumption in 2035 would require an average annual increase of approximately 60 million gallons per year. If Canadian canola oil production continues to increase at the rate projected by S&P Global from 2024–2027 (175 million gallons per year) the availability of canola oil to U.S. BBD producers could increase by over 100 million gallons per year after accounting for the projected increase in BBD demand

[474] USDA, "Biofuels Annual – Canada," December 8, 2024. https://apps.fas.usda.gov/newgainapi/api/Report/DownloadReportByFileName?fileName=Biofuels%20Annual_Ottawa_Canada_CA2024-0057.pdf.

[475] Canada Energy Regulator, "Market Snapshot: Bioenergy Use Could Double in Canada's Net-Zero Future," February 21, 2024. https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/2024/market-snapshot-bio-energy-use-could-double-canadas-net-zero-future.html.

in Canada. The estimates of the potential growth rate in the production of BBD from canola oil from both the historic data and these future projections are summarized in Table 7.2.4.2-5.

Table 7.2.4.2-5: Summary of Projections of Canola Oil Supply to BBD Producers (million gallons BBD)

Data Source	Estimated Increase	Timeframe	Annual Average Increase
EMTS BBD Production from Canola Oil	178	2021–2023	89
USDA Canola Oil Imports	285	2021–2023	143
EPA Projection in Set1	283	2022–2025	94
S&P Global (Total)[a]	700	2024–2027	175
S&P Global (50%)[a]	350	2024–2027	88

[a] Estimate includes expansion in 2024.

Based on our review of the historical data on the use of imported canola oil used for domestic BBD production and the available projections of increases in the imports of canola oil in future years we project that the production of BBD from imported canola oil could increase at a rate of 100 million gallons per year through 2030. This projection is similar to the observed rate of increase in BBD produced from canola oil since 2021, as well as the average annual increase of canola oil we projected would be available to domestic BBD producers in the Set 1 Rule. It is lower than the observed annual increase in total canola oil imports since 2021 and the projected total increase of canola oil production in Canada, reflecting continuing strong demand for canola oil from Canadian biofuel producers and non-biofuel markets. As with the previous feedstock projections, these projections assume continued incentives for the production of BBD from FOG sufficient to ensure that the U.S. remains the preferred global destination for these feedstocks.

7.2.4.3 Emerging Oilseed Feedstocks

In addition to the feedstocks that have historically been used for BBD production, a number of BBD producers have expressed interest in using emerging feedstocks, such as oil from camelina, carinata, or pennycress, for BBD production in future years. These emerging oilseed crops are most often intended to be grown as second crops on existing cropland and/or as an alternative to fallow years when no commercial crops would otherwise be grown. As such, they have the potential to increase vegetable oil production with little or no increase in total cropland or displacement of other crops. While there are currently pathways for some of these emerging oilseeds, very little BBD has been produced from them to date. We anticipate that there will be increasing interest in developing and adopting these crops in future years. The process of introducing new crops at commercial scale, however, generally takes many years. At this time we are not projecting significant volumes of vegetable oil will be made available to domestic BBD producers from emerging oilseeds through 2030.

7.2.4.4 Summary of the Availability of BBD Feedstocks

As described in the preceding Chapters, EPA has projected the average annual increase in the feedstocks available to domestic BBD producers. We have considered the primary feedstocks used to produce BBD since the beginning of the RFS program (FOG, distillers corn oil, soybean oil, and canola oil) from both domestic and imported feedstocks. Our projections assume that there continues to be sufficient incentives for BBD production in the U.S. to drive investment in domestic oilseed crushing, and that the U.S. remains the preferred destination for exported BBD feedstocks from other countries. As such, they represent the projected annual volume increases that could be achieved under favorable market conditions. Because these feedstocks are reasonable substitutes for each other in many markets we have greater confidence in the total projected annual increase than in any of the individual feedstock estimates. The actual supply of any single feedstock will likely depend on a number of factors, including the incentive available for biofuel produced from each feedstock in the U.S. and other countries. Our projected annual increases of the potential BBD feedstocks are summarized in Table 7.2.4.4-1. Further discussion of the likely supply of these feedstocks and domestic BBD production in alternative circumstances can be found in Chapter 7.2.6.

Table 7.2.4.4-1: Projected Annual Increase in BBD Feedstocks Through 2030 (million gallons BBD equivalent)

Feedstock	Projected Annual Average Increase
Domestic FOG	25
Domestic Distillers Corn Oil	0
Domestic Soybean Oil	250
Imported UCO	200
Imported Tallow/Animal Fats	50
Imported Canola Oil	100
Emerging Vegetable Oils	0
Total	625

7.2.5 Imports and Exports of Biomass-Based Diesel

In evaluating the potential consumption of BBD through 2030 we also examined BBD imports and exports in previous years. 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.[476] These tariffs were subsequently confirmed in April 2018.[477] Since the time the preliminary tariffs were announced, EIA has not reported any biodiesel imported from these countries.[478] After the imposition of these tariffs, imports of biodiesel from other countries increased marginally; however, the biggest effect of these tariffs has been a decrease in the total volume of imported biodiesel back to approximately 200 million gallons during 2018–2022. However, in 2023 biodiesel imports increased significantly once again. Most of the increase in biodiesel imports

[476] 82 FR 40748 (August 28, 2017).
[477] 83 FR 18278 (April 26, 2018).
[478] EIA, "U.S. Imports by Country of Origin – Biodiesel," *Petroleum & Other Liquids*, April 30, 2025. https://www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_EPOORDB_im0_mbbl_a.htm.

were supplied by countries in the EU, including Germany, Italy, and Spain.[479] The increase in imports from the EU observed in 2023 reflect both strong biodiesel demand in the U.S. (supported by incentives such as the RFS program, the federal tax credit, and state incentives) and weakening demand for these fuels in the EU.

Renewable diesel imports have generally increased from 2014–2021. Since 2021, renewable diesel imports have been relatively stable, ranging between 300 and 400 million gallons per year. A significant factor in the increasing imports of renewable diesel appears to be the California Low Carbon Fuel Standard (LCFS), as most of the renewable diesel consumed in the U.S. (including both domestically produced and imported renewable diesel) has been consumed in California where it could benefit from both RFS and LCFS incentives.[480] We expect that, as the CI requirements in California's LCFS program continue to decrease, and as similar LCFS programs are taken up in other states (e.g., New Mexico, Oregon and Washington), these programs, in conjunction with the RFS program and the federal tax credit, will continue to provide an attractive market for both domestically produced and imported renewable diesel.

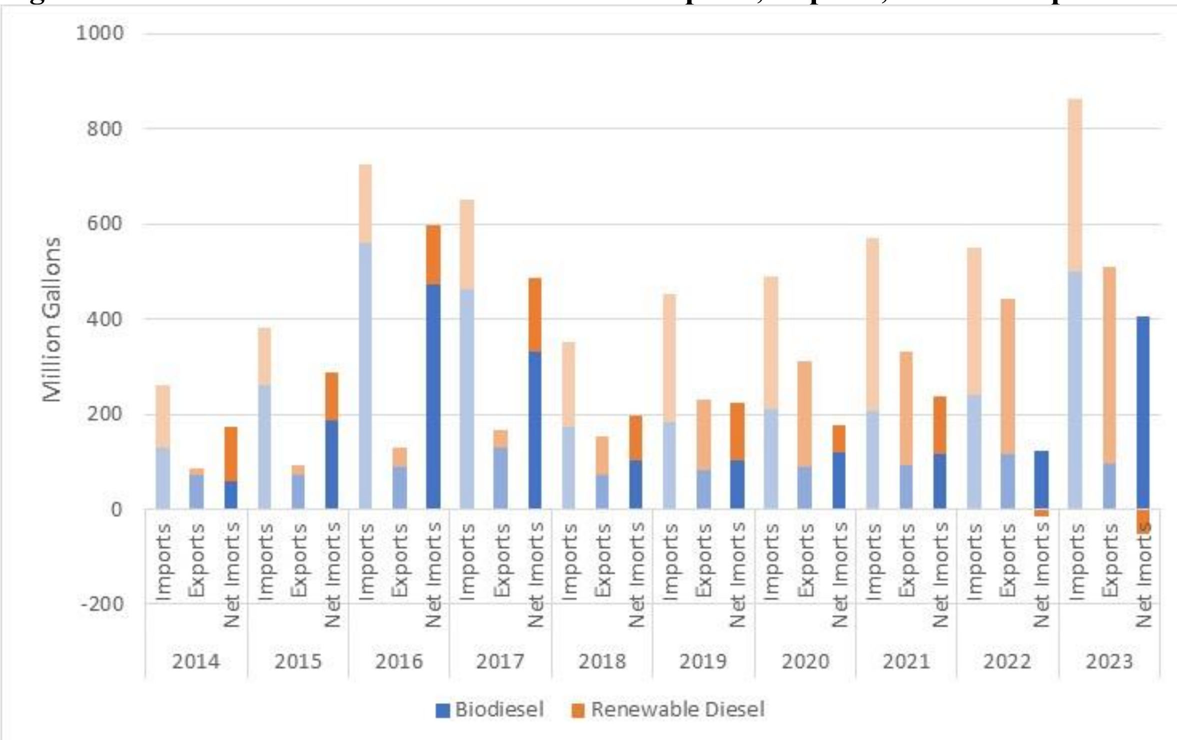
Exports of RIN generating biodiesel, based on EMTS data, have been fairly consistent since 2014, generally ranging between 70 and 130 million gallons per year. According to EMTS data, renewable diesel exports increased with domestic renewable diesel production, reaching over 400 million gallons in 2023. 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.[481] Biodiesel and renewable diesel imports, exports, and net imports are shown in Figure 7.2.5-1.

[479] Id.

[480] Data from California's LCFS program indicates that approximately 1.97 billion gallons of renewable diesel were consumed in California in 2023, the most recent year for which data are available (CARB, LCFS Data Dashboard. https://ww3.arb.ca.gov/fuels/lcfs/dashboard/dashboard.htm). Data from EMTS indicates that 2.36 billion gallons of renewable diesel were consumed in the U.S. in 2023, including both renewable diesel that generated BBD RINs and advanced RINs.

[481] Tuttle, Robert. "Canada Releases California-Style Fuel Rules to Cut Emissions," *Bloomberg*, June 29, 2022. https://www.bloomberg.com/news/articles/2022-06-29/canada-releases-california-style-fuel-rules-to-cut-emissions.

Figure 7.2.5-1: Biodiesel and Renewable Diesel Imports, Exports, and Net Imports



The fact that there are both imports and exports of BBD simultaneously 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.

This dynamic, however, is about to change. The biodiesel blenders tax credit expired at the end of 2024 and was replaced by the CFPC.[482] The CFPC differs from the biodiesel blenders tax credit is several significant ways. The CFPC is not limited to producers of biodiesel and renewable diesel, rather it is available to all transportation fuels that meet a specified emission factor. The CFPC is also only available for fuels produced in the U.S. Finally, the CFPC is not a fixed amount per gallon of qualifying fuel produced, but instead offers greater incentives to fuels with lower GHG emissions.

Because the CFPC is only available for fuels produced in the U.S., we expect the change in the tax credit will negatively impact imports of biodiesel and renewable diesel in future years. It may simultaneously increase the imports of feedstocks for use by domestic biofuel producers as these producers seek additional quantities of feedstocks with lower carbon intensities to

[482] See Chapter 1.6 for a further discussion of the CFPC, including estimates of the value available to different types of biofuels.

maximize the value of the tax credit and result in reduced exports of biodiesel and renewable diesel as U.S. markets seek alternatives to imported biodiesel and renewable diesel that are no longer eligible for the tax credit. As discussed further in Chapter 7.2.6, the CFPC may also result in greater demand for low-carbon feedstocks such as FOG and the fuels produced from these feedstocks with relatively less demand for biofuels produced from virgin vegetable oils such as soybean oil and canola oil.

In projecting net imports of BBD through 2030 we considered both the historical trends and expected impact of the change to the CFPC in 2025. Net BBD imports have been relatively stable at around 200 million gallons per year since 2018. As imported BBD is not be eligible for the CFPC, we expect imports of BBD will likely decline in future years. We do not expect imports of BBD to cease altogether, as some BBD producers with established markets in the U.S. may not find it economically viable to find alternative markets for their fuels. Further, as the CFPC is expected to provide relatively little value for BBD produced from virgin vegetable oils, imported BBD produced from these feedstocks will be at a relatively small disadvantage when competing with domestic fuels produced from the same or similar feedstocks. We acknowledge that there is significant uncertainty in projecting the available supply of imported BBD in future years. In addition to the normal market uncertainty, the potential market reactions to the new tax policy make it even more difficult to project BBD net imports going forward. Ultimately, we project that any decrease in BBD imports will likely be offset, in whole or in large part, by decreases in BBD exports, such that we do not project significant changes to net BBD imports through 2030.

7.2.6 Projected Rate of Production and Use of Biomass-Based Diesel

The preceding Chapters describe the factors EPA considered when projecting the rate of production and use of BBD through 2030. These factors include the supply of these fuels to the U.S. in previous years, the current and projected BBD production capacity, the availability for the market to consume these fuels, the available supply of feedstocks to domestic BBD producers, and the projected imports and exports of BBD. After reviewing this data we have determined that the factor most likely to limit the production and use of BBD through 2030 is the availability of qualifying feedstocks at economically sustainable prices.

The availability of qualifying feedstocks is not a hard limit, but rather reflects EPA's judgement about the quantity of feedstocks that would be reasonable to assume are available to domestic BBD producers in light of the expected impacts of supplying higher or lower quantities of feedstock. For example, the global production of vegetable oil in the 2023/2024 agricultural marketing year was approximately 223 million metric tons, or enough vegetable oil to produce over 60 billion gallons of BBD. While this entire quantity of vegetable oil may be technically available for use to BBD producers, the cost of out-bidding existing markets for this entire volume of vegetable oil would be extreme, as would be the environmental and social impacts. Our projections of available feedstock generally assume consistent demand for potential BBD feedstocks from food markets and other industries, as well as consistent demand for biofuels in other countries. In other words, we have focused our assessment of BBD feedstock availability on projections of increasing feedstock production rather than diversion from existing uses and have generally not considered feedstocks or biofuels currently being used in non-U.S. biofuel markets to be available. We recognize, however, that it is possible that feedstocks supplied to domestic BBD producers can be sourced from both new production/collection of feedstocks as well as diversions of these feedstocks from existing uses.

To project the available quantity of BBD in the U.S. through 2027 we started with a projection of the BBD supply in 2025, discussed in greater detail in Chapter 7.2.5. From that starting point we applied the projected annual growth rates for the major feedstocks used to produce BBD in the U.S. (FOG, distillers corn oil, soybean oil, and canola oil), discussed in greater detail in Chapter 7.2.3. Based on the supply trends since 2018 (discussed in Chapter 7.2.1) and the projected changes in production capacity beyond 2025 (discussed in 7.2.2) we project that all of the growth in the BBD category through 2027 will come from renewable diesel and jet fuel, and that domestic biodiesel production will remain constant during these years. The annual supply of BBD through 2027 by fuel type and feedstock that result from these projections are shown in Tables 7.2.6-1 (in million RINs) and 7.2.6-2 (in million gallons).

Table 7.2.6-1: Projected Supply of BBD Through 2027 (million RINs)

Fuel Type	2026	2027
BBD (total)	**8,690**	**9,190**
Biodiesel (total)	**2,600**	**2,620**
Soybean Oil	1,664	1,684
FOG	384	384
Corn Oil	311	311
Canola Oil	241	241
Renewable Diesel/Jet Fuel (total)	**6,090**	**6,570**
Soybean Oil	1,990	2,390
FOG	2,335	2,415
Corn Oil	1,087	1,087
Canola Oil	678	678

Table 7.2.6-2: Projected Supply of BBD Through 2027 (million gallons)

Fuel Type	2026	2027
BBD (total)	**6,826**	**7,155**
Biodiesel (total)	**2,116**	**2,145**
Soybean Oil	1,220	1,249
FOG	366	366
Corn Oil	208	208
Canola Oil	322	322
Renewable Diesel/Jet Fuel (total)	**4,710**	**5,010**
Soybean Oil	1,294	1,544
FOG	2,119	2,169
Corn Oil	681	681
Canola Oil	616	616

These projected volumes reflect two significant assumptions, both of which are subject to significant uncertainty. The first assumption is that policies in the U.S. (including the RFS, federal tax credit, and other state level incentives and volume mandates) continue to provide a strong incentive for BBD produced from virgin vegetable oils such as soybean oil and canola oil. The projected increases in the supply of BBD produced from soybean oil and canola oil are primarily driven by projected investment in and expansion of soybean and canola crushing facilities in the U.S. and Canada in addition to those already underway. While the market has demonstrated a willingness and ability to make these investments, a lack of support for biofuels produced from these vegetable oils would be expected to negatively impact the profitability of oilseed crushing in North America and any future investment in soybean and canola crushing capacity in the U.S. and Canada. Alternatively, even if investment in oilseed crushing were to continue, it is likely that the increased vegetable oil production from these facilities and/or biofuels produced from the increased supply of vegetable oils would be exported to other markets absent strong incentives for these products in the U.S.

The second assumption is that the U.S. remains the preferred destination for imported biofuel feedstocks such as UCO and animal fats. Current policies, such as the CFPC and state programs in California, Oregon, and Washington, provide greater incentives for BBD produced from these feedstocks relative to BBD produced from virgin vegetable oils. The observed increase in the import volumes of these feedstocks in 2022 and 2023 suggests that these incentives, when combined with declining demand for BBD in the EU, are capable of drawing increasing volumes of these feedstocks to U.S. markets in future years. Conversely, the proposed reduction in the number of RINs generated for renewable fuel produced from foreign feedstocks is expected to result in decreased incentives for continued feedstock imports, which may offset, in part or in whole, any incentives renewable fuel produced from these feedstocks receive from other programs.

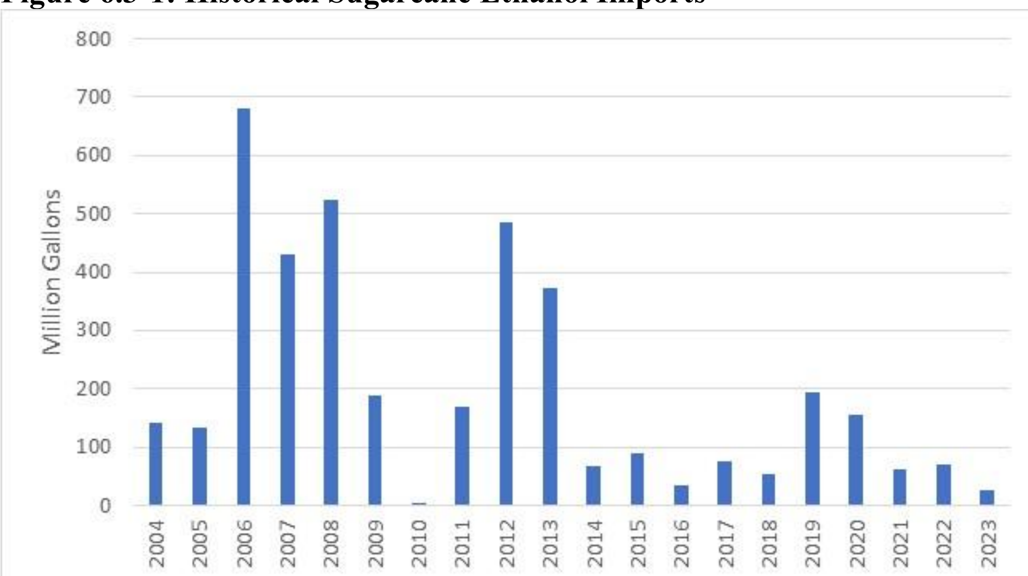
The changing import patterns for these feedstocks also demonstrate that the primary destination for these feedstocks can change quickly. Even if incentives for BBD produced from these feedstocks remain strong through 2030 the rate of increase in the imported volumes of FOG and animal fats could decline if, for example, other countries adopt mandates or even greater incentives for biofuels produced from these feedstocks in future years. It is also possible that countries currently exporting these feedstocks, primarily in Asia and South America, may seek to establish their own biofuel programs through a combination of incentives, biofuel use mandates, or taxes or prohibitions on the export of these feedstocks.

Because these projections assume strong incentives for the production and use of BBD in the U.S. and that the U.S. remains the preferred destination for feedstock exports from other countries the projection can be viewed as something akin to an upper bound or best-case scenario for the supply of BBD to the U.S. through 2030. That is not to say that higher volumes are not possible, but rather that higher volumes would likely require the diversion of BBD and/or feedstock from existing markets. It is also possible that lower volumes of BBD that projected in the chapter may be supplied in future years. All else equal, lower RFS volume requirements are expected to result in a lower supply of BBD. Even if U.S. demand remains strong, increased incentives or use mandates in other countries may similarly result in a lower supply of BBD to the U.S. While it is possible to project the domestic and global production of BBD in the near to mid-term with some degree of confidence based on projections of biofuel production capacity and feedstock supplies, projecting where in the world these biofuels will be consumed necessarily requires making assumptions about a number of factors, including potential changes to national policies related to biofuel use and broader trade policies, that are inherently uncertain.

7.3 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 2023 demonstrates considerable variability in imports of sugarcane ethanol.

Figure 6.3-1: Historical Sugarcane Ethanol Imports



Source: EIA, "U.S. Imports of Brazilian Fuel Ethanol," *Petroleum & Other Liquids*, April 30, 2025. https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=mfeim_nus-nbr_1&f=a. 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 2018–2021 ethanol imports entered the U.S. through the West Coast, as did the majority of ethanol imports in 2022 and 2023. 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 RFS rulemakings, the high variability in historical ethanol import volumes makes any projection of future imports uncertain.[483] 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, we developed a methodology used in the final rulemaking which established the volume requirements for 2022 as well as the Set 1 Rule that established volumes for 2023–2025. 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.

[483] See, e.g., 85 FR 7032-33 (February 6, 2020) and 87 FR 39600 (July 1, 2022).

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 7.3-1. The resulting weighted average is 58 million gallons. As we are projecting volumes for 2026–2030 in this action, and this is the latest data available, the same projection applies for all three years.

Table 7.3-1: Annual Advanced Ethanol Imports and Weighting Factors

Year	Imported advanced ethanol[a] (million gallons)	Weighting factor
2015	89	0.00391
2016	34	0.00781
2017	74	0.0156
2018	78	0.03125
2019	196	0.0625
2020	185	0.125
2021	60	0.25
2022	81	0.5
2023	21	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 2026–2030 could be lower or higher than 58 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 transportation fuel prices and demand.

7.4 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 7.4-1: 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	86	150
2021	7	26	2	33	105	173
2022	6	29	3	71	118	227
2023	7	30	4	33	120	194

We have used the same weighted averaging approach (see Table 7.3-1) 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 192 million RINs. This volume of other advanced biofuel is composed of 28 million RINs of domestic advanced ethanol, 111 million RINs of co-processed renewable diesel, and 52 million RINs of other advance biofuels (non-cellulosic RNG, heating oil, and naphtha). We have used these values in our candidate volumes for each 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 in very small amounts in the past, if at all, we do not believe the market will make available substantial volumes from these sources in the timeframe of this rulemaking (2026–2030).

7.5 Total Ethanol Consumption

Total ethanol consumption is the sum of ethanol blended with fossil fuel gasoline (E0) to create E10, E15, and E85 transportation fuel blends. In the Set 1 Rule, EPA projected ethanol concentration in the national gasoline pool for future years using a least-squares regression model using E15 and E85 fueling station population data.[484] This decision was the result of poor data availability for sales volumes at the retail station level especially for higher blends and unsatisfactory insight into the distribution of total sales volumes aggregated by blend level. In reevaluating our methodology for this proposed rulemaking, EPA found the percent ethanol concentration in the gasoline pool to be unrealistically high using the prior approach. To produce a more reasonable projection of total ethanol consumption that brings percent ethanol concentration in the national motor gasoline pool more in line with recent observations, EPA opted to take a different approach. For this proposal, volume data from the HBIIP program and

[484] For more details on our prior methods, see Set 1 Rule RIA Chapter 6.5.1.

volume data acquired directly from six states with high volumes of higher-level ethanol blends (CA, KS, IA, MN, NY, and ND) has enabled EPA to employ a data-driven, bottom-up approach to projecting total ethanol consumption for the years 2026–2030.

7.5.1 Projection of Motor Gasoline Consumption

The national average ethanol concentration in the nationwide gasoline pool surpassed 5% in 2007 and experienced a period of rapid growth, finally surpassing 10% (i.e. the "blend wall") for the first time in 2016. The share of ethanol in the gasoline pool has continued to increase since then, albeit at a slower pace after the market became saturated with E10. The total volume of ethanol that can be consumed, including that produced from corn, cellulosic biomass, non-cellulosic portions of separated food waste, and sugarcane, is a function of the relative volumes of E0, E10, E15, and E85 that comprise pool-wide motor gasoline consumption. Average ethanol concentration can exceed 10% only to the extent ethanol in E15 and E85 fuels can exceed the ethanol content of E10 and more than offset the dilution effect of E0 volumes.

As mentioned, EPA has adopted a new, simplified, bottom-up methodology for projecting ethanol consumption into the future for the years covered by this proposed rulemaking. Volume projections were generated using data on fueling station populations and the average volume sold per station (i.e., station throughput) using the following relation:

$$Total\ volume = Number\ of\ stations * Avg\ gallons\ sold\ per\ station$$

Volumes were projected for E0, E10, E15, and E85 independently for economic analysis because distribution practices and costs vary between different proofs of ethanol-gasoline blends.[485] Projected volumes for each blend level were generated using the equation:

$$\sum_{i=2026}^{2030} a_0^n b_0^n + a_{10}^n b_{10}^n + a_{15}^n b_{15}^n + a_{85}^n b_{85}^n$$

For each year (2026–2030), the total amount of ethanol is found by the above equation, where *a* is the total number of stations for the applicable fuel proof (E0…E85, denoted by the subscripts) in year *n* and *b* is average station throughput (gallons per station) observed for the appropriate proof in year *n*. Summing the products of *a* and *b* for each blend value within a year yields the total amount of fossil fuel gasoline and biofuel from ethanol projected to be sold for that year. Performing the summation across all years yields the total expected volume sold during the proposed rule's timeframe. A tabular presentation of the main variables and their data sources (or derivations of their values, where data was not available) is shown in Table 7.5.1-1.

In producing projections of station counts across the years covered by this proposal, EPA projected the stations located in California separate from the remainder of the country. This is due to the unique policy environment in California, where E85 sales are disproportionately high due to California's high gasoline prices and the added incentive provided by the California Low Carbon Fuel Standard allowing E85 pricing to be much more favorable than in other states.

[485] See Chapter 10 for more detailed analyses of renewable fuel costs.

Approximately 10% of E85 stations are in California and these stations move much greater volumes of fuel on a per-station basis. To reflect the most recent trends in E85 sales, we used only data from years 2021–2023 to extrapolate projections of E85 stations nationally and E85 volumes for California.

Table 7.5.1-1: Main Variables and Data Sources Used for the Projection of Poolwide Ethanol Consumption (2026–2030)

<table>
<tr><th>Variable</th><th>Data Source or Derivation</th></tr>
<tr><td>E0 Stations</td><td>Pure-Gas.org[486]</td></tr>
<tr><td>E15 Stations</td><td rowspan="3">AFDC[487]/Prime the Pump[488]</td></tr>
<tr><td>E85 Stations (Non-CA)</td></tr>
<tr><td>E85 Stations (CA)</td></tr>
<tr><td>E0 Throughput</td><td>Iowa Department of Revenue[489]</td></tr>
<tr><td>E15 Throughput</td><td rowspan="2">Derived from BIP[490]/HBIIP[491]</td></tr>
<tr><td>E85 Throughput (Non-CA)</td></tr>
<tr><td>E85 Throughput (CA)</td><td>Calculated quotient of:
E85 Total Volume (CA) / E85 Station Counts (CA)</td></tr>
<tr><td>E0 Total Volume</td><td>Calculated product of:
E0 Stations * E0 Throughput</td></tr>
<tr><td>E10 Total Volume</td><td>Remainder of projected motor gasoline consumption published by EIA in AEO2023[492] that is not E0, E15, or E85</td></tr>
<tr><td>E15 Total Volume</td><td>Calculated product of:
E15 Stations * E15 Throughput</td></tr>
<tr><td>E85 Total Volume (Non-CA)</td><td>Calculated product of:
E85 Stations (Non-CA) * E85 Throughput (Non-CA)</td></tr>
<tr><td>E85 Total Volume (CA)</td><td>CARB[493]</td></tr>
</table>

The annual average number of stations offering E15 and E85 in the U.S. are shown in Table 7.5.1-2. Historical annual averages of E15 station populations based on interpolations of data provided by Prime the Pump and corroborated by DOE's Alternative Fuel Data Center (AFDC). The AFDC does not publish E15 station population data but does report just over 3,000 stations offering E15 blends for sale in 2023. Based on communications with stakeholders and recently updated numbers from Prime the Pump, EPA expects just over 3,700 E15 fueling

[486] Pure-Gas.org, "Stations." https://www.pure-gas.org.
[487] AFDC, "Historical Alternative Fueling Station Counts." https://afdc.energy.gov/stations/states.
[488] Prime the Pump is an biofuels industry-led program seeking to encourage and expand retail adoption of E15 by building out infrastructure.
[489] Iowa Department of Revenue, "2023 Retailers Fuel Gallons Annual Report," March 2024. https://revenue.iowa.gov/media/3846/download?inline.
[490] USDA, "Biofuel Infrastructure Partnership." https://sandbox.fsa.usda.gov/programs-and-services/energy-programs/bip/index.
[491] USDA, "Higher Blends Infrastructure Incentive Program." https://www.rd.usda.gov/hbiip.
[492] AEO2023, Table 11 – Petroleum and Other Liquids Supply and Disposition.
[493] CARB, "Annual E85 Volumes," April 11, 2025. https://ww2.arb.ca.gov/resources/documents/alternative-fuels-annual-e85-volumes.

stations in operation in 33 states at the end of 2024.[494] This reported datapoint is in good agreement with our projections, which represent annual averages of station populations.

Table 7.5.1-2: Annual Average Number of Stations Offering Higher Level Ethanol Blends

Year	E15 Stations	E85 Stations
2014	88	2,839
2015	145	3,013
2016	308	3,095
2017	776	3,419
2018	1,376	3,627
2019	1,838	3,786
2020	2,180	3,946
2021	2,461	4,351
2022	2,724	4,452
2023	3,181	4,495
2024	3,521*	4,705*
2025	3,862*	5,052*

* Future value projected for this rule.
Source: AFDC, "Historical Alternative Fueling Station Counts." https://afdc.energy.gov/stations/states.

Table 7.5.1-3 shows the projection of retail fueling station growth broken down by gasoline blend. EPA is projecting slight or moderate growth in station counts for stations offering all blend types, with the fastest growing blends between 2026–2030 being E85 in California and E15. E0 stations were extrapolated based on historical data from Pure-Gas.org.

Table 7.5.1-3: Projections of Retail Fueling Station Population by Gasoline Blend

Blend	2026	2027	2028	2029	2030
E0	17,494	17,741	17,987	18,234	18,480
E15	4,202	4,512	4,883	5,223	5,564
E85 (non-CA)	5,248	5,397	5,512	5,859	6,055
E85 (CA)	633	708	783	858	933

Table 7.5.1-4 lists projected average throughput for stations selling each gasoline blend. To calculate station throughput for California E85 stations, we simply took the quotient of total E85 volume sold in California as reported by CARB and the total number of E85 stations in California from AFDC. E85 throughput for non-California stations was projected using data reported by five other states that produce or consume elevated volumes of E85 (IA, MN, NY, KS, and ND).[495] Throughput data for E85 stations reported by these five states are the best available E85 data that EPA is aware of outside of California and we therefore believe it is reasonable to accept these data as a proxy for all non-California states because they comprise a significant share of national E85 stations (representing nearly 25% of all E85 stations located outside of California). For these states combined, historical station counts, and total gallons sold for years 2015–2023 were used to calculate an average E85 sales per station figure for each year.

[494] Number based on communication between EPA and Growth Energy, January 2025.
[495] See "E85 Consumption Based on State Data for RFS Set 2 NPRM," available in the docket for this action.

We then extrapolated those average throughputs using regression analysis to calculate the average E85 gallons sold per station in all states besides California for years 2026–2030. The result shows very little growth in E85 throughput outside of California across the years covered in this proposed rulemaking. E15 throughput was projected based on BIP/HBIIP data provided to EPA. Retail sales data for E0 stations is sparse, but Iowa's Retailer Fuel Gallons annual report provides the basis for calculating E0 throughput in Iowa, which we treated as representative of national average E0 throughput mirroring the methods used in the Set 1 Rule. Annual E0 throughput declines from 110,635 gallons per station in 2026 to 102,937 gallons per station in 2030, as more volumes of ethanol-free gasoline are replaced by increased sales of higher-level ethanol blends as availability of these fuels continues to grow.

Table 7.5.1-4: Projected Average Annual Throughput Volume by Gasoline Blend (gallons per station)

Blend	2026	2027	2028	2029	2030
E0	110,635	108,711	106,786	104,861	102,937
E15	218,163	228,928	239,693	250,458	261,224
E85 (non-CA)	49,335	49,463	49,592	49,721	49,850
E85 (CA)	333,840	341,303	347,373	352,406	356,648

The total volumes of each gasoline blend that EPA projects to be consumed during the time covered by this proposed rule are shown in Table 7.5.1-5. E10 volumes are the remainder of motor gasoline volumes that are not E0, E15, or E85. Projected volumes of E10 are the calculated difference between projected overall national motor gasoline consumption as published by EIA and the sum of EPA's projected volumes of E0, E15, and E85.[496] Increasing station counts and increasing throughputs of E15 and E85 gasoline, coupled with decreasing throughputs of E0 gasoline and increased penetration of electric vehicles, causes overall gasoline consumption to decrease across these years while E15 and E85 grow as a share of the total.

Table 7.5.1-5: Projection of Total Motor Gasoline Consumption by Blend Level (million gallons)

Blend	2026	2027	2028	2029	2030
E0	1,936	1,929	1,921	1,912	1,902
E10	132,991	131,219	129,371	127,238	124,939
E15	917	1,102	1,170	1,308	1,453
E85 (non-CA)	253	263	274	285	295
E85 (CA)	211	242	272	302	333

[496] AEO2023, Table 11 – Petroleum and Other Liquids Supply and Disposition.

Table 7.5.1-6: Projection of Total Motor Gasoline Consumption Relative to 2025 Baseline by Blend Level (million gallons)

Blend	2026	2027	2028	2029	2030
E0	-5	-12	-20	-29	-39
E10	-1,897	-3,669	-5,517	-7,650	-9,949
E15	116	301	369	507	652
E85	41	82	123	164	205

There is inherent uncertainty in any projection of future conditions. Market dynamics can shift rapidly with new policy signals and political pressure. For example, E15 has historically not been approved for sale in the state of California and as such no E15 gallons are sold in the state in these projections. However, on October 25, 2024, the Governor of California directed CARB to expedite the approval of E15 gasoline to be sold in California.[497] If this were to come to pass, it would open a large, currently untapped market for E15 which would see much higher volumes than projected in this proposal. Similarly, a recent Iowa state law has set new retail E15 access requirements and will require every retail gasoline fueling station in the state to advertise and sell E15 from at least one dispenser beginning in 2026.[498] This would likewise increase the volume of E15 we would expect to see consumed for these years.

7.5.2 Projection of Total Ethanol Consumption

Total gasoline volumes from Table 7.5.1-5 were used to calculate total ethanol consumption. To do this, EPA assumes E10 contains 10.16% ethanol by volume (based on data retrieved by RFG Survey Association and assuming 2 percent denaturant), E15 contains 15% ethanol by volume, and E85 contains 74% ethanol by volume (consistent with EIA assumptions). Our projection results in just under 14 billion gallons of ethanol consumed in 2026, declining to 13.72 billion gallons in 2028 and 13.38 billion gallons in 2030. Table 7.5.2-1 depicts EPA's projections of total ethanol consumption aggregated by blend level, rounded to the nearest million gallons.

Table 7.5.2-1: Projection of Total Ethanol Consumption by Blend Level (million gallons)

Blend	2026	2027	2028	2029	2030
E10	13,512	13,332	13,144	12,927	12,694
E15	138	165	176	196	218
E85	343	374	404	434	465
Total	13,993	13,871	13,724	13,558	13,376

Table 7.5.2-2 shows EPA's projection of total ethanol consumption (equating to the proposed volumes for ethanol) and the difference in these proposed volumes from the No RFS and 2025 Baselines. Based on our projections, we expect to see a pool-wide ethanol concentration that rises to 10.32% in 2028 and 10.38% in 2030.

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[497] Letter to CARB from California Governor Gavin Newsom, October 25, 2024, available at https://d35t1syewk4d42.cloudfront.net/file/2894/10.25.24-letter-to-CARB.pdf.

[498] AFDC, "Iowa Retail E15 Access Requirements." https://afdc.energy.gov/laws/12998.

Table 7.5.1-5: Total Ethanol Consumption Projection (million gallons)

Year	Ethanol consumption	Difference from No RFS Baseline	Difference from 2025 Baseline	Ethanol concentration
2026	13,993	212	-145	10.27%
2027	13,871	228	-267	10.29%
2028	13,724	238	-414	10.32%
2029	13,558	252	-580	10.35%
2030	13,376	266	-761	10.38%

7.6 Corn Ethanol

As described in more detail in Chapter 1.4, total domestic ethanol production capacity increased dramatically between 2005 and 2010 and increased at a slower rate thereafter. By the beginning of 2024, production capacity exceeded 18 billion gallons.[499] Actual production of ethanol in the U.S. reached 16.22 billion gallons in 2024.[500] Thus, 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 2026–2030 for determining potential volumes.

The expected annual rate of future commercial production of corn ethanol will be driven primarily by gasoline demand in the U.S. as most gasoline is expected to continue to contain at least 10% ethanol. However, commercial production of corn ethanol is also a function of exports of ethanol and to a much smaller degree the demand for E15, and E85 fuels. In 2024, ethanol exported from the U.S. to foreign markets were 1.9 billion gallons.[501] As shown in Chapters 7.5.1 and 7.5.2, the contribution of E15 and E85 to domestic ethanol consumption is projected to remain below 1 billion gallons beyond 2030. Exports of fuel ethanol form the U.S. reached record levels in 2024. In the first 10 months of 2024, U.S. fuel ethanol exports were nearly 35% higher than the first 10 months of 2023, exceeding 1.155 billion gallons.[502]

Much of the growth in export volume is attributable to a combination of domestic and international market effects, with lower prices and plateauing demand on average for fuel ethanol in U.S. markets even as prices and demand is increasing elsewhere. For example, Brazil (traditionally the second-largest exporter of fuel ethanol to global markets after the U.S.) has seen their own domestic demand for fuel ethanol explode in recent years due to growth in hydrous E100 demand at retail fuel pumps. This shift has meant that as more Brazilian ethanol is being sold domestically, there has been a corresponding reduction in Brazilian outflows of fuel ethanol, which have been largely replaced by rising exports of American fuel ethanol. Similarly, other countries have updated their own renewable fuel mandates which has led to increasing

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499 EIA, "U.S. Fuel Ethanol Plant Production Capacity," *Petroleum & Other Liquids*, August 15, 2024. https://www.eia.gov/petroleum/ethanolcapacity.

500 EIA, "Monthly Energy Review," March 2025, Table 10.3. https://www.eia.gov/totalenergy/data/monthly/archive/00352503.pdf.

501 EIA, "Exports by Destination," *Petroleum & Other Liquids*, April 30, 2025. https://www.eia.gov/dnav/pet/pet_move_expc_dc_NUS-Z00_mbbl_a.htm.

502 EIA, "U.S. Exports of Fuel Ethanol," *Petroleum & Other Liquids*, April 30, 2025. https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=M_EPOOXE_EEX_NUS-Z00_MBBL&f=a.

demand for imported ethanol that has been met by increasing supplies from the American ethanol industry.[503]

As described in Chapter 7.5.1, we estimated total ethanol consumption for 2026–2030 by extrapolating from historical retail fueling station population and station-level throughput data coupled with reported volumes where available. This total volume is a combination of corn ethanol, cellulosic ethanol, and advanced ethanol. We assume that the advanced and cellulosic ethanol will be used preferentially under the RFS program due to their added RIN value and/or LCFS credits and that conventional corn ethanol will comprise the remainder. Our estimate of corn ethanol consumption for 2026–2030 for the purposes of estimating the mix of biofuels that could be made available is shown in Table 7.6.1-1.

Table 7.6.1-1: Calculation of Projected Corn Ethanol Consumption (million gallons)

	2026	2027	2028	2029	2030
Total ethanol	13,993	13,871	13,724	13,558	13,376
Imported sugarcane ethanol	58	58	58	58	58
Domestic advanced ethanol	28	28	28	28	28
Ethanol from CKF	126	125	124	122	120
Corn ethanol	13,781	13,660	13,514	13,350	13,170

7.7 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 are currently 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 2014–2023 is shown in Table 7.7-1.

[503] S&P Global, "US ethanol exports on pace for record year, fueled by low prices and increased opportunity overseas," November 19, 2024. https://www.spglobal.com/commodity-insights/en/news-research/latest-news/agriculture/111924-us-ethanol-exports-on-pace-for-record-year-fueled-by-low-prices-and-increased-opportunity-overseas.

Table 7.7-1: Conventional Biodiesel and Renewable Diesel Used in the U.S. (million gallons)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Domestic D6 Biodiesel	1	0	0	0	0	0	0	0	0	3
Domestic D6 Renewable Diesel	0	0	0	0	0	0	0	0	0	1
Imported D6 Biodiesel	52	74	113	0	0	0	0	0	0	6
Imported D6 Renewable Diesel	2	86	45	2	0	0	0	0	0	0
All D6 Biodiesel and Renewable Diesel	55	160	158	2	0	0	0	0	0	10

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 was less than 1 million gallons per years from 2018–2022. The supply of conventional biodiesel and renewable diesel increased slightly in 2023, though the overall supply remained small (less than 0.1% of the total biofuel supply to the U.S.). Nearly all of the conventional biodiesel and renewable diesel used in the U.S. has been imported, with the only exceptions being less than 5 million gallons per year in 2014 and 2023. However, conventional (D6) RINs have continued to be generated for biodiesel and renewable diesel in recent years. From 2018 through 2023 the volumes of renewable diesel for which conventional biofuel RINs were generated each year (in million gallons) were 107, 116, 76, 135, 75, and 69 respectively. Nearly all of 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. from feedstocks such as palm oil 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 223 million metric tons of vegetable oil was produced globally in the 2023/2024 agricultural marketing year.[504] If all of it were to be used to produce biodiesel and renewable diesel, this quantity of vegetable oil could be used to produce over 60 billion gallons.[505] 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. through 2030 is not without limit, but this data suggests that large

[504] USDA, "World Agricultural Supply and Demand Estimates," November 8, 2024. https://downloads.usda.library.cornell.edu/usda-esmis/files/3t945q76s/s4657804b/z029qx92b/latest.pdf.
[505] This calculation assumes one gallon of renewable diesel can be produced from 8 pounds of vegetable oil.

quantities of this fuel are being or could be produced,[506] 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.

[506] The OECD-FAO Agricultural Outlook 2024-2033 projects global biodiesel consumption to grow from an average volume of about 60 billion liters (15.8 billion gallons) in 2021–2023 to approximately 79 billion liters (20.9 billion gallons) in 2033.

Chapter 8: 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:

- Deliverability of materials, goods, and products other than renewable fuel.
- 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 projected volumes on infrastructure we have considered whether the projected volumes would require additional infrastructure relative that which 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 2026 would change even if we did not establish volume requirements for future years, at least not in the 2026–2027 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 2026 and 2027 in comparison to their recent or current status.

8.1 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.[507] 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.[508] 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 it is used in the same CNG/LNG vehicle fleet as natural gas. According to data from the AFDC, there are currently

[507] 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 is discussed in Chapter 10.1.2.5.1.
[508] See 40 CFR 80.1426(f).

approximately 1,300 public and private CNG fueling stations and approximately 100 public and private LNG refueling stations in the U.S.[509]

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 1.17–1.2 billion ethanol-equivalent gallons of CNG/LNG per year in 2026 and 2027—would represent a substantial challenge.[510] 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 7.1.3.

8.2 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.[511] 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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[509] AFDC, "Alternative Fueling Station Locator." https://afdc.energy.gov/stations#/analyze?fuel=LNG&fuel=CNG&access=public&access=private&country=US&tab=fuel.

[510] See Chapter 7.1.4 for further discussion of the estimated use of CNG/LNG as transportation fuel in 2026–2027 and Chapter 10.1.4 for discussion of the costs associated with refueling stations.

[511] See RFS2 RIA Chapter 1.2.2.

could be resolved.[512] 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.[513] Another significant difference is that much of the 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.[514] 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.[515]

Finally, there appear 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.[516] 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.[517]

While we are projecting that the Proposed Volumes for 2026 and 2027 would require substantial biodiesel volumes relative to the No RFS Baseline, we are also projecting very small increases in the volume of biodiesel relative to the volume of biodiesel projected to be used in 2025 in the Set 1 Rule. The primary 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 2027.

However, it is possible that domestic biodiesel production and/or biodiesel imports may increase in 2026 and 2027. As discussed in Chapter 7.2, domestic biodiesel production capacity is significantly higher than current production levels. A review of monthly biodiesel imports suggests that import infrastructure can support significantly higher volumes of imports.[518] For

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[512] 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.
[513] Biodiesel consumption numbers based on EMTS data.
[514] Association of Oil Pipelines and American Petroleum Institute, "Ethanol, Biofuels, and Pipeline Transportation." https://www.api.org/~/media/files/oil-and-natural-gas/pipeline/aopl_api_ethanol_transportation.pdf.
[515] ASTM specifications currently limit biodiesel contamination in jet fuel to 50 mg/kg (ASTM D1655-24b).
[516] "Pilot Flying J Fuel Offerings," Docket Item No. EPA-HQ-OAR-2021-0427-0065. https://www.regulations.gov/document/EPA-HQ-OAR-2021-0427-0065.
[517] "Average Biodiesel Blend Level By State Based on EIA Data," Docket Item No. EPA-HQ-OAR-2021-0427-0119. https://www.regulations.gov/document/EPA-HQ-OAR-2021-0427-0119.
[518] EIA, "U.S. Imports of Biodiesel," *Petroleum & Other Liquids*, April 30, 2025. https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=m_epoordb_im0_nus-z00_mbbl&f=a.

example, over 700 million gallons of biodiesel was imported in 2016.[519] 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.[520]

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.[521]

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.[522] 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.[523] 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.[524] 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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[519] Id.

[520] 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 1.3.

[521] 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.

[522] B5 blend levels can typically be maintained.

[523] Hazrat, M. A., M. G. Rasul, M. Mofijur, M. M. K. Khan, F. Djavanroodi, A. K. Azad, M. M. K. Bhuiya, and A.S. Silitonga. "A Mini Review on the Cold Flow Properties of Biodiesel and Its Blends." *Frontiers in Energy Research* 8 (December 18, 2020). https://doi.org/10.3389/fenrg.2020.598651.

[524] Verma, Puneet, M.P. Sharma, and Gaurav Dwivedi. "Evaluation and Enhancement of Cold Flow Properties of Palm Oil and Its Biodiesel." *Energy Reports* 2 (January 9, 2016): 8–13. https://doi.org/10.1016/j.egyr.2015.12.001.

8.3 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.[525] 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.[526] 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.[527]

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 2027 is significant relative to both the No RFS Baseline and the 2025 Baseline, as discussed in Chapter 7.2. 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.

[525] See RFS2 RIA Chapter 1.2.2.
[526] Such drop-in fuels are typically blended with petroleum-based diesel prior to use.
[527] See RFS2 RIA Chapter 1.6.

8.4 Ethanol

We are anticipating that the projected volumes for 2026 and 2027 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 2026 and 2027 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 2026–2027 is already being used in 2022; consequently, the infrastructure is already in place. However, the expanded volume in 2026 and 2027 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 7.5 since those projections represent only moderate changes in the nationwide average ethanol concentration in comparison to earlier years.[528]

8.4.1 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.[529] 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

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[528] A nationwide average ethanol concentration above 10.00% can only occur insofar as there is consumption of E15 and/or E85.

[529] Das, Sujit, Bruce Peterson, and Shih-Miao Chin. "Analysis of Fuel Ethanol Transportation Activity and Potential Distribution Constraints." *Transportation Research Record Journal of the Transportation Research Board* 2168, no. 1 (January 1, 2010): 136–45. https://doi.org/10.3141/2168-16.

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 infrastructure system to the blending terminal could accommodate the projected increased volume of ethanol in a timely fashion.[530]

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.[531] 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.

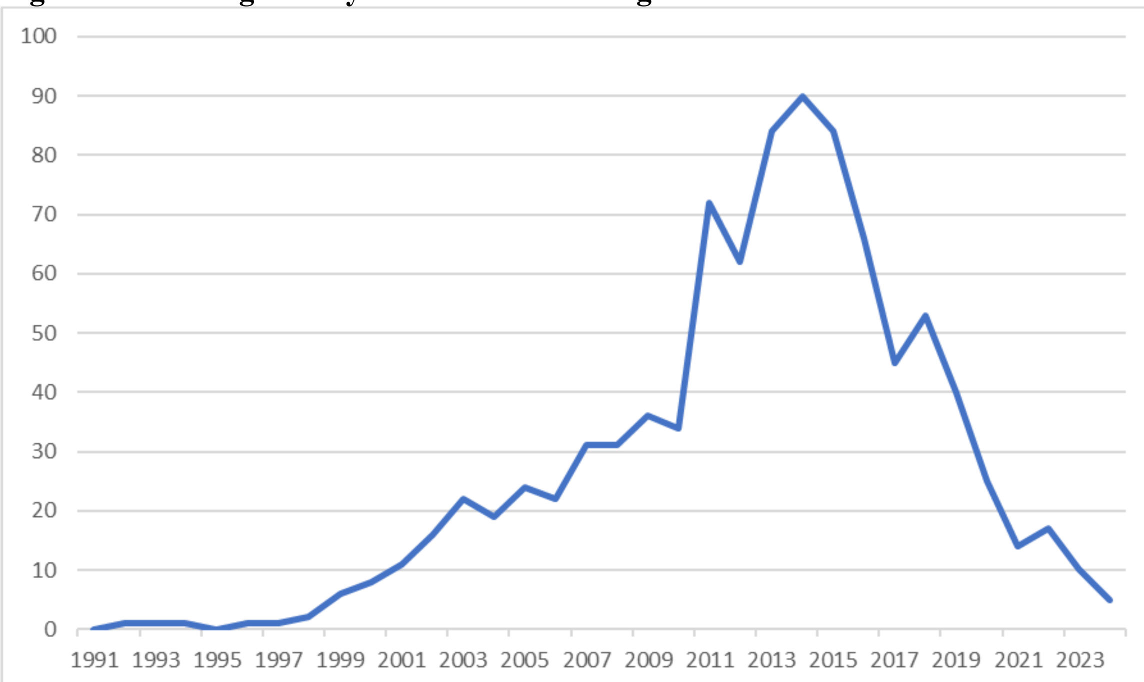
8.4.2 Infrastructure for E85

E85 is permitted to be used only in designated FFVs. As of 2023, there were about 20 million registered light-duty FFVs in the U.S., representing about 7% of all spark-ignition

[530] See RFS2 RIA Chapter 1.6.
[531] ICF, "Task 5: Impact of Biofuels on Infrastructure," January 2018.

vehicles.[532,533] The number of registered FFVs has been declining over the past several years. As of 2025, only six FFV models were in production for consumer use.[534] However, California is seeing a resurgence in use of E85 which may push a small increase in FFVs for the region.[535]

Figure 8.4.2-1: Light-Duty FFV Model Offerings

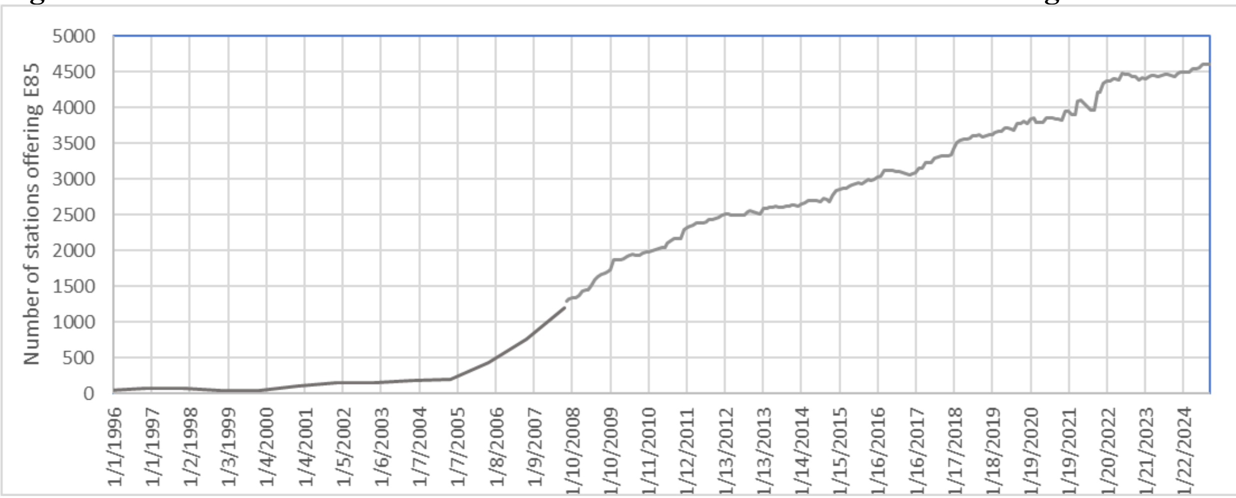


Source: AFDC, "Light-Duty AFV HEV and Diesel Model Offerings by Technology-Fuel," May 2024. https://afdc.energy.gov/data/10303.

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.[536] As shown in Figure 8.4.2-2, stations offering E85 have increased steadily since about 2005. By November 2024, the total number of stations offering E85 had reached 4,683.

532 AFDC, "Light-Duty AFV Registrations," June 2024. https://afdc.energy.gov/data/10861.
533 Bureau of Transportation Statistics, "Table 1-11: Number of U.S. Aircraft, Vehicles, Vessels, and Other Conveyances," April 24, 2025. https://www.bts.gov/content/number-us-aircraft-vehicles-vessels-and-other-conveyances.
534 AFDC, "Alternative Fuel and Advanced Vehicle Search Ethanol (E85)," 2025. https://afdc.energy.gov/vehicles/search/results?view_mode=grid&search_field=vehicle&search_dir=desc&per_page=12&current=true&display_length=25&model_year=2025&fuel_id=11,-1&all_categories=y&manufacturer_id=365,377,211,235,215,223,225,379,219,213,209,351,385,275,361,387,243,227,239,425,263,217,391,349,383,237,221,347,395,-1.
535 Renewable Fuels Association, "RFA Calls on California to Expand Flex Fuel Vehicles for Lower Costs, Cleaner Air," January 16, 2024. https://ethanolrfa.org/media-and-news/category/news-releases/article/2024/01/rfa-calls-on-california-to-expand-flex-fuel-vehicles-for-lower-costs-cleaner-air.
536 EPA, "UST System Compatibility with Biofuels," EPA-510-K-20-001, July 2020.

Figure 8.4.2-2: 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: AFDC, "Historical Alternative Fueling Station Counts." https://afdc.energy.gov/stations/states.

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 have ensured ongoing growth in the number of stations offering E85.

Although the total number of retail stations in the U.S. has varied, the fraction of those stations offering E85 has steadily increased. A large number of these E85 stations can be attributed to growth in California which has seen a large private incentivization for retail stations to supply this blend.[537] Using available data, EPA estimates retail stations offering E85 using a linear projection. With this growth rate, we estimated the total for the projected years of 2026 and 2027 as shown in Table 8.4.2-2.

Table 8.4.2-2: Projected Annual Average Number of Stations Offering E85

Year	Stations (Non-CA)	Stations (CA)
2026	5,248	633
2027	5,397	708

8.4.3 Infrastructure for E15

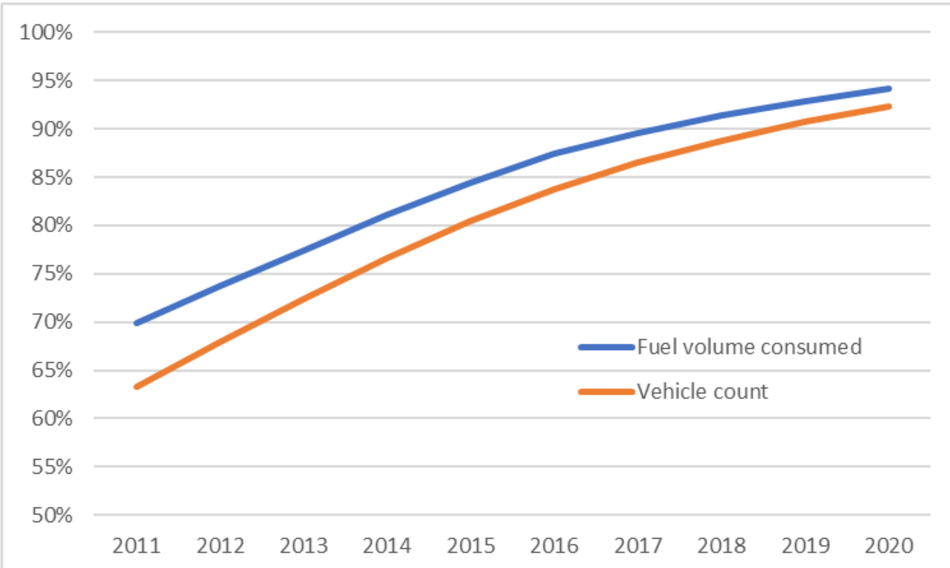
E15 is permitted to be used only in MY2001 and newer light-duty motor vehicles.[538] The infrastructure needed to support the use of E15 includes blending and storage equipment at terminals, certified storage and dispensing equipment at retail service stations, and the vehicles that are permitted to 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

[537] AFDC, "Historical Alternative Fueling Station Counts." https://afdc.energy.gov/stations/states.
[538] 76 FR 4662 (January 26, 2011).

combination of E10 (or E0) and E85—the number of terminals offering preblended E15 directly to service stations has been increasing.[539]

As shown in Figure 8.4.3-1, 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 8.4.3-1: Fraction of In-Use Fleet and In-Use Gasoline Consumption for MY2001 and Newer



Source: Davis, Stacy, and Robert Boundy. "Transportation Energy Data Book (Edition 40)," *Oak Ridge National Laboratory*, ORNL/TM-2022/2376, May 1, 2022. Tables 3.15, 4.6, 4.7, 4.12, and 9.11. https://doi.org/10.2172/1878695.

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 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. Most 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, so 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 few 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.

[539] Renewable Fuels Association, "Terminal Availability of E15 Grows as EPA Prepares to Remove RVP Barrier," March 12, 2019. https://ethanolrfa.org/media-and-news/category/blog/article/2019/03/terminal-availability-of-e15-grows-as-epa-prepares-to-remove-rvp-barrier.

Table 8.4.3-1: Number of Retail Stations Offering E15

Year	E15 Stations
2012	2
2013	70
2014	105
2015	184
2016	431
2017	1,214
2018	1,700
2019	2,081
2020	2,302
2021	2,605
2022	2,758
2023	3,414
2024	3,751

Source: Growth Energy, "Higher Blends Retail Footprint," October 1, 2024. https://growthenergy.org/data-set-category/higher-blends-retail-footprint.

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 several rounds of funding often referred to as HBIIP 1.0 and HBIIP 2.0. This program effectively began in 2021 and had been accepting applications as recently as 2024.

With regard to equipment compatibility, even if much of the existing equipment at retail is compatible with E15 as argued in studies from NREL[540] and Stillwater Associates,[541] 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:[542]

- 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,

540 Moriarty, K., and J. Yanowitz. "E15 And Infrastructure," *National Renewable Energy Laboratory*, NREL/TP-5400-64156, May 27, 2015. https://doi.org/10.2172/1215238.
541 Stillwater Associates, "Infrastructure Changes and Cost to Increase RFS Ethanol Volumes through Increased E15 and E85 Sales in 2016," July 27, 2015. https://ethanolrfa_org.cybertest.link/file/2006/Infrastructure-Changes-Cost-to-Increase-RFS_Stillwater_2016.pdf.
542 EPA, "UST System Compatibility with Biofuels," EPA-510-K-20-001, July 2020.

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.[543] 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 2027. 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.

Using the E15 station information in Table 8.4.3-1, we projected the total number of E15 stations for 2026 and 2027, as shown in Table 8.4.3-2.

Table 8.4.3-2: Projected Number of Retail Stations Offering E15

Year	E15 Stations
2026	4,202
2027	4,812

8.5 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.[544] 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 8.5.1, ORNL noted that significant investment would be needed to

[543] See, e.g., 40 CFR 1090.1420 and 1090.1510.
[544] Das, Sujit, Bruce Peterson, and Shih-Miao Chin. "Analysis of Fuel Ethanol Transportation Activity and Potential Distribution Constraints." *Transportation Research Record Journal of the Transportation Research Board* 2168, no. 1 (January 1, 2010): 136–45. https://doi.org/10.3141/2168-16

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.[545] 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 (see Chapter 7.1). Since that biogas will be displacing natural gas used in CNG/LNG vehicles, we do not expect a net increase in total volume of biogas and natural gas delivered.

As shown in Table 3.1-8, corn ethanol consumption volumes are expected to decrease in 2026–2030, with projected volumes between 13.1–13.8 billion gallons. However, ethanol production levels are not expected to decrease as export volumes have remained high. Corn collection and distribution networks have been functioning without difficulty since 2018. It is therefore anticipated that there should be no issues with the infrastructure for 2026–2027 and beyond.

We estimate that the use of FOG for the production of biofuel will increase slightly, from approximately 2.4 billion gallons in 2024 to approximately 2.54 billion gallons in 2027 (see Chapter 3). The projected increase in the use of FOG for biofuel production is consistent with the observed trend in the domestic supply of FOG for biofuel production from 2014–2021, before the rapid increase in FOG imports. 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

[545] ICF, "Impact of Biofuels on Infrastructure," January 2018.

a result, we do not anticipate any hindrances to the deliverability of FOG for the production of renewable diesel in 2026–2027.

Total soybean oil use for the production of BBD is projected to increase from approximately 2.05 billion gallons in 2024 to approximately 2.88 billion gallons in 2027. This projected increase is based on the expected expansion of soybean crushing over this time period in the U.S (see Chapter 7.2).

Chapter 9: Other Factors

CAA section 211(o)(2)(B)(ii) 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.[546,547] Broadly speaking, these factors can be thought of as various key economic impacts of the RFS program, each of which Congress believed was important to consider when determining the levels of renewable volume obligations. This chapter describes the ways in which we have assessed the impact of the Proposed Volumes on these factors through qualitative and/or quantitative economic impact analysis. Chapter 9.1 discusses the projected employment and rural economic development impacts of increased renewable fuel production. Chapter 9.2 discusses the projected impact on the supply of agricultural commodities. Chapters 9.3 and 9.4 discuss the impact of the Volume Scenarios and Proposed Volumes on the prices of agricultural commodities and food, respectively.

9.1 Employment and Rural Economic Development Impacts

Economic advantages of renewable fuels compared to fossil fuels stem from value added to the renewable fuel feedstock, increased numbers of rural manufacturing jobs, and support for the agricultural sector by providing more employment opportunities and market opportunities for domestic crops. The impacts to the local economy from investment in a new renewable fuel production plant, including increases in employment, output and income, and the subsequent increases in demand for local goods and services all create additional beneficial ripple effects.[548]

Having said that, economic models show that renewable fuel use can result in higher crop prices, though the range of estimates in the literature is wide. A 2013 study carried out to estimate the impacts of biofuels on corn prices projected (for 2015) price increases in the range of 5–53%.[549] A report by the National Research Council (NRC)[550] on the RFS program included several studies finding a 20–40% increase in corn prices from biofuels during 2007–2009. A working paper from the National Center for Environmental Economics (NCEE) found that, on average, corn prices rise by 2–3% in the long term for every billion-gallon increase in corn ethanol production, based on an analysis of 19 studies.[551] The NRC report also found that higher crop prices lead to higher food prices, though impacts on retail food in the U.S. were estimated to

[546] As explained in Preamble Section II, we also consider several other factors besides those enumerated in the statute.
[547] The impacts evaluated in this chapter are for volume increases for 2026–2030 compared to the No RFS Baseline.
[548] Demirbas, Ayhan. “Political, economic and environmental impacts of biofuels: A review.” *Applied Energy* 86 (May 23, 2009): S108–17. https://doi.org/10.1016/j.apenergy.2009.04.036.
[549] Wei Zhang et al., “The impact of biofuel growth on agriculture: Why is the range of estimates so wide?,” *Food Policy* 38 (January 11, 2013): 227–39. https://doi.org/10.1016/j.foodpol.2012.12.002.
[550] National Research Council. *Renewable fuel Standard*. *National Academies Press eBooks*, 2011. https://doi.org/10.17226/13105.
[551] Condon, Nicole, Heather Klemick, and Ann Wolverton. “Impacts of Ethanol Policy on Corn Prices: A Review and Meta-analysis of Recent Evidence.” *Food Policy* 51 (January 13, 2015): 63–73. https://doi.org/10.1016/j.foodpol.2014.12.007.

be small. Studies have found that, from a global perspective, higher crop prices might lead to higher rates of malnutrition in developing countries.[552,553,554]

Some research has also suggested the growth of biofuels may also contribute to the ongoing trend of U.S. farmland consolidation.[555] These studies suggest that increasing production of corn and soy have increasingly pushed small farms out of business because crops like corn and soy are often cultivated in large monocropping operations.[556] Historically, midsize farms have been vital to the economies of many local communities, and their decline has intensified economic and social difficulties in areas such as the rural Midwest.[557,558] According to an analysis by the Union of Concerned Scientists covering data from 1978–2017, it was observed that large crop farms are expanding, small crop farms are shrinking, and midsize crop farms are vanishing.[559] During the nearly four decades examined, the overall number of farms has decreased while farm sizes have tripled.[560] This consolidation of farmland also impacts agricultural communities by driving up real estate prices and making it difficult for small-scale farmers to buy or lease land.[561] Our analysis in this section does not attempt to quantify or model these phenomena or any potential impacts of demand for biofuel feedstock on farm size. However, we acknowledge that, to the extent these ongoing trends in farm size are linked to demand for biofuel feedstocks and do continue into the future, this may affect the magnitude of employment and rural economic development impacts associated with our RFS program standards.

Increased biofuel production is expected to offset employment in certain sectors. While our analysis presented below suggests expanding biofuel production will generate new positions in biofuel processing plants and associated industries, this expansion could also result in job reductions or transitions in sectors such as fossil fuels. While such shifts may benefit certain individuals and communities, in societal economic impact terms these jobs would be considered transfers rather than net benefits to the U.S. economy.

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[552] IIASA, "Biofuels and Food Security – Implications of an accelerated biofuels production," March 2009. https://pure.iiasa.ac.at/id/eprint/8984/1/XO-09-062.pdf.
[553] EPA, "Economics of Biofuels." https://19january2021snapshot.epa.gov/environmental-economics/economics-biofuels_.html.
[554] Rosegrant, Mark W., Tingju Zhu, Siwa Msangi, and Timothy Sulser. "Global Scenarios for Biofuels: Impacts and Implications*." *Review of Agricultural Economics* 30, no. 3 (September 1, 2008): 495–505. https://doi.org/10.1111/j.1467-9353.2008.00424.x.
[555] Scafidi, Angela. "Increased Biofuel Production in the US Midwest May Harm Farmers and the Climate." *World Resources Institute*, February 27, 2024. https://www.wri.org/insights/increased-biofuel-production-impacts-climate-change-farmers.
[556] Union of Concerned Scientists. "Losing Ground," April 14, 2021. https://www.ucs.org/resources/losing-ground.
[557] Id.
[558] Scafidi, Angela. "Increased Biofuel Production in the US Midwest May Harm Farmers and the Climate." *World Resources Institute*, February 27, 2024. https://www.wri.org/insights/increased-biofuel-production-impacts-climate-change-farmers.
[559] Union of Concerned Scientists. "Losing Ground," April 14, 2021. https://www.ucs.org/resources/losing-ground.
[560] Id.
[561] Scafidi, Angela. "Increased Biofuel Production in the US Midwest May Harm Farmers and the Climate." *World Resources Institute*, February 27, 2024. https://www.wri.org/insights/increased-biofuel-production-impacts-climate-change-farmers.

Increased U.S. biofuel production will also necessitate the development and expansion of production systems and networks to effectively cultivate, harvest, and transport substantial amounts of feedstock. Additionally, the industry requires technologies that can convert biomass more efficiently and cost-effectively for various applications.[562] These trends will result in shifting employment across sectors with subsequent impacts to local and regional spending in these impacted areas.

In this section, we focus on the gross employment impacts, not net impacts, and the income impacts that follow from increased investment in renewable fuels. Job creation is an important part of economic impact analysis since it directly addresses "well-being"—a critical aspect of economic growth and development. To that end, this section describes our evaluation of the impacts of renewable fuels on employment and on rural economic development. In subsequent sections (Chapters 9.2, 9.3, and 9.4), we talk about the impacts to prices, supply of agricultural commodities and food prices.

While these two categories of economic impacts (employment and rural economic development) are distinct, there is significant overlap between them in the context of renewable fuels, given the reliance of these supply chains on rural economic output. Most feedstocks used to produce biofuels in the U.S. are produced and processed (e.g., oilseeds are crushed) in rural areas. Biofuel production facilities themselves are also often located in rural areas. There is also overlap in the methods available to assess the impacts of renewable fuels on employment and on rural economic development. The following subsection details these methodological options.

Due to these substantial overlaps in both impacts and methodologies, we have chosen to analyze employment and rural economic development impacts together using a cohesive set of methods. We first introduce the concepts of employment and rural economic development impact analysis, followed by a discussion of available methods and existing literature.

Employment impact assessment can be conceived of as a subset of economic impact analysis that focuses specifically on the employment-related effects of a project, policy, or event, while the superset (economic impact analysis) examines broader economic changes. This method is often used to assess the employment potential and impact of sectoral policies and investments. Typically, an employment impact assessment assesses both the quantitative (number of jobs created and associated monetary impacts) as well qualitative (type of jobs created) impacts following a change in policy.[563] Such analyses are often used to support the development of evidence-based pro-employment policies and strategies that are appropriate to the context of the local or national economy.

An employment impact assessment is often carried out within the framework of an input-output (IO) model and generally characterizes three types of job impacts: direct (on-site or immediate effects created by an increase in expenditure, i.e., a policy shock), indirect (economic

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[562] DOE, "Jobs & Economic Impact of a Billion-Ton Bioeconomy," June 2017. https://www.energy.gov/eere/bioenergy/articles/jobs-economic-impact-billion-ton-bioeconomy.

[563] International Labour Organization, "Employment Impact Assessments (EmpIA): Analysing the Employment Impacts of Investments in Infrastructure," 2021. https://www.ilo.org/sites/default/files/wcmsp5/groups/public/@ed_emp/documents/publication/wcms_774061.pdf.

activity that occurs when a contractor/vendor or manufacturer receives payment for goods and services and is in turn able to pay others who support the business, i.e., business to business purchases in the supply chain taking place in the region), and induced (economic values stemming from household spending of labor income after removal of taxes, savings and commuter income).[564] In the context of developing a biofuel plant, these impacts are further divided into two temporal phases: Construction Phase (temporary jobs and other impacts) and Operations and Maintenance Phase (permanent jobs and impacts).

Figures 9.1-1 and 9.1-2 illustrate the various categories of these employment impacts, other economic impacts, and financial flows in the construction and operations phase respectively of a biofuel facility. For both figures, the light purple boxes measure the economic impacts in dollar terms while the dark purple ones measure the economic impacts in terms of job numbers. The solid arrows capture the flow of financial services.[565] In this section, we compute the direct, indirect and induced impacts from the production of biofuels to the U.S. economy. The total indirect impacts are broken out into impacts to the agricultural sector and impacts to the industry. Additionally, the job estimates have been computed based on changes from the No RFS Baseline and as such should be interpreted as additive gross jobs relative to that baseline. However, were the analysis to be carried out relative to the 2025 Baseline, some of these computed estimates would then be interpreted as jobs at risk were the RFS program discontinued.

[564] Demski, Joe. "Understanding IMPLAN: Direct, Indirect, and Induced Effects," *IMPLAN*, April 18, 2025. https://blog.implan.com/understanding-implan-effects.
[565] International Labour Organization, "Guide for Monitoring Employment and Conducting Employment Impact Assessments (EmpIA) of Infrastructure Investments," 2020. https://www.ilo.org/sites/default/files/wcmsp5/groups/public/%40ed_emp/documents/publication/wcms_741553.pdf
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Figure 9.1-1: Direct, Indirect, and Induced Economic Impacts in the Construction Phase of a Biofuel Facility

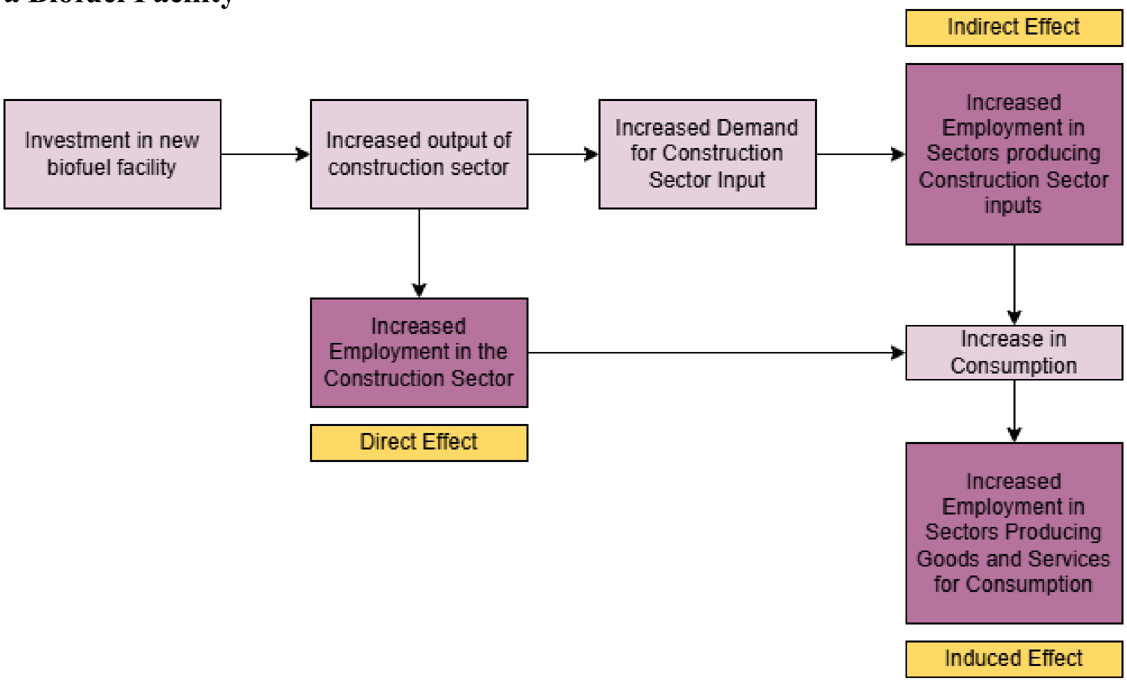
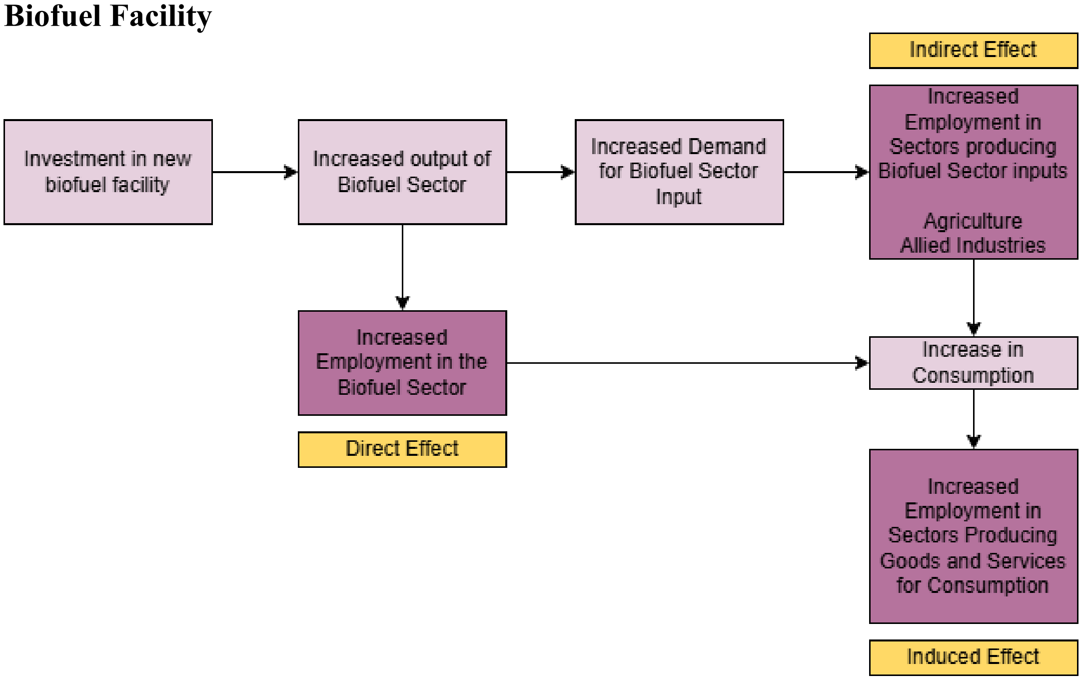


Figure 9.1-2: Direct, Indirect, and Induced Economic Impacts in the Operations Phase of a Biofuel Facility



Rural economic development encompasses a wide range of strategies and activities, all of which have the common goal of enhancing living standards and financial security of the rural community.[566] Through these strategies and activities, actors seek to enhance infrastructure, stimulate economic growth, and otherwise economically empower rural residents and communities. This involves building rural wealth and incomes through job creation and other channels; for example, by improving agricultural production to increase revenue from the sale of agricultural commodities. One can assess rural economic development through an array of metrics; the choice of metric largely depends on the dimension of development under analysis. Metrics like income, employment, and agricultural productivity—variables that are crucial to the financial growth and stability of the agricultural sector—are often used to assess aspects of rural economic development. Since income and employment are also necessary metrics of our analysis of the employment impacts of renewable fuels, and since the renewable fuel supply chain relies substantively on rural economic output, the same methodologies that we applied in the context of employment impact analysis can also be used to generate useful estimates of rural economic development impacts.

9.1.1 Methodology and Existing Literature

Economic impact analysis allows policymakers to evaluate the potential consequences of different policy options on communities and economic sectors of interest to the program. Historically, the range of models and methods available to assess economic, environmental, and social impacts of policies varied based on a wide variety of considerations, including methodological discipline (e.g., machine learning based models,[567] cross disciplinary models,[568] statistical/econometric models), methodological scope (e.g., sector specific/local/global and or static/dynamic), the nature of the policy question being analyzed (e.g., prescriptive vs. proscriptive[569]), and data availability. Table 9.1.1-1 describes a non-exhaustive list of these approaches based on ease of use.

[566] Social For Action, "How to Measure Rural Development: Key Indicators and Metrics," November 17, 2024. https://www.socialforaction.com/blog/how-to-measure-rural-development.
[567] Peet, Evan D., Brian G. Vegetabile, Matthew Cefalu, Joseph D. Pane, and Cheryl L. Damberg. "Machine Learning in Public Policy: The Perils and the Promise of Interpretability." *RAND Corporation*, 2022. https://doi.org/10.7249/pea828-1.
[568] Game, Edward T., Heather Tallis, Lydia Olander, Steven M. Alexander, Jonah Busch, Nancy Cartwright, Elizabeth L. Kalies, et al. "Cross-discipline Evidence Principles for Sustainability Policy." *Nature Sustainability* 1, no. 9 (September 6, 2018): 452–54. https://doi.org/10.1038/s41893-018-0141-x.
[569] Horne, Christine. "Norms." Data set. *Oxford Bibliographies Online Datasets*, November 27, 2013. https://doi.org/10.1093/obo/9780199756384-0091.

Table 9.1.1-1: Select Methods for Jobs and Economic Impact Analysis

	Basic Methods	Moderate Methods	Complex Methods
Approach	- Rule of thumb - Meta-analysis	- Input-Output or based on input-output	- Computable General Equilibrium (CGE) - Partial Equilibrium (PE) Econometric - System Dynamics – Linear & Non-Linear Programming
Examples	- Rule-of-thumb estimates (i.e., "5 jobs/MW") - Screening models	- Impact Analysis for Planning (IMPLAN)[a] - Regional Input-Output Modeling System (RIMS II)[b] - Jobs and Economic Development Impacts (JEDI)	- National Energy Modeling System (NEMS)[c] - Berkeley Energy & Resource (BEAR) Model[d] - U.S. Regional Energy Policy (USREP) Model[e] - Regional Economic Models Inc Policy Insight (REMI PI)[f] - RAND Econometric Model[g]
Benefits	- Easy to use - Minimal time requirement - Transparent Inexpensive	- Easy to moderately easy to use - Time requirement can be minimal but varies - Can be inexpensive - Widely used, accepted	- More comprehensive than input-output - Can model more scenarios - Retrieve more information
Limitations	- Results can be limited - Often overly simplistic assumptions - Inflexible	- Not very transparent - Many restrictive assumptions (i.e., constant prices) - Scenarios limited to changes in demand - Difficult or moderately difficult to develop - Can be expensive	- Not very transparent - Assumptions vary - Often difficult to operate or modify - Most require expensive software licenses - Difficult, expensive to build - Data intensive

	Basic Methods	Moderate Methods	Complex Methods
When to use	- When time and resources are short - For high level preliminary analysis - To get quick estimates of employment, output and price changes - As a screening tool	- When policy options are well defined - When a high degree of precision and analytic rigor is desired - When sufficient data, time, and financial resources are available	- When policy options are well defined - When a high degree of precision and analytic rigor is desired - When sufficient data, time, and financial resources are available

[a] IMPLAN is a commercially available model that uses an input output analysis technique along with social accounting matrices and publicly available data to carry out economic impact assessment.
[b] RIMS II is an input-output-based model that uses regional multipliers to help users estimate gross jobs, developed by the Department of Commerce/Bureau of Economic Analysis.
[c] The National Energy Modeling System (NEMS) is a computer-based model developed and maintained by EIA. It is used to forecast energy supply, demand, and prices, and to analyze the impacts of various energy policies.
[d] BEAR is a state-level computable general equilibrium model developed by the Lawrence Berkeley National Laboratory, which can account for many different factors affecting jobs, producing net jobs estimates.
[e] USREP is a computable general equilibrium model developed and maintained by the Massachusetts Institute of Technology (MIT). The model is national, but splits the United States into multiple regions.
[f] REMI PI is a commercial model that uses hybrid techniques, combining aspects of input-output, econometric, and computable general equilibrium techniques, and produces net jobs estimates.
[g] The RAND econometric model is a commercial tool that uses sets of related equations, and mathematical and statistical techniques to analyze economic conditions over time, generally producing net jobs estimates.
Source: NREL, "Assessment of the Value, Impact, and Validity of the Jobs and Economic Development Impacts (JEDI) Suite of Models," August 2013. https://www.nrel.gov/docs/fy13osti/56390.pdf. EPA, "Assessing the Multiple Benefits of Clean Energy – A Resource for States," February 2010. https://nepis.epa.gov/Exe/ZyPDF.cgi/P100FLQ9.PDF?Dockey=P100FLQ9.PDF.

When selecting an analytical method and interpreting the output from any of these frameworks, however, there is a need to be mindful about the strengths and limitations of each. There are times when a combination of these approaches may be necessary to capture the multifaceted impacts of policies, ensuring robust and comprehensive analysis to inform effective policymaking. In this chapter, we have relied upon multiple analytical approaches to quantify the impacts of renewable fuels on "other factors".

9.1.1.1 Overview of Methodologies Applied

We have focused our analysis on the biofuels that are projected to have the largest changes in our volume scenarios relative to the No RFS Baseline: corn ethanol, biodiesel and renewable diesel (from soybean oil, FOG, corn oil, and canola oil), and renewable natural gas.[570] For each of these fuels, we have made use of methods that we were able to identify as available off-the-shelf. We acknowledge that complex methods such as Computable General Equilibrium (CGE) models may be helpful when a high degree of precision and analytic rigor is desired given sufficient data, time, and financial resources.

[570] The impacts evaluated in this chapter are for volume increases for 2026–2030 compared to the No RFS Baseline.

For all biofuels, to estimate the impact of volume changes compared with the No RFS Baseline, we have relied on a basic method (as laid out in Table 9.1.1-1) —a rule-of-thumb approach—to draw conclusions about the economic impacts. We utilize the results of existing studies for estimates of multipliers or the impact per unit of biofuel and then apply these to the projected volumes to derive employment and other economic impacts.

For the corn ethanol case alone, we have relied on the use of two separate methods: a basic method (rule-of-thumb) and NREL's JEDI model (an input-output modeling approach). We also performed a sensitivity analysis on the results of the latter method to capture the range of impacts to the agricultural sector and the rural economy. This approach illustrates both how results from a simple rule-of-thumb type approach compare with a more robust approach like an input-output model, and how changes in some key modeling parameters will alter the extent of economic impacts on the agricultural sector and the rural economy. Since these industries bear similarities in their backward and forward linkages with other sectors of the economy (supply chain[571] and logistic networks[572]), one can expect similar type of sectoral level impacts; the size of the impacts, however, will be a function of the initial policy shock. It is important to note that the impact estimates in our analysis (for all the biofuels) correspond to the volume projections relative to the No RFS Baseline.

9.1.1.2 Rule-of-thumb Analytical Method

Of the available methods discussed above, only IO models appear to have been applied recently to estimate the impact of renewable fuels on jobs and economic output. We have identified four relevant studies with outputs which can inform our rule-of-thumb approach to estimating the impacts of renewable fuels on job creation and rural economic development. Three of these studies focused on a specific subset of the fuels we have targeted for analysis: a 2024 study on the contribution of the ethanol industry to the U.S. economy by Agriculture and Biofuels Consulting (ABF), LLP (hereafter the ABF study),[573] a 2022 study on the economic impact analysis of biodiesel and renewable diesel on the U.S. economy by LMC International (hereafter the LMC study),[574] and a 2024 study on renewable natural gas economic impact analysis by Guidehouse (hereafter the Guidehouse study).[575] A fourth study by PWC compares the impacts of renewable fuels to those of oil and gas, employing a similar IO approach to the

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[571] Babazadeh, Reza, Jafar Razmi, and Mir Saman Pishvaee. "Sustainable Cultivation Location Optimization of the Jatropha Curcas L. Under Uncertainty: A Unified Fuzzy Data Envelopment Analysis Approach." *Measurement* 89 (April 10, 2016): 252–60. https://doi.org/10.1016/j.measurement.2016.03.063.

[572] Hong, Jae-Dong, and Judith L. Mwakalonge. "Biofuel Logistics Network Scheme Design With Combined Data Envelopment Analysis Approach." *Energy* 209 (July 26, 2020): 118342. https://doi.org/10.1016/j.energy.2020.118342.

[573] ABF Economics, "Contribution of the Ethanol Industry to the Economy of the United States in 2023," February 1, 2024. https://d35t1syewk4d42.cloudfront.net/file/2659/RFA%202023%20Economic%20Impact%20Final.pdf.

[574] LMC International. "Economic Impact of Biodiesel on the United States Economy 2022: Main Report." *Clean Fuels Alliance America*, 2022. https://cleanfuels.org/wp-content/uploads/LMC_Economic-Impact-of-Biodiesel-on-the-US-Economy-2022_Main-Report_November-2022.pdf.

[575] Guidehouse, "Renewable Natural Gas Economic Impact Analysis," December 2024. https://static1.squarespace.com/static/53a09c47e4b050b5ad5bf4f5/t/67577e1c8695832cc7125f86/1733787172143/2024+RNG+Economic+Impact+Report_FINAL.pdf.

three fuel-specific studies (hereafter the PWC study).[576] The analysis in this chapter uses the results of these studies to parameterize our rule-of-thumb analysis.

While other methods have been applied to estimate impacts on job creation and rural economic development, we choose to focus on the results of IO models in our analysis, for several reasons. First, these have been the most widely used in recent literature. Second, studies using these methods can provide usable impact estimates for ethanol, biodiesel, renewable diesel, and RNG production. Third and finally, focusing on IO model results allows for direct comparisons across studies to characterize the range of potential impacts.

Before describing our analysis, we review the studies listed above and summarize their main results, which are the foundation of our rule-of-thumb analytical approach.

9.1.1.2.1 ABF Study of Ethanol Impacts

The ABF study uses the IMPLAN (Impact Analysis for Planning) multiplier database to develop a model of the national economy, including sectors that support the ethanol industry, the links between them, and the level of national economic activity. The data inputs are based on the recent benchmark input-output data and 2021 regional data published by the U.S. Bureau of Economic Analysis. The report assesses direct effects, indirect effects, and induced effects as well as the additional value of output of ethanol co-products (DDGS, distillers corn oil, corn gluten meal, and corn gluten feed). The report also incorporates the explicit impact of ethanol and DDGS exports in the economic impact analysis by applying USDA Agricultural Trade multipliers for output and employment to the estimated value of exports for 2023 reported by EIA and U.S. Census Bureau trade databases. The ABF study assesses the impact of ethanol production on job creation and GDP across several sectors of the economy, including:

- Ongoing ethanol production operations, including total production effect and the impact on farm incomes
- Research and development
- Ethanol co-product value streams
- Exports
- Construction

The ABF study estimates that the ethanol industry supported 394,464 jobs across all sectors of the economy in 2023. Excluding the impact associated with construction, the job impact was 392,371 in 2023. See Table 9.1.1.2.1-1.

[576] PwC, "Impacts of the Oil and Natural Gas Industry on the US Economy in 2021," April 2023. https://www.api.org/-/media/files/policy/american-energy/pwc/2023/api-pwc-economic-impact-report-2023.pdf.

Table 9.1.1.2.1-1: Jobs Supported by Ethanol Production in 2023 (FTE)

	All	Construction	All, Excluding Construction
Direct	72,463	1,015	71,448
Indirect	203,597	359	203,238
Induced	118,405	718	117,687
Total	394,464	2,093	392,371

The ABF study does not assess rural economic development explicitly. However, we can infer the impact on rural economies based on reported impacts for certain stages in the ethanol value chain compared to the total estimated impact of ethanol economy-wide. For instance, we could assume that corn production and ethanol production both take place predominantly within the bounds of the rural economy. Production of ethanol feedstock (mostly corn) contributed \$27,916 million to the U.S. economy, while the manufacturing activity of ethanol production accounted for another \$14,602 million. The ABF study also estimates an economy-wide impact of \$54,226 million from the ethanol industry in 2023. With the assumptions stated above, we can roughly estimate that the impact on rural economies is about 78% (= (27,916+14,602)/54,226) of the total GDP impact of ethanol. The job impact is even larger in relative terms, about 91% (= (264,464+95,166)/394,464) of the total economy-wide employment impact. See Table 9.1.1.2.1-2.

Table 9.1.1.2.1-2: Job Creation and GDP Impacts of Ethanol Production by Sector

	Job Creation (FTE)		GDP (million 2023$)	
	Agriculture	Ethanol Production	Agriculture	Ethanol Production
Direct	58,324	11,781	3,137	2,602
Indirect	127,638	46,014	14,299	7,394
Induced	78,533	37,372	10,480	4,606
Total	264,464	95,166	27,916	14,602

Our estimates here could be viewed as an upper limit since we assume that both corn and ethanol production are within the bounds of the rural economy. To get the lower limit, we assume that only corn production (excluding ethanol production) is within the bounds of the rural economy. The estimate of the impact on rural economy is about 51% (=27,916/54,226) of the total GDP impact of ethanol. The job impact is about 67% (=264,464/394,464) of the total economy-wide employment impact. We reply on the lower limit to conduct our impact analyses in Chapters 9.1.4.1 and 9.1.5.1.

9.1.1.2.2 LMC Study of Biodiesel and Renewable Diesel Impacts

The LMC study assesses the economic impact of BBD, including both renewable diesel (RD) and biodiesel (BD). The study divides its findings into several categories of effects. These include several annual (i.e., ongoing) effects, including direct effects directly attributed to the BBD value chain, such as fuel production facilities and oilseed crops grown and crushed at least in part for fuel use, indirect effects associated with industries that supply the BBD value chain, and induced effects stemming from expenditure of households from those affected industries. In addition, the study also considers "one-off effects" that are not estimated to be sustained over time, such as those associated with construction of new BBD production facilities.

LMC (2022) uses multipliers developed from the input-output tables from the U.S. Department of Commerce's Bureau of Economic Analysis across 406 industries and by state. These multipliers are applied to the direct effects that LMC estimated under the following scenarios.

- Baseline: 3.1 billion gallon of biodiesel supply (i.e., production plus net imports) in 2021 (the authors' estimate of actual 2021 U.S. supply)
- 3.5 billion gallons of supply in 2021
- 4.0 billion gallons
- 6.0 billion gallons

The effects are calculated for the actual 2021 U.S. production/import split of 80% domestic production and 20% import and for an assumed production/import split of 100% domestic production and 0% import, respectively. The analysis also assumes the 2021 market conditions (e.g., prices), an 80% utilization rate of fuel production capital (e.g., the study assumes 7.5 billion gallons of capacity is required to produce 6 billion gallons), and the RD representing half of U.S. domestic production in all except the baseline scenario (which assumes 67% BD and 33% RD).

Table 9.1.1.2.2-1 summarizes the annual impacts in terms of job creation by scenario. Based on 2021 conditions, the LMC study estimates the BBD sector's job impact was about 75,000 in that year. The study also estimates that doubling the production to 6.0 billion gallons would have also doubled the job creation impact of the BBD sector in 2021.

Table 9.1.1.2.2-1: The Annual Job Creation Impacts by Scenario (FTE)

	Scenario (billion gallons of BBD)			
	3.1 (Baseline)	**3.5**	**4.0**	**6.0**
80%/20% U.S./import split	75,196	86,204	99,078	150,572
100%/0% U.S./import split	93,755	107,373	123,299	187,003

Table 9.1.1.2.2-2 summarizes the one-off effects associated with construction. The LMC study estimates that doubling the production of BBD in 2021 would have created 144,500 temporary job-years (e.g., with two years to build an average plan, this implies 72,250 full-time equivalent [FTE] jobs lasting two years).

Table 9.1.1.2.2-2: The One-Off Job Creation Effects from Construction (FTE)

	Scenario (billion gallons of BBD)	
	4.0	**6.0**
Total temp construction job-years created	61,400	144,500

The LMC study does not explicitly assess the impact on rural economic development. we can infer the impact on rural economies based on reported impacts for certain stages in the BBD value chain compared to the total estimated impact of BBD economywide. For the purposes of our analysis, we assume that oilseed production, crushing, and processing occurs predominantly in rural areas. Table 9.1.1.2.2-3 summarizes the estimated effects on rural development in the LMC study based on these assumptions. The estimated impact on rural economic development represents at least 30% of the total economy-wide impact across job, GDP, and wages estimates.

Table 9.1.1.2.2-3: Estimates of the Impacts of BBD Production in Rural Areas

	Jobs (FTE)	GDP ($2021)	Wages ($2021)
Oilseed production	28,236 jobs 38% of the total	$7.41 billion 30% of the total	$1.36 billion 38% of the total
Oilseed processing	6,000 jobs 8% of the total	$4.97 billion 21% of the total	$380 million 11% of the total

9.1.1.2.3 Guidehouse Study of Renewable Natural Gas Impacts

The Guidehouse study estimates the economic impact of 2024 RNG industry spending in the U.S. in terms of job creation and GDP. The RNG industry generates direct economic effects through annual capital expenditures and operational spending incurred by RNG facilities (e.g., spending on new construction and RNG production and distribution). The Guidehouse study estimates these direct effects of RNG on the economy (e.g., the annual capital expenditures and operational spending incurred by RNG facilities) based on a dataset on RNG facility capacity and costs compiled and maintained by RNG Coalition. The dataset used in the report was up to date as of October 2024. In turn, these expenditures spur business-to-business transactions within the RNG supply chain (indirect effects) and increase household spending among RNG industry and supply chain employees (induced effects). The Guidehouse study employs an IMPLAN model to estimate these indirect and induced effects.

As of October 2024, the RNG Coalition database estimates there were 411 operational RNG facilities and 130 projects under construction. The Guidehouse study estimates that the RNG industry supported over 55,000 jobs and generated $7.2 billion in GDP in that year. Table 9.1.1.2.3-1 summarizes the three components of the job creation impacts.

Table 9.1.1.2.3-1: Creation Impacts of RNG Production

	Direct	Indirect	Induced	Total
Job Creation (FTE)	23,359	13,395	18,910	55,664
GDP (billion 2024$)	3.0	1.9	2.2	7.2

The Guidehouse study estimates that there are currently about 230 RNG projects in planning phases in the U.S. Table 9.1.1.2.3-2 summarizes the planned and existing RNG projects' job creation impacts by facility status. While the impact associated with construction is one-off, that associated with operations is annual. The planned projects have larger one-off impacts as well as annual impacts in terms of total job creation.

Table 9.1.1.2.3-2: The Planned and Existing RNG Projects' Job Creation Impacts by Facility Status (FTE)

	Operations	Construction	Total
Existing	23,917	31,747	55,664
Planned	19,586	74,237	93,823

The Guidehouse study does not assess rural economic development explicitly. However, we can infer this impact by disaggregating these impacts by feedstock. The Guidehouse study identifies four categories of biogas feedstocks for RNG: municipal solid waste, food waste, agricultural digesters (termed "agricultural waste" in the study), and wastewater.[577] Assuming RNG projects using agricultural digesters are those pertinent to rural areas and thus rural economic development, we can use the impact associated with agricultural digesters as an estimate for rural economic development. In 2024, agricultural digester projects created the second largest economic impacts; 19,751 jobs or 35% of the total job impact, and $2.6 billion or 36% of the total GDP impact. Table 9.1.1.2.3-3 summarizes these impacts.

Table 9.1.1.2.3-3: Agricultural Job Creation and Rural Economy Impacts

	Direct	Indirect	Induced	Total
Job creation (FTE)	8,297	4,612	6,843	19,752
GDP (billion 2024$)	1.2	0.7	0.8	2.6

9.1.1.2.4 PWC Study of Fossil Fuel Impacts and Comparison with Three Renewable Fuels Studies

We compare the impacts of renewable fuels in the ABF, LMC, and Guidehouse studies to those of oil and natural gas based on PWC (2023), which also employed a similar IO approach. The PWC study quantifies the economic impacts of the U.S. oil and natural gas industry in terms of employment, labor income, and value added at the national, state, and congressional district level for 2021. They consider all three separate channels—the direct impact, the indirect impact, and the induced impact, and in aggregate provide a measure of the total economic impact of the oil and natural gas industry.

Industries vary in size; therefore, to assess job creation, we divide the total full-time equivalents (FTE) by GDP (in billions), measuring the number of jobs generated per $1 billion GDP. Applying this metric to all four reports discussed in this section indicates that almost all renewable fuels (with the exception of BBD) create more jobs per $1 billion GDP than fossil fuels. Construction impacts, which are one-time effects, are excluded from this comparison. Table 9.1.1.2.4-1 shows employment per billion dollars GDP for the oil and gas, ethanol, BBD, and RNG industries.

[577] These categories differ somewhat from the categories established by EPA in Table 1 to 40 CFR 80.1426 in both wording and substance, but are a reasonable general guide for this purpose.

Table 9.1.1.2.4-1: Employment per GDP for Fossil Fuel and Renewable Fuel Production

	Oil & Gas	Ethanol	BBD	RNG
Employment (FTE)	9,400,000	392,371	75,196	23,917
GDP (billion 2021$)	1,618	54	23	4
Employment/GDP	5,809	7,265	3,241	6,294

Since these renewable fuels rely significantly on agricultural feedstocks and are often produced in rural areas, they contribute to rural economic development. Fossil fuels, by contrast, do not use agricultural feedstocks, and there is no direct farm income boost from crops. In addition, their indirect and induced effects on rural economic development may be mixed or negative, particularly in the long run. For instance, unlike agriculture that provides relatively stable demand for rural labor and services, fossil fuel markets are prone to price fluctuations. The resulting economic instability makes long-term rural development difficult. Fossil fuel operations may displace farmland, contaminate water sources, and pollute the air, negatively affecting crops and livestock. Table 9.1.1.2.4-2 summarizes the results based on only estimated agricultural production.

Table 9.1.1.2.4-2: Job Creation and GDP Impacts of Agricultural Production Supported by Renewable Fuel Production

	RNG	BBD	Ethanol
Job creation (FTE)	19,752	28,236	264,464
GDP (billion 2021$)	2.6	7.4	27.9

In summary, the PWC study finds renewable fuels generally create more jobs per unit of GDP than fossil fuels. This finding is supported by other studies comparing the job impacts of fossil fuel and renewable fuel production. IEA's World Energy Employment Report[578] finds that clean energy has "surpassed the 50% mark for its share of total energy employment" and has the biggest potential for job creation.[579] Peltier finds "on average, 2.65 FTE jobs are created from $1 million spending in fossil fuels, while that same amount of spending would create 7.49 or 7.72 FTE jobs in renewables or energy efficiency.[580] Thus each $1 million shifted from brown to green energy will create a net increase of 5 jobs." Though biofuels accounted for only a small fraction of the overall addition to clean jobs (Clean Jobs America reports that biofuels added over 1200 jobs in 2023[581]), the International Renewable Energy Agency (IRENA) estimated that liquid biofuels supported 2.421 million jobs globally in 2021 and most of these were in planting and harvesting feedstock,[582] implying that expansion of the biofuel industry will likely have the biggest job impacts to the agricultural and rural community.

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578 IEA, "World Energy Employment," August 2022. https://doi.org/10.1787/5d44ff7f-en.

579 E2. "Clean Jobs America 2024," September 2024. https://cleanjobsamerica.e2.org/wp-content/uploads/2024/09/E2-2024-Clean-Jobs-America-Report_September-17-2024.pdf.

580 Garrett-Peltier, Heidi. "Green Versus Brown: Comparing the Employment Impacts of Energy Efficiency, Renewable Energy, and Fossil Fuels Using an Input-output Model." *Economic Modelling* 61 (November 28, 2016): 439–47. https://doi.org/10.1016/j.econmod.2016.11.012.

581 E2. "Clean Jobs America 2024," September 2024. https://cleanjobsamerica.e2.org/wp-content/uploads/2024/09/E2-2024-Clean-Jobs-America-Report_September-17-2024.pdf.

582 IRENA. "Renewable Energy and Jobs Annual Review 2022," 2022. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2022/Sep/IRENA_Renewable_energy_and_jobs_2022.pdf.

Note that the jobs created by increased biofuel production are unlikely to be completely offset by job declines in the fossil fuel sector. Our impact analyses on employment and rural economic development in Chapters 9.1.2 through 9.1.5 focus on the gross impacts, not net impacts.

In Chapter 9.2.1, we combine the estimates derived above from each of these three studies with the projected production increases associated with our Low and High Volume Scenarios relative to the No RFS Baseline to estimate the potential impacts of our proposal on jobs and rural economic development.

9.1.1.3 Input-Output Modeling Analytical Method for Corn Ethanol

In addition to our rule-of-thumb analysis, which largely relies on estimates derived from pre-existing input-output modeling studies, we also present original input-output modeling estimates for just the corn ethanol case using a Jobs and Economic Development Impacts (JEDI) model. The JEDI modeling suite was developed by NREL for the DOE Office of Energy Efficiency and Renewable Energy (EERE). At a very high level, the JEDI suite relies on the use of an input-output based methodology to estimate gross jobs and economic impacts of building and operating selected types of renewable electricity generation and fuel plants.

Between 2004 and 2012, JEDI has been used and cited in more than 70 public studies including 12 studies in five different peer-reviewed journals. The validity of JEDI estimates was assessed through comparison to both published modeled estimates and data on empirical observations of jobs associated with renewable energy projects. For the former, compared to modeled job results for O&M of several corn ethanol plants, JEDI results ranged from 20% lower to 28% higher. For the latter, comparison of several empirical estimates for O&M jobs at corn ethanol plants showed that JEDI results ranged from 9% higher to 21% lower than the empirical estimates.

According to expert evaluations, references, and various user metrics, the JEDI suite of models is recognized as a reliable and widely utilized tool for estimating or screening gross job numbers associated with the construction and operation of renewable energy power and fuel facilities in the U.S. Considering the aforementioned comparisons involving both modeled and empirical estimates, the outcomes produced by the JEDI model are fairly similar with other modeled results and empirical observations.

The default assumptions in the JEDI model are based on interviews with industry experts and project developers. While these input assumptions are reasonable, the user does have the option to override some of these project specific data for some categories of inputs. Economic multipliers contained within the model are derived from Minnesota IMPLAN Group's IMPLAN accounting software and state data files. Construction jobs are defined as full-time equivalents (FTE), or 2,080-hour units of labor (one construction period job equates to one full-time job for one year). A part-time or temporary job may be considered one job by other models but would constitute only a fraction of a job according to the JEDI models. For example, if an engineer worked only 3 months on a wind farm project (assuming no overtime), that would be considered one-quarter of a job by the JEDI models. Operations-period results are long term, for the life of the project, and are reported as annual full-time-equivalent jobs and annual economic activity, which continue to occur throughout the operating life of the facility. Like all models, the JEDI model too has its own set of limitations, and precisely because of these the model results are meant to be estimates and not precise forecasts.

IO modeling is a data-intensive effort and requires access to sector specific multipliers[583] that permit us to compute rates of change for several different variables—output, employment, labor income, and value added. In the case of corn ethanol, IMPLAN[584] maintains a database of multipliers that is available for purchase and NREL has developed an IO model for Dry Mill Corn Ethanol[585] using these multipliers,[586] results of which have been validated with both modeled job results as well as empirical employment data.[587] However, to the extent that such tools can be developed for BBD and RNG going forward, we may choose to make use of them. Other tools to assess economic and environmental impacts, such as WIRED, BEIOM,[588] EMPLOY, and others[589] for some of the other biofuel categories and technologies are either in the R&D phase or employ slightly different modeling capabilities compared with JEDI, and could be used as well in future analyses if appropriate.[590]

9.1.2 Employment Impacts using the Rule-of-thumb Approach

Our estimates of the employment impacts relying on the use of a basic rule-of-thumb approach and existing studies are summarized by fuel type (ethanol, BBD, and RNG) in this section. In the next section, to provide a complementary estimate of the local economic impacts associated with constructing and operating a corn ethanol facility, we relied on NREL's JEDI module for dry mill corn ethanol.

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583 Multipliers are rates of change that describe how a given change in a particular industry generates impacts in the overall economy.

584 https://implan.com.

585 NREL, "JEDI Corn Ethanol Model rel. CE12.23.16." https://www.nrel.gov/docs/libraries/analysis/01d-jedi-corn-ethanol-model-rel-ce12-23-16.xlsm.

586 NREL, "Jobs and Economic Development Impact Models," April 21, 2025. https://www.nrel.gov/analysis/jedi.

587 Billman, L., and D. Keyser. "Assessment of the Value, Impact, and Validity of the Jobs and Economic Development Impacts (JEDI) Suite of Models," *National Renewable Energy Laboratory*, August 1, 2013. https://doi.org/10.2172/1090964.

588 Avelino, Andre F.T., Patrick Lamers, Yimin Zhang, and Helena Chum. "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 (September 2, 2021): 128890. https://doi.org/10.1016/j.jclepro.2021.128890.

589 Oke, Doris, Lauren Sittler, Hao Cai, Andre Avelino, Emily Newes, George G. Zaimes, Yimin Zhang, et al. "Energy, Economic, and Environmental Impacts Assessment of Co-optimized On-road Heavy-duty Engines and Bio-blendstocks." *Sustainable Energy & Fuels* 7, no. 18 (January 1, 2023): 4580–4601. https://doi.org/10.1039/d3se00381g.

590 WIRED – an updated regional IO tool much like the JEDI suite of models, is under development and will likely have a public release by the end of the year (2025). BEIOM – is both a retrospective and prospective dynamic environmentally extended input-output model that is not publicly available but can be used internally by NREL and DOE. EMPLOY – has the capability to model several fuel pathways (conventional petroleum products, corn starch ethanol, cellulosic ethanol, biodiesel, renewable diesel, sustainable aviation fuel, etc.) and is used to estimate the *net* impacts (economic, jobs, workforce and environmental) of large-scale industry deployment up to 2050.

Changes in ethanol volumes evaluated in this proposed rule result from increased consumption of higher-level ethanol motor gasoline blends (e.g., E15 and E85) and a corresponding decrease in E10 gasoline consumption that they replace. The connection between these estimated changes in domestic consumption and domestic production of ethanol is unlikely to be a perfect correlation as ethanol is produced not only for domestic consumption but also for export. Significant quantities of ethanol have been exported to foreign markets in recent years (see Chapter 7.5 and Chapter 7.6 for more details). The volume of ethanol that EPA projects to be consumed in 2026–2030 under the No RFS Baseline is significantly less than the domestic ethanol production capacity, and less than projected domestic ethanol production in 2025. For this reason, the exact strength of the correlation between ethanol production and the ethanol consumption estimates presented in our volume scenarios is not completely clear. Thus, it is possible that a decrease in ethanol consumption in the absence of the RFS program, such as that estimated in our forward-looking No RFS Baseline, could result in a decrease in domestic ethanol production or alternatively could result in increased ethanol exports.

The following is the employment impact analysis for all types of renewable fuels using the basic method based on the three specific IO studies of renewable fuels discussed in Chapter 9.1.1.2. The impact estimates from these three studies are based on total production of these renewable fuels. Tables 9.1.2-1a and 9.1.2-1b summarize the volume increases of RNG, BBD, and ethanol attributable to the RFS volume requirements relative to the No RFS Baseline under the Volume Scenarios and Proposed Volumes.

Table 9.1.2-1a: Projected Production Increases Under Volume Scenarios (million ethanol-equivalent gallons)

	Low					High				
	2026	2027	2028	2029	2030	2026	2027	2028	2029	2030
RNG	716	743	772	802	834	716	743	772	802	834
BBD	3,382	3,598	3,836	4,033	4,258	3,695	4,223	4,774	5,283	5,821
Ethanol	212	228	238	252	266	212	228	238	252	266

Table 9.1.2-1b: Projected Production Increases Under Proposed Volumes (million ethanol-equivalent gallons)

	2026	2027
RNG	716	743
BBD	4,817	5,050
Ethanol	212	228

To generate impact estimations based on projected production increases in million ethanol equivalent gallons (in Tables 9.1.2-1a and 1b), we calculate the impact per million ethanol equivalent gallons for each renewable fuel. We make the following assumptions:

- Linear impacts – Although the impact of renewable fuels may be nonlinear (e.g., a 5% increase in production may not require any increases in labor), we assume linear impacts, due to that prior research does not provide sufficient data to help accurately estimate potential nonlinear impacts.

- Impacts from operations – Since the projections under all scenarios, including the High Volume Scenario, are generally below production capacity (see Table 9.1.2-2), there may not be a need to construct new facilities even under the High Volume Scenario. As such, we focus on impacts from operations only. This is also conservative and may help mitigate potential overestimation (due to the linear assumption we make).

Table 9.1.2-2: Production Capacity and Projections by Fuel

		Production Capacity	Production		Projection 2026 (High Volume)
	Year	Original Unit	Original Unit	Million Gallons (Ethanol Equivalent)	Million Gallons (Ethanol Equivalent)
RNG	2024	133 tril Btu	878 mil gal	878	1,174
BBD	2021	4.6 bil gal	2.5 bil gal	3,925	5,701
Ethanol	2023	17.8 bil gal	15.6 bil gal	15,600	13,993

The impacts on employment (FTE) of the production of the renewable fuels based on the IO models discussed in the section above are summarized in Table 9.1.2-3. For BBD, the LMC study did not provide separate estimates for direct, indirect, and induced impacts associated with operations. We use the average effective multiplier reported in the LMC study to decompose the total impact into direct and non-direct (i.e., combined indirect and induced) effects.

Table 9.1.2-3: Job Creation Impacts of Production (FTE)

	Direct	Indirect	Induced	Indirect + Induced	Total
RNG	7,948	7,505	8,464		23,917
BBD	18,799			56,397	75,196
Ethanol	71,448	203,238	117,687		392,373

Because the job creation impacts in the studies summarized in Table 9.1.2-3 represent the impacts of differing quantities of biofuel production, we next normalized these studies to calculate the job impacts per million ethanol-equivalent gallons of biofuel production. To do this we divide the total impact estimates in Table 9.1.2-3 by the total production in million ethanol equivalent gallons to estimate the impact per million ethanol equivalent gallons for each renewable fuel, which are reported in Table 9.1.2-4. Compared with BBD and ethanol, RNG has the highest direct and total impacts per million ethanol equivalent gallons (9.1 and 27.2, respectively). BBD and ethanol have higher indirect and induced impacts relative to their direct impacts because their multipliers are higher than RNG's.

Table 9.1.2-4: Job Creation Impacts (FTE) per Million Ethanol Equivalent Gallons

	Direct	Indirect	Induced	Indirect + Induced	Total	Multiplier
RNG	9.1	8.5	9.6		27.2	3.0
BBD	4.8			14.4	19.2	4.0
Ethanol	4.6	13.0	7.5		25.2	5.5

We then estimate the impacts of the projected production increases by multiplying the projected production increases with the impact per million ethanol equivalent gallons estimates. We report two sets of the projections, one based on the directed effects only and the other based on all effects (i.e., direct, indirect, and induced effects). Tables 9.1.2-5a and 9.1.2-5b show the projected job impacts relative to the No RFS Baseline accounting for only the direct effects while Tables 9.1.2-6a and 9.1.2-6b show the projected job impacts considering the direct, indirect, and induced effects. Relative to the baseline and accounting for direct, indirect, and induced effects, BBD is projected to have the highest job creation impact, primarily due to substantially higher production increases relative to the baseline.

Table 9.1.2-5a: Job Creation Impacts of the Projected Production Increases Based on Direct Effects Only Under Volume Scenarios (FTE)

	Low				
	2026	2027	2028	2029	2030
RNG	6,482	6,726	6,988	7,260	7,550
BBD	16,198	17,233	18,373	19,316	20,394
Ethanol	971	1,044	1,090	1,154	1,218
	High				
	2026	2027	2028	2029	2030
RNG	6,482	6,726	6,988	7,260	7,550
BBD	17,697	20,226	22,865	25,303	27,880
Ethanol	971	1,044	1,090	1,154	1,218

Table 9.1.2-5b: Job Creation Impacts of the Projected Production Increases Based on Direct Effects Only Under Proposed Volumes (FTE)

	Direct	
	2026	2027
RNG	6,482	6,726
BBD	23,071	24,187
Ethanol	971	1,044
All Fuels	30,524	31,957

Table 9.1.2-6a: Job Creation Impacts of the Projected Production Increases Based on All Effects Under Volume Scenarios (FTE)

	Low				
	2026	2027	2028	2029	2030
RNG	19,504	20,240	21,030	21,847	22,718
BBD	64,793	68,931	73,491	77,265	81,576
Ethanol	5,332	5,735	5,986	6,338	6,690
	High				
	2026	2027	2028	2029	2030
RNG	19,504	20,240	21,030	21,847	22,718
BBD	70,790	80,905	91,461	101,213	111,520
Ethanol	5,332	5,735	5,986	6,338	6,690

Table 9.1.2-6b: Job Creation Impacts of the Projected Production Increases Based on All Effects Under Proposed Volumes (FTE)

	Direct + Indirect + Induced	
	2026	2027
RNG	19,504	20,240
BBD	92,285	96,749
Ethanol	5,332	5,735
All Fuels	117,121	122,723

9.1.3 Employment Impacts using NREL's JEDI model for Dry Mill Corn Ethanol

In the case of ethanol, we were able to assess employment impacts (in both the construction and the operations phase) using NREL's JEDI model to produce a second estimate. We proceed under the assumption that the volumes for this proposal relative to the No RFS Baseline comes entirely from higher domestic production, either from continuing operations in existing facilities which now produce a higher volume or from addition of new capacity. Using the JEDI model, we were able to compute the direct, indirect, and induced jobs resulting from the Volume Scenarios and Proposed Volumes under these assumptions. In this subsection, we report the cumulative impact to direct gross jobs that result from the Volume Scenarios and Proposed Volumes. We present results for the number of indirect (agriculture and industry) and induced operations jobs, along with the commensurate increase in incomes and the sensitivity analysis, in subsequent sections on Agricultural Employment (Chapter 9.1.3) and Rural Economic Development (Chapter 9.1.4).

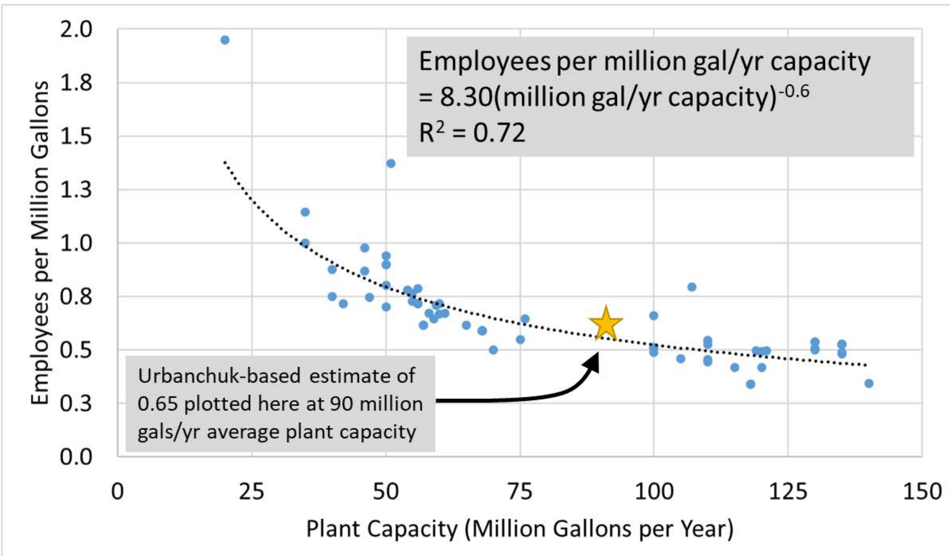
We demonstrate results for two cases. In the first case, we assume there is no new construction of ethanol facilities and the increased ethanol volume associated with the Volume Scenarios relative to the No RFS Baseline is met by increasing production levels at existing facilities (or in the alternative the avoidance of reduced corn ethanol production that would occur in the No RFS Baseline). Since the No RFS Baseline is forward-looking and represents a potential future where the RFS program ceases to exist after 2025, this may be the more realistic representation of the job impacts of the ethanol volumes in our scenarios. However, for completeness we also present a second case, in which we assume the increased ethanol volumes come from new construction. To the extent that retiring ethanol production capital is replaced with new and more efficient facilities in 2026 and 2027, this analysis would be relevant to those circumstances.

For both temporary and permanent direct job impacts, the assumed size of the model ethanol production facility in our analysis is an important assumption. In 2018, Ethanol Producer Magazine made available data on the capacity and number of employees at 65 corn ethanol facilities.[591] These plant capacities generally compare well with those reported by EIA and estimated in the ABF study, deviating by less than 3% from the EIA report when averaged on a state-by-state basis. For these 65 facilities, we examined employee concentration as a function of

[591] Ethanol plant employment data obtained via Ethanol Producer Magazine. See "Employment information sources for corn-ethanol facilities," available in the docket for this action.

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 and larger facilities are associated with fewer jobs per unit of output (Figure 9.1.3-1).

Figure 9.1.3-1: Correlation Between Employee Concentration and Facility Size for Corn Ethanol Facilities



For the purposes of this analysis, it means that depending on the size of the ethanol plant where increases (or avoided decreases) in ethanol production occur, the impacts are likely to be very different. For context, of the 187 ethanol production facilities that were currently operational in the U.S. as of January 1, 2024, approximately 57% produce less than or equal to 90 MG annually, (62.5% produce less than 100 MG or less annually), while 3.7% produce over 200 MG annually.[592] Uncertainty regarding the size of the facility or facilities which will provide the incremental volume of ethanol projected in the Volume Scenarios is therefore relevant to our analysis of employment impacts. To help address this uncertainty, we show the cumulative job impacts assuming the construction and/or operation of both a single large facility and assuming multiple 90 MGY facilities that add up to the total volume projected in our scenarios for that year.

While we have analyzed a full range of scenarios based on the permutations described above, here we present only the two scenarios which bound the lower and upper ends of the range of estimated employment impacts. Table 9.1.3-1 shows the cumulative number of direct jobs (permanent annual operations jobs), construction jobs (temporary annual jobs) and total jobs that would result under both scenarios (a single large "existing" facility that continues operations and multiple smaller facilities that are newly constructed). The last column in table 9.1.3-1 shows the range (maximum and minimum) of expected new total (direct) jobs that would be added to the economy during the time frame of the analysis in each of the two scenarios presented.

[592] EIA, "U.S. Fuel Ethanol Plant Production Capacity," *Petroleum & Other Liquids*, August 15, 2024. https://www.eia.gov/petroleum/ethanolcapacity.

Table 9.1.3-1: Cumulative Direct Permanent Annual Operations Jobs, Temporary Construction Jobs & Total Direct Jobs for Volume Scenarios (FTE)

Year	Aggregate Volume in mil gal (Multi-plant Volumes in mil gal)	Single Facility	Multi-plant Facility			Range (min–max)
		Cumulative Operations Jobs (Aggregate)	Cumulative Operations Jobs (Aggregate)	Construction Jobs	Total (Direct) Jobs	
2026	212 (90,90,32)	4	141	504	645	4–645
2027	228 (90,90,48)	5	294	538	832	5–832
2028	238 (90,90,58)	5	452	554	1,006	5–1,006
2029	252 (90,90,72)	6	612	570	1,182	6–1,182
2030	266 (90,90,86)	11	773	592	1,365	11–1,365

Table 9.1.3-2: Cumulative Direct Permanent Annual Operations Jobs, Temporary Construction Jobs & Total Direct Jobs for Proposed Volumes (FTE)

Year	Aggregate Volume in mil gal (Multi-plant Volumes in mil gal)	Single Facility	Multi-plant Facility			Range (min–max)
		Cumulative Operations Jobs (Aggregate)	Cumulative Operations Jobs (Aggregate)	Construction Jobs	Total (Direct) Jobs	
2026	212 (90,90,32)	4	141	504	645	4–645
2027	228 (90,90,48)	5	294	538	832	5–832

9.1.4 Agricultural Employment

Job creation in the agricultural sector, beyond jobs associated with the fuel production activities discussed above, is expected primarily in the areas of production and transportation of crops serving as renewable fuel 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, EPA is projecting higher volumes of ethanol and BBD (biodiesel and renewable diesel) production for 2026–2030 relative to the No RFS Baseline. Substantial volumes of these fuels are expected to be produced from domestic corn, soybean oil and canola oil.

9.1.4.1 Agricultural Employment Impacts Using the Rule-of-thumb Approach

From these studies, we have estimated the impacts of the projected crop-based renewable fuel volumes on agricultural employment. These estimates are summarized in Table 9.1.4.1-1.

Table 9.1.4.1-1: Agricultural Employment Impacts of Production (FTE)

	Feedstock	Direct	Indirect	Induced	Indirect + Induced	Total
RNG	Agricultural waste	2,823	2,584	3,063		8,470
BBD	Oilseed production	7,059			21,177	28,236
Ethanol	Feedstock (mostly corn)	58,324	127,638	78,533		264,464

As these estimated agricultural employment impacts represent different quantities of biofuel production, we then divide the total impact estimates in Table 9.1.4.1-1 by the total production estimated by each of these studies in million ethanol equivalent gallons to estimate the impact in terms of jobs per million ethanol equivalent gallons for each renewable fuel. These estimates are reported in Table 9.1.4.1-2. Ethanol has the highest direct and total effects on rural employment per million gallons of ethanol equivalent.

Table 9.1.4.1-2: Agricultural Employment Impacts per Million Ethanol Equivalent Gallons (FTE)

	Feedstock	Direct	Indirect	Induced	Indirect + Induced	Total
RNG	Agricultural waste	3.2	2.9	3.5		9.6
BBD	Oilseed production	1.8			5.4	7.2
Ethanol	Feedstock (mostly corn)	3.7	8.2	5.0		17.0

We next estimate the agricultural employment impacts associated with the Volume Scenarios and Proposed Volumes by multiplying the applicable volumes in our projections by the jobs per million gallons of ethanol equivalent. We report two sets of the projections, one based on the direct effects only and the other based on all effects (i.e., direct, indirect, and induced effects). These estimates are presented in Table 9.1.4.1-3(a and b) and 9.1.4.1-4(a and b) respectively. Relative to the No RFS Baseline and accounting for direct, indirect, and induced effects, BBD is projected to have the highest impact on agricultural employment, mainly due to substantially higher production increases relative to the baseline.

Table 9.1.4.1-3a: Agricultural Employment Impacts of the Projected Production Increases Based on Direct Effects Only Under Volume Scenarios (FTE)

	Low					High				
	2026	2027	2028	2029	2030	2026	2027	2028	2029	2030
RNG	2,302	2,389	2,482	2,579	2,682	2,302	2,389	2,482	2,579	2,682
BBD	6,082	6,471	6,899	7,253	7,658	6,645	7,595	8,586	9,501	10,469
Ethanol	793	852	890	942	994	793	852	890	942	994

Table 9.1.4.1-3b: Agricultural Employment Impacts of the Projected Production Increases Based on Direct Effects Only Under Proposed Volumes (FTE)

	Direct	
	2026	**2027**
RNG	2,302	2,389
Biodiesel	8,663	9,082
Ethanol	793	852
All Fuels	11,758	12,324

Table 9.1.4.1-4a: Agricultural Employment Impacts of the Projected Production Increases Based on All Effects Under Volume Scenarios (FTE)

	Low					High				
	2026	**2027**	**2028**	**2029**	**2030**	**2026**	**2027**	**2028**	**2029**	**2030**
RNG	6,907	7,168	7,447	7,737	8,046	6,907	7,168	7,447	7,737	8,046
BBD	24,330	25,884	27,596	29,013	30,632	26,581	30,380	34,344	38,005	41,876
Ethanol	3,594	3,865	4,035	4,272	4,509	3,594	3,865	4,035	4,272	4,509

Table 9.1.4.1-4b: Agricultural Employment Impacts of the Projected Production Increases Based on All Effects Under Proposed Volumes (FTE)

	Direct + Indirect + Induced	
	2026	**2027**
RNG	6,907	7,168
Biodiesel	34,653	36,329
Ethanol	3,594	3,865
All Fuels	45,154	47,362

9.1.4.2 Agricultural Employment Impacts Using NREL's JEDI model for Dry Mill Corn Ethanol

Once again, relying on NREL's JEDI model (as discussed in Chapter 9.1.2) and using the incremental corn ethanol volumes (compared with the No RFS Baseline) to infer the size of the policy shock, we were able to obtain estimates of the number of gross jobs (indirect and induced effects) that were added to the agricultural sector and allied industries.[593] As stated in Chapter 9.1, some of these biofuels bear similarities in terms of their backward and forward linkages to other sectors of the economy and as such the nature of the impacts (type of impacted sectors) are going to be similar. The magnitude of the impacts will be guided by the size of the initial policy shock.

We also carried out a sensitivity analysis on these projected estimates using research from a previously published Model Comparison Exercise.[594] Different modeling approaches

[593] Standard limitations associated with the limitations of the JEDI model are also applicable in this case. As with the estimates of direct jobs, please refer to the limitations of the JEDI model when it comes to interpreting these results: NREL, "Limitations of JEDI Models." https://www.nrel.gov/analysis/jedi/limitations.html
[594] EPA, "Model Comparison Exercise Technical Document," EPA-420-R-23-017, June 2023. https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1017P9B.pdf.

yield different answers to the question of the source of corn to support production of a higher volume of corn ethanol. In 2022, EPA carried out a "Model Comparison Exercise" (MCE) where the performance of five different models was compared in terms of their ability to account for the impact of the RFS program on indirect emissions (a requirement of the CAA). One of the scenarios that was modeled to facilitate model comparison was a corn ethanol shock, and the results of that analysis revealed (among other things) the source of the higher corn to fuel this shock. As expected, the results were vastly different across the competing models. Two of these models (GCAM and GLOBIOM) were used in this proposed rule to support the consequential components of the Life Cycle Analysis of biofuels (see Chapter 5). We used the sourcing estimates from those same two models in the previously published MCE to carry out the sensitivity analysis. This will allow us to compare how changing the JEDI model's default assumption (25% of this corn to support the higher production is to be sourced from new cropland) with the values obtained from GCAM (47.4%) and GLOBIOM (1%) will impact the different sectors. Tables 9.1.4.2-1 and 2 show the number of gross cumulative indirect operations jobs that are added to agriculture and allied industries and the number of gross induced operations jobs for the case of the Volume Scenarios and the Proposed Volumes, respectively, under the assumption that: (1) incremental volumes come from additional production at existing facilities, and (2) incremental volumes come from multiple facilities where the largest facility corresponds to the average size of an ethanol plant in the U.S.

Table 9.1.4.2-1 Annual Cumulative Indirect and Induced (Gross) Jobs in Agriculture, Industry and Other Sectors for Volume Scenarios (FTE)

Year	Indirect Operations Jobs (Agriculture)		Indirect Operations Jobs (Industry)		Induced Operations Jobs	
	Single Large Facility	Multiple Smaller Facilities	Single Large Facility	Multiple Smaller Facilities	Single Large Facility	Multiple Smaller Facilities
2026	648	648	429	573	477	580
2027	1,345	1,345	870	1,190	978	1,203
2028	2,072	2,073	1,316	1,832	1,493	1,853
2029	2,843	2,843	1,767	2,509	2,027	2,537
2030	3,656	3,657	2,220	3,220	2,579	3,256

Table 9.1.4.2-1 Annual Cumulative Indirect and Induced (Gross) Jobs in Agriculture, Industry and Other Sectors for Proposed Volumes (FTE)

Year	Indirect Operations Jobs (Agriculture)		Indirect Operations Jobs (Industry)		Induced Operations Jobs	
	Single Large Facility	Multiple Smaller Facilities	Single Large Facility	Multiple Smaller Facilities	Single Large Facility	Multiple Smaller Facilities
2026	648	648	429	573	477	580
2027	1,345	1,345	870	1,190	978	1,203

Since the purpose of the sensitivity analysis was to demonstrate primarily how changes in the sourcing assumption (from JEDI's default values) of this corn ethanol shock will impact gross jobs, it was applied only for the case of continuing production at existing facilities. Since the job impacts to the economy from the addition of multiple smaller facilities is significantly higher, the results from the sensitivity analysis when applied to those numbers will generate a wider range for the estimated jobs. Table 9.1.4.2-1 shows the number of gross indirect operations jobs that emerge out of this sensitivity analysis for agriculture, industry, and gross induced operations jobs sectors. The second column in Table 9.1.4.2-1 shows the outcome/impacts when 47.4% of this corn (for ethanol) is sourced from new agricultural production/new plantings, the third column shows the results when 25% is from new agricultural production, and the last column shows the impacts when 1% is sourced from new agricultural production/new plantings.[595]

Table 9.1.4.2-1: Results of Sensitivity Analysis on Cumulative (Indirect & Induced) Jobs for the Volume Scenarios (FTE)

Indirect Operations Jobs (Agriculture) - Cumulative FTE			
Year	**High Sourcing Value (47%)**	**JEDI Default Value[a] (25%)**	**Low Sourcing Value (1%)**
2026	1,229	648	26
2027	2,550	1,345	54
2028	3,929	2,072	83
2029	5,390	2,843	114
2030	6,931	3,656	146
Indirect Operations Jobs (Industry) - Cumulative FTE			
2026	429	429	429
2027	870	870	870
2028	1,316	1,316	1,316
2029	1,767	1,767	1,767
2030	2,220	2,220	2,220
Induced Operations Jobs - Cumulative FTE			
2026	658	477	283
2027	1,354	978	753
2028	2,073	1,493	1,051
2029	2,822	2,027	1,354
2030	3,602	2,579	1,663

[a] The results in this column correspond to the incremental output coming entirely from one single facility using JEDI's default sourcing assumption estimates.

[595] These percentages are the results of two competing models (PNNL's GCAM model and IIASA's GLOBIOM model) that was used by EPA in its previously published MCE.

Table 9.1.4.2-1: Results of Sensitivity Analysis on Cumulative (Indirect & Induced) Jobs for the Proposed Volumes (FTE)

Indirect Operations Jobs (Agriculture) Cumulative FTE			
Year	**High Sourcing Value (47%)**	**JEDI Default Value[a] (25%)**	**Low Sourcing Value (1%)**
2026	1,229	648	26
2027	2,550	1,345	54
Indirect Operations Jobs (Industry) Cumulative FTE			
2026	429	429	429
2027	870	870	870
Induced Operations Jobs Cumulative FTE			
2026	658	477	283
2027	1,354	978	753

[a] The results in this column correspond to the incremental output coming entirely from one single facility using JEDI's default sourcing assumption estimates.

9.1.5 Rural Economic Development

Changes in biofuel production can have economic development impacts on rural communities and financial impacts on farmers. Our volume scenarios project greater consumption of ethanol, BBD (including biodiesel and renewable diesel), and RNG used as CNG/LNG in 2026–2030 relative to the No RFS Baseline. However, the majority of the production growth (and therefore consumption growth) when considered relative to 2025 is due to expansions in renewable diesel. As discussed in Chapter 9.1.1, the impact of the RFS volumes for 2026–2030 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 ethanol exports, or alternatively, domestic ethanol production could decrease. However, even if only the renewable diesel projections are associated with additional jobs created relative to the state of the industry in 2025, all this renewable fuel production continues to sustain economic output in rural communities. In the face of uncertainty regarding the continued production of many of these fuels in the absence of the RFS program, it is worthwhile to quantify the entirety of this economic impact on rural communities.

9.1.5.1 Rural Economic Development Impacts using the Rule-of-thumb Approach

The three specific IO studies we identified in Chapter 9.1.1.2 provide a basis for estimating the impact of renewable fuels on rural economic development. From these studies, we have estimated the impacts of the projected crop-based renewable fuel volumes on rural economic development measured by GDP. These estimated impacts on rural GDP are summarized in Table 9.1.5.1-1.

Table 9.1.5.1-1: Rural GDP Impacts of Production

	Feedstock	Direct	Indirect	Induced	Indirect + Induced	Total
RNG (million 2024$)	Agricultural waste	657	380	358		1,395
BBD (million 2021$)	Oilseed production	1,853			5,558	7,410
Ethanol (million 2023$)	Feedstock (mostly corn)	3,137	14,299	10,488		27,916

We divide the total impact estimates in Table 9.1.5.1-1 by the total production of each category of fuel in million ethanol equivalent gallons in each of the relevant studies to estimate the impact per million ethanol equivalent gallons for each renewable fuel category. These results are reported in Table 9.1.5.1-2.

Table 9.1.5.1-2: Rural GDP Impacts (million dollars per million ethanol-equivalent gallons)

	Feedstock	Direct	Indirect	Induced	Indirect + Induced	Total
RNG (2024$)	Agricultural waste	0.75	0.43	0.41		1.59
BBD (2021$)	Oilseed production	0.47			1.42	1.89
Ethanol (2023$)	Feedstock (mostly corn)	0.20	0.92	0.67		1.79

The GDP impacts in Table 9.1.5.1-2 are based on data from different years. We use the GDP price index from the Federal Reserve Economic Data (FRED)[596] to compute the ratio of the GDP price index in base year (2022) to the GDP price index in year t (2021–2024), as shown in Table 9.1.5.1-3.

Table 9.1.5.1-3: GDP Price Index Ratios (Base Year 2022)

Year	GDP Price Index	GDP Price Index Ratio
2021	110	1.071
2022	118	1.000
2023	122	0.965
2024	125	0.942

We then use the ratios to compute the GDP impacts in 2022 dollars as shown in Table 9.1.5.1-4. For example, to derive 0.71 (the real value measured in 2022 dollars in Table 9.1.5.1-4), we multiply 0.75 (the nominal value in Table 9.1.5.1-2) by 0.942 (the ratio for 2024 in Table 9.1.5.1-3). Compared with RNG, BBD and ethanol have higher impacts per million ethanol equivalent gallons on rural economic development.

[596] Federal Reserve Economic Data, "Gross domestic product (implicit price deflator)," March 27, 2025. https://fred.stlouisfed.org/series/A191RD3A086NBEA.

Table 9.1.5.1-4: Rural GDP Impacts (million 2022$ per million ethanol-equivalent gallons)

	Feedstock	Direct	Indirect	Induced	Indirect + Induced	Total
RNG	Agricultural waste	0.71	0.41	0.38		1.50
BBD	Oilseed production	0.51			1.52	2.02
Ethanol	Feedstock (mostly corn)	0.19	0.88	0.65		1.73

We next estimate the impacts of the projected production increases by multiplying the projected production increases with the impact per million ethanol equivalent gallons estimates. We report two sets of the projections, one based on the direct effects only (Table 9.1.5.1-5) and the other based on all effects (i.e., direct, indirect, and induced effects, Table 9.1.5.1-6). Relative to the No RFS Baseline and accounting for direct, indirect, and induced effects, BBD is projected to have the highest impact on rural economic development, largely due to substantially higher production increases relative to the baseline.

Table 9.1.5.1-5: Rural GDP Impacts of the Projected Production Increases Based on Direct Effects Only Under Volume Scenarios (million 2022$)

	Low					High				
	2026	2027	2028	2029	2030	2026	2027	2028	2029	2030
RNG	505	524	545	566	588	505	524	545	566	588
BBD	1,710	1,819	1,940	2,039	2,153	1,868	2,135	2,414	2,671	2,943
Ethanol	41	44	46	49	52	41	44	46	49	52

Table 9.1.5.1-6: Rural GDP Impacts of the Projected Production Increases Based on All Effects Under Volume Scenarios (million 2022$)

	Low					High				
	2026	2027	2028	2029	2030	2026	2027	2028	2029	2030
RNG	1,072	1,113	1,156	1,201	1,249	1,072	1,113	1,156	1,201	1,249
BBD	6,840	7,277	7,758	8,157	8,612	7,473	8,541	9,655	10,685	11,773
Ethanol	366	394	411	435	459	366	394	411	435	459

For the Proposed Volumes, we have performed the discounting analysis using discount rates of 3% and 7%. We report the results separately from those of the Volume Scenarios in Table 9.1.5.1-7. Without discounting and based only on the direct impacts, the Proposed Volumes are projected to create $2.98 billion and $3.12 billion in 2026 and 2027, respectively. If we discount these direct impacts at 3%, the total impact is $5.84 billion over the two-year horizon, or $2.92 billion per year. If we also account for indirect and induced effects, the total impact without discounting is $11.18 billion and $11.72 billion in 2026 and 2027; with discounting, it is $21.90 billion over the two-year horizon, or $10.95 billion per year. In addition, if we amortize $21.90 billion over the two-year horizon, the annualized value is $11.45 billion.[597]

[597] An annualized value is the amount one would have to pay (or receive) at the end of each time period so that the sum of all payments in present value terms equals the original stream of values. Computing annualized costs and benefits from present values spreads the costs and benefits equally over each period, taking account of the discount rate.

Table 9.1.5.1-7: Rural GDP Impacts of the Projected Production Increases (million 2022$)

	Direct		Direct + Indirect + Induced	
	2026	2027	2026	2027
RNG	505	524	1,072	1,113
BBD	2,436	2,553	9,742	10,214
Ethanol	41	44	366	394
All Fuels	2,982	3,122	11,181	11,720
Present Value at 3%	2,895	2,943	10,855	11,047
All fuels for two years	5,838		21,902	
All fuels per year	2,919		10,951	
Present Value at 7%	2,787	2,727	10,449	10,237
All fuels for two years	5,514		20,686	
All fuels per year	2,757		10,343	

9.1.5.2 Rural Economic Development Impacts using NREL's JEDI Model for Dry Mill Corn Ethanol

We also estimated annual cumulative earnings impacts associated with corn ethanol using the NREL JEDI model. These estimates assume the ethanol volumes are associated with new domestic production. Relying on the JEDI model to compute the employment impacts stemming from such an increase in production, we were able to assess the economic impacts to the rural economy under the same scenario specifications as in Chapter 9.1.2.1.2, firstly in a situation where this higher production comes from existing facilities and, secondly, in another situation where this higher production comes from multiple new smaller facilities. Based on our analysis, Table 9.1.5.2-1 and Table 9.1.5.2-2 show the economic impacts of continued operations at higher volumes from existing facilities and from multiple new average sized facilities for the Volume Scenarios and Proposed Volumes, respectively.

Table 9.1.5.2-1: Annual Cumulative Earnings From All Indirect and Induced Jobs for Both Analytical Scenarios (million 2022$)

	Indirect Operations Earnings (Agriculture)		Indirect Operations Earnings (Industry)		Induced Operations Earnings	
Year	Single Large Facility	Multiple Smaller Facilities	Single Large Facility	Multiple Smaller Facilities	Single Large Facility	Multiple Smaller Facilities
2026	33	32	39	49	34	40
2027	68	66	78	102	69	84
2028	104	102	118	157	105	129
2029	142	140	158	215	142	176
2030	182	181	199	275	180	226

Table 9.1.5.2-2: Annual Cumulative Earnings From All Indirect and Induced Jobs for the Proposed Volumes (million 2022$)

Year	Indirect Operations Earnings (Agriculture)		Indirect Operations Earnings (Industry)		Induced Operations Earnings	
	Single Large Facility	Multiple Smaller Facilities	Single Large Facility	Multiple Smaller Facilities	Single Large Facility	Multiple Smaller Facilities
2026	33	32	39	49	34	40
2027	68	66	78	102	69	84

As in Chapter 9.1.5, we were able to conduct a sensitivity analysis where the percentage of new cropland that was sourced to produce the additional ethanol was the parameter that was given alternate values (see Chapter 9.1.4.2 for more details on this discussion). Table 9.1.5.2-1 shows the impact on earnings that emerge out of this sensitivity analysis for agriculture, industry and other sectors (induced jobs) where the second column in Table 9.1.5.2-1 shows the outcome when 47.4% of this corn (for ethanol) is sourced from new agricultural production/new plantings, the third column shows the results if 25% is from new production, and the last column shows the impacts when 1% is from production.[598]

[598] These percentages are the results of two competing models (PNNL's GCAM model and IIASA's GLOBIOM model) that was used by EPA in its previously published MCE.

Table 9.1.5.2-1: Results of Sensitivity Analysis on Cumulative (Indirect & Induced) Earnings (million 2022$)

Indirect Earnings (Agriculture)			
Year	High Sourcing Value (47%)	JEDI Default Value (25%)	Low Sourcing Value (1%)
2026	60.7	33.4	1.3
2027	99.8	67.8	2.7
2028	167.9	103.7	4.1
2029	240.0	141.7	5.6
2030	316.2	181.9	46.6
Indirect Earnings (Industry)			
2026	37.9	38.7	37.9
2027	86.6	77.8	77.1
2028	126.4	117.6	116.9
2029	166.8	158.1	157.4
2030	207.8	199.1	178.5
Induced Earnings			
2026	46.0	34.1	19.4
2027	94.6	68.9	39.3
2028	144.8	104.7	59.7
2029	197.2	141.8	80.5
2030	251.7	180.2	101.6

9.1.6 Summary of Employment and Economic Impacts

Chapter 9.1 contains our analysis of the employment, agricultural employment, and rural economic development for the Volume Scenarios and the Proposed Volumes. In this section, we summarize our main results in Tables 9.1.6-2, 4, and 6. Our analyses are based on existing studies using a rule-of-thumb method (for ethanol, BBD, and RNG) and the NREL's JEDI model approach (for corn ethanol).

The "rule-of-thumb" type approach uses job and income impact estimates from previous studies, expressed in jobs and/or dollars per unit of biofuel production, and multiplies these estimated impacts by the projected volumes to arrive at employment estimates. This approach is taken to produce estimates for the impacts of the quantities of ethanol, BBD, and RNG fuels in the Low and High Volume Scenarios relative to the No RFS Baseline. The JEDI model approach is a slightly more nuanced approach that relies on the use of an input-output modeling methodology developed specifically for analysis of dry mill corn ethanol, which is applied to the volumes of that fuel in the Low and High Volume Scenarios relative to the No RFS Baseline. In some cases, we have developed ranges of impacts for fuel volumes based on uncertainty regarding how the volumes will be provided. For example, volumes associated with new production capacity would also be associated with some number of temporary construction jobs, while expanded capacity utilization at existing facilities would not. Additionally, we were also able to carry out a sensitivity analysis on the results of these model runs using research from the MCE. This approach illustrates both how results from a simple rule-of-thumb type approach compare with a more robust approach like an input-output model, and how changes in some key modeling parameters will alter the extent of economic impacts on the agricultural sector and the rural economy.

The summary below includes the estimated potential employment impacts, agricultural employment impacts, and rural GDP impacts associated with the volumes of ethanol, BBD, and RNG attributable to the Volume Scenarios and Proposed Volumes.

With the "rule-of-thumb" approach, we estimate that all three categories of renewable fuel we analyzed—ethanol, BBD, and RNG—are associated with increases in employment to varying degrees. We observe that (1) RNG appears to be associated with the highest number of direct and total jobs created per unit of biofuel (9.1 and 27.2, respectively) and (2) BBD and ethanol have higher indirect and induced impacts relative to their direct impacts. See Table 9.1.6-1.

Table 9.1.6-1: Job Creation Impacts (FTE) per Million Ethanol-Equivalent Gallons

	Direct	Indirect + Induced			Total	Multiplier
		Indirect	Induced	Combined		
RNG	9.1	8.5	9.6		27.2	3.0
BBD	4.8			14.4	19.2	4.0
Ethanol	4.6	13.0	7.5		25.2	5.5

However, BBD is projected to have the highest job creation impact overall, primarily due to substantially higher production increases relative to the baseline, for all of the Volume Scenarios and Proposed Volumes (Tables 9.1.6-2a and b).

Using the JEDI model for corn ethanol, we created the following two scenarios to estimate the impacts of the analytical and Proposed Volumes on the economy: (1) we assume there is no new construction of ethanol facilities and the increased ethanol volume associated with the volume scenarios (relative to the No RFS Baseline) is met by increasing production levels at existing facilities (or in the alternative the avoidance of reduced corn ethanol production that would occur in the No RFS Baseline) and (2) a second case, in which we assume the increased ethanol volumes (relative to the No RFS Baseline) come from new construction. To the extent that retiring ethanol production capital is replaced with new and more efficient facilities in 2026 and 2027, this analysis would be relevant to those circumstances. Tables 9.1.6-2c and d report the cumulative number of total jobs (in FTE) that would result under the Volume Scenarios and the Proposed Volumes.

Table 9.1.6-2a: Employment Impacts of the Volume Scenario Using the Rule-of-thumb Approach (FTE)

Low Volume Scenario					
	2026	**2027**	**2028**	**2029**	**2030**
Ethanol	5,332	5,735	5,986	6,338	6,690
BBD	64,793	68,931	73,491	77,265	81,576
RNG	19,504	20,240	21,030	21,847	22,718
Total	89,629	94,906	100,507	105,450	110,984
High Volume Scenario					
Ethanol	5,332	5,735	5,986	6,338	6,690
BBD	70,790	80,905	91,461	101,213	111,520
RNG	19,504	20,240	21,030	21,847	22,718
Total	95,626	106,880	118,477	129,398	140,928

Table 9.1.6-2b: Employment Impacts of the Proposed Volumes Using the Rule-of-thumb Approach (FTE)

Proposed Volumes		
	2026	**2027**
Ethanol	5,332	5,735
BBD	92,285	96,749
RNG	19,504	20,240
Total	117,121	122,724

Table 9.1.6-2c: Employment Impacts of the Volume Scenarios Using NREL's JEDI Model for Dry Mill Corn Ethanol (FTE)[a]

Low Volume Scenario					
	2026	**2027**	**2028**	**2029**	**2030**
Ethanol	1,558–2,446	3,198–4,570	4,886–6,764	6,643–9,071	8,466–11,498
High Volume Scenario					
Ethanol	1,558–2,446	3,198–4,570	4,886–6,764	6,643–9,071	8,466–11,498

[a] The estimates are presented as ranges corresponding to the single facility outcome as the lower bound of the rance and the multi facility outcome as the upper bound of the range.

Table 9.1.6-2d: Employment Impacts of the Proposed Volumes Using NREL's JEDI Model for Dry Mill Corn Ethanol (FTE)[a]

Proposed Volumes		
	2026	**2027**
Ethanol	1,558–2,446	3,198–4,570

[a] The estimates are presented as ranges corresponding to the single facility outcome as the lower bound of the rance and the multi facility outcome as the upper bound of the range.

In terms of agricultural employment specifically, with the "rule-of-thumb" approach, we use the job creation impacts associated with agricultural feedstocks to infer the effects on agricultural employment. Ethanol has the highest direct and total effects per million gallons of ethanol equivalent, as shown in Table 9.1.6-3.

Table 9.1.6-3: Agricultural Employment Impacts per Million Ethanol Equivalent Gallons (FTE)

	Feedstock	Direct	Indirect	Induced	Indirect + Induced	Total
RNG	Agricultural waste	3.2	2.9	3.5		9.6
BBD	Oilseed production	1.8			5.4	7.2
Ethanol	Feedstock (mostly corn)	3.7	8.2	5.0		17.0

Relative to the No RFS Baseline and accounting for direct, indirect, and induced effects, BBD is projected to have the highest impact on agricultural employment, mainly due to substantially higher production increases relative to the baseline, for all of the Volume Scenarios and Proposed Volumes. See Tables 9.1.6-4a and b.

Once again, using the JEDI model for corn ethanol, we created the following two scenarios to estimate the impacts of the analytical and Proposed Volumes on the economy: (1) we assume there is no new construction of ethanol facilities and the increased ethanol volume associated with the volume scenarios (relative to the No RFS Baseline) is met by increasing production levels at existing facilities (or in the alternative the avoidance of reduced corn ethanol production that would occur in the No RFS Baseline) and (2) a second case, in which we assume the increased ethanol volumes (relative to the No RFS Baseline) come from new construction. To the extent that retiring ethanol production capital is replaced with new and more efficient facilities in 2026 and 2027, this analysis would be relevant to those circumstances. Tables 9.1.6-4 c and d report the cumulative number of total indirect operations (in agriculture and industry) jobs and the total induced operations jobs that would result under the Volume Scenarios and Proposed Volumes. For the results of the sensitivity analysis, please refer to Tables 9.1.4.2-1 and 9.1.4.2-2.

Table 9.1.6-4a: Agricultural Employment Impacts of the Volume Scenarios Using the Rule-of-thumb Approach (FTE)

Low Volume Scenario					
	2026	**2027**	**2028**	**2029**	**2030**
Ethanol	3,594	3,865	4,035	4,272	4,509
BBD	24,330	25,884	27,596	29,013	30,632
RNG	6,907	7,168	7,447	7,737	8,046
Total	34,831	36,917	39,078	41,022	43,187
High Volume Scenario					
Ethanol	3,594	3,865	4,035	4,272	4,509
BBD	26,581	30,380	34,344	38,005	41,876
RNG	6,907	7,168	7,447	7,737	8,046
Total	37,082	41,413	45,826	50,014	54,431

Table 9.1.6-4b: Agricultural Employment Impacts of the Proposed Volumes Using the Rule-of-thumb approach (FTE)

Proposed Volumes		
	2026	**2027**
Ethanol	3,594	3,865
BBD	34,653	36,329
RNG	6,907	7,168
Total	45,154	47,362

Table 9.1.6-4c: Agricultural Employment Impacts of the Volume Scenarios Using NREL's JEDI Model for Dry Mill Corn Ethanol (FTE)[a]

Low Volume Scenario					
	2026	**2027**	**2028**	**2029**	**2030**
Ethanol	1,554 – 1,801	3,193 – 3,738	4,881 – 5,758	6,637 – 7,889	8,455 – 10,133
High Volume Scenario					
Ethanol	1,554 – 1,801	3,193 – 3,738	4,881 – 5,758	6,637 – 7,889	8,455 – 10,133

[a] The estimates are presented as ranges corresponding to the single facility outcome as the lower bound of the range and the multi facility outcome as the upper bound of the range.

Table 9.1.6-4d: Agricultural Employment Impacts of the Proposed Volumes Using NREL's JEDI Model for Dry Mill Corn Ethanol (FTE)[a]

Proposed Volumes		
	2026	**2027**
Ethanol	1,554 – 1,801	3,193 – 3,738

[a] The estimates are presented as ranges corresponding to the single facility outcome as the lower bound of the range and the multi facility outcome as the upper bound of the range.

With the "rule-of-thumb" approach, we also estimate that ethanol, BBD, and RNG are all associated with increased rural economic development, again to varying degrees. Since renewable fuels rely on agricultural feedstocks, we use the GDP impacts associated with agricultural feedstocks to infer the effects on rural economic development. We estimate that BBD and ethanol have higher total impacts per million ethanol equivalent gallons on rural economic development than does RNG. See Table 9.1.6-5.

Table 9.1.6-5: Rural GDP Impacts per Million Ethanol Equivalent Gallons (million 2022$)

	Feedstock	**Direct**	**Indirect**	**Induced**	**Indirect + Induced**	**Total**
RNG	Agricultural waste	0.71	0.41	0.38		1.50
BBD	Oilseed production	0.51			1.52	2.02
Ethanol	Feedstock (mostly corn)	0.19	0.88	0.65		1.73

Relative to the No RFS Baseline and accounting for direct, indirect, and induced effects, BBD is projected to have the highest impact on rural economic development, largely due to substantially higher production increases relative to the baseline. See Tables 9.1.6-6a and b. Note that the estimates of rural GDP impacts are actual values as opposed to discounted values, implying that they do not reflect the time value of money.

Once again, using the JEDI model for corn ethanol, we created the following two scenarios to estimate the impacts of the analytical and Proposed Volumes on the economy: (1) we assume there is no new construction of ethanol facilities and the increased ethanol volume associated with the volume scenarios (relative to the No RFS Baseline) is met by increasing production levels at existing facilities (or in the alternative the avoidance of reduced corn ethanol production that would occur in the No RFS Baseline) and (2) a second case, in which we assume the increased ethanol volumes (relative to the No RFS Baseline) come from new construction. To the extent that retiring ethanol production capital is replaced with new and more efficient facilities in 2026 and 2027, this analysis would be relevant to those circumstances. Tables 9.1.6-6c and d report the cumulative earnings from the number of total indirect operations (in agriculture and industry) jobs and the total induced operations jobs (in FTE) that would result under the Volume Scenarios and the Proposed Volumes. For the results of the sensitivity analysis, please refer to Tables 9.1.5.2-1 and 9.1.5.2-2.

Table 9.1.6-6a: Rural Economic Development Impacts of the Volume Scenarios (million 2022$)

Low Volume Scenario					
	2026	**2027**	**2028**	**2029**	**2030**
Ethanol	366	394	411	435	459
BBD	6,840	7,277	7,758	8,157	8,612
RNG	1,072	1,113	1,156	1,201	1,249
Total	8,278	8,784	9,325	9,793	10,320
High Volume Scenario					
Ethanol	366	394	411	435	459
BBD	7,473	8,541	9,655	10,685	11,773
RNG	1,072	1,113	1,156	1,201	1,249
Total	8,911	10,048	11,222	12,321	13,481

Table 9.1.6-6b: Rural Economic Development Impacts of the Proposed Volumes (million 2022$)

Proposed Volumes		
	2026	**2027**
Ethanol	366	394
BBD	9,742	10,214
RNG	1,072	1,113
Total	11,180	11,721

Table 9.1.6-6c: Rural Economic Development Impacts of the Volume Scenarios Using NREL's JEDI Model for Dry Mill Corn Ethanol (million 2022$)[a]

Low Volume Scenario					
	2026	**2027**	**2028**	**2029**	**2030**
Ethanol	106 – 121	215 – 252	327 – 388	442 – 531	561 – 682
High Volume Scenario					
Ethanol	106 – 121	215 – 252	327 – 388	442 – 531	561 – 682

[a] The estimates are presented as ranges corresponding to the single facility outcome as the lower bound of the range and the multi facility outcome as the upper bound of the range.

Table 9.1.6-6d: Rural Economic Development Impacts of the Proposed Volumes Using NREL's JEDI Model for Dry Mill Corn Ethanol (million 2022$)[a]

Proposed Volumes		
	2026	**2027**
Ethanol	106 – 121	215 – 252

[a] The estimates are presented as ranges corresponding to the single facility outcome as the lower bound of the range and the multi facility outcome as the upper bound of the range.

These estimates in Chapter 9.1 for the various categories of biofuels are subject to the limitations and assumptions of the methods employed. They are not meant to be exact estimates, but rather to provide an estimate of general magnitude. In addition, while we estimate that production and consumption of these biofuels will lead to higher jobs and rural GDP in some sectors of the economy, this will likely involve some migration in jobs and rural GDP from other sectors. As such, we anticipate that there would be job and rural GDP losses as well in some sectors. Likewise, investments in rural development may involve some shifting of capital from one sector to another. We do not account for any such losses in our analysis. In other words, our estimates for jobs and rural development impacts are gross estimates and not net estimates. While we have also not been able to quantify the impacts of this proposed rule on small entities in rural areas, we note that we do anticipate that small entities (such as farms and supporting industries) would experience benefits from this proposed rule.

The existing literature also shows, in the long run, environmental regulation such as the RFS program typically affects the distribution of employment among industries rather than the general employment level.[599,600] The expectation is that there will be a movement of labor towards jobs that are associated with greater environmental protection, and away from those that are not. Even if impacts are small after long-run market adjustments to full employment, many regulatory actions move workers in and out of jobs and industries, which are potentially important distributional impacts of environmental regulations.[601]

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[599] Arrow, Kenneth J., Maureen L. Cropper, George C. Eads, Robert W. Hahn, Lester B. Lave, Roger G. Noll, Paul R. Portney, et al. "Benefit-Cost Analysis in Environmental, Health, and Safety Regulation," *American Enterprise Institute, The Annapolis Center, and Resources for the Future*, 1996. https://www.aei.org/wp-content/uploads/2014/04/-benefitcost-analysis-in-environmental-health-and-safety-regulation_161535983778.pdf.

[600] Hafstead, Marc a. C., and Roberton C. Williams. "Jobs and Environmental Regulation." *Environmental and Energy Policy and the Economy* 1 (January 1, 2020): 192–240. https://doi.org/10.1086/706799.

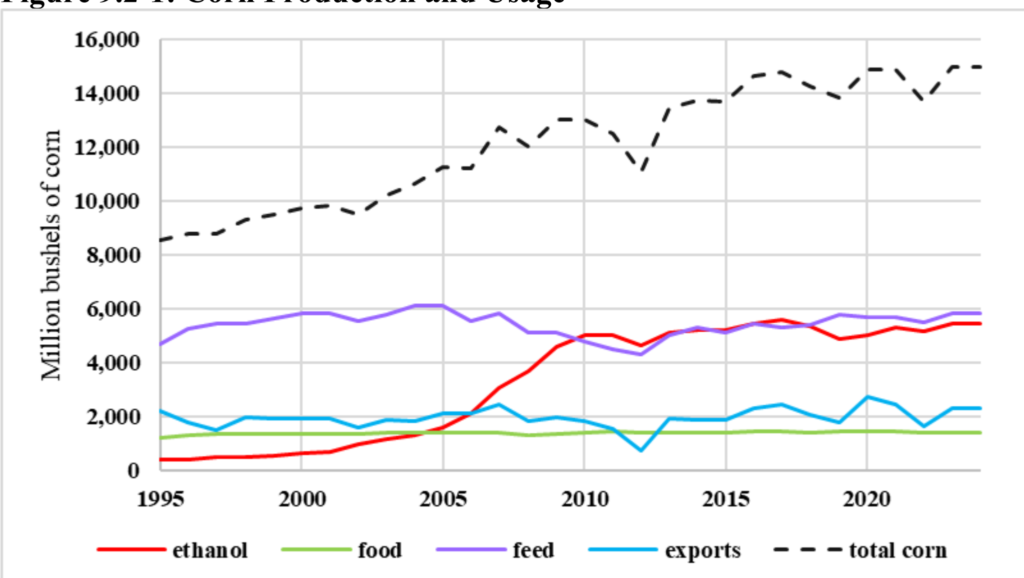
[601] Walker, W. Reed. "The Transitional Costs of Sectoral Reallocation: Evidence From the Clean Air Act and the Workforce*." *The Quarterly Journal of Economics* 128, no. 4 (August 15, 2013): 1787–1835. https://doi.org/10.1093/qje/qjt022.

9.2 Supply of Agricultural Commodities

Changes in biofuel production can have an impact on the supply of agricultural commodities. The Volume Scenarios in this proposed rulemaking suggest the potential for associated increases in underlying crop production; however, the magnitude of any potential impact cannot be estimated with any certainty. EPA notes that biogas is not produced from agricultural commodities and therefore is not expected to affect their supply or price.

For historical context, Figure 9.2-1 shows trends in corn production and uses from 1995–2024.[602] This data suggests domestic corn production has grown steadily at a 25-year average rate of around 2% year over year, or 219 million bushels added annually.

Figure 9.2-1: Corn Production and Usage



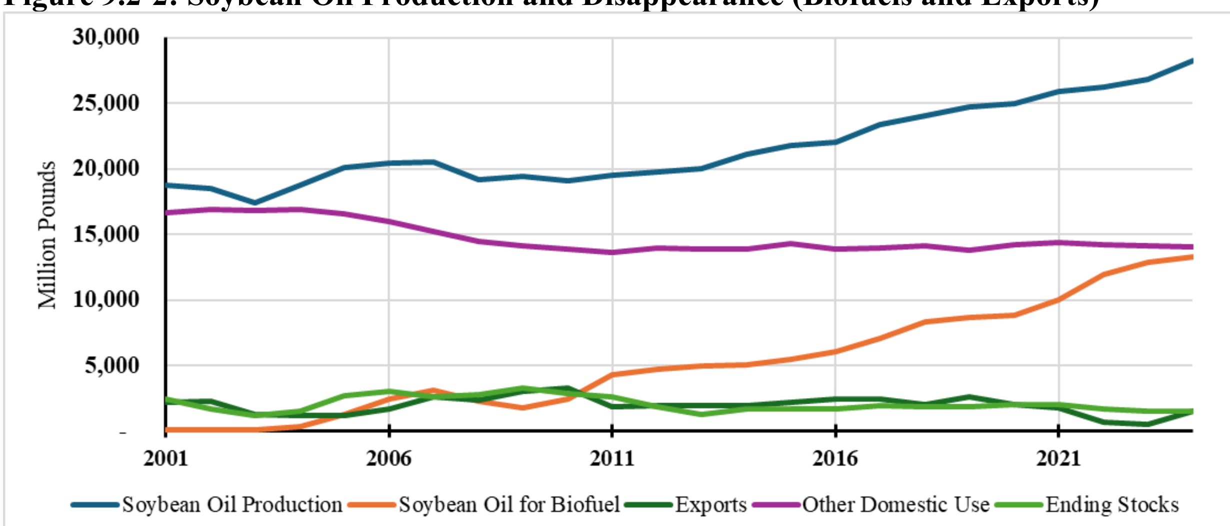
Between 2005–2010, additional corn required to satisfy increasing ethanol production was sourced primarily by diversion from animal feed until overall production caught up. Supply of corn to food uses showed modest but consistent growth at historical rates during this period, despite increased consumption 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 relative to 2025 are likely to have minimal impact on the supply of corn to food, exports, or other uses.

[602] USDA, "U.S. Bioenergy Statistics," October 2024, Table 16 – Biodiesel and Diesel Prices. https://www.ers.usda.gov/data-products/us-bioenergy-statistics.

Soybean production has risen steadily over time, similar to the trend for corn production, according to data from USDA.[603] Roughly 80% of growth in soybean production 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 crush products, soy meal and oil. These data also show 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. For context, over 95% of soybeans worldwide are eventually crushed for meal and oil.

Figure 9.2-2 shows the evolution of soybean oil production and disappearance in the U.S. since 2001. Growth in soybean oil production 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. As with corn, when considering the relatively small changes in the supply of soybean oil for food and other non-biofuel uses since 2008, we expect the Proposed Volumes would likely have minimal impact on the supply of soybean oil for food and other uses. While annual gross exports of soybean oil have declined in recent years, they reached nearly zero in 2022 and have remained there since. Because of this, we believe it is unlikely that these standards will have any significant impact on gross exports of soybean oil. The continued expansion of biofuel demand has, however, begun to shift the relative value relationship between the oil and meal crush products, as discussed in Chapter 9.3.

Figure 9.2-2: Soybean Oil Production and Disappearance (Biofuels and Exports)



9.3 Price of Agricultural Commodities

Agricultural commodities are bought and sold on the 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

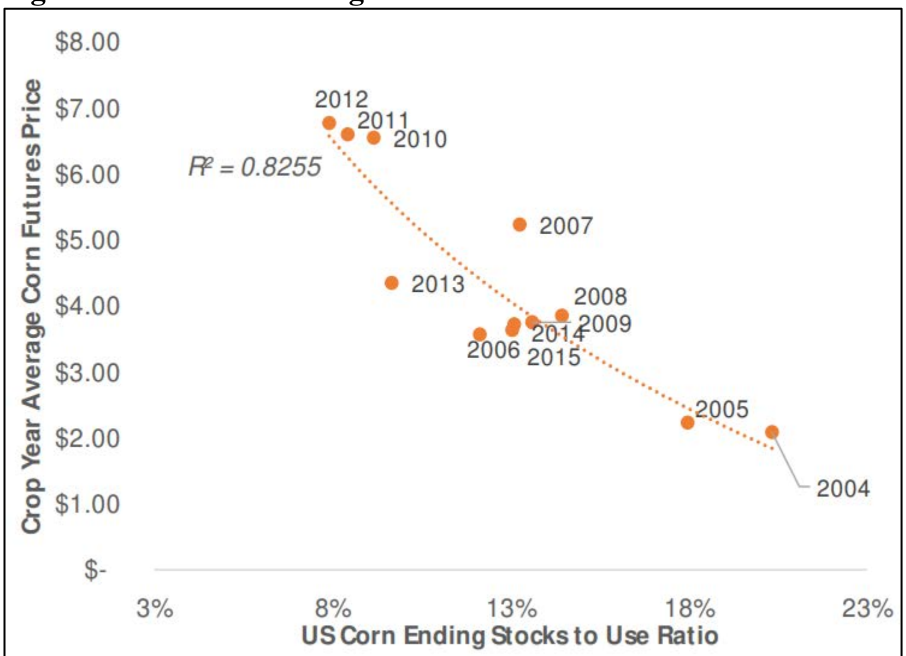
[603] USDA, "Oil Crops Yearbook," March 2025. https://www.ers.usda.gov/data-products/oil-crops-yearbook.

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.[604] 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.[605] Figure 9.3-1 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.

Figure 9.3-1: Corn Ending Stocks / Use Ratio Versus Futures Price



Source: USDA, Informa Economics IEG

[604] USDA, "Feed Grains Yearbook," May 2025. https://www.ers.usda.gov/data-products/feed-grains-database/feed-grains-yearbook-tables.

[605] Informa Economics IEG, "The Impact of Ethanol Industry Expansion on Food Prices: A Retrospective Analysis," 2016. https://d35t1syewk4d42.cloudfront.net/file/975/Retrospective-of-Impact-of-Ethanol-on-Food-Prices-2016.pdf.

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.[606] 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.[607] 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.

EPA is projecting a marginal increase in ethanol volumes for years 2026–2030 relative to 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 2026–2030, as our projected consumption volumes remain below USDA's projected domestic production volumes for these years.[608] A history of significant export volumes complicates predicting the impact of the projected volumes on agricultural commodity prices. It is possible that an increase in domestic corn ethanol consumption may result in decreased exports and minimal change in overall domestic production volumes. Were this to occur, we would expect little to no net change in domestic corn demand, and thus corn prices, which we would expect to maintain their current levels. Alternatively, it may be possible (though less likely) that an increase in consumption would result in an increase in domestic corn ethanol production. In this case we would expect a correlated decrease in corn demand and corn prices.

To illustrate the potential impact of the volume scenarios on corn prices, we have calculated the projected impact in 2026–2030 if these volumes result in increased corn ethanol production relative to the No RFS Baseline. The projected price impacts are calculated using a value from the literature of 3% increase in the price of a bushel of corn per billion gallons of corn ethanol produced, as described above. The projected impact of the candidate volumes on corn prices relative to the No RFS Baseline are shown in Table 9.3-1.

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[606] Condon, Nicole, Heather Klemick, and Ann Wolverton. "Impacts of Ethanol Policy on Corn Prices: A Review and Meta-analysis of Recent Evidence." *Food Policy* 51 (January 13, 2015): 63–73. https://doi.org/10.1016/j.foodpol.2014.12.007.
[607] FAPRI, "Literature Review of Estimated Market Effects of U.S. Corn Starch Ethanol." FAPRI-MU Report #01-16, February 2016. https://ethanolrfa.org/file/2007/FAPRI-Report-01-16.pdf.
[608] USDA, "USDA Agricultural Projections to 2034," OCE-2025-1, February 2025. https://doi.org/10.32747/2025.9015815.ers.

Table 9.3-1: Projected Impact on Corn Prices Relative to No RFS Baseline

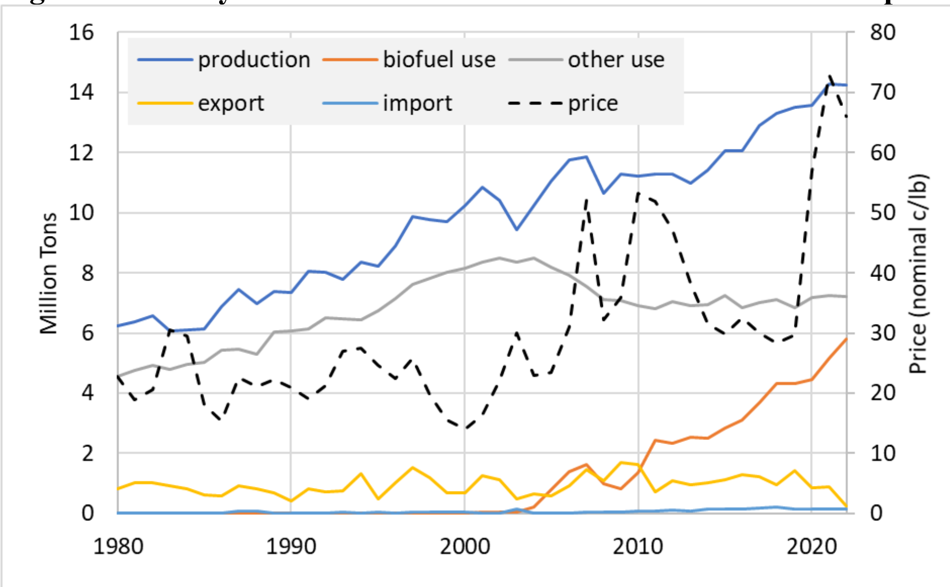
	Units	2026	2027	2028	2029	2030
Corn Price (All Volume Scenarios)[a]	$ per Bushel	$3.97	$4.07	$4.17	$4.27	$4.30
Corn Price Response	(%) per Billion Gallons of Ethanol	3%	3%	3%	3%	3%
Corn Ethanol Volume Increase Relative to No RFS Baseline	Billion Gallons	0.212	0.228	0.238	0.252	0.266
Corn Price Increase Relative to No RFS Baseline	$ per Bushel	$0.03	$0.03	$0.03	$0.03	$0.03

[a] Corn prices are from: USDA, "USDA Agricultural Projections to 2034," OCE-2025-1, February 2025. https://doi.org/10.32747/2025.9015815.ers. 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., 2025/2026 for 2026) and 2/3 of the price for the second agricultural marketing year (e.g., 2026/2027 for 2026).

With biodiesel and renewable diesel production, the commodity input of interest is soybean oil, which has an indirect link to soybean production. Soybean oil is produced by crushing soybeans, which also creates soy meal. The supply and prices of soybean oil and soybean meal can 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 soy oil and meal price minus the soybean price. Oversupplying either oil or meal markets can cause prices to fall, decreasing the crush margin. Figure 9.3-2 shows historical trends in soybean oil prices alongside allocation to biofuel and other uses, based on data taken from the USDA Oil Crops Yearbook.[609] Use of soybean oil in domestic biofuel rose from 0.8 million tons in 2005 to 7 million tons in 2024. Other domestic uses besides biofuel 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 falling following steep price increases since 2020. Noting the lack of correlation between soybean oil price and its use in biofuel production historically, we conclude that the price of soybean oil is influenced by many factors occurring in the broader economy, including petroleum prices, supply chain disruptions on a range of inputs (e.g., fertilizer), prices of other vegetable oils, weather-related shortages of vegetable oils internationally, as well as general price inflation. 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.[610]

[609] USDA, "Oil Crops Yearbook," March 2025. https://www.ers.usda.gov/data-products/oil-crops-yearbook.
[610] Wilson, Nick. "Oil prices surge — vegetable oil, that is," *Marketplace*, February 17, 2022. https://www.marketplace.org/story/2022/02/17/oil-prices-surge-vegetable-oil-that-is.

Figure 9.3-2: Soybean Oil Price and Allocation to Biofuel and Exports



There are relatively few quantitative studies on the impacts of BBD production on soy oil and bean prices, and they show a 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.

To illustrate the potential impact of the different scenario volumes on soybean prices, we calculated the projected price effects for the 2026–2030 period relative to the No RFS Baseline. As in the Set 1 Rule, our projections are primarily based on modeling by Lusk, et al., which estimates the price impact of a 20% shock to current biofuel volumes—equivalent to approximately 243 million gallons of soy-derived BBD.[611] This model links such a shock to changes in soybean oil prices and related commodities. The projected impacts of the volume scenarios on soybean oil and soybean meal prices at the time of this proposal are shown in Tables 9.3-2, 3, and 4 for the Low Volume Scenario, High Volume Scenario, and Proposed Volumes, respectively.

[611] Lusk, Jayson L. "Food and Fuel: Modeling Food System Wide Impacts of Increase in Demand for Soybean Oil," November 10, 2022. https://ag.purdue.edu/cfdas/wp-content/uploads/2022/12/report_soymodel_revised13.pdf.

Table 9.3-2: Projected Impact of the Low Volume Scenario on Soybean Oil and Meal Prices Relative to the No RFS Baseline

	Units	2026	2027	2028	2029	2030
Soybean Oil Price[a]	$ per Pound	$0.39	$0.37	$0.37	$0.36	$0.36
Soybean Oil Price Response[b]	(%) per Billion Gallons of Biofuel	35.7%	35.7%	35.7%	35.7%	35.7%
Soybean Oil Biofuel Increase Relative to No RFS Baseline	Million Gallons	1,898	1,929	1,975	2,012	2,045
Soybean Oil Price Increase Relative to No RFS Baseline	$ per Pound	$0.26	$0.26	$0.26	$0.26	$0.26
Soybean Meal Price[a]	$ per Ton	$324	$331	$339	$347	$355
Soybean Meal Price Response	(%) per Billion Gallons of Biofuel	-7.94%	-7.94%	-7.94%	-7.94%	-7.94%
Soybean Meal Price Change Relative to No RFS Baseline	$ per Ton	-$49	-$51	-$53	-$55	-$58

[a] Prices are from: USDA, "USDA Agricultural Projections to 2034," OCE-2025-1, February 2025. https://doi.org/10.32747/2025.9015815.ers. 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., 2025/2026 for 2026) and 3/4 of the price for the second agricultural marketing year (e.g., 2026/2027 for 2026).
[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).

Table 9.3-3: Projected Impact of the High Volume Scenario on Soybean Oil and Meal Prices Relative to the No RFS Baseline

	Units	2026	2027	2028	2029	2030
Soybean Oil Price[a]	$ per Pound	$0.39	$0.37	$0.37	$0.36	$0.36
Soybean Oil Price Response[b]	(%) per Billion Gallons of Biofuel	35.7%	35.7%	35.7%	35.7%	35.7%
Soybean Oil Biofuel Increase Relative to No RFS Baseline	Million Gallons	2,111	2,354	2,612	2,862	3,108
Soybean Oil Price Increase Relative to No RFS Baseline	$ per Pound	$0.29	$0.31	$0.34	$0.37	$0.40
Soybean Meal Price[a]	$ per Ton	$324	$331	$339	$347	$355
Soybean Meal Price Response	(%) per Billion Gallons of Biofuel	-7.94%	-7.94%	-7.94%	-7.94%	-7.94%
Soybean Meal Price Change Relative to No RFS Baseline	$ per Ton	-$54	-$62	-$70	-$79	-$88

[a] Prices are from: USDA, "USDA Agricultural Projections to 2034," OCE-2025-1, February 2025. https://doi.org/10.32747/2025.9015815.ers. 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., 2025/2026 for 2026) and 3/4 of the price for the second agricultural marketing year (e.g., 2026/2027 for 2026).
[b] This number is based on a modified shock from Lusk equivalent to 1 billion gallons (as opposed to approximately240 million gallons in the Lusk paper).

Table 9.3-3: Projected Impact of the Proposed Volumes on Soybean Oil and Meal Prices Relative to the No RFS Baseline

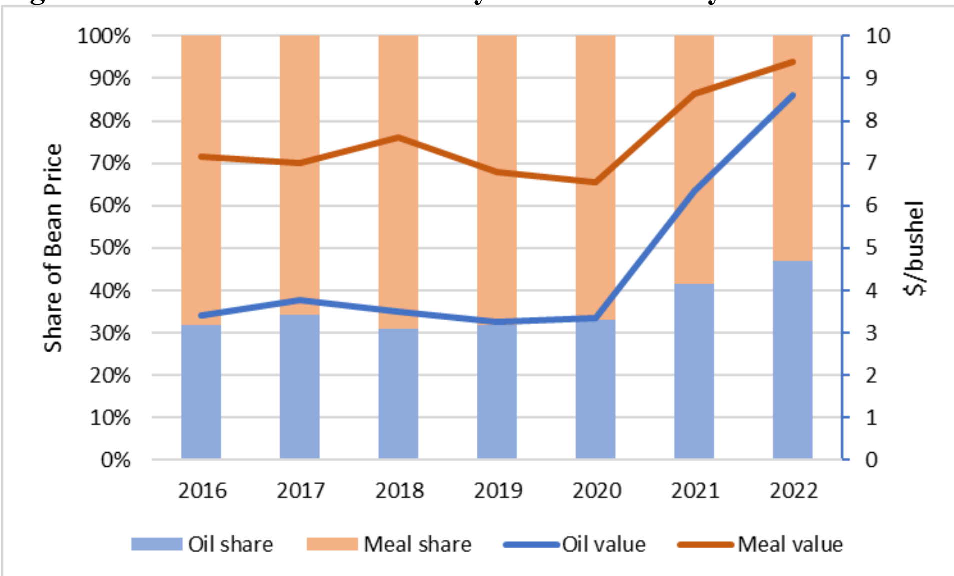
	Units	2026	2027
Soybean Oil Price[a]	$ per Pound	$0.39	$0.37
Soybean Oil Price Response[b]	(%) per Billion Gallons of Biofuel	35.7%	35.7%
Soybean Oil Biofuel Increase Relative to No RFS Baseline	Million Gallons	2,433	2,705
Soybean Oil Price Increase Relative to No RFS Baseline	$ per Pound	$0.33	$0.36
Soybean Meal Price[a]	$ per Ton	$324	$331
Soybean Meal Price Response	(%) per Billion Gallons of Biofuel	-7.94%	-7.94%
Soybean Meal Price Change Relative to No RFS Baseline	$ per Ton	-$63	-$71

[a] Prices are from: USDA, "USDA Agricultural Projections to 2034," OCE-2025-1, February 2025. https://doi.org/10.32747/2025.9015815.ers. 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., 2025/2026 for 2026) and 3/4 of the price for the second agricultural marketing year (e.g., 2026/2027 for 2026).
[b] This number is based on a modified shock from Lusk equivalent to 1 billion gallons (as opposed to approximately240 million gallons in the Lusk paper).

The results of the Lusk modeling, on which our price impacts for soybean oil and soybean meal are based, are supported by empirical data. 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.[612] In recent years soybean oil prices appear to have increased significantly relative to soybean meal prices, as shown in Figure 9.3-3. 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.[613] 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%. These trends suggest the value of the soybean is shifting more toward the oil than the meal in recent years. The supply of soybean oil may be tightening relative to soybean meal, with rising soybean oil prices exerting some downward pressure on soybean meal prices.

[612] Irwin, Scott, "The Value of Soybean Oil in the Soybean Crush: Further Evidence on the Impact of the U.S. Biodiesel Boom." *farmdoc daily* (7):169, September 14, 2017. https://farmdocdaily.illinois.edu/2017/09/the-value-of-soybean-oil-in-the-soybean-crush.html.
[613] USDA, "Oil Crops Yearbook," March 2025. https://www.ers.usda.gov/data-products/oil-crops-yearbook.

Figure 9.3-3: Relative Values of Soybean Oil and Soybean Meal



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 dried 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 DDG 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 2034 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 Proposed Volumes on sorghum, barley, oat, and DDG prices are shown in Table 9.3-4.

Table 9.3-4: Projected Impact of All Volume Scenarios on Prices of Other Commodities Relative to No RFS Baseline

	2026	2027	2028	2029	2030
Price Change Factor Relative to Corn Price Change[a]					
Corn; $/bushel	$1.00	$1.00	$1.00	$1.00	$1.00
Sorghum; $/bushel	$0.93	$0.93	$0.93	$0.93	$0.93
Barley; $/bushel	$0.88	$0.88	$0.88	$0.88	$0.88
Oats; $/bushel	$0.72	$0.72	$0.72	$0.72	$0.72
Distillers Grains; $/ton	$0.02	$0.02	$0.02	$0.02	$0.02
Projected Price Impact Relative to No RFS Baseline					
Corn; $/bushel	$0.03	$0.03	$0.03	$0.03	$0.03
Sorghum; $/bushel	$0.02	$0.03	$0.03	$0.03	$0.03
Barley; $/bushel	$0.02	$0.02	$0.03	$0.03	$0.03
Oats; $/bushel	$0.02	$0.02	$0.02	$0.02	$0.02
Distillers Grains; $/ton	$0.90	$0.99	$1.05	$1.15	$1.23

[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," Docket Item No. EPA-HQ-OAR-2012-0632-2546. https://www.regulations.gov/document/EPA-HQ-OAR-2012-0632-2546.

9.4 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. Because the Volume Scenarios 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 Volume Scenarios 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).[614]

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 Rule volumes using the general waiver authority.[615] 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.

[614] 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.
[615] 77 FR 70752 (November 27, 2012).

In Chapter 9.3, we presented estimates of the impact of the volume scenarios on commodity prices relative to the No RFS Baseline These estimates are the starting point for our estimate of the impact of the RFS scenario volumes on food prices. EPA used those price impacts in combination with the projected use of commodities for food to project the impact of commodity prices on total food expenditures, which are shown in Table 9.4-1 through Table 9.4-3. This analysis assumes changes in commodity prices are fully passed on to consumers at the retail level, and therefore changes in total food expenditures may be estimated 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 agriculture production costs, and ultimately the effects on retail prices of foods produced from livestock.[616]

EPA recognizes that projecting that the price of distillers grains (DDG) increases proportionally to the price of corn may overstate the impact of this proposed rule on these commodities and ultimately on food prices. It is possible increasing demand for biofuels may result in an over-supply of DDG as 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 DDG. This could mitigate the overall impact of this rule on food prices. There is not sufficient data to project how increasing demand for corn for biofuel production would impact the price of DDG. If the price for distillers grains increases less than the price of corn (or if it decreases) in response to increased demand for biofuels, a smaller impact on food prices than what we have estimated for the Proposed Volumes could be expected.

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.[617] Our estimates of the increase of food expenditures only reflect expenditures in the U.S. Due to the integrated nature of agricultural commodity markets, the projected increases in agricultural commodity prices may also impact food prices and expenditures globally. EPA has not attempted to quantify these global impacts.

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[616] 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.

[617] USDA, "The Demand for Disaggregated Food-Away-From-Home and Food-at-Home Products in the United States." *Economic Research Report* 139, August 2012. https://ers.usda.gov/sites/default/files/_laserfiche/publications/45003/30438_err139.pdf?v=69115.

Table 9.4-1: Changes in Food Expenditures of the Low Volume Scenario Relative to the No RFS Baseline

Year	Commodity	Commodity Price Change	Quantity Used for Food and Feed[a]	Change in Expenditures
2026	Corn	$0.03 per Bushel	7,415 million Bushels	$187 million
	Grain Sorghum	$0.02 per Bushel	110 million Bushels	$3 million
	Barley	$0.02 per Bushel	157 million Bushels	$3 million
	Oats	$0.02 per Bushel	125 million Bushels	$2 million
	Soybean Oil	$0.26 per Pound	14,438 million Pounds	$3,766 million
	Soybean Meal	-$48.79 per Ton	42,344 thousand Short Tons	-$2,066 million
	DDG	$0.90 per Short Ton	47,122 million Short Tons	$42 million
			Total	$1,938 Million
2027	Corn	$0.03 per Bushel	7,463 million Bushels	$207 million
	Grain Sorghum	$0.03 per Bushel	110 million Bushels	$3 million
	Barley	$0.03 per Bushel	158 million Bushels	$4 million
	Oats	$0.02 per Bushel	128 million Bushels	$3 million
	Soybean Oil	$0.26 per Pound	14,488 million Pounds	$3,716 million
	Soybean Meal	-$50.70 per Ton	42,950 thousand Short Tons	-$2,177 million
	DDG	$0.99 per Short Ton	47,175 million Short Tons	$47 million
			Total	$1,802 million
2028	Corn	$0.03 per Bushel	7,510 million Bushels	$224 million
	Grain Sorghum	$0.03 per Bushel	110 million Bushels	$3 million
	Barley	$0.03 per Bushel	157 million Bushels	$4 million
	Oats	$0.02 per Bushel	129 million Bushels	$3 million
	Soybean Oil	$0.26 per Pound	14,538 million Pounds	$3,754 million
	Soybean Meal	-$53.16 per Ton	43,550 thousand Short Tons	-$2,315 million
	DDG	$1.06 per Short Ton	47,175 million Short Tons	$50 million
			Total	$1,723 million
2029	Corn	$0.03 per Bushel	7,574 million Bushels	$245 million
	Grain Sorghum	$0.03 per Bushel	110 million Bushels	$3 million
	Barley	$0.03 per Bushel	160 million Bushels	$5 million
	Oats	$0.02 per Bushel	129 million Bushels	$3 million
	Soybean Oil	$0.26 per Pound	14,588 million Pounds	$3,785 million
	Soybean Meal	-$55.43 per Ton	44,150 thousand Short Tons	-$2,447 million
	DDG	$1.15 per Short Ton	47,175 million Short Tons	$54 million
			Total	$1,648 million
2030	Corn	$0.03 per Bushel	7,679 million Bushels	$264 million
	Grain Sorghum	$0.03 per Bushel	110 million Bushels	$4 million
	Barley	$0.03 per Bushel	160 million Bushels	$5 million
	Oats	$0.02 per Bushel	128 million Bushels	$3 million
	Soybean Oil	$0.26 per Pound	14,638 million Pounds	$3,847 million
	Soybean Meal	-$57.64 per Ton	44,750 thousand Short Tons	-$2,579 million
	DDG	$1.23 per Short Ton	47,175 million Short Tons	$58 million
			Total	$1,601 million

[a] Quantity used for food and feed was calculated from: USDA, "USDA Agricultural Projections to 2034," OCE-2025-1, February 2025. https://doi.org/10.32747/2025.9015815.ers. In general, this quantity is the sum of Feed & Residual & Food, and Seed & Industrial. For corn, we subtracted the quantity used for Ethanol & By-products from this total. DDG was calculated based on the production of 17 pounds of DDG for every bushel of corn used to produce ethanol. Finally, soybean oil is equal to the amount listed for food, feed & other industrial and soybean meal is the total quantity of domestic disappearance.

Table 9.4-2: Changes in Food Expenditures of the High Volume Scenario Relative to the No RFS Baseline

Year	Commodity	Commodity Price Change	Quantity Used for Food and Feed[a]	Change in Expenditures
2026	Corn	$0.03 per Bushel	7,415 million Bushels	$187 million
	Grain Sorghum	$0.02 per Bushel	110 million Bushels	$3 million
	Barley	$0.02 per Bushel	157 million Bushels	$3 million
	Oats	$0.02 per Bushel	125 million Bushels	$2 million
	Soybean Oil	$0.29 per Pound	14,438 million Pounds	$4,189 million
	Soybean Meal	-$54.26 per Ton	42,344 thousand Short Tons	-$2,298 million
	DDG	$0.90 per Short Ton	47,122 million Short Tons	$42 million
			Total	$2,129 million
2027	Corn	$0.03 per Bushel	7,463 million Bushels	$207 million
	Grain Sorghum	$0.03 per Bushel	110 million Bushels	$3 million
	Barley	$0.02 per Bushel	158 million Bushels	$4 million
	Oats	$0.02 per Bushel	128 million Bushels	$3 million
	Soybean Oil	$0.31 per Pound	14,488 million Pounds	$4,535 million
	Soybean Meal	-$61.87 per Ton	42,950 thousand Short Tons	-$2,657 million
	DDG	$0.99 per Short Ton	47,175 million Short Tons	$47 million
			Total	$2,141 million
2028	Corn	$0.03 per Bushel	7,510 million Bushels	$224 million
	Grain Sorghum	$0.03 per Bushel	110 million Bushels	$3 million
	Barley	$0.03 per Bushel	157 million Bushels	$4 million
	Oats	$0.02 per Bushel	129 million Bushels	$3 million
	Soybean Oil	$0.34 per Pound	14,538 million Pounds	$4,965 million
	Soybean Meal	-$70.31 per Ton	43,550 thousand Short Tons	-$3,062 million
	DDG	$1.06 per Short Ton	47,175 million Short Tons	$50 million
			Total	$2,187 million
2029	Corn	$0.03 per Bushel	7,574 million Bushels	$245 million
	Grain Sorghum	$0.03 per Bushel	110 million Bushels	$3 million
	Barley	$0.03 per Bushel	160 million Bushels	$5 million
	Oats	$0.02 per Bushel	129 million Bushels	$3 million
	Soybean Oil	$0.37 per Pound	14,588 million Pounds	$5,384 million
	Soybean Meal	-$78.85 per Ton	44,150 thousand Short Tons	-$3,481 million
	DDG	$1.15 per Short Ton	47,175 million Short Tons	$54 million
			Total	$2,213 million
2030	Corn	$0.03 per Bushel	7,679 million Bushels	$264 million
	Grain Sorghum	$0.03 per Bushel	110 million Bushels	$4 million
	Barley	$0.03 per Bushel	160 million Bushels	$5 million
	Oats	$0.02 per Bushel	128 million Bushels	$3 million
	Soybean Oil	$0.40 per Pound	14,638 million Pounds	$5,847 million
	Soybean Meal	-$87.61per Ton	44,750 thousand Short Tons	-$3,920 million
	DDG	$1.23 per Short Ton	47,175 million Short Tons	$58 million
			Total	$2,260 million

[a] Quantity used for food and feed was calculated from: USDA, "USDA Agricultural Projections to 2034," OCE-2025-1, February 2025. https://doi.org/10.32747/2025.9015815.ers. In general, this quantity is the sum of Feed & Residual & Food, and Seed & Industrial. For corn, we subtracted the quantity used for Ethanol & By-products from this total. DDG was calculated based on the production of 17 pounds of DDG for every bushel of corn used to produce ethanol. Finally, soybean oil is equal to the amount listed for food, feed & other industrial and soybean meal is the total quantity of domestic disappearance.

Table 9.4-3: Changes in Food Expenditures of the Proposed Volumes Relative to the No RFS Baseline

Year	Commodity	Commodity Price Change	Quantity Used for Food and Feed[a]	Change in Expenditures
2026	Corn	$0.03 per Bushel	7,415 million Bushels	$187 million
	Grain Sorghum	$0.02 per Bushel	110 million Bushels	$3 million
	Barley	$0.02 per Bushel	157 million Bushels	$3 million
	Oats	$0.02 per Bushel	125 million Bushels	$2 million
	Soybean Oil	$0.33 per Pound	14,438 million Pounds	$4,828 million
	Soybean Meal	-$62.54 per Ton	42,344 thousand Short Tons	-$2,648 million
	DDG	$0.90 per Short Ton	47,122 million Short Tons	$42 million
			Total	$2,418 million
2027	Corn	$0.03 per Bushel	7,463 million Bushels	$207 million
	Grain Sorghum	$0.03 per Bushel	110 million Bushels	$3 million
	Barley	$0.02 per Bushel	158 million Bushels	$4 million
	Oats	$0.02 per Bushel	128 million Bushels	$3 million
	Soybean Oil	$0.36 per Pound	14,488 million Pounds	$5,211 million
	Soybean Meal	-$71.09 per Ton	42,950 thousand Short Tons	-$3,053 million
	DDG	$0.99 per Short Ton	47,175 million Short Tons	$47 million
			Total	$2,421 million

[a] Quantity used for food and feed was calculated from: USDA, "USDA Agricultural Projections to 2034," OCE-2025-1, February 2025. https://doi.org/10.32747/2025.9015815.ers. In general, this quantity is the sum of Feed & Residual & Food, and Seed & Industrial. For corn, we subtracted the quantity used for Ethanol & By-products from this total. DDG was calculated based on the production of 17 pounds of DDG for every bushel of corn used to produce ethanol. Finally, soybean oil is equal to the amount listed for food, feed & other industrial and 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 2023 survey.[618] We used the ratio of the estimated change in food expenditures to the total food expenditures to estimate the change in food expenditures for the average consumer unit (households shown in Tables 9.4-4, 9.4-5, and 9.4-6 for the Low Volume Scenario, High Volume Scenario, and Proposed Volumes, respectively).

[618] Bureau of Labor and Statistics, Consumer Expenditures in 2023, Table 1101 – Quintiles of income before taxes: Shares of annual aggregate expenditures and sources of income, 2023. https://www.bls.gov/cex/tables/calendar-year/aggregate-group-share/cu-income-quintiles-before-taxes-2023.xlsx.

Table 9.4-4: Change in Food Expenditures per Consumer Unit of the Low Volume Scenario Relative to No RFS Baseline

	2026	2027	2028	2029	2030
Number of Consumer Units (thousands)	134,556	134,556	134,556	134,556	134,556
Food Expenditures per Consumer Unit	$9,985	$9,985	$9,985	$9,985	$9,985
Total Food Expenditures (millions)	$1,343,542	$1,343,542	$1,343,542	$1,343,542	$1,343,542
Change in Food Expenditures (millions)	$1,938	$1,802	$1,723	$1,648	$1,601
Percent Change in Food Expenditures	0.14%	0.13%	0.13%	0.12%	0.12%
Projected Food Expenditure Increase	$14.41	$13.40	$12.80	$12.25	$11.90

Table 9.4-5: Change in Food Expenditures per Consumer Unit of the High Volume Scenario Relative to No RFS Baseline

	2026	2027	2028	2029	2030
Number of Consumer Units (thousands)	134,556	134,556	134,556	134,556	134,556
Food Expenditures per Consumer Unit	$9,985	$9,985	$9,985	$9,985	$9,985
Total Food Expenditures (millions)	$1,343,542	$1,343,542	$1,343,542	$1,343,542	$1,343,542
Change in Food Expenditures (millions)	$2,129	$2,141	$2,187	$2,213	$2,260
Percent Change in Food Expenditures	0.16%	0.16%	0.16%	0.16%	0.17%
Projected Food Expenditure Increase	$15.82	$15.92	$16.25	$16.45	$16.79

Table 9.4-6: Change in Food Expenditures per Consumer Unit of the Proposed Volumes Relative to No RFS Baseline

	2026	2027
Number of Consumer Units (thousands)	134,556	134,556
Food Expenditures per Consumer Unit	$9,985	$9,985
Total Food Expenditures (millions)	$1,343,542	$1,343,542
Change in Food Expenditures (millions)	$2,418	$2,421
Percent Change in Food Expenditures	0.18%	0.18%
Projected Food Expenditure Increase	$17.97	$18.00

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.

Although we are proposing to set RFS volume requirements for 2026 and 2027, we first analyzed the Low and High Volume Scenarios for 2026–2030, which informed our decisions for the rule. We assessed costs for each Volume Scenario relative to the No RFS Baseline, as well as incremental to the 2025 Baseline. In projecting the costs and fuel price impacts in this chapter, we relied on AEO2023, which was the most recently published version of the AEO at the time the analyses were conducted. For the final rule we anticipate updating our analyses based on AEO2025 and other relevant information. While it is difficult to predict the impacts of updating to AEO2025 due to the wide range of factors that impact the projected cost of this rule, we anticipate that, all else equal, the costs for the final rule will be higher due to lower projected crude oil prices in AEO2025.

The large increase in domestic vegetable oil and animal fat volumes for the Proposed Volumes could pose a challenge for the agricultural sector to provide the required volumes of domestically sourced feedstocks incentivized by the proposed standards and thus cause price increases for those feedstocks. We therefore conducted a sensitivity analysis at higher prices for those feedstocks. The costs for the Proposed Volumes and the Low and High Volume Scenarios are all summarized in this chapter. Chapter 10.4.2 contains subsections that summarize the changes in renewable fuel volumes relative to the No RFS and 2025 Baselines, as well as the estimated change in fossil fuel volumes displaced by the change in volume of renewable fuels.[619] In all cases, costs are reported in 2022 dollars.

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.

For estimating feedstock costs, we used projections of feedstock prices for 2026–2030 from multiple sources, including EIA and USDA.[620] We also made adjustments to account for differences between these projections. Crude oil prices affect the cost for growing renewable fuel

[619] The spreadsheet used to estimate the costs for the Volume Scenarios relative to the No RFS and 2025 Baselines can be found in "Estimated Fuel Costs for Set 2 Proposed Rule," available in the docket for this action.
[620] USDA, "USDA Agricultural Projections to 2033," OCE-2024-1, February 2024. https://www.usda.gov/sites/default/files/documents/USDA-Agricultural-Projections-to-2033.pdf.

feedstocks, the cost to transport them to the renewable fuel production plants, the cost for transporting the produced renewable fuel from the plant to market, and may impact the cost for producing the renewable fuel. Because USDA agricultural price projections were based on lower crude oil price projections than those by EIA, the USDA agricultural price projections may have underestimated the agricultural prices that would be consistent with the EIA petroleum price projections. Therefore, we adjusted the USDA price projections for both corn and soybean oil in an attempt to remove this potential bias in the cost analysis. We also adjusted the projected nominal prices to constant year 2022 dollars.

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 2026–2030 USDA projected corn prices (row #1).[621] 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).[622]

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).[623] 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 January 2012 and November 2024, which yielded the following equation:[624,625,626]

Corn Price ($/bushel) = Crude Oil Price ($/bbl) x 0.0445 + 1.54

[621] USDA, "USDA Agricultural Projections to 2033," OCE-2024-1, February 2024. https://www.usda.gov/sites/default/files/documents/USDA-Agricultural-Projections-to-2033.pdf.

[622] USDA reports estimated future inflation rates that are used for adjusting nominal dollar values to 2022$.

[623] There seems to be an association between the renewable fuel feedstock costs and crude oil prices (regression analysis reveals an R-squared of 0.55 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.

[624] We chose the years from 2012–2024 because of the wide range in crude oil and corn prices that existed over this time period.

[625] USDA, "Corn Prices Received by Farmers," *Quick Stats*, 2024. https://quickstats.nass.usda.gov/results/3538FFA4-F207-383E-A9CF-09A1F1408C77.

[626] EIA, "U.S. Crude Oil Composite Acquisition Cost by Refiners," *Petroleum & Other Liquids*, May 1, 2025. https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=R0000____3&f=a.

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 ongoing corn production efficiency improvements. 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.

Table 10.1.1.1-1: Derivation of Corn Feedstock Production Costs ($/bushel for corn, $/bbl for Crude Oil)

		Row #	2026	2027	2028	2029	2030
Corn Prices	USDA Nominal $	1	4.30	4.30	4.30	4.30	4.30
	USDA 2022$	2	4.10	4,01	3.93	3.86	3.78
Crude Oil Prices	USDA Nominal $	3	93	96	98	101	104
	USDA 2022$	4	88.6	89.6	89.7	90.6	91.4
	EIA 2022$	5	83.9	84.3	84.6	85.2	85.7
Regressed Corn Prices	Based on USDA 2022	6	5.06	5.09	5.10	5.13	5.16
	Based on EIA 2022	7	4.88	4.90	4.91	4.93	4.95
Corn Prices	Difference in Regressed Corn Prices EIA - USDA	8	-0.17	-0.19	-0.19	-0.20	-0
Corn Prices	Adjusted USDA 2022$	9	3.92	3.82	3.75	3.66	3.57

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 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).[627] 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 ($/dry ton; 2022$)

Year	2026	2027	2028	2029	2030
Nominal	147.1	146.5	147.9	1498.3	147.1
2022$	132.8	129.6	128.2	126.0	122.5

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

[627] FAPRI, "2024 U.S. Agricultural Market Outlook," FAPRI-MU Report #01-24, March 2024. https://fapri.missouri.edu/wp-content/uploads/2024/03/2024-Baseline-Outlook.pdf.

analysis, canola oil volumes are combined with the soybean oil volume to estimate a single volume of virgin oil, but we refer to it solely as soybean oil. Because both soybean and canola have similar levels of hydrogen unsaturation, it is reasonable to assume that canola and soybean oils would have similar production costs.[628] Soybean oil price projections made by USDA are used as a starting point for this cost analysis.[629]

We followed the same methodology we used for corn prices as described above for soy oil prices; this process is summarized in Table 11.1.1.2-1 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 November 2024 yielded the following equation:[630,631,632]

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 the 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).

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[628] Kim, Juyoung, Deok Nyun Kim, Sung Ho Lee, Sang-Ho Yoo, and Suyong Lee. "Correlation of Fatty Acid Composition of Vegetable Oils With Rheological Behaviour and Oil Uptake." Food Chemistry 118, no. 2 (May 14, 2009): 398–402. https://doi.org/10.1016/j.foodchem.2009.05.011.

[629] USDA, "USDA Agricultural Projections to 2033," OCE-2024-1, February 2024. https://www.usda.gov/sites/default/files/documents/USDA-Agricultural-Projections-to-2033.pdf.

[630] There seems to be an association between the renewable fuel 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.

[631] Federal Reserve Economic Data, "Global price of Soybeans Oil," May 13, 2025. https://fred.stlouisfed.org/series/PSOILUSDM.

[632] EIA, "U.S. Crude Oil Composite Acquisition Cost by Refiners," *Petroleum & Other Liquids*, May 1, 2025. https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=R0000____3&f=a.

Table 10.1.1.2-1: Derivation of Soy Oil Feedstock Production Costs (cents/pound for soy oil, $/bbl for crude oil)

		Row #	2026	2027	2028	2029	2030
Soy Oil Prices	USDA Nominal $	1	0.50	0.46	0.45	0.44	0.43
	USDA 2022$	2	0.48	0.43	0.41	0.40	0.38
Crude Oil Prices	USDA Nominal $	3	93	96	98	101	104
	USDA 2022$	4	88.6	89.6	89.7	90.6	91.4
	EIA 2022$	5	83.9	84.3	84.6	85.2	85.7
Regressed Soy Oil Prices	Based on USDA 2022$	6	0.420	0.423	0.423	0.425	0.428
	Based on EIA 2022$	7	0.408	0.409	0.410	0.411	0.413
Soy Oil Prices	Difference in Regressed Soy Oil Prices EIA - USDA	8	-0.012	-0.012	-0.012	-0.012	-0.012
Soy Oil Prices	Adjusted USDA 2022$	9	0.46	0.42	0.40	0.38	0.36

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.[633] 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¢ per pound (ranged from 29–68¢ per pound. Corn oil and FOG prices were compared to soy oil prices, and these were priced at 82.7% and 75.4% of soybean oil, respectively. The projected soy oil, FOG, and corn oil prices used in this cost analysis are summarized in Table 10.1.1.2-2.

Table 10.1.1.2-2: Projected Vegetable Oil Production Costs (2022 $/lb)

	Projected Vegetable Oil Prices		
Year	**Soybean Oil**	**FOG**	**Corn Oil**
2026	0.46	0.36	0.38
2027	0.42	0.33	0.34
2028	0.40	0.31	0,33
2029	0.38	0.30	0.31
2030	0.36	0.28	0.30

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

[633] USDA, "Oil Crops Yearbook," March 2025. https://www.ers.usda.gov/data-products/oil-crops-yearbook.

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. The detailed cost summaries presented for each renewable fuel in this section are based on projected cost inputs for the year 2026.[634]

10.1.2.1 Cost Factors

10.1.2.1.1 Capital and Fixed Costs

The economic assumptions used to amortize capital costs over the production volume of renewable fuels are summarized in Table 10.1.2.1.1-1. These capital amortization cost factors are used in the following section for converting the one-time, total capital cost to an equivalent per-gallon cost.[635] 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.[636,637,638,639,640]

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 recent years, 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.[641] Maintenance costs can range from 1% to 8% for

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[634] All the costs summarized in this chapter are calculated in the spreadsheet, "Estimated Fuel Costs for Set 2 Proposed Rule," available in the docket for this action.
[635] The capital amortization factor is applied to the aggregate capital cost to create an amortized annual capital cost that occurs each 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 OMB Circular A-4 for these calculations.
[636] EPA, "Regulatory Impact Analysis – Control of Air Pollution from New Motor Vehicles: Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements," EPA-420-R-99-023, December 1999; .
[637] EPA, "Technical Support Document for the Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements: Air Quality Modeling Analyses," EPA-420-R-00-028, December 2000.
[638] Wyborny, Lester. "Cost Estimates of Long-Term Options for Addressing Boutique Fuels," EPA, October 22, 2001.
[639] EPA, "Final Regulatory Analysis – Control of Emissions from Nonroad Diesel Engines," EPA-420-R-04-007, May 2004.
[640] RFS2 Rule RIA.
[641] Peters, Klaus D., Max S. Timmerhaus, and Ronald E. West. *Plant Design and Economics for Chemical Engineers*. 5th ed. McGraw Hill, 2003.

industrial processes.[642] 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 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 AEO2023. The cost of process water is generally quite minimal, but a cost is estimated for it nonetheless since renewable fuel technologies can use fairly large quantities.[643,644] 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$)[a]

Year	Natural Gas ($/MMBtu)	Electricity (¢/kWh)	Water ($/1000 gals)
2025	4.48	6.88	3.0
2026	4.22	6.69	3.0
2027	4.13	6.56	3.0
2028	4.15	6.49	3.0
2029	4.21	6.48	3.0

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.[645,646] Capital costs were based on a review of corn ethanol construction costs for a 100 million gallon per year dry mill corn ethanol plant in 2016. For this analysis the capital costs were scaled to the

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[642] McNair, Sam. "Budgeting for Maintenance: A Behavior-Based Approach," *Life Cycle Engineering*, 2011. https://www.wethegoverned.com/wp-content/uploads/2019/07/110912-Life-Cycle-Engineering-budgeting-maintenance.pdf.
[643] Haas, Michael J, Andrew J McAloon, Winnie C Yee, and Thomas A Foglia. "A Process Model to Estimate Biodiesel Production Costs." *Bioresource Technology* 97, no. 4 (June 3, 2005): 671–78. https://doi.org/10.1016/j.biortech.2005.03.039.
[644] DOE, "Water and Wastewater Annual Escalation Rates for Selected Cities across the United States," September 2017. https://doi.org/10.2172/1413878.
[645] Lee, Uisung, Hoyoung Kwon, May Wu, and Michael Wang. "Retrospective Analysis of the U.S. Corn Ethanol Industry for 2005–2019: Implications for Greenhouse Gas Emission Reductions." *Biofuels Bioproducts and Biorefining* 15, no. 5 (May 4, 2021): 1318–31. https://doi.org/10.1002/bbb.2225.
[646] Mueller, Steffen. "2012 Corn Ethanol: Emerging Plant Energy and Environmental Technologies." April 29, 2013.

U.S. average sized corn ethanol plant with a nameplate capacity of 85 million gallons per year and assumed to operate at 90% of nameplate capacity, therefore producing 76 million gallons of ethanol per year.[647] 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 an average cost of 6¢ per bushel to transport the corn to corn ethanol plants.[648] Of the dry mill 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 moisture, and distillers wet grain (DWG) with 40–64% moisture. The production quantity of DWG is adjusted to an equivalent of dried DDG. The DWG with 65% or more moisture is assumed to have 75% moisture, while the DWG with 40–65% moisture is assumed to have 52% moisture. Both wet distiller grain categories are adjusted to dry distiller grain quantities assuming that dried distiller grains contain 11% moisture.[649] 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).

[647] Irwin, Scott. "Weekly Output: Ethanol Plants Remain Barely Profitable," *Successful Farming*, March 16, 2018. https://www.agriculture.com/news/business/weekly-outlook-ethanol-plants-remain-barely-profitable.
[648] Edwards, William. "Estimating Grain Transportation Costs," *Ag Decision Maker* File A3-41, August 2017. https://www.extension.iastate.edu/agdm/crops/html/a3-41.html.
[649] Shurson, Jerry. "DDGS present handling and storage considerations," *National Hog Farmer*, May 29, 2019. https://www.nationalhogfarmer.com/hog-nutrition/ddgs-present-handling-and-storage-considerations.

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.

Table 10.1.2.2-3: Corn Ethanol Plant Demands, Production Levels, and Capital Costs for 2026 (2022$)

Category of Plant Input/Output	Plant Inputs/Outputs	Cost per Input	Cost (MM$)	Cost ($/gal)
Ethanol Yield	2.86 gal/bushel	$3.98/bushel	106	1.39
DDG Yield	4.4 lb/gal	$132.8/ton	–22.2	–0.29
Corn Oil Yield	0.27 lb/gal	38¢/lb	–7.9	–0.10
CO2 Yield	1 lb/gal	$12/ton		
Thermal Demand	22,480 Btu/gal	$4.32/MMBtu	7.1	0.09
Electricity Demand	0.63 kWh/gal	6.88¢/kwh	3.3	0.04
Water Use	2.7 gal/gal	$3/1000 gals	0.6	0.01
Labor Cost	$0.07/gal	-	5.3	0.07
Capital Cost (2022$, 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 vol%		0.6	0.01
Total Cost			138	1.83

The projected corn ethanol social production cost for an 85 million gallon capacity ethanol plant producing 76 million gallons per year of ethanol is $1.83 per gallon of denatured ethanol for 2026, $1.80 for 2027, $1.78 for 2028, $1.76 for 2029 and $1.72 for 2030. 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.[650,651] Although dated, this model likely still provides representative cost estimates because the process is fairly simple and unlikely to have changed over time, and consequently its cost are likely to be fairly stable over time as well. Furthermore, the biodiesel costs are primarily (>80%) determined by the feedstock prices.

The biodiesel process comprises three separate subprocesses:

1. Transesterification to produce fatty acid methyl esters (biodiesel) and coproduct glycerol (glycerine);
2. Biodiesel purification to meet biodiesel purity specifications; and
3. Glycerol recovery.[652]

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 $^{\circ}$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 $^{\circ}$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

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[650] Haas, M.J, A process model to estimate biodiesel production costs, Bioresource Technology 97 (2006) 671-678.
[651] 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.
[652] Haas, M.J, A process model to estimate biodiesel production costs, Bioresource Technology 97 (2006) 671-678.

$14.5 million. Fixed operating costs are estimated to comprise 5.5% of the plant cost. Prices were found for methanol,[653] sodium methoxide,[654] hydrochloric acid,[655] sodium hydroxide,[656] and glycerine.[657,658] The value of methanol is from a Methanex report, plus 15¢ added on for distribution costs.[659] Prices for sodium methoxide, hydrochloric acid, and sodium hydroxide are all bulk prices from a chemicals supplier.[660]

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.[661] 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¢ 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.

[653] Methanex, "Methanex Methanol Price Sheet," January 31, 2023. https://www.methanex.com/about-methanol/pricing.
[654] Alibaba, "Food Grade Purity 28%-31% Colorless Transparent Sodium Methoxide," February 2023. https://www.alibaba.com/product-detail/Food-Grade-Purity-28-31-Colorless_1600468349215.html.
[655] ChemAnalyst, "Hydrochloric Acid Price Trend and Forecast," February 2023. https://www.chemanalyst.com/Pricing-data/hydrochloric-acid-61.
[656] eBioChem, "wholesale Caustic Soda; Sodium Hydroxide," February 2023. http://www.ebiochem.com/product/caustic-soda-sodium-hydroxide-16515.
[657] Alibaba, "Competitive Price 99.7% Refined Food/USP/Industry Grade Glycerol Glycerine," February 2023. https://www.alibaba.com/product-detail/Competitive-Price-80-99-7-Refined_1600713799582.html.
[658] Irwin, Scott. "2021 Was a Devastating Year for Biodiesel Production Profits." *farmdoc daily* (12):21, February 16, 2022. https://farmdocdaily.illinois.edu/2022/02/2021-was-a-devastating-year-for-biodiesel-production-profits.html.
[659] Methanex, "Current Posted Prices," January 31, 2023. https://www.methanex.com/about-methanol/pricing.
[660] https://www.alibaba.com.
[661] Yang, Fangxia, Milford A Hanna, and Runcang Sun. "Value-added Uses for Crude Glycerol--a Byproduct of Biodiesel Production." *Biotechnology for Biofuels* 5, no. 1 (March 14, 2012). https://doi.org/10.1186/1754-6834-5-13.

Table 10.1.2.3-1: Soy-Biodiesel Production Cost for 2026 (2022$)

	Unit Demands	Cost per Unit	Cost (MM$)	Cost ($/gal)
Soybean Oil Feed	76,875 (1000 lb)	46.4¢/lb	35,215	3.52
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¢/lb	(2160)	(0.22)
Natural Gas	66.9 million SCF	4.32 $/MMBtu	289	0.029
Electricity	1008 kW	6.88 ¢/kWh	607	0.061
Labor				0.05
Capital Cost 2006$	11.35 ($million)	-	-	-
Capital Cost 2022$	18.54 ($million)		2,039	0.20
Fixed Cost		5.5%	1,019	0.10
Total Cost			40,130	4.02

As shown in Table 10.1.2.3-1, biodiesel produced from soybean oil is estimated to cost 4.06¢ per gallon in 2026. The estimated biodiesel production cost for all vegetable oil types and for all five years is summarized in Table 10.1.2.3-2.

Table 10.1.2.3-2: Summary of Estimated Biodiesel Production Costs ($/gal)

Year	Soy Oil	Corn Oil	FOG
2026	4.02	3.41	3.15
2027	3.64	3.09	2.86
2028	3.51	2.98	2.76
2029	3.36	2.87	2.66
2030	3.22	2.75	2.55

As depicted in the table, there is a substantial production cost decline from 2026–2030, and this is almost entirely due to the declining vegetable oil prices summarized in Table 10.1.1.2-2.

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 feedstock 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, 90-95% of the product yield by volume can be blended into diesel fuel or jet fuel, 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 $1.1 billion for a standalone 400 million gallon per year facility.[662] 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 2024.[663] 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.[664] Hydrogen costs are estimated based on a 50 million SCF/day steam methane reforming hydrogen plant, adjusted to represent a 32 million SCF/day plant, which would be the quantity of hydrogen required for a typical sized 220 million gallon per year renewable diesel plant.[665]

Table 10.1.2.4-1: Hydrogen Plant Costs for 2026

	Unit Demands for a 50 MM SCF/day plant	**Cost per Unit**	**Cost for a 32 MMSCF/day plant**	
			MM$	**$/MSCF**
Feed Natural Gas	730 MMBtu/hr	$4.32/MMBtu	17.7	1.51
Fuel Gas for Heat	150 MMBtu/hr	$4.32/MMBtu	3.6	0.31
Power	1200 KW	6.88¢/kWh	0.5	0.04
Boiler feed water	160,000 lb/hr	$3/1000 gal	0.3	0.03
Cooling water	900 gal/min	$3/1000 gal	0.9	0.08
Export Steam	120,000 lb/hr 600 psi		-3.8	-0.32
Capital Cost	$70 MM in 2016	For a 50 MMSCF/ day plant		
	$81 MM in 2022	For a 32 MMSCF/ day plant	8.9	0.76
Fixed Cost		6.7%	5.4	0.46
Total Cost			33.5	2.87

Based on our cost analysis, hydrogen is estimated to cost $2.90/MSCF in 2026. If renewable fuel producers elect to produce and use renewable hydrogen as a feedstock to their

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[662] Advanced Biofuels USA, "Honeywell Ecofining Technology Helps Diamond Green Diesel Become One of The World's Largest Renewable Diesel Plants," October 2, 2019. https://advancedbiofuelsusa.info/honeywell-ecofining-technology-helps-diamond-green-diesel-become-one-of-the-worlds-largest-renewable-diesel-plants.

[663] The typical renewable diesel plant size is based on volume-weighting renewable diesel capacity. 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: (capital cost of the original plant size) * (new plant size/original plant size)$^{0.6}$.

[664] Conversation with Mike Ackerson, Duke Biofuels, May 2020.

[665] Meyers, Robert A. *Handbook of Petroleum Refining Processes, Fourth Edition*. McGraw-Hill Education, 2016.

renewable diesel plant, we would expect the cost to produce renewable diesel would increase. As summarized in Chapter 10.1.2.6, the cost to produce, clean up and distribute biogas is higher than fossil natural gas, thus the hydrogen produced from the biogas would also be more expensive. Also, the cost of producing hydrogen from electrolysis is more expensive than steam methane reforming of natural gas.[666]

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.[667] 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
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¢ per gallon of renewable diesel product to cover other costs: utilities, labor, and other operating costs.[668] Finally, the total cost per gallon was estimated at $4.64. 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 2026.

Table 10.1.2.4-3: Renewable Diesel Production Cost Estimate for a Greenfield 220 Million Gallons/Yr Plant Processing Soy Oil in 2026 (2022$)

Stream		Estimated value	MM$/yr	$/gal
Soy Oil input	198 MMgals/yr	46¢/lb	697	3.52
Naphtha output	11.8 MMgals/yr	1.81¢/gal	(20.4)	(0.10)
Light fuel gas output	11.8 MMgals/yr	173.7¢/gal	(20.4)	(0.09)
Hydrogen input	4,760 SCF/100 gals	$2.87/MSCF	27.1	0.14
Other Operating Costs			15.2	0.07
Capital Costs (2022$)		$1,052 million	115.7	0.58
Fixed Costs		5.5%	57.8	0.29
Total Costs			1020	4.40

The estimated renewable diesel production cost for all vegetable oil types and for all the years analyzed is summarized in Table 10.1.2.4-5.

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666 Congressional Research Service, "Hydrogen Production: Overview and Issues for Congress," R48196, October 3, 2024. https://www.congress.gov/crs-product/R48196.
667 Holmgren, Jennifer, Chris Gosling, Rich Mariangeli, Terry Marker, Giovanni Faraci, and Carlo Perego. "A New Development in Renewable Fuels: Green Diesel," *National Petrochemical & Refiners Association* AM-07-10, 2007.
668 Estimated based on the utility cost for an FCC naphtha hydrotreater. EPA, "Control of Air Pollution from Motor Vehicles: Tier 3 Motor Vehicle Emission and Fuel Standards Final Rule – Regulatory Impact Analysis," EPA-420-R-14-005, March 2014. https://nepis.epa.gov/Exe/ZyPDF.cgi/P100ISWM.PDF?Dockey=P100ISWM.PDF.

Table 10.1.2.4-5 Summary of Estimated Renewable Diesel Production Costs ($/gal)

Year	Soy Oil	Corn Oil	FOG
2026	4.40	3.79	3.54
2027	4.02	3.48	3.25
2028	3.89	3.37	3.15
2029	3.78	3.29	3.08
2030	3.64	3.17	2.97

As depicted in the table, there is a substantial production cost decline from 2026–2030, and this is almost entirely due to the declining vegetable oil prices summarized in Table 10.1.1.2-2.

10.1.2.5 Renewable Jet Fuel

As explained in Chapter 10.1.2.4, the production process for renewable diesel can also be used to produce jet fuel. There are two primary ways for doing so using vegetable oil and animal fats as feedstocks. The first and lowest cost way is to simply install a distillation column and distill off the lighter hydrocarbons, which boil in the jet fuel distillation range, that are produced by the renewable diesel production process. The second more expensive way, which can produce a larger amount of jet fuel, is to hydrocrack the renewable diesel hydrocarbons which fall in the diesel fuel range so that the hydrocarbon chains are shortened and then distill within the jet fuel distillation range.

Another emerging pathway for producing jet fuel is to use a recently developed chemical reaction pathway called alcohol-to-jet. In this case, alcohol compounds are reacted together to form hydrocarbon chains which fall in the jet fuel boiling range. Ethanol and isobutanol alcohols are possible reactants for this process. Since corn ethanol is widely available domestically available renewable fuel in the U.S., we will estimate the cost of this technology using corn ethanol as the feedstock.

10.1.2.5.1 Distillation

A simple distillation column can be installed to separate the jet fuel from the diesel hydrocarbons in renewable diesel. This simple distillation column, often called a stabilizer column, is designed to separate the lighter hydrocarbons from the heavier hydrocabons and only make a rough cut between the two hydrocarbon cuts. This type of distillation column would not be designed to boil off much of the heavier hydrocarbon compounds which would allow for a smaller diameter column. Also, because of the need for only a rough cut between the light and heavy hydrocarbons, the column would require a fewer number of trays and therefore not be very tall. EPA obtained cost information from Mobil Oil for such a column for the Tier 2 gasoline sulfur regulation which was designed for a similar case of separating the light and heavy gasoline naphtha compounds to minimize the cost to desulfurize gasoline.[669]

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[669] EPA, "Regulatory Impact Analysis – Control of Air Pollution from New Motor Vehicles: Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements;" EPA-420-R-99-023, December 1999. https://nepis.epa.gov/Exe/ZyPDF.cgi/P100F1UV.PDF?Dockey=P100F1UV.PDF.

The capital and operating cost information, and cost to jet fuel, for a stabilizer column to separate the jet fuel hydrocarbons from the rest of the renewable diesel compounds is summarized in Table 10.1.2.5.1-1. The capital costs are for a 50 thousand bbl/day unit from the year 2000; thus it was necessary to adjust the costs to 2022 dollars and base it on 14.4 thousand barrels per day (220 million gallon per year). A 20% factor is added on for contingency costs, and a 40% factor is added on to cover offsite costs. Jet fuel comprises hydrocarbons which range from 8 to 16 carbons in length. Analysis of the hydrocarbon chain lengths of renewable diesel produced soybean and corn vegetable oils and animal fat triglycerides reveals that the renewable diesel from vegetable oils typically contain about 20% 8 to 16 carbon hydrocarbons, while renewable diesel and animal fats typically contain 30% 8 to 16 carbon hydrocarbons. Since most renewable diesel is produced from vegetable oil, we assume that 20% of the renewable diesel produced would be separated as jet fuel by this distillation column, and we amortized the costs over only the jet fuel volume.

Table 10.1.2.5.1-1: Distillation Cost of Separating Jet Fuel from Renewable Diesel

			Annual Cost (MM$)	**Cost to Jet Fuel (¢/gal)**
Capacity Basis	50,000 bbl/day			
Capital Cost 2000$	$4.1 million			
Capital Cost for a 14.5 bbl/day unit	$2.2 million		0.24	0.54
Fixed Cost	5% of Capital		0.11	0.24
Electricity	0.17 kWh/bbl	6.69¢/kWh	0.06	0.14
HP Steam	36 lb/bbl	$4.48/MMBtu	1.27	2.8
Cooling Water	3 gal/bbl	$3/1000 gal	0.20	0.46
Total cost to jet (2900 bbl/day)			1.88	4.3

Table 10.1.2.5.1-1 summarizes our estimated cost to produce renewable diesel from soy oil in 2026 as $4.40 per gallon. Thus, adding a distillation column at a renewable diesel production facility is estimated to result in a jet fuel production cost of $4.44 per gallon.

10.1.2.5.2 Hydrocracking

The hydrocracking process utilizing a cracking catalyst can be used to convert some of the renewable diesel to jet fuel. Since this is a mild hydrocracking operation, it is estimated to only require a single stage hydrocracking reactor added after the renewable diesel hydrotreating reactor. The hydrocracking facility includes a distillation column which separates the hydrocracking reactor products into various streams, including jet fuel, renewable diesel, renewable naphtha and other light products. Table 10.1.2.5.2-1 summarizes the capital and operating cost information, input and output product information, and the estimated cost for the added hydrocracker unit.[670] A hydrocracker can produce a range of products depending on the operating conditions and catalyst used. For this analysis, a hydrocracker processing waste cooking oil is estimated to produce 64% jet fuel, 20% naphtha, 6% light hydrocarbons, and 10%

[670] Meyers, Robert A. *Handbook of Petroleum Refining Processes, Fourth Edition*. McGraw-Hill Education, 2016.

unreacted renewable diesel. However, hydrocrackers are quite flexible in their operations due to operating conditions and the catalyst used, so the product mix can be quite different from that used in this study.[671] The mild hydrocracking reaction is estimated to cause the product to swell 3 volume-percent relative to the feed volume.

The cost of the process is reflected in final cost of the renewable jet fuel being produced. The byproducts of the hydrocracking reaction were assigned monetary values to allow estimating the cost of the jet fuel produced. The unreacted renewable diesel is assigned the same price as the renewable diesel feedstock. The naphtha and light naphtha are assigned a discounted price relative to gasoline to reflect their expected low octane value. However, these streams could have higher value based on their renewability. As a sensitivity on the hydrocracking cost of producing jet fuel, naphtha is also valued the same as the renewable diesel feedstock, which could reflect its value as a renewable fuel.

Table 10.1.2.5.2-1 Estimated Renewable Jet Production Cost from Hydrocracked Renewable Diesel

			Annual Cost (MM$)	Cost to Jet Fuel (¢/gal)
Capacity Basis	14.4 kbbl/day			
Capital Cost 2016$	$5000/bbl/day			
Capital Cost 2022$	$98 million		10.7	8.2
Fixed Cost	5% of capital		2.9	3.7
Feedstock	12,916 bbl/day	$4.40/gal	872.8	667.9
Hydrogen	250 SCF/bbl	$2.87/MSCF	3.38	2.6
Natural Gas	90,000 Btu/bbl	$4.48/MMBtu	1.90	1.5
Electricity	8.4 kWh/bbl	6.88 ¢/kWh	2.72	2.1
Cooling Water	2 gal/bbl	$3/1000 ft3	0.03	0.22
Steam Export	10 lb/bbl	$4.48/MMBtu	-0.16	-0.1
Byproducts				
Other	798	$1.74/gallon	-21.3	-16.3
Naphtha – Low Naphtha - High	2,661	$1.74/gallon $4.60/gallon	-70.9 -179.6	-54.3 -137.6
Renewable Diesel	1,330	$4.40/gallon	-89.8	-68.8
Total Cost – Naphtha Low			713.4	546.6
Total Cost – Naphtha High			604.7	463.3

The analysis shows that if the hydrocracked naphtha price is significantly reduced to a value less than gasoline based on an assumption that its octane value is significantly lower than gasoline, the estimated production cost of renewable jet fuel is estimated to be $1 per gallon more expensive than renewable diesel. If the hydrocracked naphtha is assumed to be valued at the same price as renewable diesel, perhaps associated with a higher octane value, the estimated production cost of the hydrocracked jet fuel falls to 23¢ per gallon above the assumed renewable

[671] El-Araby, R., E. Abdelkader, G. El Diwani, and S. I. Hawash. "Bio-aviation Fuel via Catalytic Hydrocracking of Waste Cooking Oils." *Bulletin of the National Research Centre/Bulletin of the National Research Center* 44, no. 1 (October 12, 2020). https://doi.org/10.1186/s42269-020-00425-6.

diesel price. Hydrocracked naphtha is typically low in octane; however, it is possible for the hydrocracking reactor to include catalyst which could raise the octane of the hydrocracked naphtha.

10.1.2.5.3 Alcohol-to-Jet

Three different reaction steps are involved in converting ethanol into jet fuel. First the alcohol is dehydrated by removing the hydroxyl (-OH) group, creating and an olefin with the base hydrocarbon molecule. Thus, dehydrating ethanol produces ethylene as the intermediate product. Second, the hydrocarbons are oligomerized, which essentially daisy-chains the individual hydrocarbons molecules together. An obvious challenge of this second step is reacting enough of the short hydrocarbons together such that they boil in the jet fuel range, without combining too many together and producing diesel or an even heavier hydrocarbon. For the third step, the double carbon-carbon bonds of the oligomerized hydrocarbons are hydrogenated to saturate the double bonds.

We estimated the cost for converting alcohol to jet fuel based on a study which developed an Aspen Plus technical model for the cost analysis. The model assumed a smaller sized plant of 185 tons per day (20 million gallons per year) of alcohol feedstock, which seems appropriate for an emerging technology. The model estimates that the process produces mostly jet fuel but also produces renewable diesel and naphtha. We credit the renewable diesel exiting the ethanol-to-jet process at the feedstock price since the renewable diesel is unreacted by the process. The model estimates a total installed capital cost, but a 20% contingency factor is added to the reported capital cost. Table 10.1.2.5.3-1 summarizes the cost information and resulting estimated costs for the alcohol to jet process.

Table 10.1.2.5.3-1 Estimated Cost to Convert Corn Ethanol to Renewable Jet Fuel

			Annual Cost (MM$)	**Cost to Jet and Diesel Fuels (¢/gal)**
Capacity Basis				
Capital Cost 2022$	$21.0 million		2.3	0.24
Fixed Cost	6% of capital		1.3	0.13
Corn Ethanol	185 tons/day (20.5 million gals/yr)	$1.83/gal	37.4	3.82
Hydrogen	1.1 tons/day	$2.9/MSCF	0.41	0.04
Utilities	$2.7 million/yr	-	2.7	0.28
Catalyst	$0.5 million/yr	-	0.5	0.05
Naphtha	1.29 million gal/yr	$1.74/gal	-1.9	-0.19
Diesel	2.26 million gal/yr		-	
Jet Fuel	7.55 million gal/yr		-	
Total cost to jet and diesel (2900 bbl/day)			42.8	4.36

The cost analysis estimates that producing jet fuel from corn ethanol using the alcohol to jet process costs $4.36/gallon. This is slightly less expensive than producing jet fuel from soybean oil, although more expensive than producing jet fuel from corn and used cooking oil.

10.1.2.6 Biogas

Biogas is the result of anaerobic digestion of organic matter, including municipal waste, manure, agricultural waste, and food waste.[672] 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.[673]

The largest source of biogas, which is already being collected to avoid releasing methane into the environment, is from landfills.[674] Since landfill gas is the largest source of biogas available for the motor vehicle fleet, this cost analysis makes the simplifying assumption that the biogas will solely be provided by landfills.

While in some cases biogas can be used in local fleet vehicles which are operated at the landfill site, in most cases, a new pipeline would need to be constructed to transport the cleaned-up biogas to a nearby common carrier pipeline. Gas is then pulled off the pipeline at downstream locations and compressed into CNG or liquified into LNG for use in motor vehicles. Tracking the use of the biogas in motor vehicles occurs by proxy through contracts and/or affidavits rather than through a system designed to ensure that the same methane molecules produced at the landfill are used in CNG/LNG vehicles.

One of the costliest aspects of using biogas is its cleanup. Biogas contains large amounts of carbon dioxide, nitrogen, and other contaminants such as siloxanes which cannot be tolerated if it is to be put into a natural gas pipeline or used by fleet vehicles at the landfill site. We estimated a cost for cleaning up landfill biogas using Version 3.5 of the Landfill Gas Energy Cost Model (LFGcost-Web).[675,676] The throughput volume of landfill gas was estimated to be 8,000 SCF/min, which is at the upper end of the range of production volumes from biogas production facilities.[677] The equations from the LFGcost-Web model for biogas clean-up and interconnection are summarized in Table 10.1.2.6.1-1. We included a cost for biogas collection at a typical sized landfill which amounts to $0.09/MSCF.[678] The estimated production and clean-

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[672] Wikipedia, "Biogas." https://en.wikipedia.org/wiki/Biogas.
[673] LeFevers, Daniel. "Landfill Gas to Renewable Energy," *Waste Management*, April 26, 2013. https://www.eesi.org/files/042613_Daniel_LeFevers.pdf.
[674] EIA, "Biomass explained – Landfill gas and biogas," November 19, 2024. https://www.eia.gov/energyexplained/biomass/landfill-gas-and-biogas.php.
[675] The current version of this model and user's manual are available at: https://www.epa.gov/lmop/lfgcost-web-landfill-gas-energy-cost-model.
[676] 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.
[677] The Coalition for Renewable Natural Gas, "Economic Analysis of the US Renewable Natural Gas Industry," December 2021. https://guidehouse.com/-/media/www/site/insights/energy/2022/guidehouse-esirng-coalition-final-report122022.pdf.
[678] EPA, "LFG Energy Project Development Handbook," January 2024, Chapter 4. https://www.epa.gov/system/files/documents/2024-01/pdh_full.pdf.

up costs for landfills is summarized in Table 10.1.6.2-2. Distribution and retail costs are estimated for biogas in Chapter 10.1.4.3.

Table 10.1.2.6-1: Biogas Cleanup Cost Information[a]

	Cost Factors (2019$)
Interconnection	$400,000
Capital Costs	$6,000000*e^{(0.0003*SCF/min)}$
Operating and Maintenance	250 x SCF/min +148,000
Electricity Costs	0.009 kWh/SCF

[a] Excludes any new offsite pipeline costs and retailing costs.

Table 10.1.2.6-2 Biogas Collection and Cleanup costs

	Cost (MM$)	Cost ($/MMBtu)
Capital Cost	9.8	4.49
Operating and Maintenance	2.1	0.99
Electricity Costs	4.1	1.86
Interconnection	0.05	0.03
Total Clean-up Cost	16.1	4.62
Collection Cost	0.4	0.09
Collection and Clean-up Cost	16.5	7.36

The combined biogas collection and cleanup costs for a typical sized landfill amount to $7.36 per million Btu.

10.1.2.7 Sugarcane 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.

We estimated the cost to produce sugarcane ethanol two different ways. The first way is based on recent data on sugarcane 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 U.S. 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. The average of recent sugarcane 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 second way we estimated the cost of producing sugarcane ethanol is from a study by OECD (2008) entitled “Biofuels: Linking Support to Performance,” which provides a set of assumptions and an estimate of production costs. Our estimate of sugarcane production costs, which is shown in Table 10.1.2.6-1, primarily relies on the analysis made for that study. The original cost estimate reported in the RFS2 Rule 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 10.1.2.7-1 provides the updated production cost estimate for sugarcane ethanol.

Table 10.1.2.7-1: Sugarcane Ethanol Production Cost

Cost Basis	Sugarcane Productivity	71.5 tons/hectare	
	Sugarcane Consumption	2 million tons/year	
	Harvesting days	167	
	Ethanol productivity	85 L/ton feedstock (22.5 gal/ton feedstock)	
	Ethanol Production	170 million L/yr (45 million gals/yr)	
	Surplus power produced	40 kWh/ton sugarcane	
		RFS2 Reported Cost ($2006)	**Revised Costs ($2022)**
Capital Costs ($ million)	Investment cost in million$	97	158
	Investment cost for sugarcane production	36	59
Per Gallon Costs ($/gal)	Operating & maintenance costs	0.26	0.42
	Variable sugarcane production costs	0.64	1.05
	Capital costs	0.49	0.64
	Total production costs	1.40	2.11
	Shipping Costs to U.S.		0.15
	Delivered Cost		2.26

The average FOB ethanol price of $2.73/gallon in Brazil is somewhat higher than the estimated sugarcane 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 sugarcane ethanol.

10.1.2.8 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 that a small portion of the cellulosic fiber is converted to ethanol along with the starch in the existing starch to ethanol facilities. We project that this single reactor design is what will be used to produce the cellulosic ethanol volumes in the timeframe of this rulemaking.[679,680] 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.[681]

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 are the potential cost for the additional enzyme added to convert corn fiber to ethanol, and a cost savings due to increased corn oil production.[682] It appears that the cost of the additional enzyme is approximately equally offset by the cost savings of additional corn oil production. Therefore, we simply use the cost for producing ethanol from corn starch for the cost of producing ethanol from cellulosic ethanol.

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 standards. Each of these properties can have a different cost impact depending on the gasoline it is being blended

[679] Kacmar, Jim. “Intellulose: An Innovative Approach to Your Plant’s Profitability,” *Edeniq* 2019 Distillers Grains Symposium, May 15, 2019. https://distillersgrains.org/wp-content/uploads/2019/05/7-Kacmar-Intellulose.pdf.
[680] National Corn to Ethanol Research Center, “Conversion of Corn-Kernel Fiber in Conventional Fuel-Ethanol Plants,” Project No. 0340-19-03, November 11, 2018.
[681] EPA, “Guidance on Qualifying an Analytical Method for Determining the Cellulosic Converted Fraction of Corn Kernel Fiber Co-Processed with Starch,” EPA-420-B-22-041, September 2022. https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1015Q8V.pdf.
[682] Kacmar, Jim. “Intellulose: An Innovative Approach to your Plant’s Profitability,” *Edeniq* 2019 Distillers Grains Symposium, May 15, 2019. https://distillersgrains.org/wp-content/uploads/2019/05/7-Kacmar-Intellulose.pdf.

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 only an issue for the consumers who do not travel as far on a gallon of fuel with lower energy content. Depending on the fuel they are purchasing, the lower energy content will be either obvious to consumers (i.e., E85), impacting their purchase decisions, or not (i.e., E10; most consumers do not notice its lower energy content in comparison to E0, particularly now that almost all gasoline is E10). Since this is a social cost analysis which incorporates all the costs to society, the fuel economy effect is included in the overall cost estimates in Chapter 10.4, 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.[683] 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.[684] 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 was the principal method to increase octane. 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

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683 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.

684 EPA's contract was with ICF Incorporated, LLC, which in turn retained Mathpro for some aspects of the work.

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 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: 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 Low 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 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 Low Biofuel Cases ($/bbl)

PADD of Gasoline Origin	Type	Grade	Gasoline Marginal Values		Low Biofuel #1		Low Biofuel #2	
			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 in Table 10.1.3.1.1-2.

Table 10.1.3.1.1-2: Marginal Ethanol Replacement Cost by Gasoline Type and Season (¢/gallon)

PADD of Gasoline Origin	Type	Grade	Low Biofuel #1 Reformate-centric		Low Biofuel #2 Alkylate-centric	
			Summer	Winter	Summer	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 Grade	Reformate-centric		Alkylate-centric	
		Summer	Winter	Summer	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.[685] 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	Cost (¢/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.[686] 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¢ 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.

[685] California relies on ethanol blended at 10% for compliance with its LCFS program; thus, removing E10 ethanol from California gasoline is an unlikely possibility.
[686] Both RFG and CG must meet many of the same gasoline property specifications, including sulfur and benzene, as well as ASTM D4814.

Table 10.1.3.1.1-6: Aggregated Ethanol Marginal Replacement Cost (¢/gallon)

Gasoline	Grade	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
Annual Average		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%, the lower cost, alkylate-centric cost of 68.65¢ per gallon was used for ethanol's blending cost for ethanol blended as E10. This 68.65¢ 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 blending cost savings for blending ethanol as E15 or E85. The blending costs for higher level ethanol blends are considerably different from 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 the summers of 2022–2024, EPA granted numerous emergency waivers to allow E15 to continue to be sold with a 1 psi RVP waiver. In addition, eight states petitioned EPA to allow them to remove the 1 psi waiver for blending E10 gasoline. EPA issued a final rulemaking granting those petitions effective in 2025.[687] As a result, the same lower RVP, higher cost gasoline blendstock is required for both E10 and E15 ethanol blends in summertime conventional gasoline in those states.

E15 could potentially realize a blending cost benefit based on the increased octane for the additional ethanol if refiners could create and distribute a low RVP, low octane E15 blendstock for oxygenate blending (BOB). However, this would require a widespread shift by refineries, pipelines, and terminals in an entire geographical region to produce and distribute another even

[687] 89 FR 14760 (February 29, 2024).

lower octane BOB specially designed for producing E15 instead of E10.[688] 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%).[689] 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, except in those states which have rescinded the E10 1 psi waiver.

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.[690]

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).[691] 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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[688] 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 a refinery's gasoline sales.

[689] The RFG 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 former compliance tool of the RFG program. 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 sub-octane blendstock for oxygenate blending (CBOB). Reviewing CG aromatics levels (high octane aromatics decrease when refiners produce sub-octane CBOB), refiners switched the CG pool over to low octane CBOB from 2008–2013, which is around the time when the U.S. reached the E10 blendwall.

[690] E85 can have RVP levels that 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.

[691] EIA, "Frequently Asked Questions – How much ethanol is in gasoline, and how does it affect fuel economy?" April 1, 2024. 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.[692,693] 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.[694] 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¢ 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 may be sunk, however, in the part of the analysis where we estimate ethanol's distribution costs using spot ethanol prices, as

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[692] Farm Energy, "Animal Fats for Biodiesel Production," January 31, 2014. https://farm-energy.extension.org/animal-fats-for-biodiesel-production.

[693] McCormick, Robert, and Teresa Alleman. "Renewable Diesel Fuel," *NREL*, July 18, 2016. https://cleancities.energy.gov/files/u/news_events/document/document_url/182/McCormick___Alleman_RD_Overview_2016_07_18.pdf.

[694] ICF, "Modeling a 'No-RFS' Case," EPA Contract No. EP-C-16-020, July 17, 2018.

described below, we may inherently be including some distribution capital costs which are still being recovered.

As part of the effort by ICF/Mathpro to estimate use of renewable fuels in the absence of the RFS program, ICF estimated distribution costs for ethanol and biodiesel. We used these cost estimates for this rulemaking.[695] 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. 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. For the ethanol being shipped by unit train out of the Midwest, the ICF distribution cost analysis assumed that the ethanol is collected in Chicago by truck or manifest rail at an average cost of 7¢ per gallon and then moved out of the Midwest to other areas mostly using unit trains. Since ICF completed its analysis, we discovered that most corn ethanol plants are capable of sourcing unit trains from their plants.[696] Thus, the 7¢ 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.

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 32 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¢ per gallon, depending on the PADD. 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.

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[695] Id.

[696] EIA, "Rail congestion, cold weather raise ethanol spot prices," *Today in Energy*, April 3, 2014. https://www.eia.gov/todayinenergy/detail.php?id=15691.

Table 10.1.4.1.1-1: Ethanol Distribution Costs for Certain Cities or Areas (2017$)

Location		Distribution Cost (¢/gal) to: Hub/Terminal			Total (¢/gal)	
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. (2022$)

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 (2017$)	373,100	18.1
U.S. Average 2022$		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 cost 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.[697,698,699,700] 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.[701] 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 they could use for storing E85, but they 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).[702]

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—potentially over a million dollars. A small percentage of retail stations each year must undergo a significant overhaul once their retail station equipment (tank piping, dispensers, and other associated equipment) has significantly deteriorated, and when they do so the newly installed equipment is compatible with the higher ethanol blends. In this case, the station renovation cost for higher ethanol blends is solely the incremental cost of the ethanol-compatible equipment over non-ethanol-compatible equipment because the replacement cost for the equipment can be attributed to normal maintenance. 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

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697 Moriarty, K., and J. Yanowitz. "E15 And Infrastructure," *National Renewable Energy Laboratory*, NREL/TP-5400-64156, May 27, 2015. https://doi.org/10.2172/1215238.
698 EPA, "E15's Compatibility with UST Systems," January 2020. https://www.epa.gov/sites/default/files/2020-01/documents/e15-ust-compatibility-statement-1-23-20.pdf.
699 EPA, "UST System Compatibility with Biofuels," EPA-510-K-20-001, July 2020. https://www.epa.gov/sites/default/files/2020-07/documents/ust_compatibility_booklet_formatted_final_7-13-2020_508.pdf.
700 Conversations with Ryan Haerer, Office of Underground Storage Tanks; Spring 2022.
701 Renkes, Robert. "Scenarios to Determine Approximate Cost for E15 Readiness," *Petroleum Equipment Institute*, September 6, 2013.
702 Because only a small percentage of the motor vehicle fleet is comprised of FFVs that can refuel on E85, typically a retail station only offers E85 from a single dispenser at the retail station.

data collected by USDA through their BIP program and made available to EPA.[703] 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 (15% for E15 and 74% for E85), covering the cost of capital for the retail equipment adds 43¢ and 9¢ 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 $1.28 and 10¢ per gallon of ethanol in E15 and E85 in excess of E10, respectively.

Another potential retail cost that could apply for E85 is the increased time spent refueling. Since a motor vehicle travels fewer miles on a tankful of E85 compared to refueling with E10, the driver will need to refuel more often when running their vehicle on E85. This additional time is a cost to the driver. Such a refueling cost was not estimated for E85 for this rule.

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.[704] 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¢ 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 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 15–32¢ 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.

[703] "Communication with USDA on the BIP program 1-19-22," Docket Item No. EPA-HQ-OAR-2021-0324-0734. https://www.regulations.gov/document/EPA-HQ-OAR-2021-0324-0734.
[704] ICF, "Modeling a 'No-RFS' Case," EPA Contract No. EP-C-16-020, July 17, 2018.

Table 10.1.4.2-1: Estimated Biodiesel and Renewable Diesel Fuel Distribution Cost by PADD (2022$)

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

10.1.4.3 Renewable Natural Gas (RNG)

10.1.4.3.1 Distribution Costs

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.[705] A typical volume case was modeled of 600 SCF of renewable biogas being captured per minute to estimate the cost for a typical sized landfill.[706] When the pipeline capital costs are amortized over that typical volume of cleaned up landfill gas, the pipeline capital cost is estimated to be $1.89 per million Btu.[707] If the biogas generation facility is located far from an existing natural gas pipeline, such as a farm generating biogas from animal waste, the pipeline cost from distributing the renewable natural gas can be very expensive and maybe prohibitive.

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

[705] EPA, "LFGcost-Web – Landfill Gas Energy Cost Model." https://www.epa.gov/lmop/lfgcost-web-landfill-gas-energy-cost-model.
[706] The Coalition for Renewable Natural Gas, "Economic Analysis of the US Renewable Natural Gas Industry," December 2021. https://guidehouse.com/-/media/www/site/insights/energy/2022/guidehouse-esirng-coalition-final-report122022.pdf.
[707] 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 SCF/min.

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 $5.58/MSCF. 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 $2.40/MSCF, is assumed to apply to biogas for distribution to the natural gas pipeline.[708]

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. Many 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.[709]

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.[710] When adjusted to 2022 dollars, the estimated retail cost to dispense RNG is estimated to be $6.53 per million Btu.

[708] Biogas producers tell us that they are being charged an equivalent distribution price that natural gas producers are being charged which essentially assumes that they are using the entire natural gas pipeline. This pricing scheme, though, does not represent the true social cost for distributing biogas, and a separate distribution cost is estimated for biogas.
[709] 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. The facility may more easily be able to use the biogas onsite to generate electricity.
[710] Clean Fuel Connection, Inc. "Permitting CNG and LNG Stations, Best Practices Guide for Host Sites and Local Permitting Authorities."

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, EIA data shows that the demand for gasoline and diesel fuel is stable or somewhat in decline.[711] 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 AEO2023.[712] The projected Brent crude oil prices and gasoline and diesel fuel wholesale prices in 2026–2030 are summarized in Table 10.2.1.1-1.

Table 10.2.1.1-1: Estimated Gasoline Production Costs

		2026	**2027**	**2028**	**2029**	**2030**
Brent Crude Oil Prices ($/bbl)		87.9	88.3	88.9	89.47	90.2
Wholesale Prices (Assumed to be Production Costs) ($/gal)	Gasoline	2.24	2.22	2.23	2.24	2.25
	Diesel Fuel	2.80	2.68	2.58	2.59	2.60

Since the EIA 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 2025 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.

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[711] AEO2023, Table 12 – Petroleum and Other Liquid Prices, and Table 57 – Component of Selected Petroleum Product Prices.

[712] AEO2023, Table 57 – Components of Selected Petroleum Product Prices.

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 AEO2023, EIA projects the natural gas spot price for Henry Hub to average $3.07/MSCF in 2026 and decrease somewhat in the following years.[713] 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¢ 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. Price data for 2017 to 2019 was used to estimate the distribution and retail costs—these years were chosen because they avoided the price distortions associated with the Covid-19 pandemic and war in Ukraine. The resulting distribution costs for gasoline and diesel fuel are 5¢ and 8¢ per gallon, respectively. The retail costs for gasoline and diesel fuel are estimated to be 20¢ and 40¢ per gallon, 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 and retail costs, adjusted to 2022 dollars, to the projected wholesale gasoline and diesel fuel prices in Table 10.2.1.1-1 for

[713] AEO2023, Table 13 – Natural Gas Supply, Disposition, and Prices.

each year to estimate the gasoline and diesel fuel prices from refinery to retail. These gasoline and diesel fuel prices are summarized in Table 10.2.2.1-2.

Table 10.2.2.1-2: Projected Gasoline and Diesel Production Costs ($/gal)

		2026	2027	2028	2029	2030
	Brent Crude Oil Prices	87.9	88.3	88.9	89.47	90.2
Gasoline	Retail Cost minus taxes	2.52	2.50	2.51	2.52	2.53
	Terminal and Retail Costs	0.22	0.22	0.22	0.22	0.22
	Terminal Costs	2.30	2.28	2.29	2.30	2.31
	Distribution Cost	0.06	0.06	0.06	0.06	0.06
	Production Cost (from Table 10.2.1.1-1)	2.24	2.22	2.23	2.24	2.25
Diesel Fuel	Retail Cost minus taxes	3.31	3.19	3.09	3.10	3.11
	Terminal and Retail Costs	0.43	0.43	0.43	0.43	0.43
	Terminal Costs	2.88	2.76	2.66	2.67	2.68
	Distribution Cost	0.08	0.08	0.08	0.08	0.08
	Production Cost (from Table 10.2.1.1-1)	2.80	2.68	2.58	2.59	2.60

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.[714] 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.[715]

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 AEO2023 were subtracted from the commercial prices for 2026–2030. 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.[716]

[714] AEO2023, Table 13 – Natural Gas Supply, Disposition, and Prices.
[715] Taxes are not included in social cost estimates because they are not true costs, only transfer payments.
[716] Clean Fuel Connection, Inc. "Permitting CNG and LNG Stations, Best Practices Guide for Host Sites and Local Permitting Authorities.

Table 10.2.2.2-1: Natural Gas Distribution Cost ($/MSCF)

	2026	2027	2028	2029	2030
Commercial Prices	8.79	8.57	8.47	8.51	8.54
Henry Hub Prices $/MMBtu $/MSCF	3.07 2.96	2.85 2.75	2.80 2.70	2.83 2.72	2.91 2.81
Pipeline Distribution Costs	5.83	5.83	5.82	5.77	5.79
Retail Station Costs	6.53	6.53	6.53	6.53	6.53
Total Average Distribution & Retail Station Costs	12.11	12.11	12.11	12.11	12.11

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. The table is organized to show the relative energy density of a fuel type relative to the baseline fuel, which we assume is E10 gasoline and B5 diesel fuel.

Table 10.3-1: Lower Heating Value (LHV) Energy Densities (GREET 2024)

		LHV Energy Density (Btu/gal)	Percent of Baseline Fuel
Energy Density relative to E10 Gasoline	E10 Gasoline	110,428	-
	Gasoline (E0)[a]	114,200	103.1
	E15 Gasoline	108,542	98.3
	E85[b]	86,285	78.1
	Denatured Ethanol	76,477	69.2
Energy Density relative to B5 Diesel Fuel	B5 Diesel Fuel	128.009	-
	Diesel Fuel	128,450	100.3
	Renewable Diesel	122,887	0.960
	Biodiesel	119,550	0.934
Other Products	Crude Oil	129,670	
	Pure Ethanol	76,330	
	Natural Gas Liquids	83,686	

[a] From Diesel Fuels Technical Review; Chevron Global Marketing; 2007.
[b] Assumed to contain 74% ethanol.

To account for the fuel economy effect for the cost analysis, the change in fossil fuel volume displaced by a change in renewable fuel volume is estimated by the relative energy content of the renewable and fossil fuels. However, if the energy density is not the same between the fossil fuel and renewable fuel displacing it, the energy equivalent replacement is not one-for-one on a volume basis. For example, ethanol contains about 33% lower energy per volume than the gasoline it is displacing, such that 100 gallons of ethanol would displace 67 gallons of gasoline. The fuel economy effect is therefore inherent in the cost analysis and is not reported out separately.

For the individual 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

Costs are presented in several different ways. First, a per-gallon, individual renewable fuels cost summary presents our analysis of each renewable fuel relative to the fossil fuel being displaced.

Second, costs are presented for the Proposed Volumes and the Volume Scenarios, each relative to the No RFS and 2025 Baselines. For each case, we first present the change in volume for each renewable fuel and the fossil fuel it displaces. Then we present the costs for those volume changes by cost category (production, distribution, blending) for each renewable fuel and the fossil fuel displaced by the renewable fuel. Finally, we present total annual cost and total per-gallon costs.

In addition, 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 AEO2023 and summarized in Table 10.4-1.

Table 10.4-1: Total Gasoline, Diesel Fuel, and Natural Gas Volumes

	2026	2027	2028	2029	2030	Units
Gasoline Volume	131.53	130.00	128.31	126.47	124.48	Billion gallons
Diesel Volume	52.43	51.97	51.66	51.20	50.74	Billion gallons
Natural Gas Volume	29.68	29.15	28.95	28.8	28.55	Trillion cubic feet

Source: AEO2023, Table 11 – Petroleum and Other Liquids Supply and Disposition and Table 13 – Natural Gas Supply, Disposition, and Prices.

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 2026–2030. 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.[717] 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

[717] USDA, Higher Blends Infrastructure Incentive Program. https://www.rd.usda.gov/hbiip.

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.[718] 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.

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,” “b” and “c.”

[718] 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.

Table 10.4.1-1a: Renewable Fuels Production Costs Estimated for 2026–2030 (2022$/gal unless otherwise noted)

		Production Cost				
		2026	2027	2028	2029	2030
Corn Starch Ethanol	E10	1.83	1.80	1.78	1.76	1.72
	E15 w/ ½ Retail Costs	1.83	1.80	1.78	1.76	1.72
	E15 w/ Retail Costs	1.83	1.80	1.78	1.76	1.72
	E85 w/ ½ Retail Costs	1.83	1.80	1.78	1.76	1.72
	E85 w/ Retail Costs	1.83	1.80	1.78	1.76	1.72
Biodiesel	Soy Oil	4.02	4.02	4.02	4.02	4.02
	Corn Oil	3.41	3.41	3.41	3.41	3.41
	Waste Oil	3.15	3.15	3.15	3.15	3.15
Renewable Diesel	Soy Oil	4.40	4.40	4.40	4.40	4.40
	Corn Oil	3.79	3.79	3.79	3.79	3.79
	Waste Oil	3.54	3.54	3.54	3.54	3.54
Other Advanced	Sugarcane Ethanol	2.73	2.73	2.73	2.73	2.73
Cellulosic Biofuel	RNG ($/gal Ethanol)	0.57	0.57	0.57	0.57	0.57
	RNG ($/MMBtu)	7.46	7.46	7.46	7.46	7.46
	Corn Kernel Fiber E10 Ethanol	1.83	1.80	1.78	1.76	1.72

[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% 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 Blending, Distribution, Retail and Fuel Economy Costs Estimated for 2026–2030 (2022$/gal unless otherwise noted)

		Blending Cost	Distribution Cost	Retail Cost	Fuel Economy Cost
Corn Starch Ethanol	E10	-0.85	0.42		0.83
	E15 w/ ½ Retail Costs		0.42	0.64	0.83
	E15 w/ Retail Costs		0.42	1.28	0.83
	E85 w/ ½ Retail Costs		0.42	0.05	0.83
	E85 w/ Retail Costs		0.42	0.10	0.83
Biodiesel	Soy Oil		0.77		0.21
	Corn Oil		0.77		0.21
	Waste Oil		0.77		0.21
Renewable Diesel	Soy Oil		0.77		0.13
	Corn Oil		0.77		0.13
	Waste Oil		0.77		0.13
Other Advanced	Sugarcane Ethanol	-0.85	0.42		0.83
Cellulosic Biofuel	RNG ($/gal Ethanol)		0.43	0.50	-
	RNG ($/MMBtu)		5.58	6.53	-
	Corn Kernel Fiber E10 Ethanol	-0.85	0.42		0.83

Table 10.4.1-1c: Renewable Fuels Total Costs Estimated for 2026–2030 (2022$/gal unless otherwise noted)

		Total Cost				
		2026	2027	2028	2029	2030
Corn Starch Ethanol	E10	2.23	2.20	2.18	2.16	2.12
	E15 w/ ½ Retail Costs	3.72	3.69	3.67	3.65	3.19
	E15 w/ Retail Costs	4.36	4.33	4.31	4.29	3.83
	E85 w/ ½ Retail Costs	3.13	3.10	3.08	3.06	3.02
	E85 w/ Retail Costs	3.18	3.16	3.14	3.11	3.07
Biodiesel	Soy Oil	5.01	5.01	5.01	5.01	5.01
	Corn Oil	4.40	4.40	4.40	4.40	4.40
	Waste Oil	4.14	4.14	4.14	4.14	4.14
Renewable Diesel	Soy Oil	5.31	5.31	5.31	5.31	5.31
	Corn Oil	4.70	4.70	4.70	4.70	4.70
	Waste Oil	4.45	4.45	4.45	4.45	4.45
Other Advanced	Sugarcane Ethanol	3.13	3.13	3.13	3.13	3.13
Cellulosic Biofuel	Biogas ($/gal ethanol)	1.49	1.49	1.49	1.49	1.49
	Biogas ($/MMBtu)	19.57	19.57	19.57	19.57	19.57
	Corn Kernel Fiber E10 Ethanol	2.23	2.20	2.18	2.16	2.12

The distribution costs for the biofuels are nationwide averages, which do 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¢ per gallon for local distribution in the Midwest, to over 30¢ per gallon for moving the ethanol to the coasts. Thus, total ethanol cost blended as E10 can vary from around $3.66–3.86 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.

Tables 10.4.1-2a and Table 10.4.1-2b summarize the production, distribution, retail and total 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 AEO2023.[719] Projected natural gas spot prices from AEO2023 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 entities and the projected natural gas spot price, which reflects the price at the point of production.

Table 10.4.1-2a: Gasoline, Diesel Fuel, and Natural Gas Production, Distribution and Retail Costs for 2026–2030 (2022$)

	Production Cost					Distribution Cost	Retail Cost
	2026	2027	2028	2029	2030		
Gasoline ($/gal)	2.24	2.22	2.23	2.24	2.25	0.28	
Diesel Fuel ($/gal)	2.80	2.68	2.58	2.59	2.6	0.51	
Natural Gas $/gal ethanol	0.33	0.31	0.30	0.30	0.31	0.51	0.50
Natural Gas ($/MMBtu)	4.32	4.07	3.99	4.00	4.06	6.76	6.53

Table 10.4.1-2b: Gasoline, Diesel Fuel, and Natural Gas Total Costs for 2026–2030 (2022$)

	Total Cost				
	2026	2027	2028	2029	2030
Gasoline ($/gal)	2.52	2.50	2.51	2.52	2.53
Diesel Fuel ($/gal)	3.31	3.19	3.09	3.10	3.11
Natural Gas $/gal ethanol	1.34	1.32	1.31	1.31	1.32
Natural Gas ($/MMBtu)	17.61	17.36	17.27	17.29	17.35

Table 10.4.1-3 compares the data from Tables 10.4.1-1c and Table 10.4.1-2b to show the relative cost of the renewable fuels with the fossil fuels they are assumed to displace.

[719] AEO2023, Table 57 – Components of Selected Petroleum Product Prices.

Table 10.4.1-3: Relative Renewable Fuel Costs for 2026–2030 (2022$/gal unless otherwise noted)

		Total Net Cost				
		2026	2027	2028	2029	2030
Corn Starch Ethanol	E10	-0.29	-0.29	-0.32	-0.36	-0.41
	E15 w/ ½ Retail Costs	1.20	1.19	1.16	1.13	0.66
	E15 w/ Retail Costs	1.84	1.83	1.80	1.77	1.30
	E85 w/ ½ Retail Costs	0.61	0.61	0.58	0.54	0.49
	E85 w/ Retail Costs	0.67	0.66	0.63	0.60	0.55
Biodiesel	Soy Oil	1.69	1.81	1.91	1.90	1.89
	Corn Oil	1.08	1.20	1.30	1.29	1.28
	Waste Oil	0.83	0.95	1.05	1.04	1.03
Renewable Diesel	Soy Oil	2.00	2.12	2.22	2.21	2.20
	Corn Oil	1.39	1.51	1.61	1.60	1.59
	Waste Oil	1.13	1.25	1.35	1.34	1.33
Other Advanced	Sugarcane Ethanol	0.62	0.64	0.63	0.62	0.61
Cellulosic Biofuel	Biogas ($/gal ethanol)	0.16	0.17	0.18	0.18	0.18
	Biogas ($/MMBtu)	1.96	2.21	2.30	2.28	2.22
	Corn Kernel Fiber E10 Ethanol	-0.29	-0.29	-0.32	-0.36	-0.41

10.4.2 Costs for the Proposed Volumes

This chapter estimates the costs for the Proposed Volumes, which include a RIN reduction for imported feedstocks and renewable fuels. The costs are analyzed relative to both the No RFS Baseline as well as the 2025 Baseline. The costs are based on projected agricultural feedstock prices; however, those price projections do not consider large increases in demand due to large increases in biofuel demand. To understand the impact of the increased demand on the cost of the Proposed Volumes, we include a sensitivity analysis in Chapter 10.4.2.3 at a higher price for vegetable oils and animal fats.

10.4.2.1 Proposed Volumes 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 are described in Chapter 2). For this analysis we considered all societal costs, including production, blending, and distribution costs, and differences in energy density.

10.4.2.1.1 Volumes

The renewable fuel and fossil fuel volume changes under the Proposed Volumes relative to the No RFS Baseline are summarized in Tables 10.4.2.1.1-1a and 1b, respectively.

Table 10.4.2.1.1-1a: Proposed Volumes – Renewable Fuel Volume Changes Relative to the No RFS Baseline (million gallons, except where noted)

Fuel Type	Change in Renewable Fuel Volumes	
	2026	**2027**
Cellulosic Biofuel		
CNG - Landfill Biogas (MMSCF)	52,804	54,795
Corn Kernel Fiber Ethanol	-2	-2
Non-cellulosic Advanced		
Biodiesel - Soy	1,139	1,161
Biodiesel - FOG	-25	-28
Biodiesel - Corn Oil	118	141
Biodiesel - Canola	295	292
Renewable Diesel - Soy	1,294	1,544
Renewable Diesel - FOG	897	875
Renewable Diesel - Corn	483	448
Renewable Diesel - Canola	616	616
Sugarcane Ethanol	0	0
Conventional		
Ethanol - E10	-111	-130
Ethanol - E15	138	165
Ethanol - E85	187	195
Change in Biogas Volume	52,804	54,795
Change in Ethanol Volume	214	230
Change in Biodiesel Volume	1,527	1,566
Change in Renewable Diesel Volume	3,290	3,483

Table 10.4.2.1.1-1b: Proposed Volumes – Fossil Fuel Volume Changes Relative to the No RFS Baseline (million gallons, except where noted)

Fuel Type	Fuel Displaced	Change in Fossil Fuel Volumes	
		2026	2027
	Cellulosic Biofuel		
Natural Gas	CNG - Landfill Biogas (MMSCF)	-52,804	-54,795
Gasoline	Corn Kernel Fiber Ethanol	-1	-1
	Non-cellulosic Advanced		
Diesel Fuel	Biodiesel - Soy	-1,061	-1,081
Diesel Fuel	Biodiesel - FOG	23	26
Diesel Fuel	Biodiesel - Corn Oil	-110	-131
Diesel Fuel	Biodiesel - Canola	-274	-272
Diesel Fuel	Renewable Diesel - Soy	-1,238	-1,477
Diesel Fuel	Renewable Diesel - FOG	-859	-838
Diesel Fuel	Renewable Diesel - Corn	-462	-429
Diesel Fuel	Renewable Diesel - Canola	-589	-589
Gasoline	Sugarcane Ethanol	0.0	0.0
	Conventional		
Gasoline	Ethanol - E10	74	87
Gasoline	Ethanol - E15	-92	-111
Gasoline	Ethanol - E85	-125	-130
-	Change in Gasoline Volume	-145	-155
-	Change in Diesel Fuel Volume	-4,569	-4,791
-	Change in Natural Gas Volume	-52,804	-54,795

The change in gasoline and diesel volume for each year is used to estimate the change in imported crude oil, based on its relative energy content, and imported gasoline and diesel fuel. The change in petroleum demanded, and its effect on both imported crude oil and imported petroleum products, is mainly projected based on a comparison of two separate economic cases: the Low Economic Growth Case and the Reference Case, modeled by EIA in AEO2023.[720] The AEO Low Economic Growth Case for the years 2026–2027 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, 86% of that gasoline or diesel reduction would be attributed to reduced crude oil imports and imports of refined product would decrease by 11%.

The difference between the two AEO cases estimates that of the decrease in refined product demanded, about 89% of that decreased demand (100% minus 11%) would be caused by less gasoline and diesel fuel production by U.S. refineries. For a previous rulemaking we assessed the likely impact of reduced U.S. product demand on U.S. refineries and derived an

[720] "Change in Product Demand on Imports AEO2023 for Set 2 Proposed Rule," available in the docket for this action.

estimate based an analysis by a study conducted by McKinsey and Company.[721] Based on the McKinsey study, we estimate that of a given volume of reduced demand for gasoline and diesel fuel, half of that reduced demand would be due to U.S. refineries reducing their production of gasoline and diesel fuel (U.S. refineries produce less product or convert to produce renewable diesel fuel or shutdown), and the other half would be attributed to reduced net imports (reduced imports of gasoline and diesel fuel, or increased exports).

Relying on the McKinsey study for impacts on U.S. refinery production requires that we adjust the initial estimated impact on imports based on the two refinery modeling cases from AEO2023. These calculations are shown in Table 10.4.2.1.1-2. The first column in Table 10.4.2.1.1-2 summarizes the original AEO2023 estimates, the next two columns summarize the McKinsey Study adjustments made to the AEO2023 estimates based on the 50%/50% impact estimate on U.S. refineries, and the column furthest to the right summarizes the final estimated impact on imports based on McKinsey study adjustments to the AEO2023 estimate.

For the first column of the McKinsey study adjustment, which assumes that U.S. refineries reduce their output for 50% of the reduced refinery product demand, there would be no impact on the volume of imported refined product. Thus, the reduced volume of imported crude oil is estimated as 86.2/(86.2+3.0), which equates to 96.7%.

For the second column of the McKinsey study adjustment, which assumes that U.S. refineries maintain their output for 50% of the reduced refinery product demand, there is only an impact on the volume of net imported refined product, either decreased imports or increased refined product exports. Thus, in this case impact on the net refined product import volume is 100% of the reduced product demand.

The final estimated impact on imports is shown in the last column and is simply the average of the two McKinsey adjustment columns.

Table 10.4.2.1.1-2 Summary of AEO2023 Estimate on Imports, the McKinsey Adjustments, and Final Estimate of Impacts on Imports

		McKinsey Study: of reduced refined product		
	AEO2023	**50%: U.S. refineries reduce output**	**50%: U.S. refineries stay operating**	**Average**
Percent reduction in imported crude oil	86.2	96.7		48.3
Percent reduction in domestic crude oil	3.0	3.3		1.7
Percent reduction in net imported product	10.8		100.0	50.0
Total Percentage of imported petroleum	97.0	96.7	100.0	98.3

[721] "Estimate of the impact of decreased petroleum consumption on U.S. refinery production based on a study by McKinsey and Co.," available in the docket for this action.

As shown in Table 10.4.2.1.1-2, of a certain amount of reduced U.S. refined product demand, 48.3% of that reduced product demand is attributed to lower demand of imported crude oil and 50% is associated with lower net demand of imported refined product; thus, a total of 98.3% of that reduced demand is estimated to be attributed to reduced imports.

Based on these correlations, Table 10.4.2.1.1-3 summarizes the projected change in petroleum imports expected from the increased consumption of renewable biofuels relative to the No RFS Baseline. The change in crude oil volume and imported petroleum products is used for the energy security analysis contained in Chapter 6.

Table 10.4.2.1.1-3: Proposed Volumes – Projected Change in Petroleum Imports Due to Increase in Renewable Fuel Consumption Relative to the No RFS Baseline (million gallons)

	2026	2027
Change in Imported Gasoline	-72	-78
Change in Imported Diesel Fuel	-2,285	-2,396
Total Change in Crude Oil	-2,327	-2,441
Change in Domestic Crude Oil	-77	-81
Change in Imported Crude Oil	-2,250	-2,360

We are particularly concerned with petroleum imports due to historical incidents of imported petroleum supply shortfalls, which have since guided U.S. foreign policies to prevent such shortfalls. However, some of the renewable fuels or the vegetable oil or seeds that are used as feedstocks to produce renewable fuels may also be imported. Because renewable fuels demand continues to comprise a much smaller portion of the U.S. fuels market, and any imports and changes of imports of these fuels and feedstocks has not attracted as much concern as petroleum imports, we would not expect the same level of concern for any increases in imports of renewable fuels and their feedstocks, However, we will nevertheless discuss possible changes in imports of renewable fuels or their feedstocks. Since the federal BBD fuel subsidy has been revised to incentivize the production of these renewable fuels in the U.S., we anticipate any imports would most likely be vegetable oils, not the finished fuels.

Reviewing the projected increase in demand for renewable fuels, we identified that the renewable diesel and biodiesel vegetable oil feedstocks of canola oil, which would likely be supplied from Canada, and used cooking oil, most of which could be supplied from China, are the most likely imported renewable fuel vegetable oil feedstocks. If, for example, we conservatively assume that all the volume of canola oil and used cooking oil demanded to meet the increased volume are imported, as much as 40% of the increase vegetable oil demanded under the Proposed Volumes could be imported.

10.4.2.1.2 Cost Impacts

The component cost (production, distribution, blending retail) of each biofuel type compared to the fossil fuel it is displacing under the Proposed Volumes relative to the No RFS Baseline is summarized in Tables 10.4.2.1.2-1a and 1b.

Table 10.4.2.1.2-1: Proposed Volumes – Renewable and Petroleum Fuel Costs Relative to the No RFS Baseline (million 2022$)

		Renewable Fuel			Petroleum Fuel		
		Production	Distribution	Blending	Production	Distribution	Total
2026	*Cellulosic Biofuel*						
	CNG - Landfill Biogas	207	673	0	-228	-801	-150
	Corn Kernel Fiber Ethanol	-4	-1	-2	3	0	-3
	Non-cellulosic Advanced						
	Biodiesel - Soy	4,575	731	0	-2,970	-543	1,792
	Biodiesel - FOG	-79	-16	0	65	12	-18
	Biodiesel - Corn Oil	403	76	0	-309	-56	114
	Biodiesel - Canola	1,183	189	0	-768	-141	463
	Renewable Diesel - Soy	5,698	830	0	-3,466	-634	2,427
	Renewable Diesel - FOG	3,186	578	0	-2,412	-441	910
	Renewable Diesel - Corn	1,832	310	0	-1,293	-237	612
	Renewable Diesel - Canola	2,712	395	0	-1,650	-302	1,155
	Sugarcane Ethanol	0	0	0	0	0	0
	Conventional						
	Ethanol - E10	-202	-47	94	166	21	32
	Ethanol - E15	251	117	-78	-206	-25	58
	Ethanol - E85	342	96	-22	-281	-35	100
2027	*Cellulosic Biofuel*						
	CNG - Landfill Biogas	215	698	0	-223	-831	-142
	Corn Kernel Fiber Ethanol	0	0	0	0	0	0
	Non-cellulosic Advanced						
	Biodiesel - Soy	4,222	745	0	-2,898	-554	1,515
	Biodiesel - FOG	-80	-18	0	70	13	-15
	Biodiesel - Corn Oil	436	90	0	-352	-67	107
	Biodiesel - Canola	1,063	187	0	-729	-139	381
	Renewable Diesel - Soy	6,209	499	0	-3,959	-757	1,992
	Renewable Diesel - FOG	2,854	564	0	-2,253	-431	734
	Renewable Diesel - Corn	1,558	287	0	-1,148	-220	477
	Renewable Diesel - Canola	2,477	83	0	-1,579	-302	679
	Sugarcane Ethanol	0	0	0	0	0	0
	Conventional						
	Ethanol - E10	-234	-55	111	194	24	39
	Ethanol - E15	298	140	-94	-246	-31	68
	Ethanol - E85	350	99	-22	-289	-36	102

The costs are aggregated for each fossil fuel type and shown as annual totals and per-gallon and per MSCF costs in Table 10.4.2.1.2-3.

Table 10.4.2.1.2-3: Total Annual and Per-Gallon Costs Relative to the No RFS Baseline (2022$)

Year	Fuel Type	Total Cost (million $)	Per-Unit Cost	Units
2026	Gasoline	188	0.14	¢/gal gasoline
	Diesel Fuel	7,456	14.22	¢/gal diesel
	Natural Gas	-150	-0.50	$/MSCF natural gas
	Total	7,494	4.07	¢/gal gasoline and diesel
2027	Gasoline	206	0.16	¢/gal gasoline
	Diesel Fuel	5,871	11.30	¢/gal diesel
	Natural Gas	-142	-0.49	$/MSCF natural gas
	Total	5,936	3.26	¢/gal gasoline and diesel

10.4.2.2 Proposed Volumes Relative to 2025 Baseline

In this section, we summarize the estimated costs for the proposed changes in renewable fuel volumes described in Chapter 3.2 (changes relative to the 2025 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.

10.4.2.2.1 Volumes

The renewable fuel and fossil fuel volume changes under the Proposed Volumes relative to the 2025 Baseline are summarized in Tables 10.4.2.2.1-1a and 1b, respectively.

Table 10.4.2.2.1-1a: Proposed Volumes – Renewable Fuel Volume Changes Relative to the 2025 Volumes (million gallons, except where noted)

Fuel Type	Change in Renewable Fuel Volumes	
	2026	2027
Cellulosic Biofuel		
CNG - Landfill Biogas (MMSCF)	-9,219	-4,425
Corn Kernel Fiber Ethanol	47	46
Non-cellulosic Advanced		
Biodiesel - Soy	267	296
Biodiesel - FOG	81	81
Biodiesel - Corn Oil	145	145
Biodiesel - Canola	-1	-1
Renewable Diesel - Soy	356	606
Renewable Diesel - FOG	893	943
Renewable Diesel - Corn	392	392
Renewable Diesel - Canola	307	307
Sugarcane Ethanol	-37	-37
Conventional		
Ethanol - E10	-204	-383
Ethanol - E15	17	45
Ethanol - E85	30	61
Change in Biogas Volume	-9,219	-,4425
Change in Ethanol Volume	-109	-231
Change in Biodiesel Volume	492	521
Change in Renewable Diesel Volume	1,947	2,247

Table 10.4.2.2.1-1b: Proposed Volumes – Fossil Fuel Volume Changes Relative to the 2025 Baseline (million gallons, except where noted)

Fuel Type	Fuel Displaced	Change in Fossil Fuel Volumes	
		2026	2027
	Cellulosic Biofuel		
Natural Gas	CNG - Landfill Biogas (MMSCF)	9,219	4,425
Gasoline	Corn Kernel Fiber Ethanol	31	31
	Non-cellulosic Advanced		
Diesel Fuel	Biodiesel - Soy	248	275
Diesel Fuel	Biodiesel - FOG	76	76
Diesel Fuel	Biodiesel - Corn Oil	135	135
Diesel Fuel	Biodiesel - Canola	-1	-1
Diesel Fuel	Renewable Diesel - Soy	-340	-580
Diesel Fuel	Renewable Diesel - FOG	-854	-902
Diesel Fuel	Renewable Diesel - Corn	-375	-375
Diesel Fuel	Renewable Diesel - Canola	-293	-293
Gasoline	Sugarcane Ethanol	-25	-25
	Conventional		
Gasoline	Ethanol - E10	136	256
Gasoline	Ethanol - E15	-12	-30
Gasoline	Ethanol - E85	-20	-41
-	Change in Gasoline Volume	111	191
-	Change in Diesel Fuel Volume	-1,404	-1,664
-	Change in Natural Gas Volume	9,219	4,425

Similar to the analysis conducted in Chapter 10.4.2.1.1, the change in gasoline and diesel volume for each year is used to estimate the change in petroleum demanded and its effect on both imported crude oil, domestic crude oil, and imported petroleum products. Table 10.4.2.2.1-2 summarizes the projected change in petroleum imports expected from the increased consumption of renewable biofuels relative to the 2025 Baseline.

Table 10.4.2.2.1-2: Proposed Volumes – Projected Change in Petroleum Imports Due to Increase in Renewable Fuel Consumption Relative to the 2025 Baseline (million gallons)

	2026	2027
Change in Imported Gasoline	56	96
Change in Imported Diesel Fuel	-702	-832
Total Change in Crude Oil	-647	-740
Change in Domestic Crude Oil	-21	-25
Change in Imported Crude Oil	-625	-715

10.4.2.2.2 Cost Impacts

The component cost (production, distribution, blending retail) of each biofuel type compared to the fossil fuel it is displacing under the Proposed Volumes relative to the 2025 Baseline is summarized in Table 10.4.2.2.2-1.

Table 10.4.2.2.2-1: Proposed Volumes – Renewable and Petroleum Fuel Costs Relative to the 2025 Baseline (million 2022$)

		Renewable Fuel			Petroleum Fuel		
		Production	Distribution	Blending	Production	Distribution	Total
2026	*Cellulosic Biofuel*						
	CNG - Landfill Biogas	-36	-117	0	40	140	26
	Corn Kernel Fiber Ethanol	86	13	40	-71	-9	60
	Non-cellulosic Advanced						
	Biodiesel - Soy	1071	171	0	-695	-127	420
	Biodiesel - FOG	256	52	0	-377	-69	58
	Biodiesel - Corn Oil	493	93	0	2	0	139
	Biodiesel - Canola	-3	0	0	0	0	-1
	Renewable Diesel - Soy	1567	228	0	-953	-174	668
	Renewable Diesel - FOG	3158	573	0	-1049	-192	902
	Renewable Diesel - Corn	1486	251	0	-821	-150	496
	Renewable Diesel - Canola	1350	197	0	0	0	575
	Sugarcane Ethanol	-101	-16	31	56	7	-23
	Conventional						
	Ethanol - E10	-372	-86	173	306	38	59
	Ethanol - E15	32	15	-10	-26	-3	7
	Ethanol - E85	55	15	-3	-46	-6	16
2027	*Cellulosic Biofuel*						
	CNG - Landfill Biogas	-17	-56	0	18	67	11
	Corn Kernel Fiber Ethanol	83	13	39	-68	-9	58
	Non-cellulosic Advanced						
	Biodiesel - Soy	1075	190	0	-738	-141	386
	Biodiesel - FOG	233	52	0	-203	-39	43
	Biodiesel - Corn Oil	447	93	0	-361	-69	110
	Biodiesel - Canola	-2	0	0	2	0	-1
	Renewable Diesel - Soy	2436	-103	0	-1553	-297	483
	Renewable Diesel - FOG	3062	605	0	-2417	-462	788
	Renewable Diesel - Corn	1362	251	0	-1004	-192	417
	Renewable Diesel - Canola	1233	-115	0	-786	-150	181
	Sugarcane Ethanol	-101	-16	31	55	7	-23
	Conventional						
	Ethanol - E10	-689	-161	325	569	71	115
	Ethanol - E15	81	38	-26	-67	-8	18
	Ethanol - E85	109	31	-7	-90	-11	32

The costs are aggregated for each fossil fuel type and shown as annual totals and per-gallon and per MSCF costs in Table 10.4.2.2.2-2.

Table 10.4.2.2.2-2: Proposed Volumes – Total Annual and Per-Gallon Costs Relative to the 2025 Baseline (2022$)

Year	Fuel Type	Total Cost (million $)	Per-Unit Cost	Units
2026	Gasoline	119	0.09	¢/gal gasoline
	Diesel Fuel	3,256	6.21	¢/gal diesel
	Natural Gas	26	0.09	$/MSCF natural gas
	Total	3,401	1.85	¢/gal gasoline and diesel
2027	Gasoline	200	0.15	¢/gal gasoline
	Diesel Fuel	2,408	4.63	¢/gal diesel
	Natural Gas	11	0.04	$/MSCF natural gas
	Total	2,619	1.42	¢/gal gasoline and diesel

10.4.2.3 High Vegetable Oil Price Sensitivity Analysis

As summarized in Table 10.4.2.2.1-1a, the proposed renewable fuels standard is estimated to cause more than 1.4-billion-gallon increase in biodiesel and renewable diesel consumption which will largely be supplied by domestic feedstock sources. This large increase in demand could increase vegetable oil and animal fat feedstock prices higher than the price projections made by USDA. For this reason, we conducted cost sensitivity analyses at higher prices for those feedstocks. For 2026 we assumed a price of 75¢ per pound, and for 2027 we assumed a price of 65¢ per pound, which equates to the soybean prices we modeled in the Set 1 Rule for 2023 and 2024, respectively. Although there could be higher prices for vegetable oils and animal fats due to the large step increase in demand for domestic supplies, such price increases are likely to be transitory as the market has a chance to rebalance around the increased volumes.

10.4.2.3.1 Proposed Volumes Relative to the No RFS Baseline

The component cost (production, distribution, blending retail) of each biofuel type compared to the fossil fuel it is displacing under the Proposed Volumes at High Prices relative to the No RFS Baseline is summarized in Table 10.4.2.3.1-1.

Table 10.4.2.3.1-1: Proposed Volumes at High Prices – Renewable and Petroleum Fuel Costs Relative to the No RFS Baseline (million 2022$)

		Renewable Fuel			Petroleum Fuel		
		Production	Distribution	Blending	Production	Distribution	Total
2026	*Cellulosic Biofuel*						
	CNG - Landfill Biogas	207	673	0	-228	-801	-150
	Corn Kernel Fiber Ethanol	-4	-1	-2	3	0	-3
	Non-cellulosic Advanced						
	Biodiesel - Soy	7,128	731	0	-2,970	-543	4,346
	Biodiesel - FOG	-157	-16	0	65	12	-96
	Biodiesel - Corn Oil	741	76	0	-309	-56	451
	Biodiesel - Canola	1,844	189	0	-768	-141	1,124
	Renewable Diesel - Soy	8,596	830	0	-3,466	-634	5,326
	Renewable Diesel - FOG	5,982	578	0	-2,412	-441	3,706
	Renewable Diesel - Corn	3,207	310	0	-1,293	-237	1,987
	Renewable Diesel - Canola	4,092	395	0	-1,650	-302	2,535
	Sugarcane Ethanol	0	0	0	0	0	0
	Conventional						
	Ethanol - E10	-202	-47	94	166	21	32
	Ethanol - E15	251	117	-78	-206	-25	58
	Ethanol - E85	342	96	-22	-281	-35	100
2027	*Cellulosic Biofuel*						
	CNG - Landfill Biogas	215	698	0	-223	-831	-142
	Corn Kernel Fiber Ethanol	0	0	0	0	0	0
	Non-cellulosic Advanced						
	Biodiesel - Soy	6,069	745	0	-2,898	-554	3,362
	Biodiesel - FOG	-146	-18	0	70	13	-81
	Biodiesel - Corn Oil	736	90	0	-352	-67	408
	Biodiesel - Canola	1,528	187	0	-729	-139	846
	Renewable Diesel - Soy	9,060	499	0	-3,959	-757	4,843
	Renewable Diesel - FOG	5,155	564	0	-2,253	-431	3,035
	Renewable Diesel - Corn	2,628	287	0	-1,148	-220	1,548
	Renewable Diesel - Canola	3,615	83	0	-1,579	-302	1,817
	Sugarcane Ethanol	0	0	0	0	0	0
	Conventional						
	Ethanol - E10	-234	-55	111	194	24	39
	Ethanol - E15	298	140	-94	-246	-31	68
	Ethanol - E85	350	99	-22	-289	-36	102

The costs are aggregated for each fossil fuel type and shown as annual totals and per-gallon and per MSCF costs in Table 10.4.2.3.1-2.

Table 10.4.2.3.1-2: Total Annual and Per-Gallon Costs Relative to the No RFS Baseline (2022$)

Year	Fuel Type	Total Cost (million $)	Per-Unit Cost	Units
2026	Gasoline	188	0.14	¢/gal gasoline
	Diesel Fuel	19,379	36.96	¢/gal diesel
	Natural Gas	-150	-0.50	$/MSCF natural gas
	Total	19,417	10.56	¢/gal gasoline and diesel
2027	Gasoline	206	0.16	¢/gal gasoline
	Diesel Fuel	15,779	30.36	¢/gal diesel
	Natural Gas	-142	-0.49	$/MSCF natural gas
	Total	15,843	8.71	¢/gal gasoline and diesel

10.4.2.3.2 Proposed Volumes Relative to the 2025 Baseline

The component cost (production, distribution, blending retail) of each biofuel type compared to the fossil fuel it is displacing under the Proposed Volumes at High Prices relative to the 2025 Baseline is summarized in Table 10.4.2.3.2-1.

Table 10.4.2.3.2-1: Proposed Volumes at High Prices – Renewable and Petroleum Fuel Costs Relative to the 2025 Baseline (million 2022$)

		Renewable Fuel			Petroleum Fuel		Total
		Production	Distribution	Blending	Production	Distribution	
2026	*Cellulosic Biofuel*						
	CNG - Landfill Biogas	-36	-117	0	40	140	26
	Corn Kernel Fiber Ethanol	86	13	40	-71	-9	60
	Non-cellulosic Advanced						
	Biodiesel - Soy	1,669	171	0	-695	-127	1,017
	Biodiesel - FOG	509	52	0	-377	-69	310
	Biodiesel - Corn Oil	905	93	0	2	0	552
	Biodiesel - Canola	-4	0	0	0	0	-3
	Renewable Diesel - Soy	2,364	228	0	-953	-174	1,465
	Renewable Diesel - FOG	5,930	573	0	-1,049	-192	3,674
	Renewable Diesel - Corn	2,602	251	0	-821	-150	1,612
	Renewable Diesel - Canola	2,037	197	0	0	0	1,262
	Sugarcane Ethanol	-101	-16	31	56	7	-23
	Conventional						
	Ethanol - E10	-372	-86	173	306	38	59
	Ethanol - E15	32	15	-10	-26	-3	7
	Ethanol - E85	55	15	-3	-46	-6	16
2027	*Cellulosic Biofuel*						
	CNG - Landfill Biogas	-17	-56	0	18	67	11
	Corn Kernel Fiber Ethanol	83	13	39	-68	-9	58
	Non-cellulosic Advanced						
	Biodiesel - Soy	1,545	190	0	-738	-141	856
	Biodiesel - FOG	425	52	0	-203	-39	235
	Biodiesel - Corn Oil	756	93	0	-361	-69	419
	Biodiesel - Canola	-3	0	0	2	0	-2
	Renewable Diesel - Soy	3,555	-103	0	-1,553	-297	1,602
	Renewable Diesel - FOG	5,532	605	0	-2,417	-462	3,257
	Renewable Diesel - Corn	2,298	251	0	-1,004	-192	1,353
	Renewable Diesel - Canola	1,799	-115	0	-786	-150	748
	Sugarcane Ethanol	-101	-16	31	55	7	-23
	Conventional						
	Ethanol - E10	-689	-161	325	569	71	115
	Ethanol - E15	81	38	-26	-67	-8	18
	Ethanol - E85	109	31	-7	-90	-11	32

The costs are aggregated for each fossil fuel type and shown as annual totals and per-gallon and per MSCF costs in Table 10.4.2.3.2-2.

Table 10.4.2.3.2-2: Proposed Volumes at High Prices – Total Annual and Per-Gallon Costs Relative to the 2025 Baseline (2022$)

Year	Fuel Type	Total Cost (million $)	Per-Unit Cost	Units
2026	Gasoline	119	0.09	¢/gal gasoline
	Diesel Fuel	9,890	18.86	¢/gal diesel
	Natural Gas	26	0.09	$/MSCF natural gas
	Total	10,035	5.45	¢/gal gasoline and diesel
2027	Gasoline	200	0.15	¢/gal gasoline
	Diesel Fuel	8,469	16.30	¢/gal diesel
	Natural Gas	11	0.04	$/MSCF natural gas
	Total	8,680	4.72	¢/gal gasoline and diesel

10.4.3 Costs for the Low Volume Scenario

We analyzed the costs for the Low Volume Scenario relative to the No RFS Baseline, as well as incremental to the 2025 Baseline.

10.4.3.1 Low Volume Scenario 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.

10.4.3.1.1 Volumes

The renewable fuel and fossil fuel volume changes under the Low Volume Scenario relative to the No RFS Baseline are summarized in Tables 10.4.2.1.1-1a and 1b, respectively.

Table 10.4.3.1.1-1a: Low Volume Scenario – Renewable Fuel Volume Changes Relative to the No RFS Baseline (million gallons, except where noted)

Fuel Type	Change in Renewable Fuel Volume				
	2026	**2027**	**2028**	**2029**	**2030**
Cellulosic Biofuel					
CNG - Landfill Biogas (MMSCF)	52,804	63,866	65,931	67,996	70,282
Corn Kernel Fiber Ethanol	-2	-2	-2	-2	-1
Non-cellulosic Advanced					
Biodiesel - Soy	1,196	1,189	1,197	1,197	1,193
Biodiesel - FOG	-49	-52	-47	-53	-46
Biodiesel - Corn Oil	34	57	35	33	35
Biodiesel - Canola	330	327	330	330	328
Renewable Diesel - Soy	703	740	778	815	853
Renewable Diesel - FOG	956	1,159	1,359	1,545	1,743
Renewable Diesel - Corn	79	44	52	35	23
Renewable Diesel - Canola	130	130	130	130	130
Sugarcane Ethanol	0	0	0	0	0
Conventional					
Ethanol - E10	-111	-130	-138	-153	-169
Ethanol - E15	138	165	176	196	218
Ethanol - E85	187	195	203	211	218
Change in Biogas Volume	52,804	63,866	65,931	67,996	70,282
Change in Ethanol Volume	214	230	240	254	267
Change in Biodiesel Volume	1,511	1,521	1,515	1,507	1,510
Change in Renewable Diesel Volume	1,868	2,073	2,318	2,525	2,749

Table 10.4.3.1.1-1b: Low Volume Scenario – Fossil Fuel Volume Changes Relative to the No RFS Baseline (million gallons, except where noted)

Fuel Type	Fuel Displaced	Change in Fossil Fuel Volume				
		2026	2027	2028	2029	2030
	Cellulosic Biofuel					
Natural Gas	CNG - Landfill Biogas (MMSCF)	-52,804	-63,866	-65,931	-67,996	-70,282
Gasoline	Corn Kernel Fiber Ethanol	-1	-1	-1	-1	-1
	Non-cellulosic Advanced					
Diesel Fuel	Biodiesel - Soy	-1,114	-1,107	-1,115	-1,115	-1,111
Diesel Fuel	Biodiesel - FOG	46	48	44	49	43
Diesel Fuel	Biodiesel - Corn Oil	-32	-53	-32	-31	-32
Diesel Fuel	Biodiesel - Canola	-307	-305	-307	-307	-306
Diesel Fuel	Renewable Diesel - Soy	-673	-708	-744	-780	-816
Diesel Fuel	Renewable Diesel - FOG	-915	-1,109	-1,300	-1,478	-1,668
Diesel Fuel	Renewable Diesel - Corn	-75	-42	-50	-34	-22
Diesel Fuel	Renewable Diesel - Canola	-124	-124	-124	-124	-124
Gasoline	Sugarcane Ethanol	0.0	0.0	0.0	0.0	0.0
	Conventional					
Gasoline	Ethanol - E10	74	87	92	102	113
Gasoline	Ethanol - E15	-92	-111	-118	-131	-146
Gasoline	Ethanol - E85	-125	-130	-136	-141	-146
-	Change in Gasoline Volume	-145	-155	-162	-172	-180
-	Change in Diesel Fuel Volume	-3,194	-3,400	-3,629	-3,820	-4,036
-	Change in Natural Gas Volume	-52,804	-63,866	-65,931	-67,996	-70,282

Similar to the analysis conducted in Chapter 10.4.2.1.1, the change in gasoline and diesel volume for each year is used to estimate the change in petroleum demanded and its effect on both imported crude oil, domestic crude oil, and imported petroleum products. Table 10.4.3.1.1-2 summarizes the projected change in petroleum imports expected from the increased consumption of renewable biofuels relative to the No RFS Baseline.

Table 10.4.3.1.1-2: Low Volume Scenario – Projected Change in Petroleum Imports Due to Increase in Renewable Fuel Consumption Relative to the No RFS Baseline (million gallons)

	2026	2027	2028	2029	2030
Change in Imported Gasoline	-72	-78	-81	-86	-90
Change in Imported Diesel Fuel	-1,597	-1,700	-1,814	-1,910	-2,018
Total Change in Crude Oil	-1,646	-1,753	-1,869	-1,967	-2,078
Change in Domestic Crude Oil	-55	-58	-62	-65	-69
Change in Imported Crude Oil	-1,591	-1,694	-1,807	-1,902	-2,009

10.4.3.1.2 Cost Impacts

The component cost (production, distribution, blending retail) of each biofuel type compared to the fossil fuel it is displacing under the Low Volume Scenario relative to the No RFS Baseline is summarized in Tables 10.4.2.1.2-1a and 1b.

Table 10.4.3.1.2-1a: Low Volume Scenario – Renewable and Petroleum Fuel Costs Relative to the No RFS Baseline (million 2022$)

		Renewable Fuel			Petroleum Fuel		
		Production	Distribution	Blending	Production	Distribution	Total
2026	*Cellulosic Biofuel*						
	CNG - Landfill Biogas	207	673	0	-228	-801	-150
	Corn Kernel Fiber Ethanol	-4	-1	-2	3	0	-3
	Non-cellulosic Advanced						
	Biodiesel - Soy	4,804	767	0	-3,119	-571	1,882
	Biodiesel - FOG	-155	-31	0	128	23	-35
	Biodiesel - Corn Oil	117	22	0	-89	-16	33
	Biodiesel - Canola	1,324	211	0	-859	-157	519
	Renewable Diesel - Soy	3,095	451	0	-1,883	-345	1,319
	Renewable Diesel - FOG	3,394	616	0	-2,570	-470	969
	Renewable Diesel - Corn	299	50	0	-211	-39	100
	Renewable Diesel - Canola	572	83	0	-348	-64	244
	Sugarcane Ethanol	0	0	0	0	0	0
	Conventional						
	Ethanol - E10	-202	-47	94	166	21	32
	Ethanol - E15	251	117	-78	-206	-25	58
	Ethanol - E85	342	96	-22	-281	-35	100
2027	*Cellulosic Biofuel*						
	CNG - Landfill Biogas	250	814	0	-260	-969	-165
	Corn Kernel Fiber Ethanol	0	0	0	0	0	0
	Non-cellulosic Advanced						
	Biodiesel - Soy	4,324	763	0	-2,968	-567	1,551
	Biodiesel - FOG	-148	-33	0	129	25	-28
	Biodiesel - Corn Oil	176	37	0	-142	-27	43
	Biodiesel - Canola	1,190	210	0	-817	-156	427
	Renewable Diesel - Soy	2,976	499	0	-1,897	-363	1,215
	Renewable Diesel - FOG	3,776	746	0	-2,981	-570	972
	Renewable Diesel - Corn	153	28	0	-113	-22	47
	Renewable Diesel - Canola	523	83	0	-333	-64	209
	Sugarcane Ethanol	0	0	0	0	0	0
	Conventional						
	Ethanol - E10	-234	-55	111	194	24	39
	Ethanol - E15	298	140	-94	-246	-31	68
	Ethanol - E85	350	99	-22	-289	-36	102
2028	*Cellulosic Biofuel*						
	CNG - Landfill Biogas	258	840	0	-263	-1,000	-165
	Corn Kernel Fiber Ethanol	0	0	0	0	0	0
	Non-cellulosic Advanced						
	Biodiesel - Soy	4,197	768	0	-2,877	-571	1,517
	Biodiesel - FOG	-131	-30	0	114	23	-25
	Biodiesel - Corn Oil	104	22	0	-83	-17	26
	Biodiesel - Canola	1,157	212	0	-793	-157	418
	Renewable Diesel - Soy	3,025	499	0	-1,920	-381	1,223
	Renewable Diesel - FOG	4,286	874	0	-3,361	-667	1,132
	Renewable Diesel - Corn	174	33	0	-128	-25	54
	Renewable Diesel - Canola	506	83	0	-321	-64	204
	Sugarcane Ethanol	0	0	0	0	0	0
	Conventional						
	Ethanol - E10	-246	-58	117	206	26	45
	Ethanol - E15	312	149	-99	-262	-33	67
	Ethanol - E85	361	104	-23	-303	-38	101

Table 10.4.3.1.2-1b: Low Volume Scenario – Renewable and Petroleum Fuel Costs Relative to the No RFS Baseline (million 2022$)

		Renewable Fuel			Petroleum Fuel		
		Production	**Distribution**	**Blending**	**Production**	**Distribution**	**Total**
2029	*Cellulosic Biofuel*						
	CNG - Landfill Biogas	266	867	0	-272	-1,031	-171
	Corn Kernel Fiber Ethanol	-4	-1	-2	3	0	-2
	Non-cellulosic Advanced						
	Biodiesel - Soy	4,024	768	0	-2,887	-571	1,334
	Biodiesel - FOG	-141	-34	0	128	25	-22
	Biodiesel - Corn Oil	96	21	0	-81	-16	21
	Biodiesel - Canola	1,109	212	0	-796	-157	368
	Renewable Diesel - Soy	3,082	523	0	-2,019	-399	1,186
	Renewable Diesel - FOG	4,752	991	0	-3,828	-757	1,158
	Renewable Diesel - Corn	116	23	0	-88	-17	34
	Renewable Diesel - Canola	492	83	0	-322	-64	189
	Sugarcane Ethanol	0	0	0	0	0	0
	Conventional						
	Ethanol - E10	-268	-64	130	229	28	55
	Ethanol - E15	345	166	-111	-294	-36	69
	Ethanol - E85	371	108	-24	-316	-39	99
2030	*Cellulosic Biofuel*						
	CNG - Landfill Biogas	275	896	0	-286	-1,066	-181
	Corn Kernel Fiber Ethanol	0	0	0	0	0	0
	Non-cellulosic Advanced						
	Biodiesel - Soy	3,846	765	0	-2,888	-569	1,154
	Biodiesel - FOG	-118	-30	0	112	22	-14
	Biodiesel - Corn Oil	96	22	0	-84	-17	17
	Biodiesel - Canola	1,059	211	0	-795	-157	318
	Renewable Diesel - Soy	3,109	547	0	-2,122	-418	1,117
	Renewable Diesel - FOG	5,183	1,118	0	-4,337	-855	1,110
	Renewable Diesel - Corn	72	15	0	-56	-11	19
	Renewable Diesel - Canola	474	83	0	-323	-64	170
	Sugarcane Ethanol	0	0	0	0	0	0
	Conventional						
	Ethanol - E10	-290	-71	144	255	31	68
	Ethanol - E15	374	185	-124	-328	-40	67
	Ethanol - E85	375	111	-25	-329	-40	92

The costs are aggregated for each fossil fuel type and shown as annual totals and per-gallon and per MSCF costs in Table 10.4.3.1.2-2.

Table 10.4.3.1.2-2: Total Annual and Per-Gallon Costs Relative to the No RFS Baseline (2022$)

Year	Fuel Type	Total Cost (million $)	Per-Unit Cost	Units
2026	Gasoline	188	0.14	¢/gal gasoline
	Diesel Fuel	5,030	9.59	¢/gal diesel
	Natural Gas	-150	-0.50	$/MSCF natural gas
	Total	5,068	2.76	¢/gal gasoline and diesel
2027.	Gasoline	206	0.16	¢/gal gasoline
	Diesel Fuel	4,436	8.54	¢/gal diesel
	Natural Gas	-165	-0.57	$/MSCF natural gas
	Total	4,477	2.46	¢/gal gasoline and diesel
2028	Gasoline	211	0.16	¢/gal gasoline
	Diesel Fuel	4,549	8.80	¢/gal diesel
	Natural Gas	-165	-0.57	$/MSCF natural gas
	Total	4,595	2.55	¢/gal gasoline and diesel
2029	Gasoline	220	0.17	¢/gal gasoline
	Diesel Fuel	4,267	8.33	¢/gal diesel
	Natural Gas	-171	-0.59	$/MSCF natural gas
	Total	4,316	2.43	¢/gal gasoline and diesel
2030	Gasoline	226	0.18	¢/gal gasoline
	Diesel Fuel	3,891	7.67	¢/gal diesel
	Natural Gas	-181	-0.63	$/MSCF natural gas
	Total	3,936	2.25	¢/gal gasoline and diesel

10.4.3.2 Low Volume Scenario Relative to the 2025 Baseline

In this section, we summarize the estimated costs for the proposed changes in renewable fuel volumes described in Chapter 3.2 (changes relative to the 2025 Baseline). For this analysis we considered all societal costs, including production, blending, and distribution costs, and differences in energy density.

10.4.3.2.1 Volumes

The renewable fuel and fossil fuel volume changes under the Low Volume Scenario relative to the 2025 Baseline are summarized in Tables 10.4.2.2.1-1a and 1b, respectively.

Table 10.4.3.2.1-1a: Low Volume Scenario – Renewable Fuel Volume Changes Relative to the 2025 Baseline (million gallons, except where noted)

Fuel Type	Change in Renewable Fuel Volume				
	2026	2027	2028	2029	2030
Cellulosic Biofuel					
CNG - Landfill Biogas (MMSCF)	-9,219	4,646	9,735	15,118	20,945
Corn Kernel Fiber Ethanol	47	46	45	43	42
Non-cellulosic Advanced					
Biodiesel - Soy	324	324	324	324	324
Biodiesel - FOG	57	57	57	57	57
Biodiesel - Corn Oil	61	61	61	61	61
Biodiesel - Canola	34	34	34	34	34
Renewable Diesel - Soy	-235	-198	-160	-123	-85
Renewable Diesel - FOG	952	1,227	1,502	1,777	2,052
Renewable Diesel - Corn	-12	-12	-12	-12	-12
Renewable Diesel - Canola	-179	-179	-179	-179	-179
Sugarcane Ethanol	-37	-37	-37	-37	-37
Conventional					
Ethanol - E10	-204	-383	-570	-784	-1,017
Ethanol - E15	17	45	55	76	98
Ethanol - E85	30	61	91	121	152
Change in Biogas Volume	-9,219	4,646	9,735	15,118	20,945
Change in Ethanol Volume	-109	-231	-378	-544	-725
Change in Biodiesel Volume	476	476	476	476	476
Change in Renewable Diesel Volume	525	837	1,150	1,462	1,775

Table 10.4.3.2.1-1b: Low Volume Scenario – Fossil Fuel Volume Changes Relative to the 2025 Baseline (million gallons, except where noted)

Fuel Type	Fuel Displaced	Change in Fossil Fuel Volume				
		2026	2027	2028	2029	2030
	Cellulosic Biofuel					
Natural Gas	CNG - Landfill Biogas (MMSCF)	9,219	-4,646	-9,735	-15,118	-20,945
Gasoline	Corn Kernel Fiber Ethanol	31	31	30	29	28
	Non-cellulosic Advanced					
Diesel Fuel	Biodiesel - Soy	301	301	301	301	301
Diesel Fuel	Biodiesel - FOG	53	53	53	53	53
Diesel Fuel	Biodiesel - Corn Oil	56	56	56	56	56
Diesel Fuel	Biodiesel - Canola	32	32	32	32	32
Diesel Fuel	Renewable Diesel - Soy	225	190	153	118	81
Diesel Fuel	Renewable Diesel - FOG	-911	-1,174	-1,437	-1,700	-1,963
Diesel Fuel	Renewable Diesel - Corn	12	12	12	12	12
Diesel Fuel	Renewable Diesel - Canola	172	172	172	172	172
Gasoline	Sugarcane Ethanol	-25	-25	-25	-25	-25
	Conventional					
Gasoline	Ethanol - E10	136	256	381	525	681
Gasoline	Ethanol - E15	-12	-30	-37	-51	-65
Gasoline	Ethanol - E85	-20	-41	-61	-81	-102
-	Change in Gasoline Volume	111	191	289	397	517
-	Change in Diesel Fuel Volume	-59	-357	-657	-955	-1,255
-	Change in Natural Gas Volume	9,219	-4,646	-9,735	-15,118	-20,945

Similar to the analysis conducted in Chapter 10.4.2.1.1, the change in gasoline and diesel volume for each year is used to estimate the change in petroleum demanded and its effect on both imported crude oil, domestic crude oil, and imported petroleum products. Table 10.4.3.2.1-2 summarizes the projected change in petroleum imports expected from the increased consumption of renewable biofuels relative to the 2025 Baseline.

Table 10.4.3.2.1-2: Low Volume Scenario – Projected Change in Petroleum Imports Due to Increase in Renewable Fuel Consumption Relative to the 2025 Baseline (million gallons)

	2026	2027	2028	2029	2030
Change in Imported Gasoline	56	96	144	199	259
Change in Imported Diesel Fuel	-29	-179	-328	-478	-627
Total Change in Crude Oil	20	-93	-198	-298	-394
Change in Domestic Crude Oil	1	-3	-7	-10	-13
Change in Imported Crude Oil	19	-90	-192	-288	-381

10.4.3.2.2 Cost Impacts

The component cost (production, distribution, blending retail) of each biofuel type compared to the fossil fuel it is displacing under the Low Volume Scenario relative to the 2025 Baseline is summarized in Tables 10.4.2.2.2-1a and 1b.

Table 10.4.3.2.2-1a: Low Volume Scenario – Renewable and Petroleum Fuel Costs Relative to the 2025 Baseline (million 2022$)

		Renewable Fuel			Petroleum Fuel		
		Production	**Distribution**	**Blending**	**Production**	**Distribution**	**Total**
2026	*Cellulosic Biofuel*						
	CNG - Landfill Biogas	-36	-117	0	40	140	26
	Corn Kernel Fiber Ethanol	86	13	40	-71	-9	60
	Non-cellulosic Advanced						
	Biodiesel - Soy	1,300	208	0	-844	-154	509
	Biodiesel - FOG	181	37	0	-158	-29	41
	Biodiesel - Corn Oil	207	39	0	-90	-16	58
	Biodiesel - Canola	138	22	0	0	0	54
	Renewable Diesel - Soy	-1,035	-151	0	630	115	-441
	Renewable Diesel - FOG	3,367	611	0	33	6	962
	Renewable Diesel - Corn	-47	-8	0	480	88	-16
	Renewable Diesel - Canola	-790	-115	0	0	0	-336
	Sugarcane Ethanol	-101	-16	31	56	7	-23
	Conventional						
	Ethanol - E10	-372	-86	173	306	38	59
	Ethanol - E15	32	15	-10	-26	-3	7
	Ethanol - E85	55	15	-3	-46	-6	16
2027	*Cellulosic Biofuel*						
	CNG - Landfill Biogas	18	59	0	-19	-70	-12
	Corn Kernel Fiber Ethanol	83	13	39	-68	-9	58
	Non-cellulosic Advanced						
	Biodiesel - Soy	1,177	208	0	-808	-154	422
	Biodiesel - FOG	164	37	0	-143	-27	30
	Biodiesel - Corn Oil	188	39	0	-151	-29	46
	Biodiesel - Canola	125	22	0	-86	-16	45
	Renewable Diesel - Soy	-797	-103	0	508	97	-294
	Renewable Diesel - FOG	3,985	787	0	-3,145	-601	1,025
	Renewable Diesel - Corn	-43	-8	0	32	6	-13
	Renewable Diesel - Canola	-721	-115	0	460	88	-289
	Sugarcane Ethanol	-101	-16	31	55	7	-23
	Conventional						
	Ethanol - E10	-689	-161	325	569	71	115
	Ethanol - E15	81	38	-26	-67	-8	18
	Ethanol - E85	109	31	-7	-90	-11	32
2028	*Cellulosic Biofuel*						
	CNG - Landfill Biogas	38	124	0	-39	-148	-24
	Corn Kernel Fiber Ethanol	80	12	38	-67	-8	55
	Non-cellulosic Advanced						
	Biodiesel - Soy	1,134	208	0	-778	-154	410
	Biodiesel - FOG	158	37	0	-138	-27	30
	Biodiesel - Corn Oil	181	39	0	-146	-29	45
	Biodiesel - Canola	120	22	0	-82	-16	43
	Renewable Diesel - Soy	-623	-103	0	395	78	-252
	Renewable Diesel - FOG	4,727	963	0	-3,707	-736	1,248
	Renewable Diesel - Corn	-42	-8	0	31	6	-13
	Renewable Diesel - Canola	-698	-115	0	443	88	-282
	Sugarcane Ethanol	-101	-16	31	55	7	-23
	Conventional						
	Ethanol - E10	-1,014	-240	484	851	106	186
	Ethanol - E15	99	47	-31	-83	-10	21
	Ethanol - E85	162	46	-10	-136	-17	45

Table 10.4.3.2.2-1b: Low Volume Scenario – Renewable and Petroleum Fuel Costs Relative to the 2025 Baseline (million 2022$)

		Renewable Fuel			Petroleum Fuel		
		Production	Distribution	Blending	Production	Distribution	Total
2029	*Cellulosic Biofuel*						
	CNG - Landfill Biogas	59	193	0	-61	-229	-38
	Corn Kernel Fiber Ethanol	0	0	0	0	0	0
	Non-cellulosic Advanced						
	Biodiesel - Soy	1,088	208	0	-781	-154	361
	Biodiesel - FOG	152	37	0	-138	-27	23
	Biodiesel - Corn Oil	174	39	0	-146	-29	37
	Biodiesel - Canola	115	22	0	-83	-16	38
	Renewable Diesel - Soy	-466	-79	0	305	60	-179
	Renewable Diesel - FOG	5,465	1,140	0	-4,402	-871	1,331
	Renewable Diesel - Corn	-41	-8	0	31	6	-12
	Renewable Diesel - Canola	-678	-115	0	444	88	-261
	Sugarcane Ethanol	-101	-16	31	56	7	-23
	Conventional						
	Ethanol - E10	-1,378	-330	667	1,176	145	280
	Ethanol - E15	134	64	-43	-114	-14	27
	Ethanol - E85	213	62	-14	-182	-22	57
2030	*Cellulosic Biofuel*						
	CNG - Landfill Biogas	82	267	0	-85	-318	-54
	Corn Kernel Fiber Ethanol	0	0	0	0	0	0
	Non-cellulosic Advanced						
	Biodiesel - Soy	1,044	208	0	-784	-154	313
	Biodiesel - FOG	146	37	0	-139	-27	17
	Biodiesel - Corn Oil	167	39	0	-147	-29	30
	Biodiesel - Canola	111	22	0	-83	-16	33
	Renewable Diesel - Soy	-310	-55	0	212	42	-111
	Renewable Diesel - FOG	6,100	1,316	0	-5,104	-1,006	1,307
	Renewable Diesel - Corn	-39	-8	0	31	6	-10
	Renewable Diesel - Canola	-654	-115	0	446	88	-235
	Sugarcane Ethanol	-101	-16	31	56	7	-23
	Conventional						
	Ethanol - E10	-1,746	-428	864	1,532	188	410
	Ethanol - E15	168	83	-55	-147	-18	30
	Ethanol - E85	261	77	-17	-229	-28	64

The costs are aggregated for each fossil fuel type and shown as annual totals and per-gallon and per MSCF costs in Table 10.4.3.2.2-2.

Table 10.4.3.2.2-2: Low Volume Scenario – Total Annual and Per-Gallon Costs Relative to the 2025 Baseline (2022$)

Year	Fuel Type	Total Cost (million $)	Per-Unit Cost	Units
2026	Gasoline	119	0.09	¢/gal gasoline
	Diesel Fuel	831	1.58	¢/gal diesel
	Natural Gas	26	0.09	$/MSCF natural gas
	Total	976	0.53	¢/gal gasoline and diesel
2027.	Gasoline	200	0.15	¢/gal gasoline
	Diesel Fuel	973	1.87	¢/gal diesel
	Natural Gas	-12	-0.04	$/MSCF natural gas
	Total	1,161	0.63	¢/gal gasoline and diesel
2028	Gasoline	285	0.22	¢/gal gasoline
	Diesel Fuel	1,230	2.38	¢/gal diesel
	Natural Gas	-24	-0.08	$/MSCF natural gas
	Total	1,491	0.81	¢/gal gasoline and diesel
2029	Gasoline	393	0.31	¢/gal gasoline
	Diesel Fuel	1,339	2.62	¢/gal diesel
	Natural Gas	-38	-0.13	$/MSCF natural gas
	Total	1,694	0.95	¢/gal gasoline and diesel
2030	Gasoline	530	0.43	¢/gal gasoline
	Diesel Fuel	1,343	2.65	¢/gal diesel
	Natural Gas	-54	-0.19	$/MSCF natural gas
	Total	1,819	1.04	¢/gal gasoline and diesel

10.4.4 Costs for the High Volume Scenario

We analyzed the costs for the High Volume Scenario relative to the No RFS Baseline, as well as incremental to the 2025 Baseline.

10.4.4.1 High Volume Scenario Relative to No RFS Baseline

10.4.4.1.1 Volumes

The renewable fuel and fossil fuel volume changes under the High Volume Scenario relative to the No RFS Baseline are summarized in Tables 10.4.4.1.1-1a and 1b, respectively.

Table 10.4.4.1.1-1a: High Volume Scenario – Renewable Fuel Volume Changes Relative to the No RFS Baseline (million gallons, except where noted)

Fuel Type	Change in Renewable Fuel Volume				
	2026	2027	2028	2029	2030
Cellulosic Biofuel					
CNG - Landfill Biogas (MMSCF)	52,804	63,866	65,931	67,996	70,282
Corn Kernel Fiber Ethanol	-2	-2	-2	-2	-1
Non-cellulosic Advanced					
Biodiesel - Soy	1,196	1,189	1,197	1,196	1,192
Biodiesel - FOG	-49	-51	-47	-53	-46
Biodiesel - Corn Oil	34	57	35	33	35
Biodiesel - Canola	329	327	330	329	328
Renewable Diesel - Soy	915	1,165	1,415	1,665	1,915
Renewable Diesel - FOG	957	1,160	1,359	1,545	1,744
Renewable Diesel - Corn	79	44	52	35	22
Renewable Diesel - Canola	230	330	430	530	630
Sugarcane Ethanol	0	0	0	0	0
Conventional					
Ethanol - E10	-111	-130	-138	-153	-169
Ethanol - E15	138	165	176	196	218
Ethanol - E85	187	195	203	211	218
Change in Biogas Volume	52,804	63,866	65,931	67,996	70,282
Change in Ethanol Volume	214	230	240	254	267
Change in Biodiesel Volume	1,511	1,521	1,515	1,507	1,509
Change in Renewable Diesel Volume	2,180	2,699	3,256	3,776	4,312

Table 10.4.4.1.1-1b: High Volume Scenario – Fossil Fuel Volume Changes Relative to the No RFS Baseline (million gallons, except where noted)

Fuel Type	Fuel Displaced	Change in Fossil Fuel Volume				
		2026	2027	2028	2029	2030
	Cellulosic Biofuel					
Natural Gas	CNG - Landfill Biogas (MMSCF)	-52,804	-63,866	-65,931	-67,996	-70,282
Gasoline	Corn Kernel Fiber Ethanol	-1	-1	-1	-1	-1
	Non-cellulosic Advanced					
Diesel Fuel	Biodiesel - Soy	-1,113	-1,107	-1,115	-1,114	-1,111
Diesel Fuel	Biodiesel - FOG	45	48	44	49	43
Diesel Fuel	Biodiesel - Corn Oil	-32	-53	-32	-31	-33
Diesel Fuel	Biodiesel - Canola	-307	-304	-307	-307	-306
Diesel Fuel	Renewable Diesel - Soy	-875	-1,115	-1,354	-1,593	-1,832
Diesel Fuel	Renewable Diesel - FOG	-915	-1,110	-1,300	-1,478	-1,668
Diesel Fuel	Renewable Diesel - Corn	-75	-42	-49	-34	-22
Diesel Fuel	Renewable Diesel - Canola	-220	-316	-411	-507	-603
Gasoline	Sugarcane Ethanol	0.0	0.0	0.0	0.0	0.0
	Conventional					
Gasoline	Ethanol - E10	74	87	92	102	113
Gasoline	Ethanol - E15	-92	-111	-118	-131	-146
Gasoline	Ethanol - E85	-125	-130	-136	-141	-146
-	Change in Gasoline Volume	-145	-155	-162	-172	-180
-	Change in Diesel Fuel Volume	-3,493	-3,999	-4,525	-5,016	-5,531
-	Change in Natural Gas Volume	-52,804	-63,866	-65,931	-67,996	-70,282

Similar to the analysis conducted in Chapter 10.4.2.1.1, the change in gasoline and diesel volume for each year is used to estimate the change in petroleum demanded and its effect on both imported crude oil, domestic crude oil, and imported petroleum products. Table 10.4.4.1.1-2 summarizes the projected change in petroleum imports expected from the increased consumption of renewable relative to the No RFS Baseline.

Table 10.4.4.1.1-2: High Volume Scenario – Projected Change in Petroleum Imports Due to Increase in Renewable Fuel Consumption Relative to the No RFS Baseline (million gallons)

	2026	2027	2028	2029	2030
Change in Imported Gasoline	-72	-78	-81	-86	-90
Change in Imported Diesel Fuel	-1,746	-1,999	-2,263	-2,508	-2,765
Total Change in Crude Oil	-1,794	-2,049	-2,313	-2,560	-2,818
Change in Domestic Crude Oil	-60	-68	-77	-85	-94
Change in Imported Crude Oil	-1,734	-1,981	-2,236	-2,475	-2,725

10.4.4.1.2 Cost Impacts

The component cost (production, distribution, blending retail) of each biofuel type compared to the fossil fuel it is displacing under the High Volume Scenario relative to the No RFS Baseline is summarized in Tables 10.4.4.1.2-1a and 1b.

Table 10.4.4.1.2-1a: High Volume Scenario – Renewable and Petroleum Fuel Costs Relative to the No RFS Baseline (million 2022$)

		Renewable Fuel			Petroleum Fuel		
		Production	Distribution	Blending	Production	Distribution	Total
2026	*Cellulosic Biofuel*						
	CNG - Landfill Biogas	207	673	0	-228	-801	-150
	Corn Kernel Fiber Ethanol	-4	-1	-2	3	0	-3
	Non-cellulosic Advanced						
	Biodiesel - Soy	4,802	767	0	-3,118	-570	1,881
	Biodiesel - FOG	-153	-31	0	127	23	-34
	Biodiesel - Corn Oil	117	22	0	-90	-16	33
	Biodiesel - Canola	1,322	211	0	-858	-157	518
	Renewable Diesel - Soy	4,029	587	0	-2,451	-448	1,716
	Renewable Diesel - FOG	3,396	616	0	-2,571	-470	970
	Renewable Diesel - Corn	298	50	0	-210	-38	100
	Renewable Diesel - Canola	1,013	148	0	-616	-113	431
	Sugarcane Ethanol	0	0	0	0	0	0
	Conventional						
	Ethanol - E10	-202	-47	94	166	21	32
	Ethanol - E15	251	117	-78	-206	-25	58
	Ethanol - E85	342	96	-22	-281	-35	100
2027	*Cellulosic Biofuel*						
	CNG - Landfill Biogas	250	814	0	-260	-969	-165
	Corn Kernel Fiber Ethanol	-4	-1	-2	3	0	-3
	Non-cellulosic Advanced						
	Biodiesel - Soy	4,323	763	0	-2,967	-567	1,551
	Biodiesel - FOG	-147	-33	0	128	25	-27
	Biodiesel - Corn Oil	176	37	0	-142	-27	43
	Biodiesel - Canola	1,189	210	0	-816	-156	426
	Renewable Diesel - Soy	4,686	908	0	-2,988	-571	2,035
	Renewable Diesel - FOG	3,778	746	0	-2,982	-570	972
	Renewable Diesel - Corn	152	28	0	-112	-21	47
	Renewable Diesel - Canola	1,327	276	0	-846	-162	595
	Sugarcane Ethanol	0	0	0	0	0	0
	Conventional						
	Ethanol - E10	-234	-55	111	194	24	39
	Ethanol - E15	298	140	-94	-246	-31	68
	Ethanol - E85	350	99	-22	-289	-36	102
2028	*Cellulosic Biofuel*						
	CNG - Landfill Biogas	258	840	0	-263	-1,000	-165
	Corn Kernel Fiber Ethanol	-4	-1	-2	3	0	-2
	Non-cellulosic Advanced						
	Biodiesel - Soy	4,196	768	0	-2,876	-571	1,516
	Biodiesel - FOG	-130	-30	0	113	22	-25
	Biodiesel - Corn Oil	104	22	0	-84	-17	26
	Biodiesel - Canola	1,156	212	0	-792	-157	418
	Renewable Diesel - Soy	5,504	908	0	-3,493	-694	2,225
	Renewable Diesel - FOG	4,287	874	0	-3,362	-668	1,132
	Renewable Diesel - Corn	174	33	0	-127	-25	54
	Renewable Diesel - Canola	1,672	276	0	-1,061	-211	676
	Sugarcane Ethanol	0	0	0	0	0	0
	Conventional						
	Ethanol - E10	-246	-58	117	206	26	45
	Ethanol - E15	312	149	-99	-262	-33	67
	Ethanol - E85	361	104	-23	-303	-38	101

Table 10.4.4.1.2-1b: High Volume Scenario – Renewable and Petroleum Fuel Costs Relative to the No RFS Baseline (million 2022$)

		Renewable Fuel			Petroleum Fuel		
		Production	Distribution	Blending	Production	Distribution	Total
	Cellulosic Biofuel						
	CNG - Landfill Biogas	266	867	0	-272	-1,031	-171
	Corn Kernel Fiber Ethanol	-4	-1	-2	3	0	-2
	Non-cellulosic Advanced						
	Biodiesel - Soy	4,023	768	0	-2,886	-571	1,333
	Biodiesel - FOG	-140	-34	0	127	25	-21
	Biodiesel - Corn Oil	96	21	0	-81	-16	21
	Biodiesel - Canola	1,108	211	0	-795	-157	367
2029	Renewable Diesel - Soy	6,298	1,068	0	-4,126	-816	2,424
	Renewable Diesel - FOG	4,753	991	0	-3,829	-757	1,158
	Renewable Diesel - Corn	116	23	0	-87	-17	34
	Renewable Diesel - Canola	2,004	340	0	-1,313	-260	771
	Sugarcane Ethanol	0	0	0	0	0	0
	Conventional						
	Ethanol - E10	-268	-64	130	229	28	55
	Ethanol - E15	345	166	-111	-294	-36	69
	Ethanol - E85	371	108	-24	-316	-39	99
	Cellulosic Biofuel						
	CNG - Landfill Biogas	275	896	0	-286	-1,066	-181
	Corn Kernel Fiber Ethanol	-2	0	-1	2	0	-1
	Non-cellulosic Advanced						
	Biodiesel - Soy	3,845	765	0	-2,887	-569	1,154
	Biodiesel - FOG	-117	-30	0	111	22	-14
	Biodiesel - Corn Oil	96	22	0	-85	-17	17
	Biodiesel - Canola	1,058	210	0	-794	-157	317
2030	Renewable Diesel - Soy	6,981	1,229	0	-4,764	-939	2,507
	Renewable Diesel - FOG	5,184	1,119	0	-4,338	-855	1,111
	Renewable Diesel - Corn	71	14	0	-56	-11	19
	Renewable Diesel - Canola	2,296	404	0	-1,567	-309	825
	Sugarcane Ethanol	0	0	0	0	0	0
	Conventional						
	Ethanol - E10	-290	-71	144	255	31	68
	Ethanol - E15	374	185	-124	-328	-40	67
	Ethanol - E85	375	111	-25	-329	-40	92

The costs are aggregated for each fossil fuel type and shown as annual totals and per-gallon and per MSCF costs in Table 10.4.4.1.2-2.

Table 10.4.4.1.2-2: High Volume Scenario – Total Annual and Per-Gallon Costs Relative to No RFS Baseline (2022$)

Year	Fuel Type	Total Cost (million $)	Per-Unit Cost	Units
2026	Gasoline	188	0.14	¢/gal gasoline
	Diesel Fuel	5,615	10.71	¢/gal diesel
	Natural Gas	-150	-0.50	$/MSCF natural gas
	Total	5,653	3.07	¢/gal gasoline and diesel
2027.	Gasoline	206	0.16	¢/gal gasoline
	Diesel Fuel	5,642	10.86	¢/gal diesel
	Natural Gas	-165	-0.57	$/MSCF natural gas
	Total	5,683	3.12	¢/gal gasoline and diesel
2028	Gasoline	211	0.16	¢/gal gasoline
	Diesel Fuel	6,022	11.66	¢/gal diesel
	Natural Gas	-165	-0.57	$/MSCF natural gas
	Total	6,068	3.37	¢/gal gasoline and diesel
2029	Gasoline	220	0.17	¢/gal gasoline
	Diesel Fuel	6,087	11.89	¢/gal diesel
	Natural Gas	-171	-0.59	$/MSCF natural gas
	Total	6,135	3.45	¢/gal gasoline and diesel
2030	Gasoline	226	0.18	¢/gal gasoline
	Diesel Fuel	5,936	11.70	¢/gal diesel
	Natural Gas	-181	-0.63	$/MSCF natural gas
	Total	5,981	3.41	¢/gal gasoline and diesel

10.4.4.2 High Volume Scenario Relative to the 2025 Baseline

10.4.4.2.1 Volumes

The renewable fuel and fossil fuel volume changes under the High Volume Scenario relative to the 2025 Baseline are summarized in Tables 10.4.4.2.1-1a and 1b, respectively.

Table 10.4.4.2.1-1a: High Volume Scenario – Renewable Fuel Volume Changes Relative to the 2025 Baseline (million gallons, except where noted)

Fuel Type	Change in Renewable Fuel Volume				
	2026	2027	2028	2029	2030
Cellulosic Biofuel					
CNG - Landfill Biogas	-9,219	4,646	9,735	15,118	20,945
Corn Kernel Fiber Ethanol	47	46	45	43	42
Non-cellulosic Advanced					
Biodiesel - Soy	323	323	323	323	323
Biodiesel - FOG	58	58	58	58	58
Biodiesel - Corn Oil	61	61	61	61	61
Biodiesel - Canola	34	34	34	34	34
Renewable Diesel - Soy	-23	227	477	727	977
Renewable Diesel - FOG	952	1,227	1,502	1,777	2,052
Renewable Diesel - Corn	-13	-13	-13	-13	-13
Renewable Diesel - Canola	-79	21	121	221	321
Sugarcane Ethanol	-37	-37	-37	-37	-37
Conventional					
Ethanol - E10	-204	-383	-570	-784	-1,017
Ethanol - E15	17	45	55	76	98
Ethanol - E85	30	61	91	121	152
Change in Biogas Volume	-9,219	4,646	9,735	15,118	20,945
Change in Ethanol Volume	-109	-231	-378	-544	-725
Change in Biodiesel Volume	476	476	476	476	476
Change in Renewable Diesel Volume	837	1,462	2,087	2,712	3,337

Table 10.4.4.2.1-1b: High Volume Scenario – Fossil Fuel Volume Changes Relative to the 2025 Baseline (million gallons, except where noted)

Fuel Type	Fuel Displaced	Change in Fossil Fuel Volume				
		2026	2027	2028	2029	2030
	Cellulosic Biofuel					
Natural Gas	CNG - Landfill Biogas (MMSCF)	9,219	-4,646	-9,735	-15,118	-20,945
Gasoline	Corn Kernel Fiber Ethanol	31	31	30	29	28
	Non-cellulosic Advanced					
Diesel Fuel	Biodiesel - Soy	301	301	301	301	301
Diesel Fuel	Biodiesel - FOG	54	54	54	54	54
Diesel Fuel	Biodiesel - Corn Oil	57	57	57	57	57
Diesel Fuel	Biodiesel - Canola	32	32	32	32	32
Diesel Fuel	Renewable Diesel - Soy	22	-217	-457	-696	-935
Diesel Fuel	Renewable Diesel - FOG	-911	-1,174	-1,437	-1,700	-1,963
Diesel Fuel	Renewable Diesel - Corn	12	12	12	12	12
Diesel Fuel	Renewable Diesel - Canola	76	-20	-115	-211	-307
Gasoline	Sugarcane Ethanol	-25	-25	-25	-25	-25
	Conventional					
Gasoline	Ethanol - E10	136	256	381	525	681
Gasoline	Ethanol - E15	-12	-30	-37	-51	-65
Gasoline	Ethanol - E85	-20	-41	-61	-81	-102
-	Change in Gasoline Volume	111	191	289	397	517
-	Change in Diesel Fuel Volume	-358	-956	-1,554	-2,152	-2,750
-	Change in Natural Gas Volume	9,219	-4,646	-9,735	-15,118	-20,945

Similar to the analysis conducted in Chapter 10.4.2.1.1, the change in gasoline and diesel volume for each year is used to estimate the change in petroleum demanded and its effect on both imported crude oil, domestic crude oil, and imported petroleum products. Table 10.4.4.2.1-2 summarizes the projected change in petroleum imports expected from the increased consumption of renewable biofuels relative to the 2025 Baseline.

Table 10.4.4.2.1-2: High Volume Scenario – Projected Change in Petroleum Imports Due to Increase in Renewable Fuel Consumption Relative to the 2025 Baseline (million gallons)

	2026	2027	2028	2029	2030
Change in Imported Gasoline	56	96	144	199	259
Change in Imported Diesel Fuel	-179	-478	-777	-1,076	-1,375
Total Change in Crude Oil	-128	-389	-642	-891	-1,134
Change in Domestic Crude Oil	-4	-13	-21	-30	-38
Change in Imported Crude Oil	-124	-376	-621	-861	-1,097

10.4.4.2.2 Cost Impacts

The component cost (production, distribution, blending retail) of each biofuel type compared to the fossil fuel it is displacing under the High Volume Scenario relative to the 2025 Baseline is summarized in Tables 10.4.4.2.2-1a and 1b.

Table 10.4.4.2.2-1a: High Volume Scenario – Renewable and Petroleum Fuel Costs Relative to the 2025 Baseline (million 2022$)

		Renewable Fuel			Petroleum Fuel		
		Production	Distribution	Blending	Production	Distribution	Total
2026	*Cellulosic Biofuel*						
	CNG - Landfill Biogas	-36	-117	0	40	140	26
	Corn Kernel Fiber Ethanol	86	13	40	-71	-9	60
	Non-cellulosic Advanced						
	Biodiesel - Soy	1,299	207	0	-843	-154	509
	Biodiesel - FOG	182	37	0	-158	-29	41
	Biodiesel - Corn Oil	207	39	0	-89	-16	59
	Biodiesel - Canola	136	22	0	0	0	53
	Renewable Diesel - Soy	-102	-15	0	62	11	-43
	Renewable Diesel - FOG	3,368	611	0	34	6	962
	Renewable Diesel - Corn	-48	-8	0	213	39	-16
	Renewable Diesel - Canola	-349	-51	0	0	0	-149
	Sugarcane Ethanol	-101	-16	31	56	7	-23
	Conventional						
	Ethanol - E10	-372	-86	173	306	38	59
	Ethanol - E15	32	15	-10	-26	-3	7
	Ethanol - E85	55	15	-3	-46	-6	16
2027	*Cellulosic Biofuel*						
	CNG - Landfill Biogas	18	59	0	-19	-70	-12
	Corn Kernel Fiber Ethanol	83	13	39	-68	-9	58
	Non-cellulosic Advanced						
	Biodiesel - Soy	1,176	207	0	-807	-154	422
	Biodiesel - FOG	165	37	0	-144	-28	31
	Biodiesel - Corn Oil	188	39	0	-152	-29	46
	Biodiesel - Canola	123	22	0	-85	-16	44
	Renewable Diesel - Soy	913	306	0	-582	-111	526
	Renewable Diesel - FOG	3,986	787	0	-3,146	-601	1,026
	Renewable Diesel - Corn	-44	-8	0	32	6	-13
	Renewable Diesel - Canola	83	77	0	-53	-10	97
	Sugarcane Ethanol	-101	-16	31	55	7	-23
	Conventional						
	Ethanol - E10	-689	-161	325	569	71	115
	Ethanol - E15	81	38	-26	-67	-8	18
	Ethanol - E85	109	31	-7	-90	-11	32
2028	*Cellulosic Biofuel*						
	CNG - Landfill Biogas	38	124	0	-39	-148	-24
	Corn Kernel Fiber Ethanol	80	12	38	-67	-8	55
	Non-cellulosic Advanced						
	Biodiesel - Soy	1,133	207	0	-777	-154	410
	Biodiesel - FOG	160	37	0	-139	-28	30
	Biodiesel - Corn Oil	181	39	0	-146	-29	45
	Biodiesel - Canola	119	22	0	-82	-16	43
	Renewable Diesel - Soy	1,856	306	0	-1,178	-234	750
	Renewable Diesel - FOG	4,728	964	0	-3,708	-736	1,248
	Renewable Diesel - Corn	-42	-8	0	31	6	-13
	Renewable Diesel - Canola	469	77	0	-298	-59	190
	Sugarcane Ethanol	-101	-16	31	55	7	-23
	Conventional						
	Ethanol - E10	-1,014	-240	484	851	106	186
	Ethanol - E15	99	47	-31	-83	-10	21
	Ethanol - E85	162	46	-10	-136	-17	45

Table 10.4.4.2.2-1b: High Volume Scenario – Renewable and Petroleum Fuel Costs Relative to the 2025 Baseline (million 2022$)

		Renewable Fuel			Petroleum Fuel		Total
		Production	Distribution	Blending	Production	Distribution	
2029	*Cellulosic Biofuel*						
	CNG - Landfill Biogas	59	193	0	-61	-229	-38
	Corn Kernel Fiber Ethanol	76	12	37	-65	-8	52
	Non-cellulosic Advanced						
	Biodiesel - Soy	1,087	207	0	-780	-154	360
	Biodiesel - FOG	153	37	0	-139	-28	24
	Biodiesel - Corn Oil	174	39	0	-147	-29	38
	Biodiesel - Canola	114	22	0	-82	-16	38
	Renewable Diesel - Soy	2,750	467	0	-1,802	-356	1,058
	Renewable Diesel - FOG	5,466	1,140	0	-4,403	-871	1,332
	Renewable Diesel - Corn	-41	-8	0	31	6	-12
	Renewable Diesel - Canola	834	142	0	-547	-108	321
	Sugarcane Ethanol	-101	-16	31	56	7	-23
	Conventional						
	Ethanol - E10	-1,378	-330	667	1,176	145	280
	Ethanol - E15	134	64	-43	-114	-14	27
	Ethanol - E85	213	62	-14	-182	-22	57
2030	*Cellulosic Biofuel*						
	CNG - Landfill Biogas	82	267	0	-85	-318	-54
	Corn Kernel Fiber Ethanol	72	12	36	-63	-8	48
	Non-cellulosic Advanced						
	Biodiesel - Soy	1,043	207	0	-783	-154	313
	Biodiesel - FOG	147	37	0	-140	-28	17
	Biodiesel - Corn Oil	167	39	0	-147	-29	30
	Biodiesel - Canola	110	22	0	-82	-16	33
	Renewable Diesel - Soy	3,562	627	0	-2,431	-479	1,279
	Renewable Diesel - FOG	6,101	1,316	0	-5,104	-1,006	1,307
	Renewable Diesel - Corn	-40	-8	0	31	6	-11
	Renewable Diesel - Canola	1,169	206	0	-798	-157	420
	Sugarcane Ethanol	-101	-16	31	56	7	-23
	Conventional						
	Ethanol - E10	-1,746	-428	864	1,532	188	410
	Ethanol - E15	168	83	-55	-147	-18	30
	Ethanol - E85	261	77	-17	-229	-28	64

The costs are aggregated for each fossil fuel type and shown as annual totals and per-gallon and per MSCF costs in Table 10.4.4.2.2-2.

Table 10.4.4.2.2-2: High Volume Scenario – Total Annual and Per-Gallon Costs Relative to 2025 Baseline (2022$)

Year	Fuel Type	Total Cost (million $)	Per-Unit Cost	Units
2026	Gasoline	119	0.09	¢/gal gasoline
	Diesel Fuel	1,415	2.70	¢/gal diesel
	Natural Gas	26	0.09	$/MSCF natural gas
	Total	1,560	0.85	¢/gal gasoline and diesel
2027	Gasoline	200	0.15	¢/gal gasoline
	Diesel Fuel	2,178	4.19	¢/gal diesel
	Natural Gas	-12	-0.04	$/MSCF natural gas
	Total	2,366	1.29	¢/gal gasoline and diesel
2028	Gasoline	285	0.22	¢/gal gasoline
	Diesel Fuel	2,703	5.23	¢/gal diesel
	Natural Gas	-24	-0.08	$/MSCF natural gas
	Total	2,964	1.61	¢/gal gasoline and diesel
2029	Gasoline	393	0.31	¢/gal gasoline
	Diesel Fuel	3,158	6.17	¢/gal diesel
	Natural Gas	-38	-0.13	$/MSCF natural gas
	Total	3,513	1.98	¢/gal gasoline and diesel
2030	Gasoline	530	0.43	¢/gal gasoline
	Diesel Fuel	3,388	6.68	¢/gal diesel
	Natural Gas	-54	-0.19	$/MSCF natural gas
	Total	3,864	2.21	¢/gal gasoline and diesel

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 March 2025) as an estimate of future RIN prices, as shown in Table 10.5.1-1.

Table 10.5.1-1: Average RIN Prices (April 2024 – March 2025)

RFS Standard	RIN Type	Average RIN Price	2025 Standard	Proposed 2026 Standard	Proposed 2027 Standard
Cellulosic Biofuel (D3)	D3	$3.01	0.70%[c]	0.87%	0.92%
Biomass-Based Diesel (D4)	D4	$0.61	3.15%	4.75%	5.07%
Other Advanced Biofuel[a] (D5)	D5	$0.61	0.46%	0.40%	0.41%
Conventional Renewable Fuel[b] (D6)	D6	$0.62	8.82%	10.00%	10.14%

[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 BBD 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] Reflects the proposed partial waiver of the 2025 cellulosic biofuel 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 2025–2027

Year	RIN Cost ($/Gallon)
2025	$0.10
2026	$0.12
2027	$0.12

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 1.6 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	$0.06
E15	$0.09
E85	$0.46
Biodiesel	$0.91
Renewable Diesel	$0.97

10.5.2 Estimated Fuel Price Impacts (Gasoline)

In this section, we estimate the fuel price impacts of the Proposed Volumes on gasoline relative to the No RFS and 2025 Baselines. First, we estimated the total cost of gasoline-ethanol blends for the Proposed Volumes. We began with the production cost for each fuel,[722] 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 and 2, we estimate that average gasoline costs range from $2.43 to $2.45 per gallon.

Table 10.5.2-1: Gasoline Costs – 2026

	E0	E10	E15	E85
Cost to Produce ($/gal)	$2.52	$2.41	$2.46	$2.30
RIN Cost ($/gal)	$0.12	$0.11	$0.10	$0.03
RIN Value ($/gal)	$0.00	-$0.06	-$0.09	-$0.46
Net Cost ($/gal)	$2.64	$2.45	$2.47	$1.87
Volume (mil gal)	1,936	132,991	917	464
Total Fuel Cost ($bil)	$5.1	$325.9	$2.3	$0.9
Average Cost ($/gal)	$2.45			

Table 10.5.2-2: Gasoline Costs – 2027

	E0	E10	E15	E85
Cost to Produce ($/gal)	$2.50	$2.39	$2.44	$2.28
RIN Cost ($/gal)	$0.12	$0.11	$0.10	$0.03
RIN Value ($/gal)	$0.00	-$0.06	-$0.09	-$0.46
Net Cost ($/gal)	$2.62	$2.43	$2.45	$1.86
Volume (mil gal)	1,929	131,219	1,102	505
Total Fuel Cost ($bil)	$5.1	$319.3	$2.7	$0.9
Average Cost ($/gal)	$2.43			

Next, we estimated the cost of gasoline-ethanol blends under the No RFS and 2025 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.[723] 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 10.5.2-3 and 4, we estimate that average gasoline costs under the No RFS Baseline range from $2.39 to $2.41 per gallon.

[722] 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).
[723] For purposes of the No RFS Baseline analysis, we assumed that E0 volumes were held constant relative to the Proposed Volumes 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 2.1.5-2 and dividing by 0.1.

Table 10.5.2-3: Gasoline Costs – 2026 (No RFS Baseline)

	E0	E10	E15	E85
Cost to Produce ($/gal)	$2.52	$2.41	$2.46	$2.30
Volume (mil gal)	1,936	134,100	0	211
Total Fuel Cost ($bil)	$4.9	$322.7	$0.0	$0.5
Average Cost ($/gal)	$2.41			

Table 10.5.2-4: Gasoline Costs – 2027 (No RFS Baseline)

	E0	E10	E15	E85
Cost to Produce ($/gal)	$2.50	$2.39	$2.44	$2.28
Volume (mil gal)	1,929	132,520	0	242
Total Fuel Cost ($bil)	$4.8	$316.1	$0.0	$0.6
Average Cost ($/gal)	$2.39			

For the 2025 Baseline, we used the same approach described above for No RFS Baseline.[724] As shown in Tables 10.5.2-5 and 6, we estimate that average gasoline costs under the 2025 Baseline range from $2.43 to $2.45 per gallon.

Table 10.5.2-5: Gasoline Costs – 2026 (2025 Baseline)

	E0	E10	E15	E85
Cost to Produce ($/gal)	$2.52	$2.41	$2.46	$2.30
RIN Cost ($/gal)	$0.12	$0.11	$0.10	$0.03
RIN Value ($/gal)	$0.00	-$0.06	-$0.09	-$0.46
Net Cost ($/gal)	$2.64	$2.45	$2.47	$1.87
Volume (mil gal)	1,941	134,888	801	423
Total Fuel Cost ($bil)	$5.1	$330.5	$2.0	$0.8
Average Cost ($/gal)	$2.45			

Table 10.5.2-6: Gasoline Costs – 2027 (2025 Baseline)

	E0	E10	E15	E85
Cost to Produce ($/gal)	$2.50	$2.39	$2.44	$2.28
RIN Cost ($/gal)	$0.12	$0.11	$0.10	$0.03
RIN Value ($/gal)	$0.00	-$0.06	-$0.09	-$0.46
Net Cost ($/gal)	$2.62	$2.43	$2.45	$1.86
Volume (mil gal)	1,941	134,888	801	423
Total Fuel Cost ($bil)	$5.1	$328.2	$2.0	$0.8
Average Cost ($/gal)	$2.43			

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 Proposed Volumes. As shown in Table 10.5.2-7, we estimate that the fuel price impacts on gasoline under the No RFS Baseline range from 4.4¢ to 4.7¢ per gallon. As shown in Table 10.5.2-8, we estimate that the fuel price impacts on gasoline under the 2025 Baseline are 0.0¢ per gallon.

[724] 2025 Baseline gasoline-ethanol blend volumes from Set 1 Rule RIA Table 6.5.2-3.

Table 10.5.2-7: Gasoline Fuel Price Impacts (No RFS Baseline)

	2026	2027
Average Cost (No RFS Baseline) ($/gal)	$2.41	$2.39
Average Cost (Proposed Volumes) ($/gal)	$2.45	$2.43
Fuel Price Impact (¢/gal)	4.4¢	4.7¢

Table 10.5.2-8: Gasoline Fuel Price Impacts (2025 Baseline)

	2026	2027
Average Cost (2025 Baseline) ($/gal)	$2.45	$2.43
Average Cost (Proposed Volumes) ($/gal)	$2.45	$2.43
Fuel Price Impact (¢/gal)	0.0¢	0.0¢

10.5.3 Estimated Fuel Price Impacts (Diesel)

In this section, we estimate the fuel price impacts of the Proposed Volumes on diesel relative to the No RFS and 2025 Baselines. First, we estimated the total cost of diesel, biodiesel, and renewable diesel for the Proposed Volumes. We began with the production cost for each fuel,[725] 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 and 2, we estimate that average diesel costs range from $3.32 to $3.41 per gallon.

Table 10.5.3-1: Diesel Costs – 2026

		Biodiesel			Renewable Diesel		
	Diesel	Corn	FOG	Soybean/ Canola	Corn	FOG	Soybean/ Canola
Cost to Produce ($/gal)	$3.31	$4.19	$3.93	$4.80	$4.57	$4.32	$5.18
RIN Cost ($/gal)	$0.12	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RIN Value ($/gal)	$0.00	-$0.91	-$0.91	-$0.91	-$0.97	-$0.97	-$0.97
Tax Credit ($/gal)	$0.00	-$0.70	-$0.59	-$0.20	-$0.73	-$0.62	-$0.15
Net Cost ($/gal)	$3.43	$2.58	$2.43	$3.69	$2.87	$2.73	$4.06
Volume (mil gal)	50,490	208	366	1,542	681	2,188	1,910
Total Fuel Cost ($bil)	$173.1	$0.5	$0.9	$5.7	$2.0	$6.0	$7.8
Total Cost ($/gal)	$3.41						

[725] 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 – 2027

	Diesel	Biodiesel Corn	Biodiesel FOG	Biodiesel Soybean/ Canola	Renewable Diesel Corn	Renewable Diesel FOG	Renewable Diesel Soybean/ Canola
Cost to Produce ($/gal)	$3.19	$4.19	$3.93	$4.80	$4.57	$4.32	$5.18
RIN Cost ($/gal)	$0.12	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RIN Value ($/gal)	$0.00	-$0.91	-$0.91	-$0.91	-$0.97	-$0.97	-$0.97
Tax Credit ($/gal)	$0.00	-$0.70	-$0.59	-$0.20	-$0.73	-$0.62	-$0.15
Net Cost ($/gal)	$3.31	$2.58	$2.43	$3.69	$2.87	$2.73	$4.06
Volume (mil gal)	49,746	208	366	1,571	681	2,238	2,160
Total Fuel Cost ($bil)	$164.8	$0.5	$0.9	$5.8	$2.0	$6.1	$8.8
Total Cost ($/gal)	$3.32						

Next, we estimated the total cost of diesel under the No RFS and 2025 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.[726] 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 10.5.3-3 and 4, we estimate that average diesel costs under the No RFS Baseline range from $3.21 to $3.32 per gallon.

Table 10.5.3-3: Diesel Costs – 2026 (No RFS Baseline)

	Diesel	Biodiesel Corn	Biodiesel FOG	Biodiesel Soybean/ Canola	Renewable Diesel Corn	Renewable Diesel FOG	Renewable Diesel Soybean/ Canola
Cost to Produce ($/gal)	$3.31	$4.19	$3.93	$4.80	$4.57	$4.32	$5.18
Tax Credit ($/gal)	$0.00	-$0.70	-$0.59	-$0.20	-$0.73	-$0.62	-$0.15
Net Cost ($/gal)	$3.31	$3.49	$3.34	$4.60	$3.84	$3.70	$5.03
Volume (mil gal)	55,043	90	391	108	198	1,288	0
Total Fuel Cost ($bil)	$182.2	$0.3	$1.3	$0.5	$0.8	$4.8	$0.0
Total Cost ($/gal)	$3.32						

[726] 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 Proposed Volumes to calculate petroleum diesel fuel volumes.

Table 10.5.3-4: Diesel Costs – 2027 (No RFS Baseline)

		Biodiesel			Renewable Diesel		
	Diesel	Corn	FOG	Soybean/ Canola	Corn	FOG	Soybean/ Canola
Cost to Produce ($/gal)	$3.19	$4.19	$3.93	$4.80	$4.57	$4.32	$5.18
Tax Credit ($/gal)	$0.00	-$0.70	-$0.59	-$0.20	-$0.73	-$0.62	-$0.15
Net Cost ($/gal)	$3.19	$3.49	$3.34	$4.60	$3.84	$3.70	$5.03
Volume (mil gal)	54,521	67	394	118	233	1,360	0
Total Fuel Cost ($bil)	$173.9	$0.2	$1.3	$0.5	$0.9	$5.0	$0.0
Total Cost ($/gal)	$3.21						

For the 2025 Baseline, we used the same approach described above for the No RFS Baseline.[727] As shown in Tables 10.5.3-5 and 6, we estimate that average diesel costs under the 2025 Baseline range from $3.32 to $3.42 per gallon.

Table 10.5.3-5: Diesel Costs – 2026 (2025 Baseline)

		Biodiesel			Renewable Diesel		
	Diesel	Corn	FOG	Soybean/ Canola	Corn	FOG	Soybean/ Canola
Cost to Produce ($/gal)	$3.31	$4.19	$3.93	$4.80	$4.57	$4.32	$5.18
RIN Cost ($/gal)	$0.12	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RIN Value ($/gal)	$0.00	-$0.91	-$0.91	-$0.91	-$0.97	-$0.97	-$0.97
Tax Credit ($/gal)	$0.00	-$0.70	-$0.59	-$0.20	-$0.73	-$0.62	-$0.15
Net Cost ($/gal)	$3.43	$2.58	$2.43	$3.69	$2.87	$2.73	$4.06
Volume (mil gal)	53,244	63	285	1,276	289	1,291	1,248
Total Blend Cost ($bil)	$182.6	$0.2	$0.7	$4.7	$0.8	$3.5	$5.1
Average Cost ($/gal)	$3.42						

Table 10.5.3-6: Diesel Costs – 2027 (2025 Baseline)

		Biodiesel			Renewable Diesel		
	Diesel	Corn	FOG	Soybean/ Canola	Corn	FOG	Soybean/ Canola
Cost to Produce ($/gal)	$3.19	$4.19	$3.93	$4.80	$4.57	$4.32	$5.18
RIN Cost ($/gal)	$0.12	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RIN Value ($/gal)	$0.00	-$0.91	-$0.91	-$0.91	-$0.97	-$0.97	-$0.97
Tax Credit ($/gal)	$0.00	-$0.70	-$0.59	-$0.20	-$0.73	-$0.62	-$0.15
Net Cost ($/gal)	$3.31	$2.58	$2.43	$3.69	$2.87	$2.73	$4.06
Volume (mil gal)	53,244	63	285	1,276	289	1,291	1,248
Total Blend Cost ($bil)	$176.4	$0.2	$0.7	$4.7	$0.8	$3.5	$5.1
Average Cost ($/gal)	$3.32						

[727] 2025 Baseline biodiesel and renewable diesel volumes from Table 2.2-2. For purposes of the 2025 Baseline analysis, we assumed that total diesel energy demand was held constant relative to the Proposed Volumes to calculate petroleum diesel fuel volumes.

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 Proposed Volumes. As shown in Table 10.5.3-7, we estimate that the fuel price impacts on diesel under the No RFS Baseline range from 9.1¢ to 10.6¢ per gallon. As shown in Table 10.5.3-8, we estimate that the fuel price impacts on diesel under the 2025 Baseline range from -1.0¢ to -0.2¢ per gallon.

Table 10.5.3-7: Diesel Fuel Price Impacts (No RFS Baseline)

	2026	2027
Average Cost (No RFS Baseline) ($/gal)	$3.32	$3.21
Average Cost (Proposed Volumes) ($/gal)	$3.41	$3.32
Fuel Price Impact (¢/gal)	9.1¢	10.6¢

Table 10.5.3-8: Diesel Fuel Price Impacts (2025 Baseline)

	2026	2027
Average Cost (2025 Baseline) ($/gal)	$3.42	$3.32
Average Cost (Proposed Volumes) ($/gal)	$3.41	$3.32
Fuel Price Impact (¢/gal)	-1.0¢	-0.2¢

10.5.4 Cost to Transport Goods

In this chapter, we consider the impact of the use of renewable fuels on the cost to transport goods. Since most goods being transported utilize diesel fuel powered trucks (as opposed to gasoline or natural gas vehicles), we focus on the impacts on diesel fuel prices. Reviewing the price estimates in Table 10.5.3-7, the projected price increase for diesel fuel relative to the No RFS Baseline ranged from 9.1¢ per gallon in 2026 to 10.6¢ per gallon in 2027. As a worst-case scenario, we will use the projected diesel fuel price increase of 10.6¢ 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.[728] 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 $3.31/gal in 2026 as summarized in Table 10.2.2.1-2 and adding 60¢ per gallon state and federal taxes to it, the projected 10.6¢ per gallon increase in diesel fuel price in 2027 amounts to a 2.7% increase in diesel fuel prices. Applying the 25% ratio from the USDA study would indicate that the 2026 Proposed 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.[729] 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

[728] USDA, "How Transportation Costs Affect Fresh Fruit and Vegetable Prices," *Economic Research Report* 160, November 2013. https://ers.usda.gov/sites/default/files/_laserfiche/publications/45165/41077_err160.pdf.
Coupons.com, "Comparing Prices on Groceries," May 4, 2021.

type estimate since impacts on food prices vary greatly depending on the distance that the particular food travels by truck.

Relative to the 2025 Baseline, the impact of the Proposed Volumes is expected to cause a small decrease in diesel fuel prices, thus slightly decreasing the cost to transport goods.

10.6 Comparison of Societal Benefits and Costs

In this section, we summarize the projected societal benefits and costs of the three cases we analyzed (the Proposed Volumes, the Low Volume Scenario, and the High Volume Scenario). Table 10.6-1 summarizes only the projected societal benefits and costs of this rule. It does not, for example, include the projected rural economic development impacts of the three cases, as many of these impacts represent transfers (e.g., higher food prices paid by consumers to agricultural producers). The economic impact methodologies used in Chapter 9 do not identify incremental societal benefits and costs, so the results are not suitable for a societal benefit-cost comparison. Certain incremental benefits and costs are discussed qualitatively in other chapters but not monetized, so they are not presented here. For a full discussion of the impacts of each of these scenarios, including impacts that are not considered societal benefits or costs, see the relevant chapters of this document.

We note that the societal benefits and costs of the Proposed Volumes are greater in magnitude than the Low and High Volume Scenarios. This difference is primarily due to the fact that only the Proposed Volumes consider the impact of the proposed import RIN reduction. We project that the Proposed Volumes would result in a greater volume of renewable fuel supplied in 2026 and 2027 than either the Low or High Volume Scenario.[730] Further, because the Proposed Volumes only cover 2026–2027 while the Low and High Volume Scenarios cover 2026–2030, it can be difficult to compare the annualized societal benefits and costs between the cases. To better enable this comparison, we have only included the projected benefits and costs for 2026 and 2027 in Table 10.6-1. For further discussion of the societal benefits and costs of each case, see Chapters 6.4 and 10.4.

[730] See Chapters 3.1 and 3.2 for more detail on the volumes of renewable fuel by type we project would be supplied for each case.

Table 10.6-1: Net Benefits of the Proposed Volumes and Volume Scenarios in 2026 and 2027 (million 2022$)[a]

Type	Category	2026	2027	Present Value	Annualized Value
Proposed Volumes					
Societal Benefits	Energy Security Benefits	$196	$210	$387	$202
Societal Costs	Fuel Costs	$7,494	$5,936	$12,871	$6,726
Net Benefits	Total	-$7,297	-$5,726	-$12,484	-$6,524
Low Volume Scenario					
Societal Benefits	Energy Security Benefits	$138	$150	$275	$144
Societal Costs	Fuel Costs	$5,068	$4,477	$9,140	$4,777
Net Benefits	Total	-$4,930	-$4,327	-$8,862	-$4,633
High Volume Scenario					
Societal Benefits	Energy Security Benefits	$151	$176	$312	$163
Societal Costs	Fuel Costs	$5,653	$5,683	$10,845	$5,668
Net Benefits	Total	-$5,502	-$5,507	-$10,533	-$5,505

[a] Present and annualized values are estimated using a 3% discount rate. Computing annualized costs and benefits from present values spreads the costs and benefits equally over each period, taking account of the discount rate. The annualized value equals the present value divided by the sum of discount factors. For a calculation of present and annualized values from annual impact estimates, see "Set 2 NPRM Costs and Benefits Summary," available in the docket for this action.

Chapter 11: Regulatory Flexibility Act Screening Analysis

This chapter discusses EPA's screening analysis evaluating the potential impacts of the 2026 and 2027 RFS standards 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.

11.1 Summary

We conducted the screening analyses by looking at the potential impacts on small entities using two different methods and compared the cost-to-sales ratio for each method to a threshold of 1%.[731] For our first method, 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 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.[732]

For our second method, we estimated the cost-to-sales ratios for each small refiner that is an obligated party under the RFS program using refinery-specific data under the worst-case assumption that they could not recover RIN costs. While as noted above we have determined that small refiners fully recover their RIN costs, we have nevertheless included this hypothetical scenario in this analysis to respond to prior concerns from small refiners that they could not recover their RIN costs. Moreover, this method seems more relevant to addressing small refiner-specific concerns. This method emphasizes that even erroneously assuming no RIN cost recovery by small refiners as suggested by some parties, a No SISNOSE finding would still be appropriate.

As shown in Table 11.1-1, both methods result in a cost-to-sales ratio of less than 1%. Therefore, EPA finds that these standards would not have a significant economic impact on a substantial number of small entities.

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[731] A cost-to-sales ratio of 1% represents a typical agency threshold for determining the significance of the economic impact on small entities. EPA, "Final Guidance for EPA Rulewriters: Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act," November 2006. https://www.epa.gov/sites/default/files/2015-06/documents/guidance-regflexact.pdf.
[732] For a further discussion of the ability of obligated parties to recover the cost of RINs, see EPA, "Denial of Petitions for Rulemaking to Change the RFS Point of Obligation," EPA-420-R-17-008, November 2017. https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100TBGV.pdf.

Table 11.1-1: Estimated Cost-to-Sales Ratios of the Proposed 2026 and 2027 RFS Standards

Method	Screening Analysis	Cost-to-Sales Ratio	
		2026	2027
1	Cost as Part of RFS2 Rule	N/A	
2	Market Cost Recovery	0.00%	
3	Full RIN Price as Cost for Small Refiners	0.10–0.55%	0.11–0.67%

11.2 Background

11.2.1 Overview of the Regulatory Flexibility Act (RFA)

The RFA was amended by SBREFA to ensure that concerns regarding small entities are adequately considered during the development of new regulations that affect those entities. The RFA requires EPA to carefully consider the economic impacts that its 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.

11.2.2 Need for the Rulemaking and Rulemaking Objectives

A discussion on the need for and objectives of this action is located in Preamble Section I. CAA section 211(o) requires EPA to promulgate regulations implementing the RFS program, and to establish annual renewable fuel standards that are used by obligated parties to determine their individual RVOs.

11.2.3 Definition and Description of Small Entities

Small entities include small businesses, small organizations, and small governmental jurisdictions. For the purposes of assessing the impacts of a rule on small entities, a small entity is defined as: (1) a small business according to the Small Business Administration's (SBA) size standards; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; or (3) a small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field.

Small businesses (as well as large businesses) would be regulated by this rule, but not small governmental jurisdictions or small organizations as described above. As set by SBA, the categories of small entities that would potentially be directly affected by this rulemaking are described in Table 11.2.3-1. Other entities may be indirectly affected by this rulemaking but are not considered in this screening analysis.[733]

[733] For example, small farms might benefit (see Chapter 9.1.6) whereas small entities in other industries might be adversely affected by commodity and food price increases (see Chapters 9.3 and 9.4) or the increased price to transport goods (see Chapter 10.5.4).

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] Under the RFS program, EPA has included 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. 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 2024 EIA refinery data,[734] EPA believes that there are approximately 35–40 refiners of gasoline and diesel subject to the RFS regulations. Of these, EPA believes that there are currently 6 refiners (owning 7 refineries) producing gasoline and/or diesel that meet the small entity definition of having 1,500 employees or fewer.

11.2.4 Reporting, Recordkeeping, and Other Compliance Requirements

Registration, reporting, and recordkeeping are necessary to track compliance with the RFS standards and transactions involving RINs. However, these requirements are already in place under the existing RFS regulations.[735] While EPA is making revisions to the RFS requirements in this action, we do not anticipate that there will be any significant cost on directly regulated small entities.

11.3 Screening Analysis Approaches

This section concerns EPA's screening analyses performed for the 2026 and 2027 RFS standards. For the purposes of this screening analysis, we estimated the costs of the 2026 and 2027 RFS standards relative to a "baseline" of the 2025 RFS standards (i.e., the percentage standards established in the Set 1 Rule for 2025).

We considered two different methods for estimating the cost of the 2026 and 2027 RFS standards to obligated parties using the baseline of the 2025 RFS standards. If, as has been demonstrated, obligated parties recover the costs of RFS compliance through higher prices in the marketplace for the petroleum products they sell, there is no net cost to obligated parties.

[734] EIA, "Refinery Capacity Report 2024," *Petroleum & Other Liquids*, January 1, 2024. https://www.eia.gov/petroleum/refinerycapacity/archive/2024/refcap2024.php.
[735] 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 Rule docket (Docket ID No. EPA-HQ-OAR-2005-0161).

However, because various parties, including several small refiners, have continued to claim that they are not able to recover the cost of RFS compliance in the marketplace, we also estimated the cost-to-sales ratios for each of the 6 small refiners that are obligated parties under the RFS program using refinery-specific data under the assumption that they could not recover RIN costs.

11.3.1 Method 1: Market Cost Recover Method

One way, and we believe the most appropriate way to consider the impacts of the 2026 and 2027 RFS standards on obligated parties, is to compare their cost of compliance with the ability of 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.[736] 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.[737] 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 parties, including small refiners. This is true whether obligated parties acquire RINs by purchasing renewable fuels with attached RINs or by purchasing separated RINs.

11.3.2 Method 2: Full RIN Price as Cost for Small Refiners Method

For our extreme hypothetical case, we estimated the actual change in the total cost of the 2026 and 2027 RFS standards to the 6 obligated parties that are small refiners if they acquired the RINs necessary for compliance by purchasing separated RINs. We note, however, that in doing so we ignored the fact that these parties recover the cost of the RINs they purchase through the higher market-wide prices they receive for the petroleum-based gasoline and diesel that they sell, as discussed in Method 1. This approach would then reflect the cost they would have to pay for compliance at the end of the year if they had spent the added revenue received from the higher gasoline and diesel prices for other purposes.

Furthermore, we have also assumed that these parties would be complying with the upper-bound estimate of the 2026 and 2027 RFS standards. As described in Preamble Section VI.C, this estimate assumes that all eligible small refineries—including the 6 obligated parties that are small refiners—receive a small refinery exemption (SRE) and would not have to comply with the 2026 and 2027 RFS standards. Thus, this estimate represents a worst-case scenario for these parties in which EPA establishes higher percentage standards based on a projection that all small refineries will receive an exemption, but they do not receive an exemption and have to comply with their 2026 and 2027 RFS obligations.

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[736] For a further discussion of the ability of obligated parties to recover the cost of RINs, see EPA, "Denial of Petitions for Rulemaking to Change the RFS Point of Obligation," EPA-420-R-17-008, November 2017. https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100TBGV.pdf.

[737] Id.

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.), EPA is 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 March 2025) as an estimate of future RIN prices, as shown in Table 11.3.2-1.

Table 11.3.3-1: Average RIN Prices and RFS Standards for 2026 and 2027

RFS Standard	RIN Type	Avg RIN Price (April 2024 – March 2025)	2025 RFS Standard	2026 Standard	2026 Δ[a]	2027 Standard	2027 Δ[a]
Cellulosic Biofuel	D3	$3.01	0.70%[d]	0.87%	0.17%	0.92%	0.22%
Biomass-Based Diesel	D4	$0.61	3.15%	4.75%	1.60%	5.07%	1.92%
Other Advanced Biofuel[b]	D5	$0.61	0.46%	0.40%	-0.06%	0.41%	-0.05%
Conventional Renewable Fuel[c]	D6	$0.62	8.82%	10.00%	1.18%	10.14%	1.32%

[a] Δ represents the change relative to the baseline of the 2025 RFS standards.
[b] 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.
[c] 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.
[d] Reflects the proposed partial waiver of the 2025 cellulosic biofuel standard.

Using 2023 compliance data and SRE petition materials where available, and assuming that the total gasoline and diesel production for each of these small refiners remains unchanged, we estimated their RVOs for 2026 and 2027. The difference between the estimated RVOs for each year multiplied by the estimated RIN price for each standard then gives us the estimated cost of the 2026 and 2027 RFS standards for each small refiner that chooses to meet their obligations by purchasing separated RINs. The actual calculations for each small refiner are provided in Chapter 11.6; a non-CBI example of these calculations is shown in Tables 11.3.3-2 and 3.

Table 11.3.3-2: Example Small Refiner Costs Calculation for 2026

Company	Gas/ Diesel Prod (mil gal)	Cellulosic (D3) Δ (mil RINs)	Cellulosic (D3) Cost ($mil)	BBD (D4) Δ (mil RINs)	BBD (D4) Cost ($mil)	Other Advanced Biofuel (D5) Δ (mil RINs)	Other Advanced Biofuel (D5) Cost ($mil)	Conventional Renewable Fuel (D6) Δ (mil RINs)	Conventional Renewable Fuel (D6) Cost ($mil)	Total Cost ($mil)
Example	100	0.17	$0.51	1.60	$0.97	-0.06	-$0.04	1.18	$0.73	$2.17

Table 11.3.3-3: Example Small Refiner Costs Calculation for 2027

Company	Gas/ Diesel Prod (mil gal)	Cellulosic (D3)		BBD (D4)		Other Advanced Biofuel (D5)		Conventional Renewable Fuel (D6)		Total Cost ($mil)
		Δ (mil RINs)	Cost ($mil)	Δ (mil RINs)	Cost ($mil)	Δ (mil RINs)	Cost ($mil)	Δ (mil RINs)	Cost ($mil)	
Example	100	0.22	$0.66	1.92	$1.16	-0.05	-$0.03	1.32	$0.81	$2.61

11.4 Cost-to-Sales Ratio Result

The final step in our methodology is to compare the total estimated costs from each of the methods above to relevant total estimated revenue from the sales of gasoline and diesel in the U.S. in 2026 and 2027. 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.

For Method 1, all obligated parties—including small refiners—recover their RFS compliance costs and thus they have no net cost of compliance. For Method 2, we divided the estimated costs for each small refiner by its total estimated annual sales.[738] The resulting cost-to-sales ratios for each method are shown in Table 11.4-1, along with a non-CBI example of these calculations for Method 2 using the data from Tables 11.3.3-2 through 4.

Table 11.4-1: Estimated Cost-to-Sales Ratios of the 2026 and 2027 RFS Standards

Method	Screening Analysis	Total Cost ($mil)		Total Sale ($mil)		Cost-to-Sales Ratio	
		2026	2027	2026	2027	2026	2027
1	Market Cost Recovery	$0		n/a		0.0%	
2	Full RIN Price as Cost for Small Refiners (Actual)[a]	--		--		0.10–0.55%	0.11–0.67%
	Full RIN Price as Cost for Small Refiners (Example)	$2.17	$2.34	$500	$500	0.43%	0.52%

[a] The actual calculations for Method 2 for each small refiner are provided in Chapter 11.6.

11.5 Conclusion

Based on our outreach, fact-finding, and analysis of the potential impacts of this rule on small businesses, we have concluded that this rule would not have a significant economic impact on a substantial number of small entities. As described in Method 1, since obligated parties have been shown to recover their RFS compliance costs through the resulting higher market prices for their petroleum products, there is no net cost to small refiners resulting from the RFS program.

However, as described in Method 2, we also conducted a worst-case sensitivity analysis that ignored the fact that obligated parties recover their costs. Under this extreme assumption, we were able to estimate the costs of this rule on small refiners and then use a cost-to-sales ratio test

[738] Estimated annual sales data gathered from SRE petition materials.

(a ratio of the estimated annualized compliance costs to the value of sales per company) to assess whether the costs were significant. Under this method, the cost-to-sales analyses indicated that the 6 small refiners would be affected at less than 1% of their sales (i.e., the estimated costs of compliance with the rule would be less than 1% of their sales). The cost-to-sales percentages estimated using Method 2 ranged from 0.10% to 0.67%.

11.6 Small Refiner CBI Data

[Information Redacted – Claimed as CBI]