ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 63, 80, and 1090

[EPA–HQ–OAR–2024–0505; FRL–11947–02–OAR]

RIN 2060–AW23

Renewable Fuel Standard (RFS) Program: Standards for 2026 and 2027, Partial Waiver of 2025 Cellulosic Biofuel Volume Requirement, and Other Changes

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: Under the Clean Air Act (CAA), the U.S. Environmental Protection Agency (EPA) is required to determine the applicable volume requirements for the Renewable Fuel Standard (RFS) for years after those specified in the statute. The EPA is establishing the applicable volumes and percentage standards for 2026 and 2027 for cellulosic biofuel, biomass-based diesel (BBD), advanced biofuel, and total renewable fuel. The EPA is also partially waiving the 2025 cellulosic biofuel volume requirement and revising the associated percentage standard due to a shortfall in cellulosic biofuel production. Finally, the EPA is promulgating several regulatory changes to the RFS program, including removing renewable electricity as a qualifying renewable fuel under the RFS program (eRINs) and making minor revisions to the biogas provisions of the RFS program.

DATES: This rule is effective on June 15, 2026, except for amendatory instruction 47, which is effective on April 28, 2026, and amendatory instruction 17, which is effective on January 1, 2027. The incorporation by reference of certain publications listed in this regulation is approved by the Director of the Federal Register as of June 15, 2026.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2024–0505. All documents in the docket are listed on the *https://www.regulations.gov* website. Although listed in the index, some information is not publicly available, *e.g.,* confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material is not available on the internet and will be publicly available only in hard copy form. Publicly available docket materials are available electronically through *https://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: For information about this final rule, contact Dallas Burkholder, Assessment and Standards Division, Office of Transportation and Air Quality, Environmental Protection Agency, 2000 Traverwood Drive, Ann Arbor, MI 48105; telephone number: 734–214–4766; email address: *RFS-Rulemakings@epa.gov.*

SUPPLEMENTARY INFORMATION:

Does this action apply to me?

Entities potentially affected by this action are those involved with the production, distribution, and sale of transportation fuels (*e.g.,* gasoline and diesel fuel) and renewable fuels (*e.g.,* ethanol, biodiesel, renewable diesel, and biogas). Potentially affected categories include:

Category	NAICS [a] codes	Examples of potentially affected entities
Industry	111110	Soybean farming.
Industry	111150	Corn farming.
Industry	112111	Cattle farming or ranching.
Industry	112210	Swine, hog, and pig farming.
Industry	211130	Natural gas liquids extraction and fractionation.
Industry	221210	Natural gas production and distribution.
Industry	324110	Petroleum refineries (including importers).
Industry	325120	Biogases, industrial (*i.e.,* compressed, liquefied, solid), manufacturing.
Industry	325193	Ethyl alcohol manufacturing.
Industry	325199	Other basic organic chemical manufacturing.
Industry	424690	Chemical and allied products merchant wholesalers.
Industry	424710	Petroleum bulk stations and terminals.
Industry	424720	Petroleum and petroleum products wholesalers.
Industry	457210	Fuel dealers.
Industry	562212	Landfills.

[a] North American Industry Classification System (NAICS).

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities potentially affected by this action. This table lists the types of entities that the EPA is now aware could potentially be affected by this action. Other types of entities not listed in the table could also be affected. To determine whether your entity would be affected by this action, you should carefully examine the applicability criteria in 40 CFR parts 80 and 1090. If you have any questions regarding the applicability of this action to a particular entity, consult the person listed in the **FOR FURTHER INFORMATION CONTACT** section.

Preamble Acronyms and Abbreviations

Throughout this document the use of "we," "us," or "our" is intended to refer to the EPA. We use multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

AEO Annual Energy Outlook
AFDC Alternative Fuels Data Center
ATJ alcohol-to-jet
BBD biomass-based diesel
CAA Clean Air Act
CKF corn kernel fiber
CNG compressed natural gas
CO_2e carbon dioxide equivalent
CWC cellulosic waiver credit
DOE U.S. Department of Energy
EIA U.S. Energy Information Administration
EMTS EPA Moderated Transaction System
EPA U.S. Environmental Protection Agency
EU European Union
FOG fats, oils, and greases
GCAM Global Change Analysis Model
gCO_2e/MJ grams of carbon dioxide equivalent per megajoule
GHG greenhouse gas
GLOBIOM Global Biosphere Management Model
GREET Greenhouse gases, Regulated Emissions, and Energy use in Technologies
GTAP–BIO Global Trade Analysis Project-Biofuels
LCFS Low Carbon Fuel Standard
LNG liquefied natural gas
MSW municipal solid waste

OBBB One Big Beautiful Bill Act of 2025
OPEC Organization of Petroleum Exporting Countries
PTD product transfer document
RFS Renewable Fuel Standard
RIA Regulatory Impact Analysis
RIN Renewable Identification Number
RNG renewable natural gas
RVO Renewable Volume Obligation
STP standard temperature and pressure
UCO used cooking oil
USDA U.S. Department of Agriculture

Outline of This Preamble

I. Executive Summary

The EPA initiated the RFS program in 2006 pursuant to the requirements of the Energy Policy Act of 2005 (EPAct), codified in CAA section 211(o). Congress subsequently amended the statutory requirements in the Energy Independence and Security Act of 2007 (EISA). The RFS provisions of the CAA set forth annual, nationally applicable volume targets for three of the four categories of renewable fuel (cellulosic biofuel, advanced biofuel, and total renewable fuel) through 2022 and for BBD through 2012. For subsequent calendar years, CAA section 211(o)(2)(B)(ii) directs the EPA to determine the applicable volume targets for each of the four categories of renewable fuel in coordination with the Secretary of Energy and the Secretary of Agriculture, based on a review of the implementation of the RFS program to date and an analysis of specified statutory factors.

In this final rule, we are establishing the volume targets and applicable percentage standards for cellulosic biofuel, BBD, advanced biofuel, and total renewable fuel for 2026 and 2027.[1] We are also promulgating a number of important regulatory changes, including removing renewable electricity as a qualifying renewable fuel under the RFS program (commonly referred to as ''eRINs''). This preamble describes our rationale for the final volume requirements and regulatory changes and how public comments informed the rulemaking process.

In June 2025, the EPA issued a proposed rule that included volume requirements for 2026 and 2027,[2] as well as regulatory changes, including proposals to reduce the number of Renewable Identification Numbers (RINs) generated for imported renewable fuel and renewable fuel produced from foreign feedstocks and to remove renewable electricity as a qualifying renewable fuel under the RFS program.[3] In September 2025, the EPA issued a supplemental notice of proposed rulemaking to address recently granted small refinery exemption (SRE) petitions for the 2023–2025 compliance years.[4] Subsequent to each proposal, the EPA held a public hearing and provided an opportunity for stakeholders to submit written comments. Stakeholders from various industries and perspectives provided the EPA with comments, data, and updated analyses on the Set 2 proposals, and we appreciate stakeholders' input and interest in strengthening the implementation of the RFS program. We also engaged directly with stakeholders throughout the rulemaking process and have documented those discussions.

This final rule reflects decisions made after review of public input, coordination with the U.S. Department of Agriculture (USDA) and Department of Energy (DOE), and extensive technical analysis. Wherever possible, we used the most recent data available to inform our analyses and support the final decisions and approaches described in this preamble and

[1] The 2023–2025 volume requirements and applicable percentage standards were established on July 12, 2023 (88 FR 44468) (the ''Set 1 Rule'').

[2] 90 FR 25784 (June 17, 2025) (the ''Set 2 proposal'').

[3] Throughout this section we refer to imported renewable fuel and renewable fuel produced from foreign feedstocks collectively as ''import-based renewable fuel'' and RINs generated for these types of renewable fuel as ''import RINs.''

[4] 90 FR 45007 (September 18, 2025) (the ''Set 2 supplemental proposal''). Collectively, the two proposals are referred to as the ''Set 2 proposals.''

supporting documentation. Where appropriate, in this final rule preamble, we highlight key stakeholder comments and provide a summary of our response to those comments. Detailed responses to stakeholder comments can be found in the Response to Comments (''RTC'') document for this action.[5]

In the Set 2 proposal, we proposed a significant modification to how import-based renewable fuel would be treated under the RFS program. We proposed these changes to better align the RFS program with American economic interests by strengthening support for domestic growers and biofuel producers. The Set 2 proposal did this by proposing a new ''import RIN reduction'' (IRR) policy. Stakeholders provided a significant number of comments and data on the proposed IRR provisions, and we appreciate the information and analyses that were submitted or shared directly with the Agency during stakeholder meetings. Following careful review of this information, we have concluded that more time would be needed to successfully establish and implement IRR provisions. Therefore, we are not finalizing the proposed IRR provisions as part of this final rule in connection with the renewable fuel volume requirements for 2026 and 2027. We intend, however, to establish IRR provisions that will take effect beginning in the 2028 compliance year or shortly thereafter. We discuss IRR considerations and our intent for future action further in section I.C of this preamble.

The volume requirements finalized in this action will strengthen the RFS program, boost renewable fuel use, and provide strong support to the domestic feedstock producers, renewable fuel producers, and agricultural communities across the country. The final volume requirements further these objectives, even though the IRR provisions will follow at a later date. Ensuring a growing supply of domestically produced renewable fuels is a key component in meeting the statutory goals of increasing the energy independence and security of the United States. Increasing domestic production of renewable fuel also contributes to unleashing American energy production towards the goal of achieving energy dominance, consistent with the Administration's ''Unleashing American Energy'' Executive Order[6] and the energy dominance pillar of the EPA's ''Powering the Great American Comeback'' initiative.[7] The requirements in this action are responsive to input from key agricultural and energy stakeholders on ways to bolster the RFS program.

A. Summary of the Key Provisions of This Action

1. Volume Requirements for 2026 and 2027

Based on our analysis of the factors required in the statute, and in coordination with USDA and DOE, we are establishing the volume requirements for 2026 and 2027, as shown in Table I.A.1–1. The final volumes represent significant increases of over 15 percent from those established for 2023–2025. Much of the increase in the volume requirements in this final rule are attributable to the EPA's decision not to finalize the proposed IRR provisions in this action. The total quantity of renewable fuel we project will be supplied to the U.S. to meet these volume requirements (shown in Table I.A.1–2) are very similar to the quantities we projected would be supplied to meet the proposed volume requirements.[8] We note that the volume requirements in Table I.A.1–1 do not include the SRE reallocation volumes we are also finalizing in this action (see section I.A.2 of this preamble).

Table I.A.1-1: Volume Requirements for 2023–2027

RFS Standard	Units	Volume Requirement Established in Set 1 Rule			Volume Requirement Established in This Action	
		2023	2024	2025	2026	2027
Cellulosic biofuel	billion RINs	0.84	1.01[a]	1.21[b]	1.36	1.43
Biomass-based diesel	billion gallons	2.82	3.04	3.35	5.40	5.70
	billion RINs	4.51	4.86	5.36	8.86	8.95
Advanced biofuel	billion RINs	5.94	6.54	7.33	10.82	10.98
Total renewable fuel	billion RINs	20.94[c]	21.54	22.33	25.82	25.98

Note: One RIN is equivalent to one ethanol-equivalent gallon of renewable fuel. Throughout this preamble, RINs are generally used to describe total volumes in each of the four renewable fuel categories, while gallons are generally used to describe volumes for individual types of biofuel (*e.g.*, ethanol, biodiesel, renewable diesel, etc.).

[a] The 2024 cellulosic biofuel volume requirement was originally established as 1.09 billion RINs in the Set 1 Rule. We subsequently reduced this volume requirement to 1.01 billion RINs in a separate action.

[b] The 2025 cellulosic biofuel volume requirement was originally established as 1.38 billion RINs in the Set 1 Rule. As described in section VI of this preamble, we are reducing this volume requirement to 1.21 billion RINs in this action.

[c] The 2023 total renewable fuel volume requirement does not include the 0.25 billion RIN supplemental standard.

[5] EPA, ''RFS Program Standards for 2026 and 2027, Partial Waiver of 2025 Cellulosic Biofuel Volume Requirement, and Other Changes: Response to Comments Document,'' EPA–420–R–26–012, March 2026.

[6] Executive Order 14154, ''Unleashing American Energy,'' January 20, 2025 (90 FR 8353; January 29, 2025).

[7] EPA, ''EPA Administrator Lee Zeldin Announces EPA's 'Powering the Great American Comeback' Initiative,'' February 4, 2025. *https://www.epa.gov/newsreleases/epa-administrator-lee-zeldin-announces-epas-powering-great-american-comeback.*

[8] In the Set 2 proposal, we projected that the total volume of renewable fuel supplied to meet the proposed volume requirements would be 22.10 billion gallons and 22.37 billion gallons in 2026 and 2027, respectively. As shown in Table I.A.1–2, we project that 21.87 billion gallons and 22.25 billion gallons of renewable fuel will be supplied in 2026 and 2027, respectively, to meet the volume requirements we are finalizing in this rule.

We project that the production and use of renewable fuels in the U.S. will increase significantly in response to these volume requirements. The quantities of renewable fuel we project will be supplied to satisfy the volume requirements, after accounting for the nested nature of the RFS volume requirements, are shown in Table I.A.1–2. These volumes are similar to those we projected would be supplied in the Set 2 proposal and reflect updates to EPA's analysis of the potential supply of renewable fuel in these years and the impacts of these fuels on the statutory factors.

Table I.A.1-2: Projected Supply of Renewable Fuel to Satisfy the 2023–2027 Volume Requirements (billion gallons)

RFS Standard	Projected Volume in the Set 1 Rule			Projected Volume in This Action	
	2023	2024	2025	2026	2027
Cellulosic biofuel	0.84	1.01[a]	1.21[b]	1.36	1.43
Biomass-based diesel	3.71	3.85	4.24	6.07	6.45
Other advanced biofuel[c]	0.23	0.23	0.23	0.16	0.16
Conventional renewable fuel[d]	13.85[e]	13.96	13.78	14.27	14.20
Total renewable fuel	18.63[e]	19.12	19.63	21.87	22.25

[a] The 2024 cellulosic biofuel volume was originally projected as 1.09 billion RINs in the Set 1 Rule. We subsequently reduced this volume projection to 1.01 billion RINs in a separate action.

[b] The 2025 cellulosic biofuel volume was originally projected as 1.38 billion RINs in the Set 1 Rule. As described in section VI of this preamble, we are reducing this volume projection to 1.21 billion RINs in this action.

[c] Other advanced biofuel is not an RFS standard category but includes all advanced biofuels that do not qualify as cellulosic biofuel or BBD.

[d] Conventional renewable fuel is not an RFS standard category but includes all renewable fuels that do not qualify as cellulosic biofuel, BBD, or advanced biofuel.

[e] Volumes do not include the 0.25 billion RIN supplemental standard established for 2023.

As discussed above, CAA section 211(o) requires the EPA to analyze a specified set of factors in making our determination of the appropriate volume requirements. Many of those factors, particularly those related to economic and environmental impacts, are difficult to analyze in the abstract. To facilitate a more concrete and meaningful analysis of the statutory factors, we first identified a set of renewable fuel volumes to analyze prior to determining the final volume requirements. To identify those renewable fuel volumes for analysis, we generally considered factors most likely to limit the domestic production and/or use of qualifying renewable fuels in 2026 and 2027. In some cases, the limiting factors we identified were based on our assessment of the ability of the U.S. market to consume renewable fuels in the transportation sector, while in other cases they were based on domestic production capacity. We discuss the derivation of these volumes for analysis in section III of this preamble. We also discuss in section III of this preamble the analysis of the statutory factors with respect to these volumes and our conclusions regarding the appropriate volume requirements to establish in light of the analyses we conducted.

The cellulosic biofuel volumes we are finalizing for 2026 and 2027 represent increases over the volumes in the Set 1 Rule. Compressed natural gas (CNG) and liquefied natural gas (LNG) derived from biogas comprise most of the qualifying cellulosic biofuel that we project will be supplied through 2027. Consistent with the analysis presented in the Set 2 proposal,[9] and supported by data submitted by commenters and analysis conducted subsequent to the Set 2 proposal, we project that the use of renewable CNG/LNG used as transportation fuel will be limited by the number of vehicles capable of using these fuels in 2026 and 2027. The cellulosic biofuel volume requirements we are finalizing in this action reflect an updated analysis of the quantity of renewable CNG/LNG that will be used as transportation fuel in 2026 and 2027. The final cellulosic biofuel volumes also include projections of cellulosic ethanol from corn kernel fiber (CKF) produced at existing corn starch ethanol production facilities.

Stakeholders provided the EPA with extensive comments and data regarding the proposed BBD and advanced biofuel volume requirements along with their views on appropriate levels for the final volume requirements. Following issuance of the Set 2 proposal, we carefully reviewed all new information and engaged directly and extensively with stakeholders from relevant sectors on this topic. The BBD and advanced biofuel volumes we are finalizing for 2026 and 2027 reflect the significant growth observed in the production of these fuels over the past several years and build off the volumes already achieved in the marketplace in previous years. The final volume requirements reflect the projected growth in the domestic production capacity and supply of feedstocks, primarily soybean oil, with smaller projected increases in other feedstocks including used cooking oil (UCO) and animal fats. We have also adjusted the final BBD volume requirements, as expressed in billion RINs, relative to the proposed volume requirements to account for the fact that we are not finalizing the proposed IRR provisions at this time in connection with the volume requirements for 2026 and 2027.

The final volume requirements for total renewable fuel in 2026 and 2027 reflect an implied conventional biofuel volume requirement of 15 billion gallons each year. This is consistent with the implied conventional renewable fuel volumes in the statutory

[9] 90 FR 25784 (June 17, 2025).

tables for 2015–2022,[10] as well as the implied conventional biofuel volumes we established for 2023–2025 in the Set 1 Rule. We recognize that while the supply of conventional biofuel in 2026 and 2027 will likely fall short of the 15-billion-gallon implied conventional biofuel volume requirement, the final total renewable fuel volume requirements are still achievable through the use of additional volumes of advanced biofuel beyond the volume requirement for that category.

Although the Set 1 Rule established volumes for three years (2023–2025), we believe that it is appropriate at this time to establish volume requirements for two years instead of a longer timeframe. There is increased uncertainty in trying to project out further in the future, which increases the likelihood of needing to adjust volumes in the future. Retroactive adjustments to volume requirements create uncertainty in the RFS program and hinder the purpose of projecting future years, which is meant to provide certainty to the market.

2. Reallocation of Small Refinery Exemptions for 2023–2025

After the release of the Set 2 proposal, the EPA issued decisions on 175 SRE petitions in August 2025.[11] These decisions included numerous grants and partial grants that relieved many small refineries from their renewable volume obligations (RVOs) for past compliance years. To mitigate the potential market impacts of these decisions, in the Set 2 supplemental proposal we proposed reallocating all or a portion of the exempted RVOs for the 2023–2025 compliance years (the years for which the exemptions would potentially materially impact the current RIN and renewable fuel markets) to the 2026 and 2027 compliance years.[12] After the release of the Set 2 supplemental proposal, the EPA issued decisions on an additional 16 SRE petitions in November 2025.[13] In this final rule, after considering relevant comments, data, and analyses received from interested stakeholders on the Set 2 proposals, we are finalizing a 70 percent partial reallocation of the 2023–2025 exempted RVOs to the 2026 and 2027 compliance years. This partial reallocation is intended to prevent the 2023–2025 exemptions from significantly and negatively impacting biofuel demand in 2026 and 2027, while also recognizing the importance of the availability of carryover RINs to a liquid and smoothly functioning RIN market. The renewable fuel volume requirements, SRE reallocation volumes, and total applicable volumes we are finalizing in this action for 2026 and 2027 are shown in Table I.A.2–1. We further discuss our reallocation of 2023–2025 exempted RVOs in section IV of this preamble.

Table I.A.2-1: 2026 and 2027 Renewable Fuel Volume Requirements, SRE Reallocation Volumes, and Total Applicable Volumes (billion RINs)

	Volume Requirement		SRE Reallocation Volume		Total Applicable Volume	
	2026	2027	2026	2027	2026	2027
Cellulosic biofuel	1.36	1.43	0	0	1.36	1.43
Biomass-based diesel	8.86	8.95	0.21	0.25	9.07	9.20
Advanced biofuel	10.82	10.98	0.28	0.34	11.10	11.32
Total renewable fuel	25.82	25.98	0.99	1.04	26.81	27.02

The total applicable volumes that we are establishing in this action are the basis for the calculation of percentage standards applicable to producers and importers of gasoline and diesel. The calculation of the final percentage standards is discussed further in section V of this preamble.

3. Partial Waiver of the 2025 Cellulosic Biofuel Volume Requirement

Consistent with the Set 2 proposal, we are finalizing a partial waiver of the 2025 cellulosic biofuel volume requirement and revising the associated percentage standard due to a 0.17 billion RIN shortfall in the volume of cellulosic biofuel available in 2025. As such, we are using our CAA section 211(o)(7)(D) ''cellulosic waiver authority'' to reduce the 2025 cellulosic biofuel volume from 1.38 billion RINs to 1.21 billion RINs. The use of such waiver authority also makes cellulosic waiver credits (CWCs) available for the 2025 compliance year. We further discuss our partial waiver of the 2025 cellulosic biofuel volume requirement in section VI of this preamble.

4. Removal of Renewable Electricity From the RFS Program

In the Set 2 proposal, we proposed to remove renewable electricity as a qualifying renewable fuel under the RFS program. We discussed the EPA's difficulties in establishing a workable regulatory framework for such a program and sought comment on whether such a program is consistent with the best reading of the statute in the first instance.[14] In this final rule, after considering relevant comments received on this issue, we are finalizing the removal of electricity as a qualifying renewable fuel under the RFS program. We conclude that renewable electricity does not meet the definition of renewable fuel under CAA section 211(o)(1)(J), read in context and considering the structure of the statute as a whole. We are therefore removing the regulations related to the production and use of renewable electricity as a transportation fuel, including the regulations related to facility registration for renewable electricity producers and the provisions for generating RINs for use of renewable electricity as a transportation fuel. We are also removing the definition of ''renewable electricity'' and the renewable electricity pathways in Table 1 to 40 CFR 80.1426 in connection with this change. In addition, we are withdrawing our December 2022 proposal associated with the Set 1 Rule pertaining to renewable electricity,[15]

[10] CAA section 211(o)(2)(B)(i).

[11] EPA, ''August 2025 Decisions on Petitions for RFS Small Refinery Exemptions,'' EPA–420–R–25–010, August 2025 (''August 2025 SRE Decisions Action'').

[12] 90 FR 45007 (September 18, 2025).

[13] EPA, ''November 2025 Decisions on Petitions for RFS Small Refinery Exemptions,'' EPA–420–R–25–013, November 2025 (''November 2025 SRE Decisions Action'').

[14] 90 FR 25784, 25841–42 (June 17, 2025).

[15] 87 FR 80582 (December 30, 2022).

which was not finalized as part of the Set 1 Rule.[16]

5. Other Regulatory Changes

In the Set 2 proposal, we proposed a series of regulatory changes in several areas to strengthen our implementation of the RFS program that we are now finalizing. The final changes take into account comments and new information provided by stakeholders during the public comment period. These regulatory changes are discussed in greater detail in section VIII of this preamble and include:

• Specifying new equivalence values for renewable diesel, naphtha, and jet fuel.

• Updating RIN generation and assignment provisions.

• Clarifying that RINs cannot be generated for renewable fuel that is used for process heat or electricity generation.

• Changing the percentage standards equations, including specifying the BBD standard in RINs rather than physical gallons.

• Updating existing renewable fuel pathways and adding new ones.

• Adding definitions for terms used throughout the regulations and updating other definitions.

• Adding a joint and several liability provision applicable to importers of renewable fuel.

• Revising compliance reporting and registration provisions, including clarifying that small refineries that receive an exemption from their RFS obligations must still submit an annual compliance report.

• Clarifying certain requirements for biodiesel and renewable diesel.

• Other minor changes and technical corrections.

In addition, we are also finalizing several revisions to the RFS regulations that were originally proposed in the proposed partial waiver of the 2024 cellulosic biofuel volume requirement, including provisions that will automatically extend the annual compliance reporting deadline for a given compliance year if we propose to revise an existing RFS standard for that year.[17]

We are also making minor revisions to two main areas of the RFS program's biogas regulations that were identified after the EPA and market participants began implementing the regulations promulgated in the Set 1 Rule. First, we are clarifying and providing flexibility for how biogas, renewable natural gas (RNG), and renewable CNG/LNG are measured, sampled, and tested to demonstrate compliance.

Second, we are making the following technical amendments to the biogas regulations:

• Clarifying what constitutes a batch of RNG.

• Clarifying the requirements for the generation, assignment, and separation of RINs for RNG.

• Clarifying the registration requirements for biogas producers, RNG producers, and RNG RIN separators.

• Clarifying the attest engagement requirements for biogas producers, RNG producers, and RNG RIN separators.

• Numerous clarifications, corrections, and consistency edits to the biogas regulations.

B. Impacts of This Rule

CAA section 211(o)(2)(B)(ii) requires the EPA to assess several factors when determining volume requirements for calendar years after 2022. These factors are described in section II of this preamble, and the expected impacts on each factor are discussed briefly in section III of this preamble and in greater detail in the Regulatory Impact Analysis (RIA) accompanying this rule.[18] However, the statute does not specify how the EPA must assess each factor or the weight each factor bears on the overall analysis. For two of these statutory factors—costs and energy security—we provide monetized estimates of the impacts of the final volume requirements. For the other statutory factors, we are either unable to quantify impacts at this time or we provide quantitative estimated impacts that nevertheless cannot be easily monetized. Thus, we are unable to quantitatively compare all the evaluated impacts of this rulemaking.

We considered all statutory factors in developing this final rule, including factors for which we provide monetized impacts, otherwise quantify impacts, or provide a qualitative assessment of relevant impacts, and we find that the final volumes are appropriate under our statutory authority after balancing all relevant factors. This approach is consistent with CAA section 211(o)(2)(B)(ii), which requires the Administrator to ''determin[e]'' volumes based on ''an analysis of'' the statutory factors and does not require that analysis to monetize or quantify all relevant considerations. A summary of our assessment of the impacts of this action can be found in section III.H of this preamble. RIA Table ES–1 provides a list of all the impacts that we assessed, both quantitative and qualitative. Additional detail for each of the assessed factors is provided in RIA Chapters 4 through 10.

C. Policy Considerations

The RFS program is a critical policy tool that supports the domestic production and use of renewable fuels. This final rule seeks to get the RFS program back on track by aligning the incentives provided by the RFS program with the statutory goals of, among other things, increasing energy independence and energy security. The final volumes for 2026 and 2027 reflect the significant growth potential, in particular, for domestic renewable fuel production in the U.S., and will help strengthen rural agricultural communities and industries.

As discussed above, the Set 2 proposal included provisions that would have reduced the number of RINs generated for import-based renewable fuel, thereby better aligning the RFS program with American economic and security interests and strengthening support for American farmers and domestic renewable fuel producers. The RFS program has always allowed for import-based renewable fuel, but the surge of imports of both feedstocks and renewable fuels in recent years has destabilized domestic biofuel investments and U.S. agricultural production, all while rewarding foreign feedstock and renewable fuel producers. We proposed IRR provisions affecting import-based renewable fuel in the Set 2 proposal. Such import-based renewable fuels do not further energy independence and are projected to result in fewer employment and rural economic development benefits relative to renewable fuels produced in the U.S. from domestic feedstocks. We proposed that, under the IRR provisions, import-based renewable fuels would only generate half the number of RINs that they generate under the current RFS regulations, and sought comment on this overall concept and how it should be implemented if finalized.

We appreciate the extensive stakeholder input we received on the proposed IRR provisions. Public comments provided perspectives on all aspects of the proposed IRR provisions, from overarching concepts and policy goals to timing and other implementation details. We carefully reviewed all the comments we received and found that many stakeholders made compelling arguments regarding when and how IRR provisions could be most effectively phased in and integrated into

[16] 88 FR 44468, 44471 (July 12, 2023).

[17] 89 FR 100442 (December 12, 2024).

[18] EPA, ''RFS Program Standards for 2026 and 2027, Partial Waiver of 2025 Cellulosic Biofuel Volume Requirement, and Other Changes: Regulatory Impact Analysis,'' EPA–420–R–26–011, February 2026.

the RFS program. Commenters indicated that the proposed IRR provisions could result in significant changes in the supply of renewable fuels and feedstocks to U.S. markets and that these changes could be disruptive without sufficient lead time for the market to prepare and make the necessary adjustments—including leading to increase in gasoline and diesel prices. Other comments provided constructive feedback concerning regulatory or definitional gaps in the proposed design of the IRR provisions and suggested that we could strengthen the IRR provisions by clarifying various elements of the proposed approach. We also recognize that there have been important changes in the broader policy context in which the RFS program operates, including changes to key Federal biofuel tax credits (we discuss those changes in section III of this preamble and the RIA).

After reviewing this input, we have determined that it is appropriate and prudent to take additional time to address some of these timing and implementation questions regarding the proposed IRR provisions. In light of that determination, we are not finalizing the proposed IRR provisions in this final rule in the context of establishing the volume requirements for 2026 and 2027. We continue to believe that the IRR concept is appropriate and would better align the RFS program with the statutory goals for the program. Given the importance of the policy objectives underlying the proposed IRR provisions, and the support expressed for it by many stakeholders, we intend to establish IRR provisions that will take effect at the beginning of the 2028 compliance year or sometime shortly thereafter. We are currently considering our next steps and will communicate with stakeholders as we establish our plans.

In the Set 2 proposal, we also requested comment on other opportunities to improve the RFS program that could be considered in future actions. Our request for comments included areas such as a general pathway for the production of renewable jet fuel from corn ethanol, the definition of ''produced from renewable biomass,'' additional RFS program amendments to ensure that imported renewable fuels are produced from qualifying feedstocks and enhance our ability to track feedstocks to their point of origin, RFS program enhancements to increase the use of qualifying woody-biomass to produce renewable transportation fuel, and any other modifications to the RFS program designed to unleash the production of American energy. We also received comments on the definitions for different types of woody biomass under the RFS program. EPA may consider modifications to relevant definitions such as ''areas at risk of wildfire,'' ''slash,'' ''pre-commercial thinnings,'' and ''tree residue,'' in a future rulemaking. We appreciate stakeholders' input on these topics and many others raised in the comments and will consider potential ways to address these areas in future actions.

D. Endangered Species Act

Section 7(a)(2) of the Endangered Species Act (ESA), 16 U.S.C. 1536(a)(2), requires that federal agencies such as the EPA, in consultation with the U.S. Fish and Wildlife Service (USFWS) and/or the National Marine Fisheries Service (NMFS) (collectively ''the Services''), ensure that any action authorized, funded, or carried out by the action agency is not likely to jeopardize the continued existence of any endangered or threatened species or result in the destruction or adverse modification of designated critical habitat for such species. Under relevant implementing regulations, the action agency is required to consult with the Services for actions that ''may affect'' listed species or designated critical habitat.[19] Consultation is not required where the action would have no effect on such species or habitat.

Consistent with ESA section 7(a)(2) and relevant implementing regulations at 50 CFR part 402, we engaged in informal consultation with the Services and completed a Biological Evaluation (BE) for the Set 2 Rule.[20] Supported by the analysis in the Set 2 Rule BE, we determined that formal consultation is not required for the Set 2 Rule because of the absence of likely adverse effects on listed species and their habitats. EPA has prepared an ESA section 7(d) determination memorandum that discusses our decision to finalize this action before the informal consultation process is complete.[21]

II. Statutory Requirements and Conditions

A. Directive To Set Volumes Requirements

Congress enacted the RFS program for the purpose of increasing the use of renewable fuel in transportation fuel over time. Congress specified statutory volumes for the initial years of the program, including for BBD through 2012, and for total renewable fuel, advanced biofuel, and cellulosic biofuel through 2022, but allowed the EPA to waive the statutory volumes in certain circumstances. For years after 2022, Congress provided the EPA with the directive and authority to establish the applicable renewable fuel volume requirements.[22] This section of the preamble discusses our statutory authority and additional factors we have considered due to the timing of this rulemaking, as well as the severability of the various portions of this rule. We generally respond to stakeholder comments received on these topics in the RTC document.

B. Statutory Factors

CAA section 211(o)(2)(B)(ii) establishes the processes, criteria, and standards for setting the applicable annual renewable fuel volumes. That provision provides that the EPA shall, in coordination with USDA and DOE,[23] determine the applicable volumes of each renewable fuel category, based on a review of the implementation of the program during the calendar years specified in the tables in CAA section 211(o)(2)(B)(i) and an analysis of the following factors:

- The impact of the production and use of renewable fuels on the environment, including on air quality, climate change, conversion of wetlands, ecosystems, wildlife habitat, water quality, and water supply;
- The impact of renewable fuels on the energy security of the United States;
- The expected annual rate of future commercial production of renewable fuels, including advanced biofuels in each category (cellulosic biofuel and BBD);
- The impact of renewable fuels on the infrastructure of the United States, including deliverability of materials, goods, and products other than renewable fuel, and the sufficiency of infrastructure to deliver and use renewable fuel;
- The impact of the use of renewable fuels on the cost to consumers of transportation fuel and on the cost to transport goods; and

[19] 50 CFR 402.14.

[20] EPA, ''Biological Evaluation of the Renewable Fuel Standard Set 2 Rule,'' 2026 (''Set 2 Rule BE'').

[21] See ''Endangered Species Act Section 7(d) Determination with Respect to the Issuance of the Renewable Fuel Standard (RFS) Program: Standards for 2026 and 2027, Partial Waiver of 2025 Cellulosic Biofuel Volume Requirement, and Other Changes,'' available in the docket for this action.

[22] We refer to CAA section 211(o)(2)(B)(ii) as the ''set authority.''

[23] In furtherance of this requirement, we have continued periodic discussions with USDA and DOE on this action. We have documented the coordination with the EPA Administrator and Secretaries in a memorandum available in the docket for this action.

• The impact of the use of renewable fuels on other factors, including job creation, the price and supply of agricultural commodities, rural economic development, and food prices.

Congress enumerated factors that the EPA must consider without mandating any particular types of analyses or specifying how the EPA must weigh the various factors against one another. Thus, as the CAA "does not state what weight should be accorded to the relevant factors," the statute "give[s] EPA considerable discretion to weigh and balance the various factors required by statute." [24] These factors were analyzed in the context of the Set 1 Rule,[25] as well as the 2020–2022 RFS Rule that modified volumes under CAA section 211(o)(7)(F),[26] which requires the EPA to comply with the processes, criteria, and standards in CAA section 211(o)(2)(B)(ii). Our assessment of the factors in the 2020–2022 RFS Rule was upheld by the D.C. Circuit in *Sinclair*.[27] Similarly, our assessment of the factors in the Set 1 Rule was largely upheld in *CBD*.[28] Consistent with our past practice in evaluating the factors,[29] in this final rule we have again determined that a holistic balancing of the factors is appropriate.[30]

In addition to those factors listed in the statute, the EPA also has authority to consider "other" factors, including both the implied authority to consider factors that inform our analysis of the statutory factors and the explicit authority under CAA section 211(o)(2)(B)(ii)(VI) to consider "the impact of the use of renewable fuels on other factors." Accordingly, for this final rule, we considered several other relevant factors beyond those enumerated in CAA section 211(o)(2)(B)(ii), including:

• The interconnected nature of the volume requirements for 2026 and 2027, including the nested nature of those volume requirements and the availability of carryover RINs (sections III.E and III.H of this preamble).[31]

• The ability of the market to respond given the timing of this rulemaking (RIA Chapter 7).[32]

• The supply of qualifying renewable fuels to U.S. consumers (section III of this preamble).[33]

C. Statutory Conditions on Volume Requirements

As indicated above, the CAA does not specify how the EPA is to consider the enumerated factors or any particular weight each factor must be given in the overall analysis. However, the CAA contains three overarching conditions that affect our determination of the applicable volume requirements:

• A constraint in setting the applicable volume of total renewable fuel as compared to advanced biofuel, with implications for the implied volume requirement for conventional renewable fuel.

• Direction in setting the cellulosic biofuel applicable volume regarding potential future waivers.

• A floor on the applicable volume of BBD.

We discuss these conditions in further detail below.

1. Advanced Biofuel as a Percentage of Total Renewable Fuel

While the statute generally provides broad discretion in setting the applicable volume requirements for advanced biofuel and total renewable fuel, it also establishes a constraint on the relationship between these two volume requirements. CAA section 211(o)(2)(B)(iii) provides that the applicable advanced biofuel requirement must "be at least the same percentage of the applicable volume of renewable fuel as in calendar year 2022," meaning that the EPA must, at a minimum, maintain the ratio of advanced biofuel to total renewable fuel that was established for 2022 for all future years in which the EPA itself sets the applicable volume requirements. In effect, this proportional requirement limits the proportion of the implied volume of conventional renewable fuel within the total renewable fuel volume for years after 2022 based on the proportion that existed for calendar year 2022.

The applicable advanced biofuel volume requirement established for 2022 was 5.63 billion gallons.[34] The total renewable fuel volume requirement established for 2022 was 20.63 billion gallons, resulting in an implied conventional volume requirement of 15 billion gallons. Thus, advanced biofuel represented 27.3 percent of total renewable fuel for 2022, and we must maintain at least that percentage of the advanced biofuel volume requirement as compared to the total renewable fuel volume requirement for all subsequent years. The volume requirements we are establishing in this action for 2026 and 2027, including the SRE reallocation volumes further described in section IV of this preamble, and shown in Table I.A.2–1, exceed this 27.3 percent minimum, and thus satisfy this statutory requirement for each year.

2. Cellulosic Biofuel

CAA section 211(o)(2)(B)(iv) requires that the EPA set the applicable cellulosic biofuel requirement "based on the assumption that the Administrator will not need to issue a waiver . . . under [CAA section 211(o)](7)(D)" for the years in which the EPA sets the applicable volume requirement. We have historically interpreted this requirement to mean that the cellulosic biofuel volume requirement should be set at a level that is achievable such that we do not anticipate a need to further lower the requirement through a waiver under CAA section 211(o)(7)(D).[35] CAA section 211(o)(7)(D) provides that if "the projected volume of cellulosic biofuel production is less than the minimum applicable volume established under paragraph (2)(B)," the EPA "shall reduce the applicable volume of cellulosic biofuel required under paragraph (2)(B) to the projected volume available during that calendar year." We maintain this interpretation of the statute. Therefore, we are establishing the cellulosic biofuel volume requirements such that a waiver of those requirements is not anticipated to be necessary for those future years. Operating within this limitation, and in light of our consideration of the statutory factors explained in section III of this preamble, we are establishing cellulosic volumes for 2026 and 2027 at

[24] *CBD,* 141 F.4th at 171; *Sinclair Wyo. Refin. Co. LLC* v. *EPA,* 101 F.4th 871, 887 (D.C. Cir. 2024); *see also Brown* v. *Watt,* 668 F.2d 1290, 1317 (D.C. Cir. 1981) ("A balancing of factors is not the same as treating all factors equally. The obligation instead is to look at all factors and then balance the results. The Act does not mandate any particular balance, but vests the [agency] with discretion to weigh the elements . . . .").

[25] *See* 88 FR 44468, 44476 (July 12, 2023).

[26] *See* 87 FR 39600, 39607–08 (July 1, 2022).

[27] *Sinclair,* 101 F.4th at 888–89.

[28] *CBD,* 141 F.4th at 169–76. To the extent the court found fault in our analysis, we have provided a response in section IX of this preamble.

[29] 87 FR 39600, 39607–08 (July 1, 2022).

[30] EPA, "RFS Annual Rules: Response to Comments," EPA–420–R–22–009, June 2022 ("2020–2022 RFS Rule RTC"), at 10.

[31] This also informs our analysis of the statutory factor "review of the implementation of the program" in CAA section 211(o)(2)(B)(ii).

[32] This also informs our analysis of the statutory factor "the expected annual rate of future commercial production of renewable fuels" in CAA section 211(o)(2)(B)(ii)(III).

[33] This is based on our analysis of the statutory factor the expected annual rate of future commercial production of renewable fuel as well as of downstream constraints on biofuel use, including the statutory factors relating to infrastructure and costs.

[34] 87 FR 39601 (July 1, 2022).

[35] The cellulosic waiver authority applies when the projected volume of cellulosic biofuel production is less than the minimum applicable volume, per CAA section 211(o)(7)(D).

the projected volume available in each year, respectively, consistent with our past actions in determining the cellulosic biofuel volume.[36] These projections, discussed further in section III.A.1 of this preamble, represent our best efforts to project the potential for growth in the volume of cellulosic biofuel that can be achieved in 2026 and 2027.

We recognize that, for 2024 and 2025, the volume of cellulosic biofuel available was less than the volume required, and we have partially waived the 2024 cellulosic biofuel volume requirement and are partially waiving the 2025 cellulosic biofuel volume requirement in this action as discussed in section VI of this preamble. In projecting the available volume of cellulosic biofuel in 2026 and 2027, we have considered our over-projections in previous years and have adjusted our methodology as discussed in section III.A of this preamble and RIA Chapter 7.1 to reflect our consideration of the prior shortfalls in the standards. Retroactive waivers of the volume requirements under the RFS program decrease certainty for the market and undermines confidence in the volumes and standards we set, which could negatively impact investment in renewable fuel production in future years. In this action, we are changing the methodology used to project cellulosic biofuel volumes to avoid the need for waivers of the RFS standards in the future.

3. Biomass-Based Diesel

We have established the BBD volume requirement under CAA section 211(o)(2)(B)(ii) for the years since 2013 because the statute only specifies BBD volume requirements through 2012. CAA section 211(o)(2)(B)(iv) also requires that the BBD volume requirement be set at, or greater than, the 1.0-billion-gallon volume requirement enumerated by statute for 2012, but it does not provide any other numerical criteria that the EPA must consider. In the years since 2012, we have steadily increased the BBD volume requirement beyond 1.0 billion gallons to 3.35 billion gallons in 2025. In this action, we are establishing 2026 and 2027 BBD applicable volumes of 9.07 and 9.20 billion RINs, respectively.[37] These numbers are not directly comparable with the BBD volume requirements in previous years, as they express the required volume of BBD in RINs rather than physical gallons. Nevertheless, the final BBD volume requirements guarantee that at least 5.33 and 5.75 billion gallons of BBD will be used in 2026 and 2027, respectively,[38] far greater than 1.0-billion-gallon minimum requirement.[39]

D. Authority To Establish Volume Requirements and Percentage Standards for Multiple Years

In this action, we are establishing the applicable volume requirements and percentage standards for 2026 and 2027. We have a statutory obligation to promulgate volume requirements under CAA section 211(o)(2)(B)(ii) and are addressing that requirement in this final rule. We acknowledge that the statutory deadlines for promulgating the 2026 and 2027 applicable volume requirements passed on October 31, 2024, and October 31, 2025, respectively. Nevertheless, we are establishing the 2026 and 2027 applicable volume requirements ahead of the 2027 compliance year, and early in the 2026 compliance year.

As to the percentage standards with which obligated parties must comply, CAA section 211(o)(A)(i) and (iii) requires the EPA to promulgate regulations that, regardless of the date of promulgation, contain compliance provisions applicable to refineries, blenders, distributors, and importers that ensure that the volumes in CAA section 211(o)(2)(B)—which includes volumes set by the EPA after 2022—are met. As in the Set 1 Rule, we are also establishing corresponding percentage standards in this action.[40]

In summary, we are establishing applicable volume requirements and associated percentage standards for 2026 and 2027, as further described in sections III and V of this preamble.

E. Considerations Related to the Timing of This Action

In this action, we are establishing applicable volume requirements for the 2026 and 2027 compliance years after the statutory deadlines to establish such requirements (October 31, 2024, and October 31, 2025, respectively).[41] We have also missed statutory deadlines in the past for promulgating RFS standards, including the 2023 and 2024 standards established in the Set 1 Rule, and the BBD volume requirements for 2014–2017, which were established under CAA section 211(o)(2)(B)(ii), the same provision under which we are establishing the 2026 and 2027 standards in this action.

In its review of the EPA's 2015 action establishing BBD volume requirements for 2014–2017,[42] the D.C. Circuit found that the EPA retains authority beyond the statutory deadlines to promulgate volumes and annual percentage standards, even those that apply retroactively, so long as the EPA exercises this authority reasonably.[43] We had missed the statutory deadline under CAA section 211(o)(2)(B)(ii) to establish an applicable volume requirement for BBD no later than 14 months before the first year to which that volume requirement will apply for all years. The D.C. Circuit held that when the EPA exercises this authority after the statutory deadline, the EPA must balance the burden on obligated parties of a delayed rulemaking with the broader goal of the RFS program to increase renewable fuel use.[44] In specifically upholding the portion of that rulemaking that was late but not retroactive, the court considered whether there was sufficient lead time and adequate notice for obligated parties.[45] The court found that the EPA properly balanced the relevant considerations and provided sufficient notice to parties in establishing the applicable volume requirements for 2014–2017.[46]

Similarly, in its review of the Set 1 Rule, the D.C. Circuit concluded that the EPA's determination of the 2023 and

[36] *See, e.g.,* 87 FR 39600 (July 1, 2022) (2020–2022 RFS Rule).

[37] As noted in section I.A.1 and explained further in section VII.C of this preamble, we are specifying the BBD volume requirement in RINs, rather than gallons. This is in contrast to establishing the 2025 BBD volume requirement at 3.35 billion physical gallons.

[38] These volumes represent the lowest possible volume of BBD that could be used to meet the final BBD volume requirements for 2026 and 2027. These numbers are calculated by dividing the final BBD RIN requirements by 1.7 in 2026 (the equivalence value for renewable diesel in 2026) and 1.6 in 2027 (the highest equivalence value we anticipate in 2027, as discussed in in section VIII.A of this preamble). In practice, we project that significantly greater volumes of BBD will be supplied to meet the BBD volume requirements, as biodiesel and some renewable diesel will only generate 1.5 RINs per gallon in these years.

[39] Because the EPA interpreted the BBD volume requirement in physical gallons at the time the 1.0-billion-gallon standard for 2012 was established, we provide our comparison of the 2026 and 2027 BBD volume requirements to this minimum volume requirement in physical gallons, rather than RINs.

[40] 88 FR 44468, 44519–21 (July 14, 2023).

[41] *See* CAA section 211(o)(2)(B)(ii), requiring the EPA to promulgate applicable volume requirements no later than 14 months prior to the first year in which they will apply.

[42] 80 FR 77420, 77427–28, 77430–31 (December 14, 2015).

[43] *Americans for Clean Energy (ACE)* v. *EPA,* 864 F.3d 691 (D.C. Cir. 2017) (the EPA may issue late applicable volumes under CAA section 211(o)(2)(B)(ii)); *Monroe Energy, LLC* v. *EPA,* 750 F.3d 909 (D.C. Cir. 2014); *NPRA* v. *EPA,* 630 F.3d 145, 154–58 (D.C. Cir. 2010); *see also CBD,* 141 F.4th at 184–85; *Sinclair,* 101 F.4th at 887.

[44] *NPRA* v. *EPA,* 630 F.3d at 164–65.

[45] *ACE,* 864 F.3d at 721–22.

[46] *ACE,* 864 F.3d at 721–23.

2024 standards after the statutory deadline was permissible.[47] The court noted its repeated holdings that the ''EPA may promulgate late, and even retroactive, volume requirements so long as it 'reasonably considers and mitigates any hardship caused to obligated parties by reason of the lateness.' ''[48] In so holding, the court noted that the EPA's explanation of the achievability of the RFS standards, the timing of compliance demonstrations in relation to the final rule and existing flexibilities in the RFS program for obligated parties.[49]

In this final rule, we are exercising our authority to set the applicable renewable fuel volume requirements for 2026 and 2027 after the statutory deadline to promulgate such volume requirements under CAA section 211(o)(2)(B)(ii). The 2026 standards will also have a partially retroactive effect, as we are finalizing the standards after the beginning of the 2026 calendar year. Nevertheless, we believe that the 2026 and 2027 standards being finalized in this action can be met in the market by obligated parties (see section III of this preamble and RIA Chapter 7). We are finalizing the 2027 standards prior to the beginning of the 2027 compliance year (*i.e.,* before January 1, 2027) and thus these standards do not apply retroactively. Additionally, we provided obligated parties notice as of June 17, 2025, and September 18, 2025, of the proposed 2026 and 2027 standards, several months ahead of when the 2026 standards would apply, and over a year in advance of when the 2027 standards would apply. As described in section I.C of this preamble, while the volume requirements we are finalizing in this action appear larger than the proposed volume requirements, this is in part due to the fact that we are not finalizing the proposed IRR provisions, which would have reduced the number of RINs generated for import-based renewable fuel by half. The total volumes of renewable fuel we expect will be supplied to meet the volume requirements of this final rule are very similar to those we projected would be supplied to meet the proposed volume requirements. Obligated parties will have at least 12 months from the time of promulgation of this final rule before they are required to submit associated compliance reports for 2026. There will additionally be at least 24 months between the finalization of this rule and the compliance deadline for the 2027 standards. Obligated parties will also continue to have the ability to use existing compliance flexibilities to comply with the 2026 and 2027 RFS standards, such as the use of carryover RINs and carrying forward a deficit from one compliance year into the next.[50]

We also note that separate components of the 2026 and 2027 advanced biofuel, BBD, and total renewable fuel applicable volumes—the SRE reallocation volumes—were proposed with the intent that the standards be met through the use of carryover RINs as a result of the recent SRE decisions. In this final rule, we again intend for the SRE reallocation volumes to be met using carryover RINs that are already available in the market, and as such do not anticipate additional burden on obligated parties to obtain newly generated RINs for compliance with this portion of the applicable volumes.

F. Impact on Other Waiver Authorities

While we are establishing applicable volume requirements in this action for future years that are achievable and appropriate based on our consideration of the statutory factors, we retain our legal authority to waive volumes in the future under the relevant waiver authorities should circumstances so warrant.[51] For example, the general waiver authority under CAA section 211(o)(7)(A) provides that the EPA may waive the volume requirements in ''paragraph (2),'' which provides both the statutory applicable volume tables and the EPA's set authority (the authority to set applicable volumes for years not specified in the table). Therefore, similar to our exercise of the waiver authorities to modify the statutory volumes in past annual standard-setting rulemakings, the EPA has the authority to modify the applicable volumes for 2023 and beyond in future actions through the use of our waiver authorities. The Agency's general preference is to establish requirements in a manner that reduces the need for such waivers as much as possible. This policy, however, should not be read as conceding the EPA's authority to implement such waivers if warranted under the circumstances despite best efforts to project future conditions in a reasonable and well-informed manner.

We note that, as described above, CAA section 211(o)(2)(B)(iv) requires that the EPA set the cellulosic biofuel volume requirements for 2023 and beyond based on the assumption that we will not need to waive those volume requirements under the cellulosic waiver authority. Consistent with our approach in the Set 1 Rule, because we are establishing the applicable volume requirements for 2026 and 2027 under the set authority in this action, we do not believe we could also waive those requirements using the cellulosic waiver authority in this same action in a manner that would be consistent with CAA section 211(o)(2)(B)(iv), since that waiver authority is only triggered when the projected production of cellulosic biofuel is less than the ''applicable volume established under [211(o)(2)(B)].'' In other words, it does not appear that we could use both the set authority and the cellulosic waiver authority to establish volumes at the same time in this action.[52]

Establishing the volume requirements for 2026 and 2027 using our set authority apart from the cellulosic waiver authority has important implications for the availability of CWCs in these years. When we reduce cellulosic volumes under the cellulosic waiver authority, we are also required to make CWCs available under CAA section 211(o)(7)(D)(ii). In this rule we are establishing the 2026 and 2027 cellulosic biofuel volume requirements without utilizing the cellulosic waiver authority. We interpret CAA section 211(o)(7)(D)(ii) such that CWCs are only made available in years in which we use the cellulosic waiver authority to reduce the cellulosic biofuel volume. Because of this, CWCs would not be available as a compliance mechanism for obligated parties in these years absent a future action to exercise the cellulosic waiver authority. Despite the absence of CWCs, we expect that obligated parties will be able to satisfy their cellulosic biofuel obligations for these years because we are establishing the 2026 and 2027 cellulosic biofuel volume requirements based on the quantity of cellulosic biofuel we project will be used as transportation fuel in the U.S. each year.

G. Severability

In the event of judicial review, the EPA intends for the volume requirements and percentage standards for each single year covered by this rule (*i.e.,* 2026 and 2027) to be severable from the volume requirements and

[47] *CBD,* 141 F.4th at 183–84.

[48] *CBD,* 141 F.4th at 184.

[49] *Id.*

[50] CAA section 211(o)(5); 40 CFR 80.1427(a)(6)(i) and (b).

[51] *See J.E.M. Ag Supply, Inc.* v. *Pioneer Hi-Bred Intern., Inc.,* 534 U.S. 124, 143–44 (2001) (holding that when two statutes are capable of coexistence and there is not clearly expressed legislative intent to the contrary, each should be regarded as effective).

[52] We address comments that suggested we interpret this provision differently in RTC Section 2.1.

percentage standards for the other year. Each year's volume requirements and percentage standards are supported by analyses for that year.

We also intend for the SRE reallocation volumes for total renewable fuel, advanced biofuel, and BBD for 2026 and 2027 to be severable from the 2026 and 2027 volume requirements. Our justification for each volume is independent, such that invalidation of the SRE reallocation volumes would not impact our estimates of renewable fuel that are associated with new renewable fuel production in the market in 2026 and 2027. Our justification for the SRE reallocation volume is independent of that establishing the 2026 and 2027 volume requirements, despite the fact that the two terms are additive. We do not believe that it would be appropriate to further delay implementation of the 2026 and 2027 volume requirements if a court were to find defects in the SRE reallocation volumes.[53]

We intend for the revised 2025 cellulosic biofuel volume requirement and percentage standard in section VI of this preamble to be severable from the volume requirements and percentage standards for the other years. The 2025 cellulosic biofuel volume requirement and percentage standard is supported by the analysis and legal authority for that year independent of the analysis and legal authority for the 2026 and 2027 standards.

We also intend for the removal of renewable electricity from the RFS program discussed in section VII of this preamble and the regulatory amendments discussed in section VIII of this preamble to be severable from the volume requirements and percentage standards. These regulatory amendments are intended to improve the RFS program in general and are not part of our analysis for the volume requirements and percentage standards for any specific year. Additionally, because we have not registered any parties to generate RINs for renewable electricity, no such RINs are able to be generated and we have not relied on any such RINs in setting the standards. Further, each regulatory amendment in sections VII and VIII of this preamble is severable from the other regulatory amendments because they all function independently of one another.

If any of the portions of the rule identified in the preceding paragraph (*i.e.,* volume requirements and percentage standards for a single year, the individual regulatory amendments) were invalidated by a reviewing court, we intend the remainder of this action to remain effective as described in the prior paragraphs. To further illustrate, if a reviewing court were to invalidate the volume requirements and percentage standards, we intend the other regulatory amendments to remain effective. Or, as another example, if a reviewing court invalidates the removal of renewable electricity as a qualifying renewable fuel under the RFS program, we intend the volume requirements and percentage standards as well as other regulatory amendments to remain effective.

H. Judicial Review

Under section 307(b)(1) of the CAA, petitions for judicial review of this action must be filed in the United States Court of Appeals for the District of Columbia Circuit by June 1, 2026. Filing a petition for reconsideration by the Administrator of this final action under CAA section 307(d)(7)(B) does not affect the finality of the action for purposes of judicial review, nor does it extend the time within which a petition for judicial review must be filed, and shall not postpone the effectiveness of the action.

III. Volume Requirements for 2026 and 2027

This section of this preamble presents information related to how the EPA analyzed renewable fuel volumes, assessed the impacts of the potential volumes on the statutory factors, and other relevant information. Section III.A of this preamble describes how we identified volumes of component categories to facilitate our assessment of the statutory factors. Sections III.B and C of this preamble discuss the baselines we used for our analyses and the differences between these baselines and the analyzed volumes. A summary of our analyses of certain statutory factors on the analyzed volumes is in section III.D of this preamble, with more detail on our analyses and the results in the RIA. Sections III.E through H of this preamble discuss the volumes we are finalizing for each component category of renewable fuel, our consideration of carryover RINs, our consideration of alternative volumes, and finally a summary of the volumes we are finalizing for 2026 and 2027 in this final rule.

A. Analyzed Volumes

As required under CAA section 211(o)(2)(B)(ii), we reviewed the implementation of the RFS program to date and analyzed a specified set of factors. Many of the statutory factors, particularly those related to economic and environmental impacts, are difficult to analyze in the abstract; it is challenging to assess impacts without understanding the scale of the volume changes that are the driving force behind those impacts. In light of this, in the Set 1 Rule we first projected candidate volumes based on supply-side statutory factors and then analyzed the impacts on the other statutory factors of those candidate volumes before setting final volumes,[54] an approach that was upheld by the D.C. Circuit in *CBD.*[55]

We similarly framed our analysis of the statutory factors in this rule: we opted to first identify renewable fuel volumes for each category of renewable fuel (hereinafter the ''Analyzed Volumes'') so that a more concrete and meaningful analysis of the impacts of other statutory factors may be undertaken. This section (III.A) of this preamble describes how we developed the Analyzed Volumes as well as how and why they changed from the Set 2 proposal. Our analysis of the impacts of the Analyzed Volumes on a selection of the statutory factors is summarized in section III.D of this preamble, and the volume requirements for 2026 and 2027 that we are establishing in this action based on our analysis of all the statutory factors and a review of the implementation of the RFS program to date are described in section III.E of this preamble and summarized in section III.H of this preamble. Further details of all analyses performed for this action are provided in the RIA.

The Analyzed Volumes were determined based primarily on two statutory criteria: the expected annual rate of future commercial production of renewable fuels and sufficiency of infrastructure to deliver and use renewable fuels.[56] This is similar to the EPA's approach to identifying ''candidate volumes'' in the Set 1 Rule, which were also based on supply-side factors.[57] However, the development of the Analyzed Volumes is more closely tied to the statutory goals of the RFS program to, among other things, increase the domestic production and use of renewable fuel to increase the energy independence and security of the U.S. To best achieve these goals and consistent with the statutory requirements, the Analyzed Volumes are designed to account for the maximum potential production and use

[53] We have also calculated what the total renewable fuel, advanced biofuel, and BBD percentage standards for 2026 and 2027 would be without the SRE reallocation volumes. See ''Calculation of 2026 and 2027 RFS Percentage Standards Without the SRE Reallocation Volumes,'' available in the docket for this action.

[54] 88 FR 44480–508 (July 12, 2023).

[55] *CBD,* 141 F.4th at 170.

[56] CAA section 211(o)(2)(B)(ii)(III) and (IV).

[57] 88 FR 44480–81 (July 12, 2023).

of renewable fuels in the U.S. while at the same time recognizing infrastructure constraints that could limit the production and use of these fuels.

The Analyzed Volumes in this final rule differ from the volume scenarios and the proposed volumes in several ways, reflecting consideration of public comments received and certain adjustments that were contemplated at proposal. The Analyzed Volumes reflect additional analyses based on data received since proposal. The Analyzed Volumes also reflect modifications to our methodologies for projecting the potential volumes of renewable fuel production and use made in response to the public comments, including comments asserting that certain intervening developments discussed below warranted adjustments.[58] Finally, the Analyzed Volumes have been adjusted to reflect the EPA's decision not to finalize the proposed IRR provisions in this action.

For cellulosic biofuel and conventional renewable fuel, the Analyzed Volumes are equal to the projected volumes of these fuels we project will be used as RFS-qualifying transportation fuel in 2026 and 2027. Our projections of the use of these fuels assume continued incentives for the production and use of these fuels provided by the RFS program and by other State and Federal programs remain in place for the periods of time currently described in their respective statutes and regulations.

For non-cellulosic advanced biofuel (including BBD and other advanced biofuel), the projected supply of these fuels in future years is highly dependent on the incentives for these fuels provided by the RFS program, other State and Federal incentives in the U.S., and actions by foreign countries. Unlike cellulosic biofuel and conventional renewable fuel, we do not expect that the supply of non-cellulosic advanced biofuel will be limited by the ability for the market to use these fuels as RFS-qualifying transportation fuel. Instead, we project that the available supply of non-cellulosic advanced biofuel will depend on a number of interrelated factors, including the supply of feedstocks to produce these fuels, demand for these feedstocks in non-biofuel markets, and the available incentives for the production and use of these fuels in the U.S. and other countries.

The non-cellulosic advanced biofuel volumes we chose to analyze are based on the projected domestic production capacity of biodiesel and renewable diesel in 2026 and 2027, as well as the projected supplies of other advanced biofuels. In determining the Analyzed Volumes for non-cellulosic advanced biofuel, we also considered the availability of qualifying feedstocks to produce these fuels but ultimately determined that feedstock availability was unlikely to limit the production of these fuels to a level below the domestic production capacity. Developing volumes of non-cellulosic advanced biofuel for analysis based on the domestic production capacity for these fuels is consistent with the statute's goals of increasing energy independence and security and the Administration's goals of achieving energy dominance.

We recognize that imported renewable fuels are eligible to generate RINs under the RFS program, provided these fuels meet all relevant statutory and regulatory requirements. Imported renewable fuels are expected to continue to contribute to the supply of renewable fuel to the U.S. in 2026 and 2027. However, the volume of non-cellulosic advanced biofuels imported into the U.S. decreased significantly in 2025 and we believe based on the balance of available evidence that this trend will continue into 2026 and 2027 due to new trends in trade dynamics. Data from the EPA Moderated Transaction System (EMTS) indicates that biodiesel and renewable diesel imports decreased from approximately 830 million gallons in 2024 to approximately 140 million gallons in 2025. This drop in imported renewable fuel was a response to changing economic conditions, including the transition to the Federal Internal Revenue Code Section 45Z Clean Fuel Production tax credit (hereinafter the ''45Z credit''), which does not provide credit for imported biofuels. The 45Z credit was amended by the One Big Beautiful Bill Act of 2025 (OBBB).[59] Among other changes, OBBB required biofuels to be produced from North American feedstocks to qualify for the tax credit. Because the 45Z credit is effective for fuel produced after December 31, 2024, EPA had insufficient data on the impacts of the new structure of the credit and the market's response to consider these impacts in the Set 2 proposal. However, the significant drop in the total volume of imported non-cellulosic advanced biofuels observed in 2025 further supports our decision to base the non-cellulosic advanced biofuel Analyzed Volumes on our projection of domestic production capacity for these fuels.

Given the nested nature of the statutory renewable fuel categories, we largely framed our assessment of volumes in terms of the component categories rather than in terms of the statutory categories (cellulosic biofuel, BBD, advanced biofuel, and total renewable fuel). The statutory categories are those addressed in CAA section 211(o)(2)(B)(i)–(ii). The component categories are the categories of renewable fuels that make up the statutory categories, but which are not nested within one another. They possess distinct economic, environmental, technological, and other characteristics relevant to the factors we must analyze under the statute, making our focus on them rather than the nested categories in the statute technically sound. Finally, an analysis of the component categories is equivalent to analyzing the statutory categories, since doing so would effectively require us to evaluate the difference between various statutory categories (*e.g.,* assessing ''the difference between volumes of advanced biofuel and total renewable fuel'' instead of assessing ''the volume of conventional renewable fuel''), adding unnecessary complexity to our analysis. In any event, were we to frame our analysis in terms of the statutory categories, we believe that our substantive approach and conclusions would remain materially the same.

In sections III.A.1 through 4 of this preamble, we provide greater detail on the methodology and data used for identifying the Analyzed Volumes of cellulosic biofuel, non-cellulosic advanced biofuel, and conventional renewable fuel.

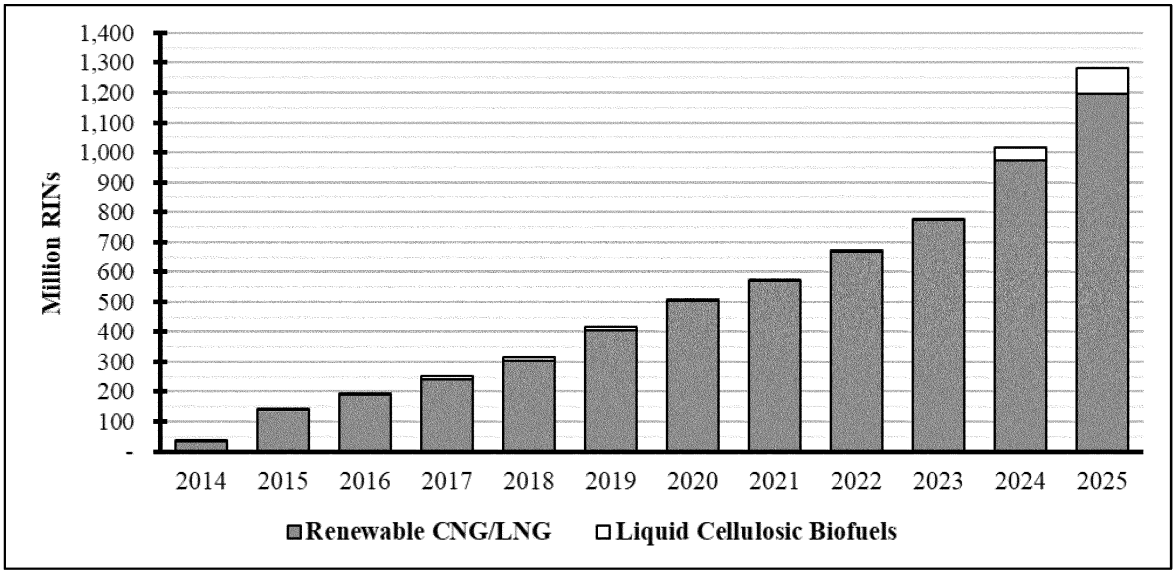
1. Cellulosic Biofuel

CAA section 211(o)(1)(E) defines cellulosic biofuel as renewable fuel derived from any cellulose, hemi-cellulose, or lignin that has lifecycle greenhouse gas (GHG) emissions that are at least 60 percent less than the baseline lifecycle GHG emissions. Since the inception of the RFS program, cellulosic biofuel production has steadily increased, reaching record levels in 2025. This growth has primarily been driven by renewable CNG/LNG, although small volumes of liquid cellulosic biofuels, particularly ethanol produced from CKF, have also played a contributing role.

Figure III.A.1–1: Cellulosic RINs Generated

[58] For example, the analyses that support this final rule have been revised to reflect tax credit changes in OBBB.

[59] Public Law 119–21 (2025).



Note: We do not yet have final renewable CNG/LNG generation data at the time of this analysis. Based on the information currently available and the timing of this analysis, we do not expect the reported figures to differ materially from the final data.

Sections III.A.1.a–d of this preamble describe our methodology for determining the appropriate volumes of renewable CNG/LNG and CKF ethanol and, in turn, the total cellulosic biofuel volume used in our statutory factor analysis. Additional details on our volume projections for cellulosic biofuel are provided in RIA Chapter 7.1.

a. Renewable CNG/LNG

To qualify as a RIN-generating fuel under the RFS program biogas from qualifying sources must first be collected and upgraded for vehicle use. The upgrading process varies depending on the final application but typically involves removing undesirable components and contaminants from the raw biogas. Biogas that has been upgraded and distributed through a closed distribution system, either as a biointermediate or for the production of renewable fuel, is defined as ''treated biogas,'' whereas biogas that has been upgraded to be suitable for injection into the commercial natural gas pipeline system and could be used to produce renewable fuel is defined as ''renewable natural gas'' (RNG).[60] 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. Likewise, we use ''renewable CNG/LNG'' to refer to both treated biogas and RNG when used as a transportation fuel in CNG/LNG vehicles, and we apply this term in contexts where such use is eligible for and results in RIN generation and separation under the RFS program.

To determine appropriate volumes of renewable CNG/LNG, we analyzed two factors: the amount of RNG that could be produced and the amount of renewable CNG/LNG that could be consumed as RFS-qualifying transportation fuel. As discussed further below and in RIA Chapter 7.1, we updated the analysis from the Set 2 proposal, taking into consideration data and information provided by commenters, and we continue to find that consumption, not production, is the primary constraint on future volumes of renewable CNG/LNG.

For our assessment of consumption of renewable CNG/LNG, we first estimate total CNG/LNG use in transportation, regardless of whether the fuel is fossil-based or renewable. Our methodology is the same as in the Set 2 proposal: we combine estimates of the number of vehicles capable of using CNG/LNG with data on vehicle miles traveled, fuel economy, and fuel consumption. Since the Set 2 proposal, we updated these inputs using more recent data. Commenters generally agreed with our methodologies for estimating consumption, though some urged more aggressive assumptions for fuel use and anticipated market growth. We address these points in detail in RTC Section 3; based on the available data, however, we believe our estimates strike an appropriate balance that reflects potential growth in total CNG/LNG consumption while remaining grounded in observed market trends. Having established this total-use baseline, we then assess the practical limits on the share of CNG/LNG that can be supplied by RNG. Fully replacing total CNG/LNG usage with RNG is unlikely due to facility-specific infrastructure limitations, costs, and other challenges. Therefore, to account for this, we adjusted our total CNG/LNG estimate to reflect these constraints and calculated the share that can realistically be met with RNG.

To calculate this usage and verify that it reflects real-world conditions, we examined data from California's Low Carbon Fuel Standard (LCFS) program. This data shows that approximately 97 percent of transportation CNG/LNG demand in California has been supplied by RNG over the past several years, which is the same figure cited in the Set 2 proposal and remains valid based on updated data.[61] Accordingly, we applied a 97 percent factor to total CNG/LNG consumption to estimate potential renewable-based volume. The results of our projected total CNG/LNG transportation use and the applied 97 percent efficiency factor are shown in Table III.A.1.a–1 and further discussed in RIA Chapter 7.1.4.1.

To validate this expected consumption-limitation on renewable CNG/LNG volumes, we also examined potential production capacity under unconstrained market conditions (*i.e.,* assuming no consumption limits) to determine whether production, rather

[60] 40 CFR 80.2.

[61] CARB, ''LCFS Quarterly Data Summary Spreadsheet,'' August 11, 2025. *https://ww2.arb.ca.gov/resources/documents/low-carbon-fuel-standard-reporting-tool-quarterly-summaries.*

than consumption, may be the limiting constraint in 2026 and 2027. To do this, we used the same industry-wide production projection method employed in RFS standard-setting since 2018: applying an industry-wide year-over-year growth rate to the current RNG production rate (see RIA Chapter 7.1.2).

Specifically, we determined an appropriate year-over-year production growth rate by analyzing cellulosic RIN generation for RNG over the two most recent full calendar years. While we have historically used a rolling 24-month window, including in the Set 2 proposal, for this analysis we aligned to calendar years to reduce seasonal distortion as RIN generation typically slows early in the year and surges at year-end. Early 2025 departed from this pattern, likely due to new biogas regulatory reform regulations, so using full calendar year data captures both the complete seasonal cycle and any changes to the seasonal pattern of RIN generation for RNG attributable to the biogas regulatory reform changes. From this data, we derived a 24 percent year-over-year growth rate. We applied this rate to the 2025 cellulosic RIN generation baseline for RNG to project 2026 RIN generation and then used the 2026 projection to estimate 2027 RIN generation. Results from our growth rate-based production estimate are shown in Table III.A.1.a–1 and discussed further in RIA Chapter 7.1.4.2.

Table III.A.1.a-1: Estimated Total CNG/LNG Consumption, Renewable CNG/LNG Consumption, and Renewable CNG/LNG Production

	Total CNG/LNG (million ethanol-equivalent gallons)	Renewable CNG/LNG (million RINs)	
Year	Consumption	Consumption	Production
2026	1,273	1,235	1,495
2027	1,347	1,306	1,853

Performing this analysis and comparing RNG production with consumption of renewable CNG/LNG confirms that for 2026 and 2027, production is expected to exceed consumption as transportation fuel. This shows that the volume of these fuels will most likely be constrained by the market's capacity to use RNG as an RFS-qualifying transportation fuel. Importantly, under the RFS regulations for biogas-derived renewable fuel as amended in the Set 1 Rule,[62] while RINs for renewable CNG/LNG are generally generated when the RNG is injected into a commercial pipeline,[63] they are separated and available for compliance only once the gas is used as transportation fuel.[64] Consequently, even if production is higher than consumption, the number of separated RINs from renewable CNG/LNG remains constrained by total CNG/LNG use in transportation.

In previous RFS rulemakings, we recognized that renewable CNG/LNG consumption could eventually become the limiting factor in determining volumes but did not know when it would do so. In the Set 1 Rule, we set the 2023–2025 cellulosic biofuel volume requirements based on projected production and the historical growth of cellulosic RIN generation, assuming production capacity, not end-use consumption, would be the primary constraint.[65] Evidence now shows a potential shift toward a consumption-limited baseline for those years. Cellulosic biofuel deficits from 2023 and 2024 carried into the following year were significantly larger than the deficits in previous years.[66] EPA partially waived the 2024 cellulosic biofuel volume requirement due to a shortfall in the projected volume of cellulosic biofuel available relative to the 2024 cellulosic biofuel standard.[67] Similarly, as described in section VI of this preamble, we are partially waiving the 2025 cellulosic biofuel volume requirement due to a shortfall in 2025 cellulosic RINs necessary to meet the original 2025 requirement established in the Set 1 Rule.

In addition, we are also now seeing a rapid increase in cellulosic RINs retired for non-transportation purposes, which provides further evidence that consumption, rather than production capacity, is increasingly the binding constraint. Specifically, retirements of cellulosic RINs for non-transportation use increased from 0.4 million RINs in 2024 to 74.5 million RINs in 2025,[68] further reducing the number of cellulosic RINs available for compliance.[69] Thus, while we still project continued growth in cellulosic biofuel production in 2026 and 2027, growth in cellulosic RIN availability is likely to remain significantly constrained for the foreseeable future by the ability of fuel consumers to use renewable CNG/LNG.

Based on our analysis of renewable CNG/LNG consumption and RNG production, we reach the same conclusion as in the Set 2 proposal: in 2026 and 2027, cellulosic volumes from renewable CNG/LNG are constrained by total CNG/LNG transportation usage. Commenters were divided on this point; some agreed that consumption could limit volumes in the near term, while others argued that we should base our Analyzed Volumes solely on projected production without consideration of the end use of the CNG/LNG. Because cellulosic RINs can only be separated and made available to demonstrate compliance if the CNG/LNG is used as transportation fuel, EPA decided it was appropriate to consider constraints related to the use of CNG/LNG as transportation fuel in determining the Analyzed Volumes. Accordingly, we treat the volumes in Table III.A.1.a–2 as the renewable CNG/LNG contribution to the total cellulosic biofuel volume used in our statutory factor analysis.

[62] Prior to these regulatory changes, which went into effect on January 1, 2025, RINs for CNG/LNG derived from biogas could not be generated until parties demonstrated that the CNG/LNG had been produced from qualifying renewable biomass and used as transportation fuel.

[63] 40 CFR 80.125(b).

[64] 40 CFR 80.125(d).

[65] Set 1 RIA Chapter 6.1.3.

[66] Cellulosic biofuel deficits for 2023 and 2024 were approximately 55–60 million RINs each year. Prior the 2023, the largest cellulosic biofuel deficit in a single year was approximately 20 million RINs in 2017. See "RFS Compliance Data as of February 20, 2026," available in the docket for this action.

[67] 90 FR 29751 (July 7, 2025).

[68] See "RIN retirement data from January 2026" RIN data file available at: *https://www.epa.gov/fuels-registration-reporting-and-compliance-help/spreadsheet-rin-retirement-data-renewable-fuel.*

[69] For a detailed discussion, see RIA Chapter 7.1.3.

Table III.A.1.a-2: Estimated Volume of Renewable CNG/LNG (million RINs)

Year	Volume
2026	1,235
2027	1,306

b. Ethanol From Corn Kernel Fiber

Several technologies are currently being developed to produce liquid fuels from cellulosic biomass. However, most of these technologies are unlikely to yield significant volumes of cellulosic biofuel by 2027. One notable exception is the production of ethanol from CKF, for which several companies have developed production processes. Many of these processes involve co-processing of both the starch and cellulosic components of the corn kernel. However, to be eligible for cellulosic RIN generation, facilities must accurately determine the amount of ethanol produced specifically from the cellulosic portion of the corn kernel using approved methodologies. 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, we issued updated guidance on analytical methods that could be used to quantify the amount of ethanol produced when co-processing CKF and corn starch.[70]

We 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, we believe that cellulosic ethanol production from CKF could be feasible at all existing corn ethanol facilities, with minimal additional processing units or modifications. To generate cellulosic RINs for ethanol produced from CKF, a facility would need to demonstrate the converted fraction consistent with appropriate test methods. For the purposes of this analysis, we assume that 90 percent of facilities will produce cellulosic ethanol over this period due to potential facility-specific challenges that may prevent 100 percent adoption.

Based on data submitted to the EPA by renewable fuel producers generating cellulosic RINs for CKF ethanol, the current industry-wide average conversion among registered facilities is approximately 1 percent. Accordingly, for this analysis we use a 1 percent conversion rate. We recognize that some parties have claimed they can demonstrate up to 1.5 percent conversion using analytical methods consistent with EPA guidance, but we do not yet have sufficient data to support adopting that higher rate.

Commenters generally supported our inclusion of robust volumes of CKF ethanol. Some, however, as discussed earlier, urged more aggressive assumptions for facility participation and conversion efficiency. We address these comments in detail in RTC Section 3. Based on the available data, we do not find sufficient support to increase these rates at this time.

The projected production of cellulosic ethanol from CKF, as shown in Table III.A.1.b–1, is based on projections of total corn ethanol production, with a 90 percent facility participation rate and a 1 percent conversion efficiency applied.[71]

Table III.A.1.b-1: Projected Production of Ethanol from CKF (million RINs)

Year	Volume
2026	128
2027	128

c. Other Cellulosic Biofuels

We expect U.S. commercial-scale production of cellulosic biofuels, other than renewable CNG/LNG and CKF ethanol, to be very limited in 2026 and 2027. Several technologies in development may be capable of producing small volumes by 2027. These technologies primarily target cellulosic hydrocarbons from feedstocks such as separated municipal solid waste (MSW), precommercial thinnings, and tree residues, which can be blended into gasoline, diesel, and jet fuel. However, because no producer has achieved sustained U.S. production to date, projected volumes for 2026 and 2027 remain highly uncertain and are likely to be small. Accordingly, we do not project production of cellulosic biofuels beyond renewable CNG/LNG and CKF ethanol during 2026 and 2027.

d. Summary of Cellulosic Biofuel Volumes

In determining the Analyzed Volumes of cellulosic biofuel for 2026 and 2027, we started by considering the statutory volume targets for 2010–2022. The statutory volumes for cellulosic biofuel increased rapidly, from 100 million gallons in 2010 to 16 billion gallons in 2022 with the largest increases in the later years. These increases are even more notable in comparison to the implied statutory volumes for the other renewable fuel volumes. Statutory BBD volumes did not increase after 2012, implied conventional renewable fuel volumes did not increase after 2015, and non-cellulosic advanced biofuel volumes reached a maximum of 5 billion in 2022. Thus, by 2022, the statute was clearly oriented toward expanding cellulosic biofuel volumes.

Given the statute's emphasis on growing cellulosic biofuel volumes, our statutory analysis evaluates the highest feasible volume of cellulosic biofuel. However, as discussed in section II.C of this preamble, CAA section 211(o)(2)(B)(iv) requires the EPA to set the cellulosic biofuel volume requirement such that we do not anticipate a need to waive the volumes under CAA section 211(o)(7)(D). Accordingly, the Analyzed Volumes of cellulosic biofuel used in our statutory analysis for 2026 and 2027 are equal to the projected amount of cellulosic biofuel used as RFS-qualifying transportation fuel in those years,

[70] 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.

[71] A detailed discussion of the methodology used to project cellulosic ethanol production from CKF can be found in RIA Chapter 7.1.5.

balancing the statute's goal of increasing cellulosic biofuel while avoiding the need to waive future volumes.

Table III.A.1.d–1 presents the Analyzed Volumes of cellulosic biofuels for 2026 and 2027. Because production characteristics and market conditions differ across cellulosic fuels, we present CKF ethanol and renewable CNG/LNG separately.

Table III.C.1-1: Analyzed Volumes of Cellulosic Biofuel (million RINs)

	2026	2027
Renewable CNG/LNG	1,235	1,306
Ethanol from CKF	128	128
Total cellulosic biofuel	1,363	1,434

2. Non-Cellulosic Advanced Biofuel

CAA section 211(o)(1)(D) defines BBD as renewable fuel that is biodiesel as defined by 42 U.S.C. 12330(f) and that has GHG emissions reductions of at least 50 percent from the baseline. It also excludes biodiesel that is co-processed with petroleum feedstocks. The BBD standard is nested within the advanced biofuel standard. Historically, the BBD supply under the RFS program has exceeded the BBD standard, with the additional supply used by obligated parties to meet their advanced biofuel volume requirements. Thus, the advanced biofuel standard has incentivized the use of BBD beyond just the BBD standard.

a. Biodiesel and Renewable Diesel

Since 2010, when the BBD volume requirement was added to the RFS program, production of BBD has generally increased annually. 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 including the RFS program; the availability of imported BBD; the demand for BBD (and feedstocks used to produce BBD) in foreign markets; and several other economic factors.

Most renewable fuel that qualifies as BBD is either biodiesel or renewable diesel. Both these fuels are replacements for petroleum diesel and are produced from the same lipid-based feedstocks, a diverse category that includes animal fats, UCO, and vegetable oil feedstocks. Biodiesel and renewable diesel differ in their production processes and chemical composition. Biodiesel is an oxygenated fuel that is generally produced using a transesterification process. Renewable diesel, on the other hand, is a hydrocarbon fuel that closely resembles petroleum diesel and that is generally produced by hydrotreating renewable feedstocks.

i. Historic Production of Biodiesel and Renewable Diesel

From 2012 through 2022 the largest volume of advanced biofuel supplied in the RFS program was biodiesel. Domestic biodiesel production increased from approximately 1.3 billion gallons in 2014 to approximately 1.8 billion gallons in 2018. From 2018 to 2024, domestic biodiesel production decreased slightly to approximately 1.7 billion gallons. In 2025, domestic biodiesel production decreased to an estimated 1.1 billion gallons.[72]

In the early years of the RFS program renewable diesel was produced and imported in smaller quantities than biodiesel, as shown in Figure III.A.2.a.i–1. In recent years, however, domestic production of renewable diesel has increased significantly. Renewable diesel production facilities generally have higher capital costs relative to biodiesel, which likely accounts for the historically higher volumes of biodiesel production relative to renewable diesel production prior to 2023. The higher capital cost of renewable diesel production can largely be offset through the benefits of economies of scale, since renewable diesel production facilities tend to be much larger than biodiesel production facilities.[73] For example, according to data from the U.S. Energy Information Administration (EIA), in 2025, there were 19 active renewable diesel facilities that produced an average of 248 million gallons of renewable diesel per facility,[74] compared to 48 active biodiesel facilities that produced an average of 41 million gallons of biodiesel per facility.[75]

Because renewable diesel more closely resembles petroleum diesel than biodiesel, renewable diesel can be blended at much higher concentrations with diesel than biodiesel. This allows renewable diesel to more easily be blended into diesel at higher rates and enables renewable diesel producers to sell greater volumes of renewable diesel in California, benefiting from the LCFS credits in California in addition to RFS incentives and the 45Z credit.[76] The greater ability for renewable diesel to generate credits under California's LCFS program provides a significant advantage over biodiesel. Biodiesel blends in California containing 6–20 percent biodiesel require the use of an additive to comply with California's Alternative Diesel Fuels Regulations, making the use of higher-level biodiesel blends more challenging in California.[77] The Washington, Oregon, and New Mexico programs modeled from the California LCFS have generally mirrored this incentive structure. If additional States were to adopt clean fuels programs using a similar structure, these programs could provide an additional advantage to renewable diesel production relative to biodiesel production in the U.S.

Figure III.A.2.a.i–1: Domestic Production of Biodiesel and Renewable Diesel

[72] Further details on these volume projections can be found in RIA Chapter 7.2.

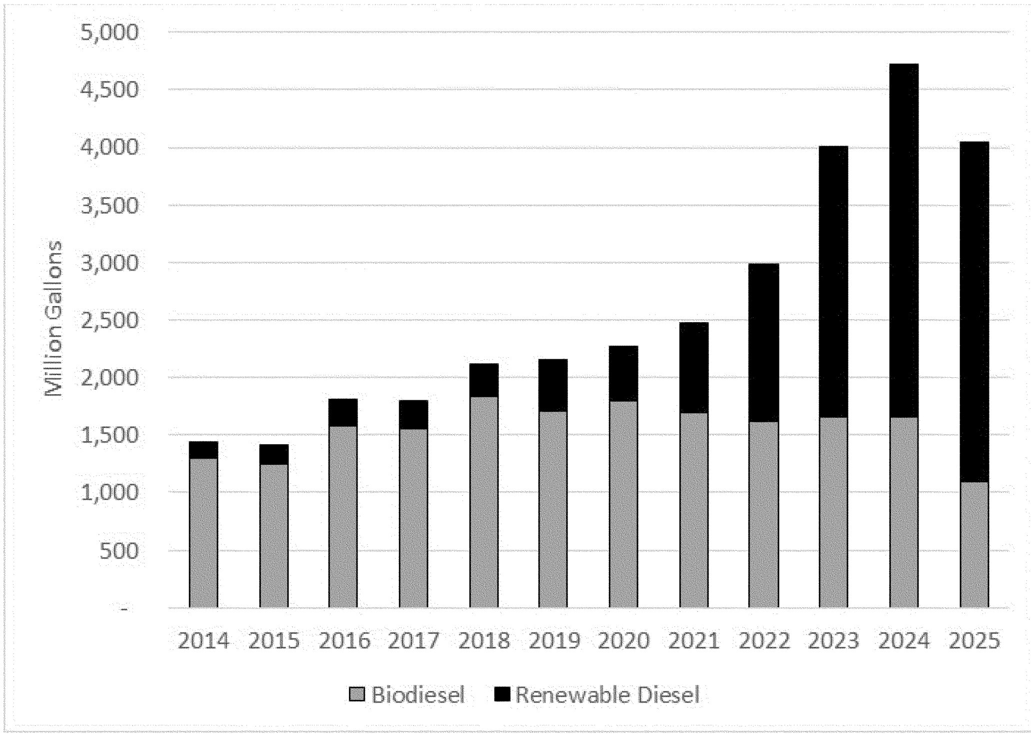
[73] See RIA Chapter 10 for more detail on our assessment of the cost to produce biodiesel and renewable diesel.

[74] EIA, ''U.S. Renewable Diesel Fuel and Other Biofuels Plant Production Capacity,'' September 26, 2025. *https://www.eia.gov/biofuels/renewable/capacity.*

[75] EIA, ''U.S. Biodiesel Plant Production Capacity,'' September 26, 2025. *https://www.eia.gov/biofuels/biodiesel/capacity.*

[76] For example, when LCFS credits are worth $100/metric ton, blending renewable diesel into California generates LCFS credits worth approximately $0.25 to $0.90 per gallon (assuming carbon intensities of 70 and 20 gCO_2e/MJ respectively). Renewable fuel producers that sell qualifying renewable fuel in California can generate both RINs under the RFS program and LCFS credits.

[77] CARB, ''Frequently Asked Questions on the Alternative Diesel Fuels Regulation,'' November 2017. In 2021, nearly all renewable diesel consumed in the U.S. was consumed in California. Together renewable diesel and biodiesel represented approximately 65–70 percent of all diesel fuel consumed in California in the second half of 2024.



Data Source: EMTS. This figure does not include jet fuel that was produced or fuels that did not generate RINs. This figure also does not include advanced (D5) or conventional (D6) biodiesel and renewable diesel, which are discussed in sections III.A.2.c and III.A.3.b of this preamble and RIA Chapters 7.4 and 7.7.

Imports and exports of biodiesel and renewable diesel also impact the domestic supply of these fuels. The U.S. has been a net importer of biodiesel since 2013. Biodiesel imports reached a peak in 2016, with the majority of the imported biodiesel coming from Argentina.[78] In August 2017, the U.S. announced tariffs on biodiesel imported from Argentina and Indonesia.[79] These tariffs were subsequently confirmed in April 2018 and remain in place after being reaffirmed in 2023.[80] Biodiesel imports started dropping in 2017 but increased precipitously in 2023, reaching approximately 500 million gallons.[81] Biodiesel imports saw large declines in 2024 and 2025 to 398 million gallons and 34 million gallons, respectively.[82]

Imports and exports of renewable diesel have also varied over time. Nearly all the renewable diesel imported into the U.S. through 2025 was imported from Singapore.[83] In more recent years, the U.S. has also exported increasing volumes of renewable diesel. In 2022–2025, renewable diesel exports exceeded renewable diesel imports based on data collected through EMTS (see Table III.A.2.b–1).

The simultaneous import and export of significant volumes of biodiesel and renewable diesel is likely the result of a number of factors, including the design of the previous biodiesel tax credits (which were available with respect to biodiesel and renewable diesel that was either produced or used in the U.S. and thus eligible for exported volumes as well), the varying structures of the available incentives (with the level of incentives varying by country and often depending on the feedstocks used), and logistical considerations (biodiesel and renewable diesel may be imported and exported from different parts of the country). Starting in 2026, the 45Z credit, which consolidated and replaced the previous $1 per gallon credits for biodiesel and renewable diesel, is only available for fuel produced in the U.S. from feedstocks sourced from North America. As the 45Z credit, unlike the tax credits it replaced, does not provide tax incentives to imported biofuels, imports of biodiesel and renewable diesel dropped significantly in 2025 relative to previous years. The magnitude of the effect of the structure of the 45Z credit was not apparent in the available data at the time of the Set 2 proposal. We expect that biodiesel and renewable diesel imports will continue to be available in future years, but that the structure of the 45Z credit will continue to provide strong support for biodiesel and renewable diesel produced in the U.S. relative to imported fuels.

[78] In 2016 and 2017, 67 percent of all biodiesel imports were from Argentina. 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.*

[79] 82 FR 40748 (August 28, 2017).

[80] 83 FR 18278 (April 26, 2018).

[81] 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.*

[82] See RIA Chapter 7.2 for further discussion of EPA estimates of imports and exports of BBD.

[83] EIA, ''U.S. Imports by Country of Origin—Renewable Diesel Fuel,'' Petroleum & Other Liquids, April 30, 2025. *https://www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_EPOORDO_im0_mbbl_a.htm.*

Table III.A.2.b-1: Renewable Diesel Imports and Exports (million gallons)

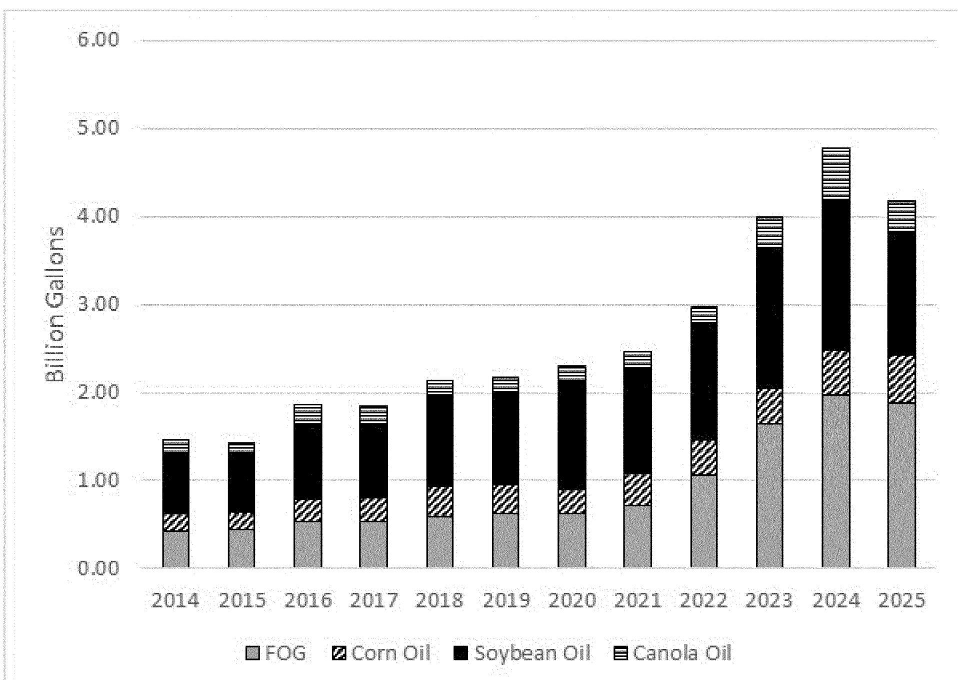
	Biodiesel			Renewable Diesel		
Year	Imports	Exports	Net Imports	Imports	Exports	Net Imports
2015	261	73	188	120	21	99
2016	562	89	473	165	40	125
2017	462	129	333	191	37	154
2018	175	74	101	176	80	96
2019	185	81	104	267	148	119
2020	209	88	121	280	223	57
2021	208	91	117	262	241	121
2022	240	117	123	311	326	-15
2023	501	97	404	361	414	-53
2024	398	82	316	430	581	-151
2025	34	32	2	105	458	-353

Data Source: EMTS

ii. Biodiesel and Renewable Diesel Feedstock Assessment

When considering the potential production and import of biodiesel and renewable diesel in future years and the likely impacts of biodiesel and renewable diesel production, feedstock availability is a key consideration. Currently, biodiesel and renewable diesel in the U.S. are produced from a number of different feedstocks, including fats, oils, and greases (FOG), distillers corn oil, and virgin vegetable oils such as soybean oil and canola oil. The available supply of distillers corn oil is primarily a function of corn ethanol production, as most corn ethanol facilities currently extract and sell distillers corn oil. The available supply of soybean oil and canola oil is primarily a function of the quantity of these oils produced by oilseed crushing facilities, both of which have increased in recent years.[84]

Figure III.A.2.a.ii–1: Feedstocks Used To Produce Biodiesel and Renewable Diesel in the U.S.



Data Source: EMTS. Includes biodiesel and renewable diesel produced in the US from imported feedstocks.

[84] USDA, "Fats and Oils: Oilseed Crushings, Production, Consumption, and Stocks," February 2, 2026. *https://esmis.nal.usda.gov/sites/default/release-files/795753/cafo0226.pdf.*

Use of soybean oil to produce biodiesel grew from approximately 10 percent of all domestic soybean oil production in the 2009/2010 agricultural marketing year to 48 percent in the 2023/2024 agricultural marketing year, the latest data available at the time of writing.[85] In the intervening years, the total increase in domestic soybean oil production and the increase in the quantity of soybean oil used to produce biodiesel and renewable diesel were similar while the use of soybean oil in non-biofuel markets has been fairly stable. This indicates that the increase in oil production was likely driven by the increasing demand for biofuel. Notably, the percentage of the soybean value that came from the soybean oil (rather than the meal and hulls) had been relatively stable and averaged approximately 33 percent from 2016–2020. The percentage of the soybean value that came from the soybean oil increased significantly starting in 2021, reaching a high of 53 percent in October 2021, before declining slightly to 39 percent in August 2024 (the most recent date for which data are available).[86]

Available volumes of FOG (including UCO and animal fats) and distillers corn oil from domestic sources are expected to continue to increase in future years, but these increases are expected to be limited, especially as new trade dynamics take hold. FOG feedstocks, like UCO, are the byproducts of other activities (*e.g.,* food production and rendering operations), and production of FOG is not responsive to increasing demand for biofuel production. Similarly, distillers corn oil is a byproduct of ethanol production. Since we do not anticipate significant growth in ethanol production in future years (see section III.A.3.a of this preamble), we do not project significant increases in the production of distillers corn oil for biofuel production, as most ethanol production facilities currently produce distillers corn oil. Therefore, if biodiesel and renewable diesel production increase in future years, it will likely require increased use of vegetable oils such as soybean oil and canola oil, either from new production or diverted from other markets, or increased use of imported feedstocks, as occurred in 2022 and 2023 to some extent.

Greater volumes of soybean oil are projected to be produced from new or expanded soybean crushing facilities through 2027. In recent years, several parties announced plans to expand existing soybean crushing capacity or build new soybean crushing facilities, including a swing plant in Louisiana and a dedicated soy crush plant in Illinois.[87] Public announcements of near-certain expansions and new builds suggest that domestic soybean crush capacity could reach 615,000 bushels per day in 2026, with growth largely coming from announced or planned crush plants.[88] This projection, which only accounts for plants recently completed or under construction as of Q1 2026 would result in 360 million additional gallons of BBD in 2026 alone.[89] At the time of writing, USDA projects 2026 increases in soy crush that could result in domestic soybean oil production sufficient to produce approximately 200 million gallons over current levels annually.[90] Including announced future capacity, some projections of the domestic crush capacity could result in an increase in domestic soybean oil production sufficient to produce approximately 750 million additional gallons of BBD per year and suggests a 250 million gallon per year annual increase in soybean oil production through 2026.[91] Similarly, a 2024 assessment of potential BBD feedstocks in future years estimated that increases in domestic soybean oil production could support the production of an additional 1 billion gallons of BBD from 2023 to 2027.[92]

Recent data suggests that the domestic soybean crushing industry is capable of continuing to add significant capacity in future years, but any investment in domestic soybean crushing is highly dependent on demand for soybean oil (and soybean meal) from biofuel producers and other markets.[93]

If domestic crushing of soybeans increases at the expense of soybean exports, domestic vegetable oil production could increase without the need for increasing domestic soybean acreage. Increased demand for BBD feedstock could also be met through diversion of increasing volumes of qualifying feedstocks (*e.g.,* soybean oil and canola oil) from existing markets to produce biodiesel and renewable diesel. Were this diversion to occur, non-qualifying feedstocks (*e.g.,* palm oil, imported soybean oil from Latin American, or other virgin vegetable oils) could be used in larger quantities in place of soybean and canola oil in food and oleochemical markets. Diverting feedstocks from existing uses would be projected to result in higher prices for these feedstocks, as biofuel producers would have to outbid the current users of these feedstocks.

In addition to processing domestic feedstocks such as distillers corn oil and soybean oil, a number of domestic biodiesel and renewable diesel producers produce fuel from imported feedstocks. In recent years, the market has seen a significant increase in the quantity of imported feedstocks. Imports of feedstocks that are often considered wastes or by-products of other industries, such as UCO and tallow, have seen the greatest increase in recent years. Figure III.A.2.b.ii-1 shows total imports of common biodiesel and renewable diesel feedstocks through 2024. Figure III.A.2.b.ii-2 shows the total volumes of domestic biodiesel and renewable diesel produced from domestic feedstocks, domestic biodiesel and renewable diesel produced from imported feedstocks, and imported biodiesel and renewable diesel. Greater discussion of both domestic and imported feedstocks can be found in RIA Chapter 7.2.

Figure III.A.2.b.ii–1: Imports of BBD Feedstocks

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

[86] *Id.*

[87] American Soybean Association, ''Soybean Crush Expansion, 2025 Update,'' April 10, 2025. *https://soygrowers.com/news-releases/soybean-crush-expansion-2025-update.*

[88] American Soybean Association, ''Soybean Crush Expansion, 2025 Update,'' April 10, 2025. *https://soygrowers.com/news-releases/soybean-crush-expansion-2025-update.*

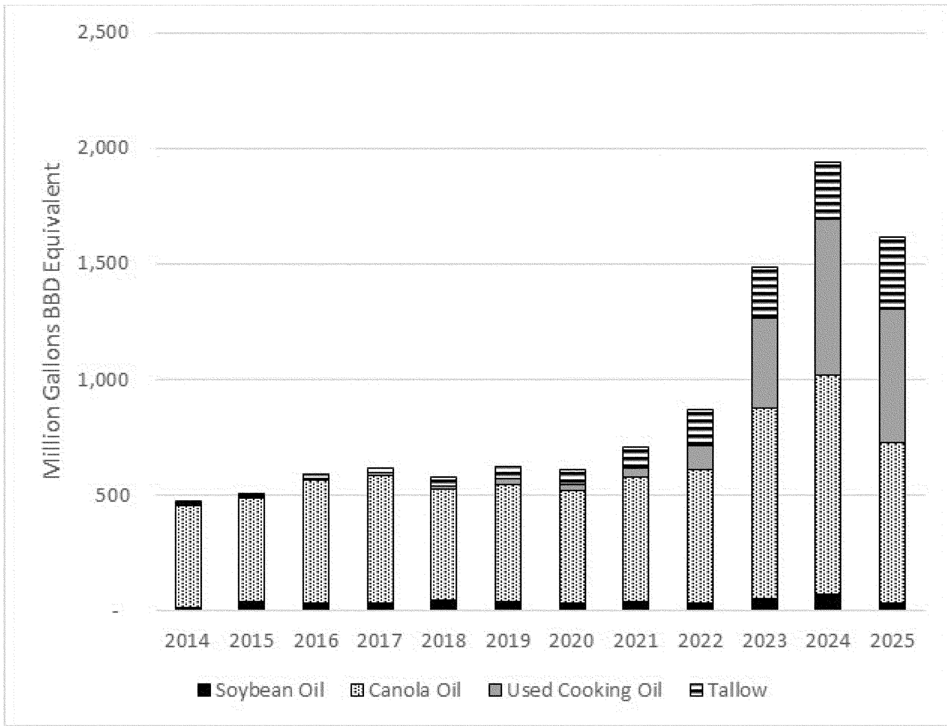
[89] To note, announced facilities that have not begun construction as of Q1 2026 are considered too uncertain.

[90] USDA, ''World Agricultural Supply and Demand Estimates Report,'' January 12, 2026. *https://www.usda.gov/oce/commodity/wasde/wasde0126.pdf.*

[91] See RIA Section 7.2. This estimate assumes a soybean oil yield of 12 lbs per bushel of soybeans and 1 gallon of BBD per 7.75 lbs of soybean oil.

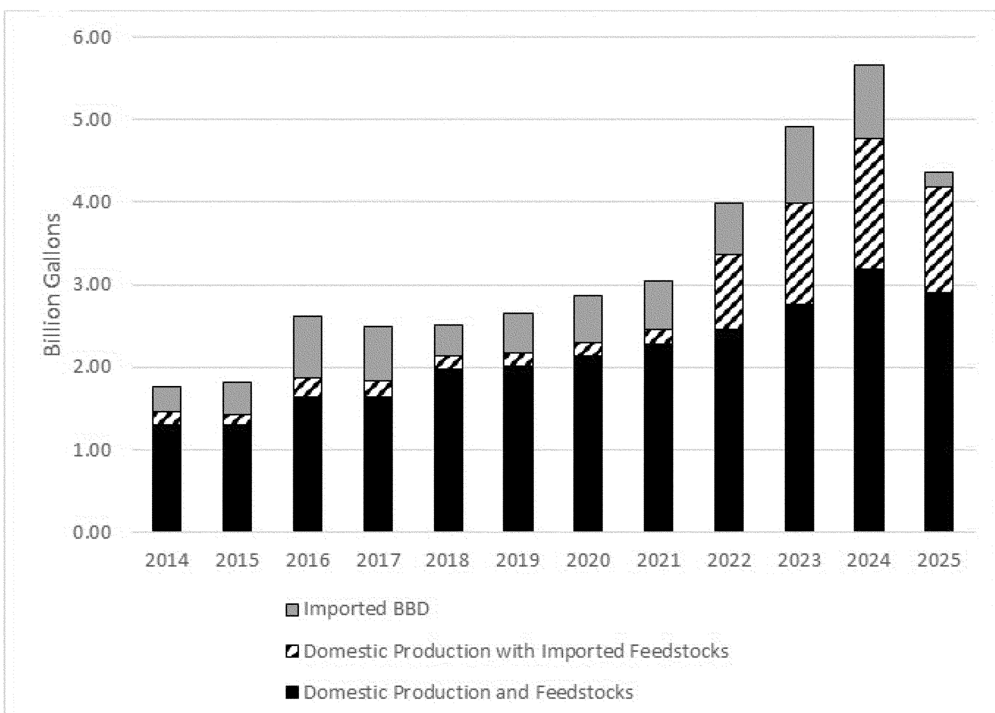
[92] S&P Global, ''Availability of Feedstocks for Biofuel Use—Key Highlights,'' July 2024.

[93] See RIA Chapter 7.2 for further discussion of this topic.



Data Source: UN ComTrade. Data for 2025 is projected based on available data through October 2025.

Figure III.A.2.b.ii–2: Domestic BBD From Domestic and Imported Feedstocks and Imported BBD



Data Source: EMTS. Includes all BBD for which RINs are generated; does not account for exported BBD.

There are several factors that have likely contributed to the recent increases in imports of certain BBD feedstocks to the U.S. Three key factors contributing to the increase in imported feedstocks are increasing domestic demand for these feedstocks, increasing available supply of these feedstocks in other countries, and the structure of incentive programs for biofuels in the U.S. relative to other countries' policies. As noted in section III.A.2.b.iii of this preamble, the production capacity for renewable diesel and renewable jet fuel has increased rapidly and is expected to continue to be maintained or grow in future years. As the total production capacity for these fuels has grown, the demand for feedstocks for renewable fuel production has grown along with the production capacity. This has led to increases in not only domestic feedstock demand, but imported feedstock demand as well. For example, we project that production of canola oil will increase in future years due to expanding canola crushing capacity in Canada and that much of this expanded production will be exported to the U.S. for biofuel production.[94] Similar to the investments in soybean crushing in the U.S., a number of companies have announced investment in additional canola crushing capacity in Canada, and some of these projects are already under construction. Increasing canola oil production in Canada could provide an opportunity for domestic renewable diesel producers to import canola oil for biofuel production. We note that these parties will face competition for this feedstock from Canadian biofuel producers as well as food and other non-biofuel markets. For example, in 2023, Canada began implementing their Clean Fuels Requirements, requiring that the carbon intensity of transportation fuel decrease by 1.5 gCO_2e/MJ per year each year from 2023 to 2030.[95]

Canadian canola oil is the most prominent non-domestic beneficiary after the 45Z credit changes in OBBB, but other non-domestic North American feedstocks will also likely begin to expand their role in the U.S. biofuels markets. This includes virgin seed oils, animal fats, and larger UCO markets. In particular, Mexican UCO collection is poised to expand, due to a precipitous dip in the observed trend of imported Asian UCO in 2025 and lower collection costs than Canada.[96] Domestic incentives, coupled with rapidly shifting international financial backing for biofuels, are poised to shift the biofuels feedstocks market.

The incentives available in foreign countries to encourage production and use of BBD are changing rapidly, on an almost annual basis. For example, in response to the Russian invasion of Ukraine in February 2022, many European countries reduced biofuel mandates and penalties for not fulfilling the mandates.[97] The reduction in demand from these countries resulted in an increase in the available feedstock supply to the U.S. Around the same time, the European Union (EU) took actions to discourage the importation of UCO and biodiesel produced from China. On December 20, 2023, the EU announced an anti-dumping investigation on biodiesel imported from China,[98] finalized in July 2024.[99] These actions, in part, led to increased UCO importation into the U.S. from China. By that same token, however, export of Chinese UCO was greatly affected by the removal of an export rebate by the Chinese government in order to incentivize use in their burgeoning sustainable aviation industry, contributing to declining growth of UCO importation in the U.S. in 2024 and 2025.[100]

Recent changes in the trade flows of UCO from China illustrate the changing nature of incentive programs and the impact these changes can have on the supply of biofuel feedstocks. From 2018–2023, exports of UCO from China increased significantly, from approximately 0.6 million metric tons in 2018 to about 2.1 million metric tons in 2023. From 2018–2022, the primary destination of these exports was Europe, accounting for approximately 60 percent of all exports of UCO from China, while less than 1 percent of all exports of UCO from China were exported to the U.S.[101] In 2023, however, the market dynamics changed significantly. Exports of UCO from China to Europe fell to just 23 percent of total exports, while exports to the U.S. increased to 41 percent.[102] The decline in European UCO imports was due to a combination of factors, including reduced demand for biodiesel and renewable diesel in some EU member states and concerns that imported UCO from China may include palm oil. These concerns resulted in decreased demand for UCO sourced from China in the EU and simultaneous increased demand for this feedstock in the U.S. In 2025, this dynamic again shifted, with a precipitous drop in U.S. imports of Chinese UCO. This coincided with a high tariff environment, the removal of a UCO export rebate by the Chinese government in December 2024,[103] and a upsurge of Chinese sustainable aviation fuel refining.[104] The unpredictable nature of changes to biofuel incentives in both the U.S. and other countries in future years, combined with the potentially significant impact of these changes, makes it very difficult to predict the supply of these feedstocks to U.S. biofuel producers with a high degree of certainty.

Incentive programs for biofuels in the U.S. have also contributed to the recent observed increases in biofuel feedstock imports. State low carbon fuel standards or clean fuels programs, such as California's LCFS, provide greater incentives for fuels with lower carbon intensities. In general, fuels produced from byproducts such as UCO or tallow have lower carbon intensity values under these programs and thus generate greater credits relative to virgin vegetable oils such as soybean oil and canola oil. In recent years, additional States such as Oregon, Washington, and New Mexico have adopted programs that similarly provide higher incentives for fuels with lower carbon intensity.

While these State programs do not explicitly favor imported fuels and/or feedstocks over domestic fuels and feedstocks, most of the available waste and by-product feedstocks such as UCO and tallow available in the U.S. are already being used for biofuel production. The nature of these programs has played a role in biofuel producers seeking to import UCO and

[94] Some of the projected expansion in soybean crushing capacity discussed in section III.B.2.c of this preamble is from facilities also capable of crushing canola and other oilseeds. Domestic production of canola is limited, however, and the majority of canola oil supplied to biofuel producers through 2027 is expected to be imported from Canada.

[95] Government of Canada, ''What are the Clean Fuel Regulations?'' July 7, 2022. *https://www.canada.ca/en/environment-climate-change/services/managing-pollution/energy-production/fuel-regulations/clean-fuel-regulations/about.html.*

[96] See RIA chapter 7.2 for further discussion of North American feedstock growth potential.

[97] USDA, ''Biofuel Mandates in the EU by Member State—2024,'' June 27, 2024.

[98] European Commission, ''European Commission to Examine Allegations of Unfairly Traded Biodiesel from China,'' December 20, 2023. *https://policy.trade.ec.europa.eu/news/european-commission-examine-allegations-unfairly-traded-biodiesel-china-2023-12-20_en.*

[99] Reuters, ''EU to Set Tariffs on Chinese Biodiesel in Anti-Dumping Probe,'' July 19, 2024. *https://www.reuters.com/business/energy/eu-set-tariffs-chinese-biodiesel-imports-anti-dumping-probe-2024-07-19.*

[100] USDA FAS, ''UCO Export Tax Rebate Terminated'', *https://www.fas.usda.gov/data/china-uco-trade-update.*

[101] UN Comtrade Database, Trade Data, HS Code 1518.

[102] *Id.*

[103] USDA Foreign Agricultural Service, ''UCO Export Tax Rebate Terminated,'' CH2024–0149, November 25, 2024. *https://apps.fas.usda.gov/newgainapi/api/Report/DownloadReportByFileName?fileName=UCO%20Export%20Tax%20Rebate%20Terminated_Beijing_China%20-%20People%27s%20Republic%20of_CH2024-0149.pdf.*

[104] International Civil Aviation Organization, ''Progress of Sustainable Aviation Fuels Pilot In China,'' September 13, 2025. *https://www.icao.int/sites/default/files/Meetings/a42/Documents/WP/wp_573_en.pdf.*

tallow from foreign countries rather than increasing their use of domestic soybean oil to maximize their generation of credits under these programs.

For the reasons discussed above, in recent years, animal fats and UCO have become a popular source of feedstock. Most of the economically recoverable UCO and animal fats in the U.S. are currently collected and productively used, primarily for biofuel production.[105] It is a well-established market and while the supply of these feedstocks are projected to grow, the rate of growth will be modest and driven by domestic meat production and the use of vegetable oil for food production.

In contrast, there is both significant growth potential and a high degree of uncertainty surrounding the supply of animal fats and UCO that could be imported into the U.S. and used for biofuel production. There is large supply capable of being bid away from other markets, but rapidly shifting trading dynamics and strong domestic feedstock availability may dampen growth in future years. The global supply of animal fats is expected to increase with global meat consumption. Global meat production increased 53 percent from 2000 to 2021 and is expected to continue to increase in future years.[106] Like other biodiesel and renewable diesel feedstocks, animal fats have historically been used in other markets such as for oleochemical production and livestock feed. We project that strong incentives for biofuels produced from animal fats in the U.S. (from both State and Federal incentive programs) will result in increasing quantities of these feedstocks being used for biofuel production. Thus, we project that the available supply of animal fats to biofuel producers will increase in future years due to both increasing animal fat production as a byproduct of increasing meat production. It may also supplant some UCO imports as an alternative biofuel feedstock. In 2025, for example, tallow imports surged as UCO imports declined.[107] The environmental benefits associated with biofuels produced from diverting animal fats (or any feedstock) diverted from existing markets are likely less than the environmental benefits associated with biofuels produced from feedstocks that would not otherwise be productively used.[108]

The global supply of UCO is primarily a function of UCO collection rates, which are themselves a function of the total quantity of vegetable oils used in food production and the infrastructure in place to collect and productively use UCO. UCO collection rates vary significantly by country, from virtually nothing in many countries to approximately 2.5 pounds per capita per year in the U.S.[109] Demand for UCO as a feedstock for biofuel production in recent years has resulted in a rapid increase in the global collection of UCO, from approximately 2.3 billion gallons in 2018 to approximately 3.7 billion gallons in 2022.[110] A recent study projected that the increase in global UCO collection from 2022 to 2027 could range from 1.4 billion gallons (based on projected increases in population and GDP) to 6.1 billion gallons (based on increasing collection rates in countries that currently have some UCO collection infrastructure in place).[111]

Despite competing incentives and a growing worldwide biofuels market, feedstocks abound, with the U.S. remaining the preeminent destination for renewable fuel production. As renewable diesel and biodiesel capacity has expanded, so too has the flexibility of the market to utilize different feedstocks. More facilities than ever before accept mixed streams of feedstocks, and those feedstocks are all growing rapidly. With an unyielding supply of distillers corn oil, ever-expanding UCO collection coverage, and robust growth in canola and soy crush, domestic renewable fuel producers are likely to be able to source the quantities of feedstocks they need in order to maximize production. We do not believe feedstocks will be a limiting factor in 2026 and 2027, and we believe that the industry is capable of utilizing more capacity than it has over the previous several years.

iii. Biodiesel and Renewable Diesel Production Capacity

Available data suggests that there is significant unused biodiesel production capacity in the U.S., and thus domestic biodiesel production could grow without the need to invest in additional production capacity. Data reported by EIA shows that domestic biodiesel production capacity in November 2025 was approximately 1.96 billion gallons per year, roughly 800 million gallons more than was utilized through 2025.[112] According to this data, annual average biodiesel production capacity grew relatively slowly from about 2.1 billion gallons in 2012 to a peak of approximately 2.6 billion gallons in 2019. Reduction in EIA's reported operable capacity from 2015 to present likely reflects facility inactivity or closure. While EIA reports operable capacity, EPA data suggests that there are potential mothballed, inactive, or temporarily halted facilities beyond EIA's reported operable capacity.[113] This is a result of unfavorable economics in many cases. Renewable diesel has supplanted much of the available biodiesel capacity over the past decade.

Total domestic renewable diesel production capacity has increased significantly in recent years from approximately 280 million gallons in 2017 [114] to approximately 5 billion gallons at the end of 2025.[115] Additionally, a number of parties have announced plans to build new renewable diesel production capacity with the potential to begin production in future years. While production slowed down in 2025, capacity expansions are buoyed by continued demand for renewable jet fuel and the strength of State market incentives. This new capacity includes 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 previously projected that renewable diesel production capacity would continue to expand and could reach nearly 6 billion gallons by the end of 2025, but acknowledged that they expected some of these projects would

[105] Global Data, "UCO Supply Outlook," August 2023.

[106] Food and Agriculture Organization of the United Nations, "World Food and Agriculture—Statistical Yearbook 2023," 2023. *https://doi.org/10.4060/cc8166en.*

[107] Argus Media, "Viewpoint: US Policy Shift Elevates Domestic Feedstocks," February 1, 2026. *https://www.argusmedia.com/en/news-and-insights/latest-market-news/2771306-viewpoint-us-policy-shift-elevates-domestic-feedstocks.*

[108] When feedstocks are diverted from existing uses, the markets that previously used these feedstocks generally seek alternative feedstocks. Potential alternatives could include petroleum-based feedstocks or palm oil. Increased use of these feedstocks in non-biofuel markets could reduce or negate the intended environmental benefits from increased biofuel production.

[109] Global Data, "UCO Supply Outlook," August 2023.

[110] Id.

[111] Id.

[112] EIA, "U.S. Biodiesel Production Capacity," Petroleum & Other Liquids, February 6, 2026. *https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=M_EPOORDB_8BDPC_NUS_MMGL&f=M.*

[113] See "BBD Facility Capacity," available in the docket for this action.

[114] Renewable diesel capacity based on facilities registered in EMTS.

[115] EIA, "U.S. Total Biofuels Operable Production Capacity," Petroleum & Other Liquids, October 30, 2025. *https://www.eia.gov/dnav/pet/pet_pnp_capbio_dcu_nus_m.htm.*

be delayed or cancelled.[116] This projection was not met, but EIA continues to project robust annual production growth of 25 percent over the next two years.[117] A 2024 report found that by 2028 the domestic production capacity for renewable diesel and renewable jet fuel through the hydrotreating process alone could increase to 9.6 billion gallons per year.[118] In previous years, domestic renewable diesel production has increased in concert with increases in domestic production capacity, with renewable diesel facilities generally operating at high utilization rates.[119]

iv. Biodiesel and Renewable Diesel Analyzed Volumes

In developing the Analyzed Volumes of biodiesel and renewable diesel, we have identified the maximum quantity of BBD that could reasonably be produced utilizing all the currently operating domestic production capacity, mirroring utilization seen in similar industries (90 percent utilization rate).[120] Our assessment of available feedstocks indicates that domestic production capacity, rather than the availability of feedstock, is the factor most likely to constrain domestic biodiesel and renewable diesel production in 2026 and 2027, based on new data and analysis subsequent to the Set 2 proposal.

In addition to projecting the overall Analyzed Volumes of biodiesel and renewable diesel we have also projected the mix of feedstocks used to produce these fuels in 2026 and 2027. The mix of the feedstocks used to produce BBD will indirectly impact other statutory factors, as the environmental and economic impacts of biodiesel and renewable diesel may differ depending on the feedstocks used to produce these fuels. For example, the impacts of increasing biodiesel and renewable diesel production vary depending on whether the fuel was produced from UCO that would not otherwise have been collected, soybean oil from additional production and processing of soybeans, or the diversion of feedstocks or biofuels that would otherwise have been used in other markets. Our projections of the feedstocks used to produce biodiesel and renewable diesel in 2026 and 2027 reflect input received from commenters, the most recent data available at the time the projections were completed, and our assessment of the impact of the 45Z credit. As biodiesel and renewable diesel producer feedstock procurement is driven largely by input feedstock cost, the composition of feedstocks contributing to the actual volumes of biodiesel and renewable diesel in 2026 and 2027 may differ.[121]

Table III.A.2.1.iv-1: Analyzed Volumes of Biodiesel and Renewable Diesel

Renewable Fuel	Units	2026	2027
Biodiesel	Billion gallons	1.78	1.78
	Billion RINs	2.67	2.67
Renewable Diesel	Billion gallons	4.29	4.66
	Billion RINs[a]	7.29	7.45

[a] Renewable diesel RIN numbers reflect the current equivalence value for renewable diesel in 2026 (1.7 RINs/gallon) and the revised equivalence value we are finalizing in this rule for 2027 and future years. We expect most renewable diesel will generate 1.6 RINs/gallon in 2027 through the equivalence value application process.

b. Renewable Jet Fuel

There is also a small volume of renewable jet fuel that qualifies as BBD. Renewable jet fuel has qualified as a RIN-generating BBD and advanced biofuel under the RFS program since 2010 and must achieve at least a 50 percent GHG reduction in comparison to petroleum-based fuels. While relatively little renewable jet fuel was produced or imported through 2023 (20 million gallons or less per year) production volumes have been increasing in recent years, reaching approximately 110 million gallons in 2024 and approximately 290 million gallons in 2025.[122]

Tax credits for renewable jet fuel available during 2023 and 2024, often referred to as the ''sustainable aviation fuel credit'' or ''40B credit'' (also available as the 6426(k) excise tax credit), may have resulted in increasing volumes of renewable jet fuel produced from existing renewable diesel production facilities. The 45Z credit is available from 2025 through 2029 and, starting in 2026, provides up to $1.00 per gallon of renewable jet fuel, provided the relevant wage and apprenticeship requirements are met by the producer. The 45Z credit may provide continued support for renewable jet fuel production. Renewable jet fuel production from existing renewable diesel facilities, however, would likely result in a decrease in renewable diesel production, with little or no net change in their overall production of RIN-generating fuels.[123]

The vast majority of renewable jet fuel produced through 2025 was produced using the same feedstocks and very similar production technologies as renewable diesel, and in most cases are produced at the same production facilities. For example, Montana Renewables produced both renewable diesel and renewable jet fuel at their Great Falls, Montana facility in 2024,[124] as did Phillips 66 in their Rodeo, California facility.[125] Historically,

[116] 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*.

[117] EIA, ''Short-Term Energy Outlook,'' January 2026, Table 4d—U.S. Biofuel Supply, Consumption, and Inventories. *https://www.eia.gov/outlooks/steo/tables/pdf/4dtab.pdf*.

[118] 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*.

[119] For further discussion and visualization of capacity and utilization rates, see RIA Chapter 7.2.

[120] EIA, U.S. Percent Utilization of Refinery Operable Capacity, *https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=mopueus2&f=a*.

[121] More detail on the development of this projection can be found in RIA Chapters 3 and 6.

[122] Renewable jet fuel volumes are based on data from EMTS.

[123] The equivalence values for renewable diesel and jet fuel are similar. As discussed in section VIII.A of this preamble, we are revising the renewable diesel equivalence value to be 1.5 RINs per gallon, while also establishing the renewable jet fuel equivalence value to be 1.5 RINs per gallon. However, we expect most renewable diesel will generate 1.6 RINs/gallon in 2027 through the equivalence value application process.

greater incentives have been available for renewable diesel production than for renewable jet fuel production. This has resulted in most production facilities choosing to maximize renewable diesel production, although based on the production data at the time of this writing this dynamic may be starting to change.

In the near term, we expect that because the vast majority of renewable jet fuel will be produced using the same feedstocks and at the same facilities as renewable diesel any increase in renewable jet fuel production will result in a corresponding decrease in renewable diesel production. We recognize that new technologies are being developed to produce renewable jet fuel from a wider variety of feedstocks, some of which are not suitable for use in the hydrotreating process that dominates renewable diesel production. For example, several companies are developing new technologies intended to produce renewable jet fuel from ethanol or other alcohols, through a technology often referred to as the ''alcohol-to-jet'' (''ATJ'') process. To date, we have not approved a generally applicable pathway for these fuels, but we have approved a facility-specific pathway for the production of renewable jet fuel from ethanol to generate D4 RINs.[126] While ATJ has the potential to produce significant volumes of renewable jet fuel in future years, there is a high degree of uncertainty related to the production of these fuels through 2027 as commercial scale production of these fuels has been limited and no RINs have yet been generated for these fuels at the time of this writing. Production of renewable jet fuel using these emerging technologies may not negatively impact renewable diesel production to the extent that they do not compete for feedstocks.

In this action, we have not separately projected growth in renewable jet fuel production. Instead, we are considering any production of renewable jet fuel from hydrotreating lipid feedstocks in our projection of renewable diesel production. We recognize that other renewable jet fuel production technologies and production facilities are being developed and, in some cases, may produce small fuel volumes in the near term. These could enable the future production of renewable jet fuel from new facilities and feedstocks that are not expected to impact renewable diesel production.

c. Other Advanced Biofuels

In addition to biodiesel, renewable diesel, and renewable jet fuel, other renewable fuels that qualify as advanced biofuel have been produced and used in the U.S. in the past and are expected to contribute to compliance with applicable RFS volume requirements in the future. These other advanced biofuels include imported sugarcane ethanol, domestically produced advanced ethanol, RNG used in CNG/LNG vehicles not produced from cellulosic biomass, and heating oil, naphtha, and co-processed renewable diesel that does not qualify as BBD.[127]

These biofuels have been used in much smaller quantities than biodiesel and renewable diesel in the past, and the production volumes of many of these fuels have been highly variable. Some of these ''other advanced biofuels'' such as naphtha and heating oil are byproducts of the production of other types of renewable fuel. Others, such as co-processed renewable diesel and sugarcane ethanol, are consistently produced or imported at volumes far below their theoretical production capacity. This variability in the technologies used to produce these fuels and their production volumes over time makes projecting the potential production or import volumes in future years challenging.

To determine the Analyzed Volumes of these other advanced biofuels in 2026 and 2027, we used the same general methodology as in the Set 2 proposal and the Set 1 Rule. We projected the supply of these other advanced biofuels using historic data on the supply of these fuels from 2015–2025. Our methodology addresses the historical variability in these categories of advanced biofuel while recognizing that consumption in more recent years is likely to provide a better basis for making future projections than consumption in earlier years. Specifically, we applied a weighting scheme to historical volumes wherein the weighting was higher for more recent years and lower for earlier years. The result of this approach is shown in Table III.A.2.c–1. Details of the derivation of these estimates can be found in RIA Chapter 5.4. As the available data varies significantly from year to year, it does not allow us to identify an upward or downward trend in the historical consumption of these other advanced biofuels. Therefore, we have used the volumes in Table III.A.2.c–1 both 2026 and 2027.

[124] Montana Renewables, ''Products,'' *https://montanarenewables.com/products.*

[125] Phillips 66, ''Rodeo Renewable Energy Complex,'' *https://www.phillips66.com/rodeo-renewable-energy-complex.*

[126] *See, e.g.,* EPA, ''Letter from EPA to LanzaJet, Inc.,'' January 12, 2023.

[127] Renewable diesel produced through coprocessing vegetable oils or animal fats with petroleum cannot be categorized as BBD but remains advanced biofuel.

Table III.A.2.c-1: Estimate of Annual Consumption of Other Advanced Biofuel (million RINs)

Fuel	Volume
Imported sugarcane ethanol	15
Domestic ethanol	24
CNG/LNG	4
Heating oil	4
Naphtha[a]	87
Renewable diesel[b]	90
Total	224

Note: This table does not include fuels that qualify as cellulosic biofuel or BBD.

[a] While renewable naphtha is generally a co-product of renewable diesel production, the supply of renewable naphtha has not increased in line with the observed increases in renewable diesel production.

[b] Includes renewable diesel that is co-processed with petroleum, which does not qualify as BBD.

d. Analyzed Volumes of Non-Cellulosic Advanced Biofuels

Non-cellulosic advanced biofuel has been the fastest growing category of renewable fuel in the RFS program since 2021, with the majority of the growth coming from renewable diesel. While the supply of non-cellulosic advanced biofuels decreased from 2024 to 2025, our analyses indicate that sufficient domestic production capacity and feedstocks are available to enable the production of these fuels to increase significantly in 2026 and 2027. Sections III.A.2.a through c of this preamble describe our derivation of the Analyzed Volumes of different types of non-cellulosic advanced biofuels for 2026 and 2027. These Analyzed Volumes are summarized in Table III.A.2.d–1.

Table III.A.2.d-1: Non-Cellulosic Advanced Biofuel Analyzed Volumes (billion RINs)

	2026	2027
Biodiesel	2.67	2.67
Renewable Diesel	7.29	7.45
Other advanced biofuel	0.22	0.22
Total con-cellulosic advanced biofuel	10.19	10.34

Note: Totals may not always add due to rounding.

3. Conventional Renewable Fuel

Conventional renewable fuel includes any renewable fuel that is made from renewable biomass as defined in 40 CFR 80.1401, does not qualify as advanced biofuel (including cellulosic biofuel and BBD), and meets one of the following criteria:

- Is demonstrated to achieve a minimum 20 percent reduction in lifecycle GHG emissions in comparison to the gasoline or diesel which it displaces; or
- Is exempt (''grandfathered'') from the 20 percent minimum GHG reduction requirement due to having been produced in a facility or facility expansion that commenced construction on or before December 19, 2007, as described in 40 CFR 80.1403 and pursuant to CAA section 211(o)(2)(A)(i).

Under the statute, there is no volume requirement for conventional renewable fuel. Instead, conventional renewable fuel may fill that portion of the total renewable fuel volume requirement that is not required to be advanced biofuel. In some cases, this portion of the total renewable fuel requirement that can be met with conventional renewable fuel is referred to as an ''implied'' volume requirement. However, obligated parties are not required to comply with it per se, since any portion of it can be met with advanced biofuel volumes exceeding what is needed to meet the advanced biofuel volume requirement.

To develop the Analyzed Volumes of conventional renewable fuel for 2026 and 2027, we focused primarily on projecting volumes of ethanol consumed via motor gasoline use across all gasoline blends with varying concentrations of ethanol (*i.e.,* E10, E15, and E85). We also investigated potential volumes of non-advanced biodiesel and renewable diesel.

a. Corn Ethanol

Ethanol made from corn starch has historically been the renewable fuel supplied in the greatest quantities basis in the past and is expected to continue to do so in 2026 and 2027.[128] Corn starch ethanol is prohibited by CAA section 211(i)(1)(B)(i) from being an advanced biofuel regardless of its lifecycle GHG emissions performance in comparison to gasoline.

Total domestic corn ethanol production capacity increased dramatically between 2005 and 2010 and increased at a slower rate thereafter. As of late 2025, domestic corn ethanol production capacity exceeded 18 billion gallons.[129] Actual production of corn ethanol in the U.S. was approximately

[128] Conventional ethanol from feedstocks other than corn starch have been produced in the past, but at significantly lower volumes. Production of ethanol from grain sorghum reached 125 million gallons in 2019, representing just less than 1 percent of all conventional ethanol in that year; grain sorghum ethanol in 2024 was only 46 million gallons. Waste industrial ethanol and ethanol made from non-cellulosic portions of separated food waste have been produced more sporadically and at even lower volumes. These other sources do not materially affect our assessment of volumes of conventional ethanol that can be produced.

[129] EIA, ''Monthly Biofuels Capacity and Feedstocks Update,'' November 28, 2025. *https://www.eia.gov/biofuels/update.*

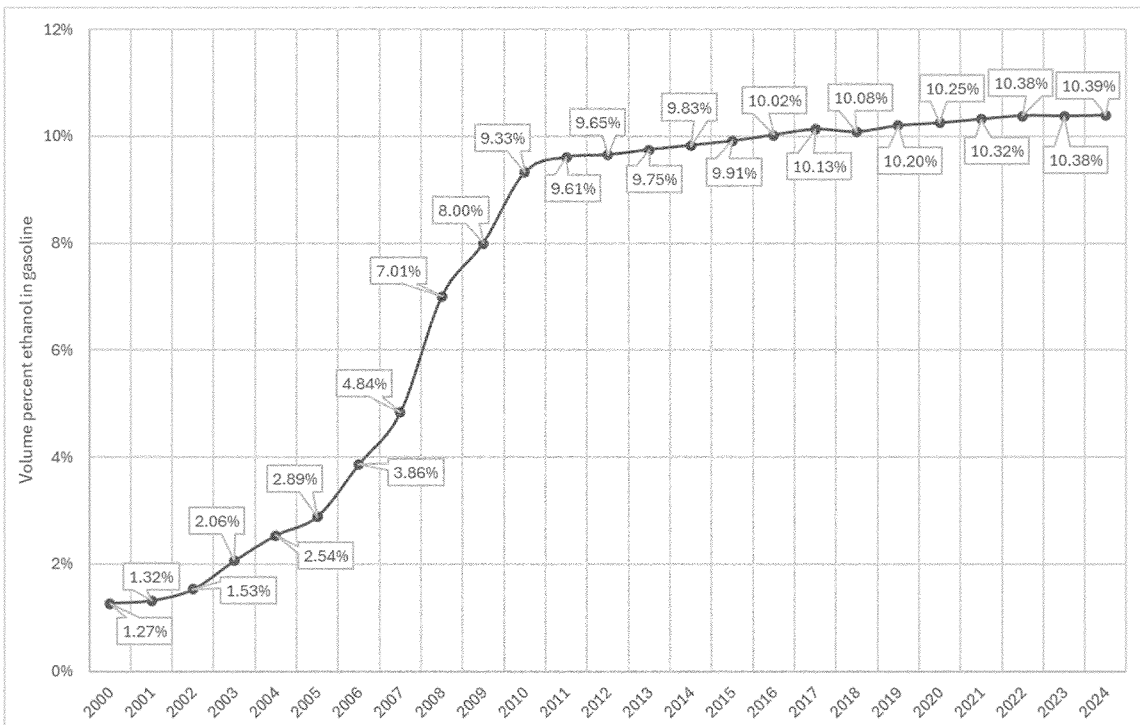
16.2 billion gallons in 2024 and is estimated to have reached 16.4 billion gallons in 2025.[130]

The expected annual rate of future commercial production of corn ethanol will continue to be driven primarily by gasoline demand in 2026 and 2027, as most gasoline is expected to continue to contain 10 percent ethanol during this period. Commercial production of corn ethanol is also a function of exports of ethanol and the demand for E0, E15, and E85. There is evidence that some fuel retailers sell higher volumes of E15 than E10, leveraging lower prices at the pump and marketing higher-level ethanol blends to their customers as a cheaper fuel option with only negligible effects on fuel economy (a 1–2 percent reduction compared to E10). In addition to government incentives, industry-led efforts such as Prime-the-Pump have enjoyed great success in growing markets for higher ethanol gasoline blends by providing technical and financial assistance to fuel retailers.[131] Acknowledging the potential for growth in these fuel markets, we have incorporated projected growth in opportunities for sales of E15 and E85 blends into our assessment.

Despite this steady growth, there remains excess production capacity of ethanol and corn feedstock in comparison to the ethanol volumes that we estimate will be consumed domestically during 2026 and 2027, given constraints on U.S. ethanol consumption. Thus, as was the case with the Set 1 Rule, we do not expect production capacity to be a limiting factor in determining the Analyzed Volumes.

The total volume of ethanol that can be used—including ethanol produced from corn, grain sorghum, cellulosic biomass, the non-cellulosic portions of separated food waste, and sugarcane—is a function of demand for E10, E15, and E85 ethanol blends most commonly used in the U.S. and for E0. Ethanol concentration across the entire gasoline pool can exceed 10 percent only insofar as the incremental ethanol in E15 and E85 volumes more than offsets the lack of ethanol in E0 volume. As shown in Figure III.A.3.a-1, poolwide ethanol concentration increased dramatically from 2003 through 2010 and has continued to grow more slowly since 2010. As the average ethanol concentration approached and then exceeded 10 percent, the gasoline pool became saturated with E10, with a small, likely stable volume of E0 and small but gradually increasing volumes of E15 and E85. We expect this trend to continue during 2026 and 2027.

Figure III.A.3.a–1: Historical Poolwide Volumetric Ethanol Concentration



Source: Derived from ethanol and gasoline consumption in EIA, "Monthly Energy Review," Total Energy, January 2026. Full-year 2025 data not available at the time of this writing.

[130] EIA, ''Monthly Energy Review,'' Total Energy, March 2025. *https://www.eia.gov/totalenergy/data/monthly/pdf/mer.pdf.*

[131] Transportation Energy Institute, ''The Case of E15,'' February 2018.

For this action, volume data from USDA's Higher Blends Infrastructure Incentive Program (HBIIP)[132] and additional volume data acquired directly from six States with high volumes of higher-level ethanol blends (California, Kansas, Iowa, Minnesota, New York, and North Dakota) has enabled a data-driven, bottom-up approach to projecting ethanol volumes into the future that differs from the way these projections were calculated in previous years. More information on this method of projection ethanol concentration can be found in RIA Chapter 7.5.1. We introduced this new methodology in the Set 2 proposal and continue to refine it here. In the Set 1 Rule, we projected ethanol concentration in the national gasoline pool using a least-squares regression model using then-current E15 and E85 fueling station population data.[133] This was due to lack of data and a subsequent inability to aggregate sales volumes by ethanol volume at the retail fuel station level. Now, greater availability of sales volume data from the aforementioned six States, HBIIP, and industry partners has enabled an updated and simplified methodology for producing the ethanol volume projections in this action.

Using the average sales of each gasoline-ethanol blend per retail fueling station, as well as updated station populations from DOE's Alternative Fuels Data Center (AFDC)[134] and the California Air Resources Board (CARB)[135] for 2021–2024, we produced projections of expected growth in station counts and throughputs out to 2027 for each gasoline-ethanol blend other than E10. In addition to a projection for each blend, E85 projections were expanded in this action relative to the Set 1 Rule. After reviewing the State-specific data, the difference between the E85 market in California compared to five other States (*i.e.,* Kansas, Iowa, Minnesota, New York, and North Dakota) became apparent. Thus, we chose to analyze the California E85 market separately from the other States in order to more accurately project E85 in California versus the rest of the U.S. We then used these projections to estimate the total fuel volume for these gasoline-ethanol blends (E0, E15, and E85) for 2026 and 2027 using the following relation: for gasoline-ethanol blends at each concentration, the total fuel volume consumed in any given year is equal to the product of the number of retail fueling stations offering that blend for sale and the volume of that fuel blend sold at a fueling station (*i.e.,* throughput) on average during that year. Finally, we projected E10 as the remainder of the gasoline pool, after accounting for the Analyzed Volumes of E0, E15, and E85, using the most recent version of EIA's Annual Energy Outlook to project total gasoline demand for 2026 and 2027.[136]

Total ethanol consumption is the sum of gasoline (E0) blended with ethanol to create E10, E15, and E85.[137] The ethanol portion of the projected total consumption for each fuel blend (*i.e.,* total ethanol consumption) is shown in Table III.A.3.a-1. While we project that the ethanol concentration in the gasoline pool will increase in future years, total ethanol consumption is projected to decrease due to decreases in total gasoline consumption in future years.

Table III.A.3.a-1: Projected Fuel Blends and Ethanol Consumption (million gallons)

Year	E0	E10	E15	E85	Ethanol
2026	2,061	137,404	998	443	14,438
2027	2,075	136,301	1,124	477	14,370

b. Conventional Biodiesel and Renewable Diesel

Other than conventional ethanol, the only other conventional renewable fuels that have been used at significant levels in the U.S. in recent years have been conventional biodiesel and renewable diesel. Conventional biodiesel and renewable diesel are produced at facilities grandfathered under 40 CFR 80.1403 because there are no currently valid RIN-generating pathways for their production. Almost all conventional biodiesel and renewable diesel historically used in the U.S. has been imported.[138] According to EMTS data, the use of conventional biodiesel and renewable diesel did grow marginally in 2024 after a period of very low volume (less than 1 million gallons per year from 2018–2022), though the overall supply remained negligible (less than 0.1 percent of total biofuel supply to the U.S.) and the total supply of conventional biodiesel and renewable diesel in 2025 was once again less than one million gallons. While some sparse generation of D6 RINs for these fuels have been observed in recent years, nearly all these RINs were retired for being designated for use in any application other than transportation fuel and therefore do not represent qualifying fuel under the RFS program. As discussed in RIA Chapter 7.7, there exists much greater potential for domestic production and use of conventional biodiesel and renewable diesel than has actually been supplied in prior years, suggesting the use of these fuels in the U.S. is largely a function of domestic demand for these fuels and the incentives available for conventional biodiesel and renewable diesel in the U.S. relative to other countries. While there exists some potential for growth in 2026 and 2027, we are not including volumes of conventional biodiesel and renewable diesel in our analyses for this final rule.

c. Conventional Renewable Fuel Summary

The Analyzed Volumes of conventional renewable fuel represent the volume of these fuels we project would be supplied to the market when considering the incentives that could be available through the RFS program and other State and Federal incentives. Since the supply of ethanol is projected to be limited by the ability for the market to consume ethanol in gasoline blends, the supply of conventional ethanol in 2026 and 2027 can be estimated from the total ethanol

[132] USDA, ''Higher Blends Infrastructure Incentive Program,'' May 2023. *https://www.rd.usda.gov/hbiip.*

[133] See ''Renewable Fuel Standard (RFS)Program: Standards for 2023–2025 and Other Changes Regulatory Impact Analysis,'' EPA–420–R–23–015, June 2023 (''RFS Set 1 RIA''), Chapter 7.5.1.

[134] AFDC, ''Historical Alternative Fueling Station Counts.'' *https://afdc.energy.gov/stations/states.*

[135] CARB, ''Annual E85 Volumes,'' April 11, 2025.

[136] EIA, ''Annual Energy Outlook 2025,'' April 15, 2025 (''AEO2025''). *https://www.eia.gov/outlooks/aeo.*

[137] See RIA Chapter 7.5.1 for a more comprehensive discussion of the methodology employed to produce the total ethanol consumption projection.

[138] Less than 15 million gallons total of conventional biodiesel and renewable diesel has been produced domestically from 2014–2025.

consumption projections from Table III.A.3.a–1 and our projections for other forms of ethanol as discussed earlier in this section. Our projected volumes of ethanol consumption are presented in Table III.A.3.c–1. We do not currently project that non-ethanol conventional renewable fuels will be supplied to the U.S. under the RFS program in 2026 and 2027.

Table III.A.3.c-1: Ethanol Consumption Analyzed Volumes (million gallons)

	2026	2027
Total ethanol consumption	14,438	14,370
Cellulosic ethanol	128	128
Imported sugarcane ethanol	15	15
Domestic advanced ethanol	24	24
Conventional ethanol	14,270	14,203

4. Summary of Analyzed Volumes

For the reasons explained in the introduction of section III.A of this preamble, we have developed Analyzed Volumes for 2026 and 2027 to aid our analyses under CAA section 211(o)(2)(B)(ii). The methodology used to develop the Analyzed Volumes of each component category of fuel are summarized in sections III.A.1 through 3 of this preamble. The Analyzed Volumes used to support this final rule are presented in Tables III.A.4–1 and 2.

Table III.A.4-1: Analyzed Volumes (million RINs)

	2026	2027
Cellulosic biofuel (D3 & D7)	1,364	1,435
Biomass-based diesel (D4)	9,961	10,118
Other advanced biofuel (D5)	224	224
Conventional renewable fuel (D6)	14,270	14,203

Table III.A.4-2: Analyzed Volumes (million gallons)

	2026	2027
Cellulosic biofuel (D3 & D7)	1,364	1,435
Biomass-based diesel (D4)	6,074	6,445
Other advanced biofuel (D5)	162	162
Conventional renewable fuel (D6)	14,270	14,203

To determine the final volume requirements for 2026 and 2027, we developed and evaluated these Analyzed Volumes to facilitate our analysis of the statutory factors listed in CAA section 211(o)(2)(B)(ii)(I)–(VI). A summary of several of these analyses is described in section III.D of this preamble and discussed in greater detail in the RIA. Details of the individual biofuel types and feedstocks that make up the Analyzed Volumes are provided in RIA Chapter 3. In section III.E of this preamble we discuss the volume requirements based on a consideration of all the factors that we analyzed.

B. Baselines

To estimate the impacts of the Analyzed Volumes, we must identify the appropriate baseline(s). The primary baseline developed for this final rule reflects the use of renewable fuels absent this final rule or the RFS program (*i.e.,* the alternative collection of biofuel volumes by feedstock, production process (where appropriate), and biofuel type that would be anticipated to occur in 2026 and 2027 in the absence of RFS program), and acts as the point of reference for assessing the impacts of this final rule. To this end, we have developed a ''No RFS'' scenario that we used as the baseline for analytical purposes (hereinafter the ''No RFS Baseline''). Many of the same supply-related factors that we used to develop the Analyzed Volumes were also relevant in developing the No RFS Baseline.

We also developed a 2025 baseline that in some cases is more informative in understanding the impacts of the Analyzed Volumes relative to the status quo.

1. No RFS Baseline

Broadly speaking, the RFS program is designed to increase the use of renewable fuels in the transportation sector beyond what would occur in the absence of the program. It is appropriate, therefore, to use a scenario representing what would occur if the RFS program did not continue to exist as the baseline for estimating the costs and impacts of the Analyzed Volumes. Our No RFS Baseline is consistent with the Office of Management and Budget's Circular A–4, which says that the appropriate baseline would normally ''be a 'no action' baseline: what the world will be like if the proposed rule is not adopted.'' [139]

Importantly, this No RFS Baseline is not equivalent to a market scenario

[139] Office Management and Budget, ''Circular A–4,'' 68 FR 58366 (October 9, 2003).

wherein no renewable fuels are used at all. Prior to the RFS program, both biodiesel and ethanol were used in the transportation sector, whether due to State or local incentives, tax credits, or a price advantage over conventional petroleum-based gasoline and diesel. This same situation would exist in 2026 and 2027 in the absence of the RFS program. Federal, State, and local tax credits, incentives, and support payments would continue to be in place for these fuels, as well as State programs such as blending mandates and LCFS programs. Furthermore, now that capital investments in renewable fuels have been made and markets have been oriented towards their use, there are strong incentives in place for continuing their use even if the RFS program were to disappear. As a result, it would be improper and inaccurate to attribute all use of renewable fuel in 2026 and 2027 to the applicable standards under the RFS program.

To inform our assessment of the volume of renewable fuels that would be used in the absence of the RFS program for the years 2026 and 2027, we began by analyzing the trends in the economics for renewable fuels blending in prior years. Assessing these trends is important because the economics for blending renewable fuels changes from year to year based on renewable fuel feedstock and petroleum product prices and other factors that affect the relative economics for blending renewable fuels into petroleum-based transportation fuels. A renewable fuel facility investor and the financiers who fund their projects will review the historical (*e.g.,* did they lose money in a previous year), current, and perceived future economics of the renewable fuel market when deciding whether to continue to operate their renewable fuel facilities, and our analysis attempted to account for these factors.

The No RFS Baseline economic analysis for 2026 and 2027 compares the projected renewable fuel cost with the projected cost for the fossil fuel it displaces. The comparison is performed at the point that the renewable fuel is blended with the fossil fuel (generally a fuel terminal) to assess whether the renewable fuel provides an economic advantage to blenders. If the renewable fuel is lower cost than the fossil fuel it displaces, it is assumed that the renewable fuel would be used absent the RFS program (within the constraints described below). The No RFS Baseline economic analysis that we conducted mirrors the fuel cost analysis described in section III.D.4 of this preamble, but there are several differences. The primary difference is that the No RFS Baseline economic analysis was conducted from the fuels industry's perspective, asking whether they would find it economically advantageous to blend renewable fuel into petroleum fuel in the absence of the RFS program. Conversely, the social cost analysis in section III.D.4 of this preamble reflects the overall fuel cost impacts on society at large.[140] A primary example of a social cost not considered for the No RFS Baseline economic analysis is the fuel economy effect due to the lower energy density of the renewable fuel, as this cost is generally borne by consumers, not the fuels industry. Other ways that the No RFS Baseline economic analysis is different from the social cost analysis include:

- In the context of assessing production costs, we amortized the capital costs at a higher rate of return more typical for industry investment instead of the rate of return used for social costs.
- We assessed renewable fuel distribution costs to the point where it is blended into petroleum fuel, not all the way to the point of use, which is necessary for estimating the fuel economy cost.[141]
- While we generally do not account for the fuel economy disadvantage of most renewable fuels for the No RFS Baseline economic analysis, the exception is E85 where the lower fuel economy of using E85 is noticeable to vehicle owners such that they demand a lower price to make up for this loss of fuel economy. As a result, retailers must price E85 lower than the primary alternative E10 to account for the lower energy content of E85 and they must consider this in their decisions to blend and sell E85.[142]

To estimate the relative cost of a renewable fuel compared to the fossil fuel being displaced, we considered several different cost components (*i.e.,* production cost, distribution cost, any blending cost, retail modification costs) together to reflect the relative cost of each renewable fuel to its respective fossil fuel. We also considered any applicable Federal or State programs, incentives, or subsidies that could reduce the apparent blending cost of the renewable fuel at the terminal, including the 45Z credit. The exact amount of credit under 45Z is more variable and depends on a range of factors. However, generally speaking, the amount of credit that fuel producers are able to claim under 45Z is less than the previous $1 per gallon tax credits that biodiesel and renewable diesel producers were able to claim under 40A and 6426.[143] In the case of higher-level ethanol blends, the retail cost associated with the equipment or use of compatible materials needed to enable the sale of these newer fuels is assumed to be reduced by 75 percent due to the HBIIP program.

In addition, there are a number of State programs that create subsidies for biodiesel and renewable diesel, the largest being offered by California and Oregon through their LCFS programs.[144] We accounted for State and local biodiesel mandates by including their mandated volume regardless of the economics. Several States offer tax credits for blending ethanol at 10 percent. Other States offer tax credits for E85, of which the largest is New York. We are not aware of any State tax credits or subsidies for E15.[145] To account for the various State assumptions, it was necessary to model the cost of using these biofuels on a State-by-State basis.

For most renewable fuels, the economic analysis provided consistent results, indicating that they are either economical in all years or are not economical in any year. However, this was not true for biodiesel and renewable diesel, where the results varied from year to year. Such swings in the economic attractiveness of biodiesel and renewable diesel confound efforts on the part of investors to project future returns on their investments to determine whether to continue to operate their facilities or shut down. Thus, to smooth out the swings in the economics for using biodiesel and renewable diesel and look at it the way facility operators and their investors would do in the absence of the RFS

[140] See section III.D.4 of this preamble and RIA Chapter 10 for descriptions of the social cost analysis.

[141] For several renewable fuels (*e.g.,* ethanol blended as E10, biodiesel, and renewable diesel), the fuel economy cost is paid by the consumer. Because it is the fuels industry (*i.e.,* refiners, terminals, and retailers) that decides whether to blend renewable fuels into petroleum fuels, they are only concerned about the relative cost at the point in which the renewable fuel is blended into the petroleum fuel, not the costs downstream of that blending point.

[142] See RIA Chapter 2 for further discussion of this topic.

[143] See RIA Chapter 1 for a further discussion of the 45Z credit.

[144] At the time the analysis for the No RFS Baseline was completed, there was insufficient data to project the impacts of LCFS programs in New Mexico on biofuel consumption in these States in the absence of the RFS program.

[145] In light of the fluid situation with respect to a 1-psi RVP waiver for E15 or actions to remove the 1-psi waiver for E10 in seven Midwestern States, our analysis did not specifically assume either of these potential changes. These assumptions can affect the relative cost of E15; however, adopting these assumptions would not have impacted the overall conclusions with respect to blending E15 in the absence of the RFS program.

program, we made two key assumptions. First, the economics for biodiesel and renewable diesel were modeled starting in 2009 and the trend in their use was made dependent on the relative economics in comparison to petroleum diesel over distinct four-year periods. As a result, the first four-year period modeled the costs over 2009–2012 to estimate the volume of biodiesel and renewable diesel that would be used in 2012 in the absence of the RFS program. Second, the estimated biodiesel and renewable diesel volumes were limited in the analysis to no greater volume than what occurred under the RFS program in any year, since the existence of the RFS program would be expected to create a much greater incentive for using these fuels than if the RFS program was not in place.

We also conducted an analysis for cellulosic biofuels, focusing primarily on renewable CNG/LNG and CKF ethanol. We found that renewable CNG/LNG is more expensive than fossil natural gas and, without targeted incentives and given competing demand in other sectors, would see little transportation use. However, because California, Oregon, and Washington do have State-level biofuels programs that incentivize CNG/LNG in transportation, we assumed these programs would support some use even without the RFS program. To estimate that future level of use, we analyzed each State's program data and extrapolated trends through 2027. Additionally, CKF ethanol is eligible for additional incentives through programs such as California's LCFS program, so we expect CKF ethanol will continue to be produced at the volumes determined in this rule even in the absence of the RFS program. The No RFS Baseline for 2026 and 2027 is summarized in Table III.B.1–1.[146] More details on the No RFS Baseline can be found in RIA Chapter 2.

Table III.B.1-1 No RFS Baseline (million RINs)

	2026	2027
Cellulosic biofuel (D3 & D7)	565	597
Biomass-based diesel (D4)	4,068	3,563
Other advanced biofuel (D5)	129	129
Conventional renewable fuel (D6)	14,040	13,958

Our analysis shows that conventional ethanol is economical to use in 10 percent blends (E10) without the presence of the RFS program. Conversely, higher-level ethanol blends are only partially economical without the RFS program. E85 is economical in 2026 and 2027 in California; thus, we assumed that E85 would be consumed in California without the RFS program.[147] Conversely, E15 is not economical without the RFS program due to the relatively low sales volumes per station and high cost associated with the equipment needed to be installed at retail stations, even if these costs are partially subsidized by government funding, and the lack of octane blending value. Some volume of biodiesel is estimated to be blended based on State mandates in the absence of the RFS program, and some additional volume of both biodiesel and renewable diesel is estimated to be economical to use without the RFS program, particularly in California and Oregon due to the LCFS incentives. The volumes of renewable CNG/LNG and imported sugarcane ethanol are projected to be consumed in States with an LCFS program due to the economic support provided by their programs.

2. 2025 Baseline

The applicable volume requirements established for one year under the RFS program do not roll over automatically to the next, nor do the volume requirements that apply in one year become the default volume requirements for the following year in the event that no volume requirements are set for that following year. Nevertheless, the volume requirements established for the previous year represent the most recent set of volume requirements that the market was required to meet and are indicative of current market conditions.

Since the previous year's volume requirements represent the starting point for any adjustments that the market may need to make to meet the next year's volume requirements, they represent another informational baseline for comparison. For this reason, in previous RFS annual standard-setting rulemakings we used previous year's standards as a baseline against which to compare the projected impacts of the volume requirements and are also doing so here in addition to the No RFS Baseline for some of the factors (*e.g.,* the cost of this action).

In the Set 2 proposal, we estimated a 2025 baseline using the analysis performed in the Set 1 Rule. We considered using 2025 partial-year data for the 2025 Baseline in the Set 2 proposal, but we instead continued to rely on the Set 1 Rule analysis. In this final rule, we now have data from EMTS on the actual production and use of renewable fuel in the U.S. in 2025. In this final rule we have revised and updated the 2025 Baseline using this data, such that the 2025 Baseline reflects the actual production and use of biofuels in 2025 rather than the projected volumes from the Set 1 Rule. In some cases (such as the feedstocks used to produce biodiesel and renewable diesel) we have supplemented the data collected by EMTS with other data sources.

Our estimates of the actual use of qualifying biofuels in 2025 are shown in Table III.B.2–1. More details on the 2025 Baseline can be found in RIA Chapter 2.

[146] See RIA Chapter 2 for a more complete description of the No RFS Baseline and its derivation.≤

[147] Since E85 is borderline economical in California in the No RFS Baseline when we do not assume any increase in California's LCFS credit, a likely increase in the LCFS credit under the No RFS Baseline increases the certainty that E85 would be economic. Additionally, we did not consider the possibility that cellulosic ethanol, which receives a larger LCFS credit, could be used to produce E85 and may be more economical than corn ethanol.

Table III.B.2-1: 2025 Baseline (million RINs)

	Volume
Cellulosic biofuel (D3 & D7)	1,247
Biomass-based diesel (D4)	5,739
Other advanced biofuel (D5)	218
Conventional renewable fuel (D6)	14,183

C. Volume Changes Analyzed

In general, our analyses of the impacts of this rule were based on the differences between the No RFS Baseline and the Analyzed Volumes (*i.e.,* our assessment of how the market would respond to the Analyzed Volumes were they to become the final volume requirements). Those differences are shown in Table III.C–1.[148] Because this approach is squarely focused on the differences in volumes between the No RFS Baseline and the Analyzed Volumes, our analyses do not assess impacts from total renewable fuel use in the U.S. As noted above, we also consider the impacts of the Analyzed Volumes relative to the 2025 Baseline for some of our analyses. The changes in renewable fuel consumption relative to the 2025 Baseline are shown in Table III.C–2.

Table III.C-1: Changes in Renewable Fuel Consumption – Analyzed Volumes vs. No RFS Baseline

	Million Gallons		Million RINs	
	2026	2027	2026	2027
Cellulosic biofuel (D3 & D7)	799	838	799	838
Biomass-based diesel (D4)	3,597	4,175	5,893	6,555
Other advanced biofuel (D5)	67	67	95	95
Conventional renewable fuel (D6)	231	245	231	245

Table III.C-2: Changes in Renewable Fuel Consumption – Analyzed Volumes vs. 2025 Baseline

	Million Gallons		Million RINs	
	2026	2027	2026	2027
Cellulosic biofuel (D3 & D7)	117	188	117	188
Biomass-based diesel (D4)	2,340	2,711	4,222	4,379
Other advanced biofuel (D5)	9	9	6	6
Conventional renewable fuel (D6)	87	20	87	20

D. Summary of the Assessed Impacts of the Analyzed Volumes

As described in section II.B of this preamble, the statute specifies a number of factors that the EPA must analyze in making a determination of the appropriate volume requirements to establish for years after 2022 (and for BBD, years after 2012).[149] In this section, we provide a summary of the analysis of a selection of factors, including employment, rural economic development, energy security, climate change, costs, environmental impacts, and various other economic impacts, for the Analyzed Volumes, along with some implications of those analyses. We provide a summary of our consideration of all factors in determining the final volume requirements in section III.E of this preamble.

We received numerous comments on the analyses of statutory factors presented in the proposal. In some cases, we have updated our analyses to incorporate feedback provided by commenters (*e.g.,* climate change, prices of agricultural commodities). Changes in methodology relative to the Set 2 proposal are described in the sections below and in the corresponding RIA Chapters. Other comments not addressed in those sections are addressed in the Response to Comment document in the docket for this rule.

It was not always possible to precisely identify the implications of the analysis of a specific factor for a specific component category of renewable fuel. For instance, while we analyzed the impact of biodiesel and renewable diesel on the cost to consumers of transportation fuel (section III.D.4 of this preamble), biodiesel and renewable diesel can be used to satisfy multiple biofuel requirements (*e.g.,* BBD, advanced biofuel, and total renewable fuel) and this analysis therefore does not apply to a single standard in that regard. Additionally, air quality impacts are driven primarily by biofuel type (*e.g.,* ethanol, biodiesel) rather than by biofuel category (*e.g.,* advanced biofuel,

[148] See RIA Chapter 2 for more details of this assessment, including a more precise breakout of those differences.

[149] A full description of the analysis for all factors is provided in the RIA.

cellulosic biofuel), and energy security impacts are driven by the amount of fossil fuel energy displaced. In these cases, we have analyzed one or more of the standards collectively rather than individually.

Moreover, except for CAA section 211(o)(2)(ii)(III), the statute does not require that the requisite analyses be specific to each category of renewable fuel. Rather, the statute directs the EPA to analyze certain factors, without specifying how that analysis must be conducted. In addition, the statute directs the EPA to analyze the ''program'' and the impacts of ''renewable fuels'' generally, further indicating that Congress intended to provide flexibility regarding how and at what level of specificity to analyze the statutory factors.[150]

1. Job Creation and Rural Economic Development

In this section, we summarize our estimates of the impacts (relative to the No RFS Baseline) of the Analyzed Volumes on economy-wide employment and rural economic development. These estimates include direct, indirect, and induced impacts for both job creation and rural economic development and are presented in Table III.D.1–1. More details on these analyses can be found in RIA Chapter 9.

We apply two analytical approaches common in the literature—the ''rule-of-thumb'' approach and, where feasible, input-output (IO) modeling. The rule-of-thumb approach uses employment and economic development impact estimates from previous studies, expressed in jobs and GDP per unit of biofuel production, and multiplies these estimated impacts by the Analyzed Volumes to arrive at employment and GDP estimates. This approach is taken to produce estimates for the impacts of the quantities of ethanol, BBD, and RNG in the Analyzed Volumes relative to the No RFS Baseline.

The IO modeling approach relies on the use of a methodology developed specifically for analysis of dry mill corn ethanol. Using the results from this IO analysis we have developed ranges of potential impacts from the projected corn ethanol volumes based on uncertainty regarding how the volumes will be provided. For example, volumes of corn ethanol associated with new production capacity would also be associated with some number of temporary construction jobs, while expanded capacity utilization at existing dry mill corn ethanol facilities would not. These ranges of potential impacts are summarized in tables in RIA Chapter 9 along with detailed explanations of the associated methodology. Similar IO modeling methods were not readily available to estimate impacts from other types of ethanol, BBD or RNG, so we have not attempted to do so.

We estimate that all three categories of renewable fuel we analyzed—ethanol, BBD, and RNG—are associated with increases in jobs to varying degrees. BBD is projected to have the highest job creation impact overall, primarily due to substantially higher projected fuel volume increases relative to the No RFS Baseline. In terms of rural employment specifically, ethanol has the highest direct and total effects per million gallons of ethanol equivalent. 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, again primarily due to substantially higher projected fuel volume increases due to the 2026 and 2027 standards relative to the No RFS Baseline.

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 impacts per million gallons of ethanol equivalent on rural economic development than does RNG. 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, again primarily due to substantially higher projected fuel volume increases due to the 2026 and 2027 standards relative to the No RFS Baseline.

Table III.D.1–1 summarizes the estimated economy-wide employment impacts, expressed in terms of full-time equivalent jobs, and rural economic development impacts, expressed in terms of rural GDP in 2024$ associated with the Analyzed Volumes of ethanol, BBD, and RNG.[151]

Table III.D.1-1: Job Creation and Rural Economic Development Impacts of the Analyzed Volumes (number of jobs in full-time equivalents; million 2024$)

Fuel Type	Jobs		Rural GDP	
	2026	2027	2026	2027
RNG	21,765	22,827	1,272	1,334
BBD	68,912	79,986	7,731	8,974
Ethanol[a]	5,810	6,162	424	450
Total	96,487	108,975	9,427	10,757

[a] For the corn ethanol case alone, using NREL's JEDI module for dry mill corn ethanol we are able to generate employment and income estimates under the Analyzed Volumes and also carry out a sensitivity analysis. See RIA Chapter 9 for more details.

2. Energy Security

Our analysis shows that the Analyzed Volumes will have a positive impact on energy security by reducing U.S. reliance on foreign sources of energy. Monetized energy security impacts of the Analyzed Volumes are summarized in Table III.D.2–1. Energy security and methods of quantifying energy security impacts are discussed further below and in RIA Chapter 6.

[150] *See CBD,* 141 F.4th at 171 (''The text of the CAA does not require EPA to monetize or otherwise quantify all of the factors it must consider[.]'').

[151] More detail on our estimates of job creation and rural economic development, including a discussion of the limitations of these estimates, can be found in RIA Chapter 9.1.

Table III.D.2-1: Energy Security Benefits of the Analyzed Volumes (million 2024$)

	3% Discount Rate	7% Discount Rate
Present value (2026)	$787	$771
Annualized value	$411	$426

Note: 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.

Changes in the required volumes of renewable fuels under the RFS program can significantly impact: (1) the U.S.'s trade in crude oil and petroleum products, affecting both imports and exports—collectively referred to as ''net petroleum imports'' and (2) the financial and energy security risks associated with this oil trade. These changes directly influence U.S. national energy security. Similarly, the Analyzed Volumes may alter imports and exports of renewable fuels and renewable fuel feedstocks, which may also affect U.S. energy security.

Energy security is defined as the continued availability of energy sources at an acceptable price.[152] Achieving the separate but related goal of energy independence involves reducing reliance on foreign energy imports to minimize their impact on economic, military, or foreign policies.[153] A longstanding goal of U.S. energy policy has been to decrease oil imports, thereby reducing dependency on foreign oil suppliers.

Since the beginning of the RFS2 regulatory program in 2010, the U.S. has experienced significant changes in its exposure to the global oil market, with implications for energy security. In 2010, U.S. net petroleum imports were approximately 9.4 million barrels a day (MMBD).[154] Since then, increased domestic production of shale oil and renewable fuels have shifted the U.S. from a large net petroleum importer to a net exporter,[155] with net exports reaching 2.4 MMBD in 2024.[156] EIA projects continued growth in U.S. net exports of petroleum, reaching 3.3–3.8 MMBD by 2026 and 2027. Despite this shift, substantial imports of renewable fuels and feedstocks have been used to meet RFS obligations in recent years. This trend has implications for the U.S.'s energy security and independence.

Even with the long-term shift in U.S.'s net petroleum trade position, energy security risks persist due to three main factors. First, even as a net exporter, the U.S. economy can be adversely affected by energy price shocks. Both crude oil and renewable fuels are globally traded commodities, making global price and supply shocks an ongoing concern even from a relatively comfortable national net trade position. Second, many U.S. refineries depend heavily on imported heavy crude oil, making them susceptible to international supply disruptions. In 2024, gross petroleum imports were about 8.4 MMBD.[157] Likewise, the U.S. has experienced period of elevated imports of BBD feedstocks in recent years (see Figure III.A.2.b.ii–2). Third, oil exporters with a large share of global production can alter global oil prices through the Organization of Petroleum Exporting Countries (OPEC) by affecting oil supply relative to demand. These factors contribute to the vulnerability of the U.S. economy to fuel supply shocks and price spikes, despite EIA's projections of continued net petroleum exports through 2026 and 2027.

The EPA collaborates with Oak Ridge National Laboratory (ORNL) to assess the energy security implications of reduced net petroleum imports and exposure to global oil markets. ORNL has developed methodologies to evaluate social costs and energy security impacts of oil imports. This approach estimates two distinct impacts of importing petroleum in addition to the purchase price of petroleum itself: (1) the risk of reductions in U.S. economic output and disruption to the U.S. economy caused by sudden disruptions in the supply of imported oil to the U.S. (*i.e.,* macroeconomic disruption/adjustment costs); and (2) the impacts that a change in U.S. net oil imports have on overall U.S. oil demand and subsequent changes in the world oil price (*i.e.,* the ''demand'' or ''monopsony'' impacts).[158] Consistent with previous RFS rulemakings, we consider demand impacts to be transfer payments and exclude them from estimated monetized social benefits of the Analyzed Volumes.[159] However, the economy-wide benefits of avoiding macroeconomic disruption costs (estimated using ORNL's methodology) are societal benefits, which we label ''macroeconomic oil security premiums.'' For this final rule, the EPA and ORNL have developed estimates of these premiums based upon recent energy security literature and oil price projections and energy market and economic trends from AEO2025.[160]

To calculate the energy security benefits of the Analyzed Volumes, ORNL's macroeconomic oil security premiums are combined with estimates of annual reductions in net U.S. petroleum imports due to renewable fuel volume changes.[161] Table III.D.2–1 presents the macroeconomic oil security premiums and the total energy security benefits for the Analyzed Volumes. The average macroeconomic oil security premiums are estimated to be $3.69 per barrel in 2026 to $3.67 per barrel in 2027. Because there is uncertainty associated with these estimates, we also present confidence intervals in the table. In terms of cents per gallon, the macroeconomic oil security premiums are estimated to be 0.088¢ per gallon in 2026 and 0.087¢ per gallon in 2027.

[152] IEA, ''Energy Security.'' *https://www.iea.org/topics/energy-security.*

[153] 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.*

[154] 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.*

[155] *Id.*

[156] EIA, AEO2025, Table 11—Petroleum and Other Liquids Supply and Disposition.

[157] EIA, ''U.S. Supply and Disposition,'' Petroleum & Other Liquids, May 30, 2025. *https://www.eia.gov/dnav/pet/pet_sum_snd_d_nus_mbblpd_a_cur.htm.*

[158] Monopsony impacts stem from changes in the demand for imported oil, which changes the price of all imported oil.

[159] See RIA Chapter 6.4.2 for more discussion of our assessment of monopsony impacts of this action. Also, for a discussion of monopsony oil security premiums, 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.

[160] See RIA Chapter 6.4.2 for how the macroeconomic oil security premiums have been updated based upon a review of recent energy security literature on this topic.

[161] See RIA Chapter 6.4.1 for a discussion of the methodology used to estimate changes in U.S. annual net petroleum imports from the Analyzed Volumes.

Table III.D.2-1 Macroeconomic Oil Security Premiums and Total Undiscounted Energy Security Benefits for the Analyzed Volumes

Year	Macroeconomic Oil Security Premiums (2024$/barrel of reduced imports)	Total Energy Security Benefits – Analyzed Volumes (millions 2024$)
2026	$3.69 ($0.25–$7.25)	$361 ($24–$710)
2027	$3.67 ($0.16-$7.31)	$438 ($19–$873)

Note: Top-values in each cell are the mean values, while the values in parentheses define 90 percent confidence intervals.

3. Climate Change

CAA section 211(o)(2)(B)(ii) provides that when determining the applicable volumes of each renewable fuel category after the year 2022, the EPA shall include as part of its review ‘‘an analysis of . . . the impact of the production and use of renewable fuels on the environment, including on . . . climate change.’’ The statute does not define the term ‘‘climate change’’ and expressly provides that regulations issued pursuant to the RFS provisions shall not impact the regulatory status of any GHG under any other provision of the CAA.[162]

Although the uncertainty inherent in our analysis does not allow us to determine whether these regulations would have a material impact on climate change, the EPA is providing the GHG emission amounts for the Analyzed Volumes for 2026 and 2027. As such, we have undertaken an assessment of the GHG emission changes of the Analyzed Volumes for 2026 and 2027 relative to the No RFS Baseline. Several commenters stated that we should consider estimates based on the Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET) and Global Trade Analysis Project-Biofuels (GTAP–BIO) models in the climate change analysis. We agree; our climate change analysis of the Analyzed Volumes includes additional estimates based on these models, alongside estimates based on the Global Change Analysis Model (GCAM) and Global Biosphere Management Model (GLOBIOM) models presented in the proposal. More details on this analysis can be found in RIA Chapter 5.

Our analysis of the effects of the Analyzed Volumes on climate change includes three estimates of potential changes in GHG emissions. In terms of average annual CO_2e emissions through 2055, these three estimates are: (1) a 1 million metric ton increase; (2) a 17 million metric ton decrease; and (3) a 31 million metric ton decrease. Two of these estimates show the potential for reductions in GHG emissions relative to the assessed No RFS Baseline, while one estimate shows a comparatively much smaller increase in GHG emissions. As illustrated by the wide range of estimates, modeling of GHG emissions impacts of biofuel use is inherently uncertain, especially over the multiple decade-long analytical timeframe used for these estimates. Additionally, while we consider the impacts on climate change as required by statute, the range of potential GHG emission reductions, when coupled with additional uncertainties involved in commonly used climate change end points, makes it difficult to quantify potential climate change impacts such as changes in global temperature. However, our assessment of the Analyzed Volumes shows the potential for net GHG emissions reductions in the majority of our estimates over that time period but does not conclude such reductions are likely to result in a material difference in commonly evaluated ‘‘climate endpoints.’’ In past rulemakings for the RFS program, the EPA has considered this factor by using ‘‘lifecycle GHG emissions estimates as a proxy for climate change impacts.’’[163] The analytical approach we are taking in this final rule is similar in that we are providing GHG emissions as a proxy; this factor is one of many Congress instructed the EPA to consider when setting volumes, and we have considered it in a transparent and reasonable manner.

Scenarios included in the climate change analysis estimate cumulative GHG emissions impacts for a 30-year analytical scenario duration.[164] Cumulative emissions impact estimates for this 30-year analytical time period are presented in Table III.D.3–1. We present three separate estimates of these emissions, two of which estimate emissions reductions associated with the Analyzed Volumes. See RIA Chapter 5 for further information.

Table III.D.3-1: Cumulative Net Emissions Through 2055 for the Analyzed Volumes Relative to No RFS Baseline (millions of metric tons CO_2e emissions)

Measure	Estimate 1	Estimate 2	Estimate 3
Cumulative	-936	-496	33
Average Annual	-31	-17	1

[162] CAA section 211(o)(12).

[163] *See, e.g.,* 88 FR 44468, 44500 (July 12, 2023).

[164] See RIA Chapter 5.2 for the EPA's explanation regarding why the Agency has not monetized the GHG emissions impacts of this rule.

4. Fuel Costs

This section provides a brief discussion of the methodology used to estimate the cost impacts for the renewable fuels expected to be produced and consumed for the Analyzed Volumes and summarizes the estimated costs.

The cost analysis compared the cost of biofuels attributable to the RFS program to the cost of the fossil fuels they displace. The net estimated fuel cost impacts are social costs, excluding any subsidies and transfer payments. The fuel cost of each biofuel estimated to be consumed and of each fossil fuel being displaced as a result can be divided into various subcomponents:

• Production cost: feedstock cost is usually the most prominent factor, though production processing costs are also significant for some fuels.

• Distribution cost: because a given biofuel often has a different energy density than the petroleum fuel it is replacing, the distribution costs are estimated all the way to the point of use to capture the full fuel economy effect of using these fuels.

• Blending value: in the case of ethanol blended as E10, there is a blending value that mostly accounts for ethanol's octane value realized by lower gasoline production costs, but also a volatility cost that accounts for ethanol's blending volatility in RVP-controlled gasoline.

• Retail infrastructure cost: in the case of higher-level ethanol blends, there is a retail cost since retail stations usually need to add equipment or use compatible materials to enable the sale of these newer fuels.

• Fuel economy cost: different fuels have different energy content, leading to different cost levels of fuel economy, which impacts the relative fossil fuel volume being displaced and the cost to the consumer.

We added these various cost components together as appropriate for each renewable fuel to reflect the cost of that fuel. We conducted a similar cost estimate for the fossil fuels being displaced since their relative cost to biofuels is used to estimate the net cost of the increased use of biofuels. Unlike for biofuels, however, we did not calculate production costs for the fossil fuels since their production costs are inherent in the wholesale price projections provided in AEO2025.[165]

As described in section III.A.2 of this preamble, the Analyzed Volumes of biodiesel and renewable diesel reflect large year-over-year increases relative to current volumes; thus, we anticipate higher biodiesel and renewable diesel prices as the industry increases production to meet the volume requirements. Higher demand for biodiesel and renewable diesel feedstocks is projected to result in higher vegetable oil prices, which have a first order impact on costs. We have considered the impact of increased demand for vegetable oils used to produce biofuels in our assessment of fuel costs and the fuel price impacts for this final rule. This represents a change from our analysis for the Set 2 proposal, which used a static vegetable oil price for our projection of fuel costs and fuel price impacts.

Our vegetable oil price projection is based on a vegetable oil modeling study for how increased vegetable oil demand for biofuel use would impact its price. Based on this study, we project that soybean oil will rise into the $0.60 per pound range, with FOG and corn oil priced somewhat lower. This is different from the analysis conducted for the Set 2 proposal, which assumed that vegetable oil prices would continue at the projected USDA price for 2026 and 2027. The higher projected BBD feedstock prices, along with lower projected crude oil prices, are the principal reasons for the higher estimated costs of this final rule compared to the cost analysis in the Set 2 proposal.

There is uncertainty in projecting soybean oil prices, the market of which is also associated with, and affected by, the markets for whole soybeans, soybean meal, and soybean oil consumed in foods, as well as the markets for other vegetable oils. To provide an upper- and lower-bound on estimated costs at higher and lower vegetable oil prices, we estimate costs based on higher (approximately $0.80 per pound) and lower (USDA projected) soybean oil prices. Modeling USDA projected soybean oil prices (approximately $0.40 per pound) for the Analyzed Volumes aims to capture the costs presuming that the agricultural market will at some point stabilize at a lower price point consistent with current USDA projections. Because of the large increase in biodiesel and renewable diesel volumes over the baseline volumes, we can attribute a cost for the price increase not just to the new incremental volume increase, but to all biodiesel and renewable diesel, including that in the baseline. Thus, the prices projected in the Analyzed Volumes case are higher than the prices projected in the No RFS Baseline case and this substantially increases the estimated cost of the RFS program. Over time, though, the market is expected to restabilize at lower prices. Consistent with previous analyses, we also estimate costs at the primary, high, and low vegetable oil price estimates relative to the 2025 Baseline.

The estimated fuel costs for the Analyzed Volumes based on the middle estimate of vegetable oil prices and relative to both the No RFS and 2025 Baselines are presented in Tables III.D.4–1 and 2.[166] Table III.D.4–3 discounts the costs in 2027 to 2026 and adds them to the costs incurred in 2026 to provide a single cost estimate for the 2026 and 2027 standards.

[165] Estimating production costs for renewable fuels facilities is possible because the plants are generally single purpose production processes producing a predictable, limited array of feedstocks into products, while petroleum refineries are each configured differently and each is refining a different mix of feedstocks of varying quality and each refinery is producing a unique number and volume of products.

[166] More detailed information on the costs for the Analyzed Volumes is available in RIA Chapter 10.4.2.

Table III.D.4-1: Aggregated Total Social Costs (million 2024$)

	Relative to No RFS Baseline		Relative to the 2025 Baseline	
	2026	2027	2026	2027
Gasoline	$320	$392	$118	$183
Diesel	$17,877	$20,802	$14,223	$14,606
Natural Gas	$44	$50	$4	$8
Total	$18,241	$21,244	$14,797	$14,797

Note: Total cost of the renewable fuel expressed over the fossil fuel it is blended into.

Table III.D.4-2: Per-Unit Costs (2024$)

		Relative to No RFS Baseline		Relative to the 2025 Baseline	
	Units	2026	2027	2026	2027
Gasoline	$/gal	$0.002	$0.003	$0.001	$0.001
Diesel	$/gal	$0.305	$0.359	$0.242	$0.252
Natural Gas	$/thousand ft^3	$0.001	$0.002	$0.0001	$0.0002
Gasoline and Diesel	$/gal	$0.093	$0.110	$0.073	$0.076

Note: Per-gallon or per thousand cubic feet cost of the renewable fuel expressed over the fossil fuel it is blended into; the last row expresses the cost over the obligated pool of gasoline and diesel fuel.

Table III.D.4-3: Estimated Discounted Fuel Costs Impacts of the Analyzed Volumes (million 2024$)

	Relative to No RFS Baseline		Relative to the 2025 Baseline	
	3% Discount Rate	7% Discount Rate	3% Discount Rate	7% Discount Rate
Present value (2026)	$38,866	$38,095	$29,163	$28,626
Annualized value	$20,312	$21,070	$15,241	$15,833

Note: 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.

The biofuel costs are generally higher than the costs of the gasoline, diesel, and natural gas that they displace as evidenced by the increases in fuel costs shown in Table III.D.4–1 through 3.[167] As described more fully in RIA Chapter 10, our assessment of costs did not yield a specific threshold value below which the incremental costs of biofuels are reasonable and above which they are not. Given the significant inherent uncertainty in both the crude oil and agricultural feedstock price forecasts, any attempt to identify such a threshold value is extremely difficult. Nevertheless, throughout section III of this preamble we consider the directional cost inferences along with the other factors that we analyzed in the context of our discussion of the Analyzed Volumes for 2026 and 2027.

The fuel cost estimates for the high and low vegetable oil prices relative to the No RFS Baseline, and fuel costs relative to the 2025 Baseline, along with a more detailed discussion of the cost analysis, are summarized in RIA Chapter 10.

5. Cost to Transport Goods

We also estimated the impact of the Analyzed Volumes on the cost to transport goods. However, we do not include these estimates in our social cost analysis because the fuel prices used to form these estimates include a number of other factors, such as RIN value and Federal incentives. Because these factors are economic transfers and are not separable from the non-transfer components of the cost to transport goods, it would not be appropriate to include the overall estimates of these impacts in our social cost estimates.

To estimate price impacts, the per-unit costs from Table III.D.4–2 are adjusted to reflect RIN price impacts and account for the 45Z credit and other market factors, and the resulting values can be thought of as retail price impacts. Consistent with our assessment of the fuels markets, we have assumed that obligated parties pass through their RIN costs to consumers and that fuel blenders reflect the RIN value of the renewable fuels in the price of the blended fuels they sell.[168] Table III.D.5–1 summarizes the estimated impacts of the Analyzed Volumes on gasoline and diesel fuel prices at retail when the costs of each biofuel are amortized over the fossil fuel it displaces.

[167] Natural gas shows a cost savings despite the fact that RNG is more expensive than fossil natural gas. This is because the Analyzed Volume for cellulosic biofuel is estimated to cause a smaller RNG volume in 2026 and 2027 compared to either the No RFS Baseline or the 2025 Baseline.

[168] See RIA Chapter 10.5 for more detailed information on our estimates of the fuel price impacts of this action.

Table III.H.5-1: Estimated Effect of Analyzed Volumes on Retail Fuel Prices ($/gal)

		2026	2027
Relative to No RFS Baseline	Gasoline	$0.051	$0.052
	Diesel	$0.195	$0.223
Relative to 2025 Baseline	Gasoline	$0.000	$0.000
	Diesel	$0.062	$0.076

For estimating the cost to transport goods, we focus on the impact on diesel fuel prices since trucks that transport goods are normally fueled by diesel fuel. Reviewing the data in Table III.D.5–1, the largest projected price increase is $0.223 per gallon for diesel fuel in 2027 relative to the No RFS Baseline.

The impact of fuel price increases on the price of goods overall can be estimated based on a USDA study that analyzed the impact of fuel prices on the wholesale price of produce.[169] Applying the price correlation from the USDA study indicates that the $0.223 per gallon diesel fuel cost increase raises retail diesel fuel prices by about 6 percent, which would then increase the wholesale price of produce by about 1.5 percent. If produce being transported by a diesel truck costs $3 per pound, the increase in that product's price would be $0.045 per pound.[170] If the estimated price impacts are averaged over the combined gasoline and diesel fuel pool, the impact on produce prices would be proportionally lower based on the lower per-gallon cost.

6. Conversion of Natural Lands, Water, Soil, and Ecosystem Impacts

Increases in volumes attributable to the Analyzed Volumes could lead to potential increases in agricultural land conversion to produce biofuel feedstocks. Such land use changes could subsequently contribute to negative impacts to water and soil quality, water quantity, and ecosystems and wildlife habitat. This is discussed further in RIA Chapters 4.2 through 4.5.

7. Infrastructure

We evaluated the Analyzed Volumes and how they may impact the existing renewable fuels infrastructure required for product distribution. This includes whether the current infrastructure system is sufficient to accommodate the increases in the Analyzed Volumes and potential changes that could occur with increases in renewable fuel production and use. Based on our analysis, we project that the Analyzed Volumes would be compatible with existing infrastructure and that the supply of these fuels will not adversely impact the infrastructure required for product distribution. A more detailed summary of this analysis can be found in RIA Chapter 8.

8. Commodity Supply

We project that the supply of commodities used for biofuel production for the Analyzed Volumes, such as corn and soybeans, will continue to increase in future years primarily due to yield increases, consistent with historic trends. It is possible that increasing demand for biofuel feedstocks such as soybean oil will divert these feedstocks from other markets; however, we project that substitute feedstocks will be available to markets that previously used soybean oil diverted to biofuel production. See RIA Chapter 9.2 for more detail on our analysis of the impact of biofuel production on the supply of commodities.

9. Air Quality

We expect some localized increases in some emissions due to the Analyzed Volumes, particularly at locations near biofuel production and transport routes. Overall, considering end use, transport, and production, emission changes are expected to have variable impacts on ambient concentrations of emitted gases in specific locations across the U.S. Air quality impacts are discussed further in RIA Chapter 4.1.

10. Food and Commodity Prices

Our analysis indicates that the Analyzed Volumes have the potential to affect the prices of agricultural commodities and food prices. Corn price impacts are estimated using a literature-based elasticity of 3 percent per additional billion gallons of corn ethanol, applied to the difference between the Analyzed Volumes and the No RFS Baseline. Our analysis for soybean oil and meal uses a linear equilibrium displacement model from the literature, which maps biofuel demand shocks to commodity prices. Specifically, a 20 percent increase in soybean oil demand for biofuel corresponds to an 8.17 percent increase in the soybean oil price. We then quantify 2026 and 2027 price impacts for the Analyzed Volumes relative to the No RFS Baseline. We also assess grain sorghum, barley, oats, and distillers grains using historical price relationships with corn and find only small impacts. Combining these commodity price changes with forecasts of commodity use for food production suggests modest effects on total food expenditures, given that commodity costs represent a small share of retail food prices. A summary of the estimated impacts is provided in Table III.D.10–1, and further discussion can be found in RIA Chapters 9.3 and 9.4.

[169] USDA, ''How Transportation Costs Affect Fresh Fruit and Vegetable Prices,'' Economic Research Report 160, November 2013.

[170] *Coupons.com,* ''Comparing Prices on Groceries,'' May 4, 2021.

Table III.D.10-1: Estimated Impact of the Analyzed Volumes on Food and Agricultural Commodity Prices

	Units	2026	2027
Corn Price Increase	$ per bushel	$0.03	$0.03
Grain Sorghum Change	$ per bushel	$0.02	$0.03
Barley Price Change	$ per bushel	$0.02	$0.02
Oat Price Change	$ per bushel	$0.02	$0.02
Soybean Oil Price Change	$ per pound	$0.28	$0.35
Soybean Meal Price Change	$ per short ton	-$39.88	-$48.51
Distillers Grains Price Change	$ per short ton	$0.90	$0.99
Projected Food Expenditure Increase	$ per consumer unit	$19.51	$23.52
Total Change in Food Expenditure	billion $	$2.65	$3.19

E. Volume Requirements for 2026 and 2027

Our review of the history of the RFS program to date and assessment of the impact of the Analyzed Volumes on the statutory factors, some of which are described briefly in section III.D of this preamble, provide the basis for the volumes we are finalizing in this action for 2026 and 2027. While we do not separately discuss each of the statutory factors for each component category in section III.D of this preamble, we have analyzed all the statutory factors in the RIA. Determining the appropriate volumes for 2026 and 2027 requires that we balance these factors, a task complicated by the fact that higher volumes of renewable fuel production and use are projected to impact some of the statutory factors positively and others negatively. Further, some of the impacts we are directed to consider have varying impacts on different stakeholders. As discussed in section II.B of this preamble, Congress provided the EPA flexibility by enumerating factors that we must consider without mandating any particular forms of analysis or specifying how we must weigh the various factors against one another.[171] The following sections describe our consideration of our review of the implementation of the RFS program to date and the statutory factors to determine the appropriate volumes for 2026 and 2027.

1. Cellulosic Biofuel

In EISA, Congress set increasing targets for cellulosic biofuel, aiming to reach 16 billion gallons by 2022.[172] After 2015, all growth in the mandated total renewable fuel volume was designated for advanced biofuels, with the majority of that growth focused on cellulosic biofuels.[173] This indicates that Congress intended the RFS program to strongly incentivize cellulosic biofuels, placing a particular emphasis on their development after 2015. While cellulosic biofuel production has not reached the levels envisioned by Congress in 2007, we remain committed to supporting the advancement and commercialization of these fuels. As described in section III.A.1 of this preamble, the Analyzed Volume for cellulosic biofuel project growth in cellulosic biofuel production and transportation use through 2027, while accounting for potential constraints on both. We evaluated these volumes using additional statutory factors. The results of these evaluations are summarized here and detailed further in the RIA.

Our analysis of the statutory factors, summarized here and discussed in greater detail in the RIA, shows that cellulosic biofuels have the potential to provide significant reductions in GHG emissions. We expect that in 2026 and 2027 the cellulosic biofuel supply will come mainly from three sources: renewable CNG/LNG produced from landfill biogas, renewable CNG/LNG produced from agricultural digester biogas, and CKF ethanol. Renewable CNG/LNG produced from landfill biogas and agricultural digester biogas is expected to account for the largest share of total volume. Because both fuel sources recover energy from waste materials and byproducts of existing processes, they are not expected to drive significant land-use change. As a result, we project that producing these fuels will help limit adverse impacts identified in the statutory factors, including the conversion of wetlands and other ecosystems, the loss of wildlife habitat, degradation of soil and water quality, and volatility in food prices and supply. Although we recognize potential soil and water concerns that could result from increased production of biogas from manure and agricultural digestors, the relatively small volumes of these fuels relative to landfill-sourced biogas suggests these impacts will remain minimal.

Beyond these environmental benefits, cellulosic biofuels deliver substantial economic and energy security gains. Converting otherwise unused products into transportation fuel supports jobs and generates positive economic impacts. However, the combination of growing CNG/LNG use as transportation fuel and high cellulosic RIN prices, which refiners typically recover through fuel sales, is expected to increase gasoline and diesel prices. Despite this increase, strengthening the cellulosic biofuel market advances statutory goals for energy independence and security, reduces reliance on foreign fuel sources, and supports long-term economic resilience.

In summary, our analysis of the statutory factors indicates that the benefits of increasing cellulosic biofuel volumes outweigh the potential downsides. We are finalizing cellulosic biofuel volumes for 2026 and 2027 at levels that align with projected growth in the consumption of CNG/LNG as transportation fuel in these years. These volumes, based on the most current data at the time of this action, represent a

[171] *See CBD* at 171–172.

[172] CAA section 211(o)(2)(B)(i)(III).

[173] CAA section 211(o)(2)(B)(i).

well-informed estimate of the achievable growth in cellulosic biofuel production during this period. We believe that these volumes will continue to encourage investment in and development of cellulosic biofuels while adhering to statutory requirements, including those under CAA section 211(o)(2)(B)(iv) that the EPA set the cellulosic fuel volumes such that we do not anticipate a need to lower the requirement through a waiver under CAA section 211(o)(7)(D). To that end, because the "projected volume available"[174] equals the analyzed volume, we are finalizing the cellulosic biofuel volumes at the analyzed level—*i.e.,* the level to which the EPA would reduce the cellulosic biofuel requirement if it exercised the cellulosic waiver authority—as shown in Table III.E.1–1.

Table III.E.1-1: Final Cellulosic Biofuel Volumes (million RINs)

	2026	2027
Renewable CNG/LNG	1,235	1,306
Ethanol from CKF	128	128
Total Cellulosic Biofuel	1,360	1,430

Note: Total cellulosic biofuel volume is rounded to the nearest 10 million RINs.

2. Non-Cellulosic Advanced Biofuel

The volume targets established by Congress through 2022 anticipated volumes of advanced biofuel beyond what would be needed to satisfy the cellulosic standard. The statutory target for advanced biofuel in 2022 (21 billion gallons) allowed for up to five billion gallons of non-cellulosic advanced biofuel to be used towards the advanced biofuel volume target, with additional quantities of non-cellulosic advanced biofuel able to contribute towards meeting the total renewable fuel requirement.[175] The applicable volumes for 2022 similarly include five billion RINs of non-cellulosic advanced biofuel.[176] In the Set 1 Rule, we continued to grow the implied non-cellulosic advanced biofuel category, which reached 5.95 billion RINs in 2025.[177]

The non-cellulosic advanced biofuel volumes in this action reflect growth rates based on analysis of feedstock availability and production capacity potential. In this action, we are finalizing volume requirements that reflect 4.2 and 4.4 billion RIN increases in the projected supply of non-cellulosic advanced biofuel for 2026 and 2027, respectively. These increases are relative to the volume of non-cellulosic advanced biofuel supplied to the U.S. in 2025 based on available data. Our decision to finalize these volumes is based on our assessment of the impacts of non-cellulosic advanced biofuels (primarily biodiesel and renewable diesel) on the statutory factors. Our assessment of the statutory factors, and how these assessments support the final non-cellulosic advanced biofuel volumes, are summarized in the remainder of this section and are discussed in greater detail in the RIA. Section V.E.3 of this preamble discusses our consideration of what portion of the non-cellulosic advanced biofuel volume should be restricted to BBD.

To date, the vast majority of non-cellulosic advanced biofuel in the RFS program has been biodiesel and renewable diesel, with relatively small volumes of sugarcane ethanol and other advanced biofuels. Advanced biodiesel and renewable diesel together accounted for 95 percent, or more, of the total supply of non-cellulosic advanced biofuel over the last several years, and this trend is expected to continue through 2027 due to the limited production and import of other types of non-cellulosic advanced biofuels.[178] We therefore focused our attention on the impacts of these fuels in relation to the statutory factors in determining appropriate levels of non-cellulosic advanced biofuel for 2026 and 2027.[179]

As in past RFS rulemakings, our analyses indicate that for some of the statutory factors the projected impacts of increasing production and use of biodiesel and renewable diesel are expected to be generally positive or neutral, while for other factors the impacts are expected to be generally negative. For some factors, the projected impacts vary significantly depending on where the fuel is produced (*i.e.,* foreign or domestic), whether the feedstock used to produce the fuel is a waste or byproduct (*e.g.,* UCO) or an agricultural commodity (*e.g.,* soybean oil), and whether it is sourced domestically or imported.

With respect to GHG emission reductions, while there remains considerable uncertainty as to the GHG emission impacts of non-cellulosic advanced biofuels (particularly biofuel produced from crop-based feedstocks) our assessment suggests these fuels have the potential to provide net GHG emission reductions. Regardless of the potential resulting impacts to climate change from the reduction in GHG emissions due to this program, as Congress intended to emphasize lower GHG-emitting fuels within the RFS program, the potential GHG reductions suggest that higher non-cellulosic advanced biofuel volumes than those established by Congress for 2022 (5.0 billion RINs) or established by the EPA for 2025 (5.95 billion RINs) may be appropriate.

All qualifying biodiesel and renewable diesel is expected to diversify the transportation fuel supply and thus have a positive impact on the energy security of the U.S. Similarly, because we project that a greater percentage of the increase in the supply of biodiesel and renewable diesel through 2027 will be supplied from domestic biofuel producers using domestic feedstocks, we expect these fuels to positively impact employment and rural economic development. We do not anticipate the availability of infrastructure to distribute or use biodiesel and renewable diesel will limit the consumption of these fuels in future years, nor do we anticipate that increasing supplies of these fuels will negatively impact the deliverability of materials, goods, and products other than renewable fuel. Together, these statutory factors further support higher volumes of biodiesel and renewable diesel in future years.

[174] CAA section 211(o)(7)(D)(i).

[175] CAA section 211(o)(2)(B)(i).

[176] 87 FR 39600, 39624 (July 1, 2022).

[177] 88 FR 44468, 44518 (July 12, 2023).

[178] See RIA Chapters 7.2 through 7.4.

[179] We have also considered the potential for increasing volumes of renewable jet fuel. Given its similarity to renewable diesel, for purposes of projecting appropriate volume requirements for 2026 and 2027, in most cases we consider renewable jet fuel to be a component of renewable diesel.

Other statutory factors suggest that lower volumes of biodiesel and renewable diesel may be appropriate. Biodiesel and renewable diesel have historically had higher costs than the diesel fuel they displace and are expected to continue to cost more into the future, primarily due to relatively high feedstock costs. These higher costs are expected to ultimately be passed through to consumers, resulting in higher costs for transportation fuel and higher costs to transport goods.[180]

Biodiesel and renewable diesel produced from vegetable oils are also expected to result in higher prices for these oils and the crops from which they are derived (*e.g.,* soybeans and canola). These higher vegetable oil prices are projected to have both positive and negative impacts. Higher vegetable oil prices are expected to drive increased investment in the domestic oilseed crushing industry, resulting in increased employment and economic impact, as well as higher revenue for feedstock producers. This projected increased investment in domestic oilseed crushing capacity would reduce domestic oilseed producers reliance on export markets, as it would increase the capacity for processing oilseed domestically. Higher vegetable oil prices are, however, expected to result in higher prices for products that use them as inputs (*e.g.,* food and feed).

Notably, the projected impacts on some of the statutory factors are expected to vary depending on the feedstock used to produce biodiesel or renewable diesel. We have generally assumed that biofuels produced from FOG feedstocks such as UCO and tallow do not drive the conversion of land to cropland, increase the intensity of farming practices, or raise agricultural commodity or food prices.[181] Because of this assumption, biofuels produced from FOG are also generally expected to result in greater GHG emission reductions. However, commodities such as UCO and tallow now command prices comparable to those of crop-derived vegetable oils in some cases which makes forecasting which feedstocks will be economically preferable more difficult than in previous years.

Increases in domestic sources of FOG feedstocks in future years are projected to be limited as much of the available feedstocks are already being used for biofuel production with smaller quantities collected for other productive uses. Significant volumes of these feedstocks may be available from foreign countries, though there is significant uncertainty in the quantities and origin of these feedstocks that will be available to the U.S. in future years.

Biodiesel and renewable diesel produced from domestic agricultural commodities such as soybean oil and canola oil are more likely to have negative impacts on wetlands, wildlife habitat and ecosystems, and water quality, as demand for these feedstocks can result in increased conversion of native lands to cropland. This land conversion (whether land is converted directly to produce biofuel crops or induced through higher commodity prices) generally results in GHG emissions, and therefore biofuels produced from these feedstocks may have lifecycle GHG emission greater than biofuels produced from wastes or byproducts.[182] Significant opportunities exist for increasing domestic production of soybean oil (which would be expected to positively impact job creation and rural economic development), as well as imported canola oil from Canada. Generally, agricultural feedstocks grown in North America are eligible for lower incentives in foreign biofuel programs compared to waste feedstocks. Consequently, we have greater confidence in projecting the potential supply of these feedstocks available for domestic renewable fuel production in future years.

Our analysis of the Analyzed Volumes indicated likely differences in impacts on the statutory factors between growth in the supply of biodiesel and renewable diesel produced from FOG feedstocks such as UCO and tallow (the marginal supplies of which are primarily sourced from foreign countries) and those produced from virgin vegetable oils (the marginal supplies of which are primarily sourced from the U.S. and Canada). Thus, the availability and likely use of these feedstocks for biofuel production and use in the U.S. is a key factor in our consideration of the Analyzed Volumes of non-cellulosic advanced biofuel. As discussed in section III.A.2 of this preamble and RIA Chapter 7, there is relatively less uncertainty in the projected availability of marginal quantities of vegetable oils than there is in the projected availability of marginal quantities of FOG. The higher uncertainty in the projected availability of the waste and byproduct feedstocks is not only a function of the quantity of these feedstocks that can be collected globally, but also of demand for these feedstocks for biofuel production, other productive uses in other countries, and highly dynamic trading environments. Due to the relatively high uncertainty in the available supply of FOG and the structure of the 45Z credit (which is not available to imported biofuels nor, starting in 2026, biofuels produced from feedstocks originating outside of North America), we project that biofuels produced from domestic feedstocks are more likely to be used in significant quantities in future years than imported biofuels and feedstocks, particularly imported feedstocks originating outside North America.

We have also considered how the increased production of domestic biodiesel and renewable diesel relates to the statutory factors. As is typically the case, not all factors are affected positively or negatively in a uniform fashion by increasing or decreasing domestic biodiesel and renewable diesel production. However, there are several statutory factors that have the potential to be positively impacted in a material way by increasing domestic production of these fuels, including employment and rural economic development and energy security impacts. Energy security is bolstered through a further displacement of fossil fuels by increasing volumes of renewable fuel, a large and increasing fraction of which will be produced from domestic feedstocks as we move forward and changes in trade dynamics and tax incentives (45Z) work through renewable fuel markets.

Employment and rural economic development can be affected very positively by increasing the domestic production of biodiesel and renewable

[180] This discussion refers to societal costs. We recognize that with the incentives provided by the RFS program and other State and local programs, the price for biodiesel and renewable diesel (net available incentives) may be lower than the price of petroleum fuels. See RIA Chapter 10 for a further discussion of our cost estimates.

[181] This is particularly true if the feedstocks used to produce these biofuels would otherwise be landfilled or not productively used. It is not the case, however, that all feedstocks assumed to be wastes or byproducts would otherwise be landfilled or not productively used. For example, UCO and animal fats such as tallow have historically had a variety of productive uses, include use as animal feed and use as a feedstock to produce soaps, detergents, and other oleochemicals. Historically, such demands have been outstripped significantly by product supply, leading to unproductive disposal of excess supply in the absence of a productive use opportunity. However, increasing levels of demand for these feedstocks for biofuel production could not only fully consume this previously excess supply, but also result in the diversion of these feedstocks from existing markets. In turn, markets that previously used these waste and byproduct feedstocks may seek alternatives, and any impacts on cropland, GHG emissions, or other factors that result from the sourcing of these alternative feedstocks should then be attributable to biofuel production.

[182] However, the land use impacts with respect to GHG emissions may be outweighed by additional transportation GHG emissions especially if obtained from international sources.

diesel by more fully utilizing the production assets which have been underutilized or ceased production in recent years. Our analysis indicates that significantly higher domestic production of biodiesel and renewable diesel from existing facilities is possible given the low utilization rates in 2025 compared to previous years and historical precedent and that the industry has been able to achieve utilization rates greater than 90% in past years.[183]

Increasing the domestic production of non-cellulosic advanced biofuels would have several positive effects for employment and rural economic development. Direct effects of increased production would be increased employment as additional workers would be required to restart or expand production and increased economic activity for the rural communities wherein these renewable production facilities are often located. Increasing domestic production of biodiesel and renewable diesel is also expected to result in increased investment in domestic oilseed crushing to supply feedstocks for biofuel production. These investments would decrease the reliance of domestic soybean producers on export markets and further benefit rural economic development and employment. A few second order positive impacts may include: increased demand for feedstock produced in rural communities, expansion of associated input and service sector employment related to biofuel and feedstock production, and potential for either new or expanded biofuel production capacity in rural communities. In totality, our analysis of the statutory factors suggests that higher non-cellulosic advanced biofuel volumes intended to realize higher and historically-precedented capacity utilization rates are appropriate.

Based on our analyses of all the statutory factors, we are finalizing volumes for 2026 and 2027 that reflect the Analyzed Volumes of non-cellulosic advanced biofuel. These volumes were calculated projecting a 90 percent utilization rate of existing biodiesel and renewable diesel production capacity (with some growth from 2026 to 2027) and the projected production and import of other advanced biofuels. These volumes reflect our consideration of the impacts of these fuels on the statutory factors, including the potential increases in employment and economic impacts for renewable fuel producers, feedstocks producers and processors, and the rural communities in which these facilities are located. These volumes also reflect our consideration of the impact of these fuels on fuel prices and climate change, although the potential impacts on climate change are more uncertain, as discussed previously. The final non-cellulosic advanced biofuel volume requirements also reflect our assessment of the available supply of feedstocks used to produce these fuels (including the uncertainties associated with these projections), the projected high costs for these fuels relative to the petroleum fuel they displace, and the potential negative impacts associated with increasing demand for vegetable oils or diverting feedstocks from existing uses to biofuel production.

We project that the feedstocks needed to produce the final non-cellulosic advanced biofuel volume requirements could be supplied primarily, if not exclusively from domestic sources and imports from Canada and Mexico. Trade dynamics and changes to the 45Z credit increase the likelihood that the increase in the supply of non-cellulosic advanced biofuels through 2027 will be supplied by domestic biofuel producers using North American feedstocks. Through 2027, we project that imported renewable fuels and imported feedstocks from countries other than Canada and Mexico may continue to contribute towards the total supply of non-cellulosic advanced biofuels, but that the relative share of these fuels will decrease in future years as domestic supplies (and the supply of feedstocks from Canada and Mexico) increase in response to the incentives provided by tax and trade policy.

We recognize that there are potential negative impacts likely to result from non-cellulosic advanced biofuel volume requirements that are too high or too low. If we establish volume requirements for these fuels that are too low, the market will likely supply lower volumes of these fuels to the U.S. than could be achieved with higher volume requirements. This could negatively impact biofuel producers and result in lower employment, economic impacts, and GHG emission reductions than could be achieved with higher volume requirements. Conversely, if we establish volume requirements for these fuels that are too high, the costs of these fuels would be expected to rise, increasing the prices of food, fuel, and other goods for consumers. It is also possible that the market would be unable to supply higher volumes, requiring the EPA to reduce the volume requirements in the future, undermining the market stability the RFS program is designed to provide.

Non-cellulosic advanced biofuel is again expected to fill some of the total renewable fuel volume requirement in excess of the advanced biofuel requirement. Consistent with the approach taken in the Set 1 Rule, and as discussed in greater detail in section III.E.4 of this preamble, we are finalizing volume requirements in this action that reflect an implied conventional renewable fuel requirement of 15 billion gallons in each year. Since we project that the quantity of conventional renewable fuel available in these years will be limited, significant volumes of non-ethanol biofuels will be needed to meet the conventional renewable fuel volume requirement of 15 billion gallons.

We project that the most likely source of non-ethanol biofuel will be biodiesel and renewable diesel that qualifies as advanced biofuel. Biodiesel and renewable diesel cannot be used to satisfy the projected shortfall in conventional renewable fuel if we already require the use of these fuels to meet the non-cellulosic advanced biofuel volume requirement. Therefore, the final renewable fuel volumes we are establishing for 2026 and 2027 reflect non-cellulosic advanced biofuel volumes equal to the analyzed volumes of these fuels less the volume projected to be needed to meet the shortfall in the conventional renewable fuel volume requirement. The final non-cellulosic advanced biofuel volumes for 2026 and 2027 are summarized in Table III.E.2–1.

[183] See further discussion in RIA Chapter 7.2.

Table III.E.2-1: Final Non-Cellulosic Advanced Biofuel Volumes (million RINs)

	2026	2027
Non-cellulosic advanced biofuel volume (total supply)	10,190	10,340
Needed to meet the implied conventional volume	730	800
Available for the advanced biofuel standard	9,460	9,550

Note: All volumes rounded to the nearest 10 million RINs.

3. Biomass-Based Diesel

Because BBD makes up for the vast majority of non-cellulosic advanced biofuel, we did not separately assess the impacts of BBD on the statutory factors from those of non-cellulosic advanced biofuels. Our analysis of the impacts of the Analysis Volumes for BBD can be found in section III.E.2 of this preamble. In determining the appropriate BBD volumes for 2026 and 2027, our primary consideration is how much of the non-cellulosic advanced biofuel volume to reserve exclusively for BBD based on our review of the implementation of the RFS program to date and our analysis of the statutory factors. This approach is consistent with the approach we have taken to establishing the BBD volume requirements in previous years.

In previous RFS rulemakings, we have adopted an approach of increasing the BBD volume requirement in concert with the change, if any, in the implied non-cellulosic advanced biofuel volume requirement.[184] This approach provides ongoing support for BBD producers, while maintaining an opportunity for other advanced biofuels to compete for market share. In reviewing the implementation of the RFS program to date, we determined that this approach successfully balanced a desire to provide support for BBD producers with an increasing guaranteed market, while at the same time maintaining an opportunity for other advanced biofuels to compete within the advanced biofuel category. Our assessment of the impacts of BBD on the statutory factors is discussed further in the RIA.

As in recent years, we believe that excess volumes of BBD beyond the BBD volume requirements will be used to satisfy the advanced biofuel volume requirement within which the BBD volume requirement is nested. Historically, the BBD standard has not independently driven the use of BBD in the market. This is due to the nested nature of the standards and the competitiveness of BBD relative to other advanced biofuels. Moreover, BBD use can also be driven by the implied conventional renewable fuel volume requirement as an alternative to using increasing volumes of corn ethanol in higher-level ethanol blends such as E15 and E85. We believe these trends will continue through 2027.

We also believe it is important to maintain space for other advanced biofuels to participate within the advanced biofuel standard of the RFS program. Although the BBD industry has matured over the past decade, the production of advanced biofuels other than biodiesel and renewable diesel continues to be relatively low and uncertain. Maintaining this space for other advanced biofuels can in the long-term facilitate increased commercialization and use of other advanced biofuels, which may have superior environmental benefits, avoid concerns with food prices and supply, and have lower costs relative to BBD. Furthermore, rather than only supporting BBD, the 45Z credit may support the production and use of North American non-BBD advanced biofuels as well. Despite the potential impacts of the 45Z credit, we do not think increasing the size of this space is necessary through 2027 given that only small quantities of these other advanced biofuels have been used in recent years relative to the space we have provided for them in those years.

The final BBD volumes represent significant growth from the volumes established in the Set 1 Rule. At the same time, these volumes preserve an opportunity for non-cellulosic advanced biofuels other than BBD to compete for market share within the advanced biofuel category. We are finalizing BBD volumes that maintain a 600 million RIN opportunity for non-cellulosic advanced biofuels other than BBD, which is approximately equal to the opportunity for these fuels from 2023–2025. The final BBD volumes are shown in Table III.E.3–1.[185]

Table III.E.3-1: Final BBD Volumes (million RINs)

	2026	2027
BBD	9,960	10,120
Opportunity for advanced biofuel other than BBD	600	600
Total non-cellulosic advanced biofuel	9,360	9,520

Note: All volumes rounded to the nearest 10 million RINs.

[184] *See, e.g.,* 88 FR 44516–17 (July 12, 2023).

[185] Note that, unlike in previous years, the BBD volume requirement is expressed in RINs rather than physical gallons. As discussed in section VIII.C of this preamble, we are making this change to better align the BBD requirement with the requirements for the other three categories of renewable fuel, which are expressed in RINs rather than gallons.

4. Conventional Renewable Fuel

Although Congress had intended cellulosic biofuel to become the most widely used renewable fuel by 2022,[186] conventional renewable fuel has continued to account for the majority of renewable fuel supply since the RFS program began in 2005. The favorable economics of blending corn ethanol at 10 percent into gasoline, even without the incentives created by the RFS program, caused it to quickly saturate the gasoline supply shortly after the RFS program began.

The implied statutory volume target for conventional renewable fuel rose annually between 2009 and 2015 until it reached 15 billion gallons, where it remained through 2022.[187] We have maintained the implied statutory volume target for conventional renewable fuel at 15 billion gallons since 2022, including in the Set 1 Rule.[188]

As discussed in section III.A.3.a of this preamble, constraints on ethanol consumption have prevented the volume of ethanol used in transportation fuel from reaching 15 billion gallons, even with the incentives provided by the RFS program and after accounting for the projected increase in the availability of higher-level ethanol blends such as E15 and E85. Such higher-level ethanol blends are an avenue through which higher volumes of renewable fuel can be used in the transportation sector to reduce GHG emissions and improve energy security over time. Incentives created by the implied conventional renewable fuel volume requirement contribute to the economic attractiveness of these fuels. However, we expect the constraints that currently limit adoption of these blends, and ethanol consumption as a whole, to continue to exist through 2027. The difficulty in reaching 15 billion gallons with ethanol is compounded by the fact that gasoline demand for 2026 and 2027 is expected to continue to decline slightly relative to gasoline demand in 2025.

We do not believe that constraints on ethanol consumption should be the single determining factor in the appropriate level of conventional renewable fuel to establish for 2026 and 2027. The implied volume requirement for conventional renewable fuel is not a requirement for ethanol, nor even for conventional renewable fuel. Instead, conventional renewable fuel is the portion of total renewable fuel that is not required to be advanced biofuel. The implied volume requirement for conventional renewable fuel can be satisfied by any approved renewable fuel. Examples of non-ethanol renewable fuels that regularly contribute to this volume include conventional biodiesel and renewable diesel, as well as advanced biodiesel and renewable diesel beyond what is required by the advanced biofuel volume requirement. For these reasons, we are establishing the appropriate level of conventional renewable fuel on a broader basis than just the amount of conventional ethanol likely to be consumed each year.

While this segment of the RFS program creates opportunities for all approved renewable fuels to contribute, our analyses of several of the statutory factors, described in more detail in the RIA, also highlights the importance of ongoing support for corn ethanol generally and for an implied conventional renewable fuel volume requirement that helps to incentivize the domestic consumption of corn ethanol. Moreover, sustained and predictable support of higher-level ethanol blends through consistent implied conventional renewable fuel volume requirements helps provide some longer-term incentives for the market to invest in the infrastructure necessary to expand the availability of higher-level ethanol blends. The benefits of this approach include potential increases in employment and economic impact, most notably for corn farmers, but also positive impacts on ethanol producers and related ethanol blending and distribution activities. The rural economies surrounding these industries also benefit from strong demand for ethanol. Increased demand for higher-level ethanol blends could also increase employment and economic impact more broadly if retail station owners respond to the incentives created by the RFS program and other Federal actions by investing in infrastructure necessary to increase the availability of higher-level ethanol blends at their stations. In addition, the consumption of renewable fuels, including domestically produced ethanol, reduces our reliance on foreign sources of petroleum imports and increases the energy security status of the U.S. as noted in section III.D.2 of this preamble.

We are projecting that total ethanol consumption will remain steady in 2026 and 2027 despite the increase in consumption of E15 and E85, as discussed in section III.A.3.a of this preamble. At the same time, we are projecting that sufficient BBD and other non-ethanol advanced biofuels will be available in 2026 and 2027 to compensate for this reduction in ethanol consumption and to enable an implied volume requirement for conventional renewable fuel of 15 billion gallons to be met. We are thus establishing the implied conventional renewable fuel volume requirement for 2026 and 2027 at the Analyzed Volumes of 15 billion gallons of conventional biofuel.

Table III.E.4-1: Final Conventional Renewable Fuel Volumes (million RINs)

	2026	2027
Conventional ethanol	14,270	14,200
Non-cellulosic advanced biofuel (beyond what is needed to meet the advanced biofuel volume requirement)	730	800
Total conventional renewable fuel	15,000	15,000

Note: All volumes rounded to the nearest 10 million RINs.

5. Summary of the Volume Requirements for 2026 and 2027

Sections III.E.1 through 4 of this preamble summarize our holistic balancing of the statutory factors to determine the appropriate volumes for each of the component categories of renewable fuel. After determining the appropriate volumes for each component category, we calculated the volumes for each of the four statutory renewable fuel categories. These volumes for 2026 and 2027 are shown in Table III.E.5–1.

[186] CAA section 211(o)(2)(B)(i).

[187] *Id.*

[188] 88 FR 44517–18 (July 12, 2023).

Table III.E.5-1: Renewable Fuel Volumes for Statutory Categories (billion RINs)

	2026	2027
Cellulosic biofuel	1.36	1.43
Biomass-based diesel	8.86	8.95
Advanced biofuel	10.82	10.98
Total renewable fuel	25.82	25.98

Note: All volumes rounded to the nearest 0.01 billion RINs.

In balancing the factors to arrive at these volumes, we have recognized that the cost of achieving them is significant, and that these costs are not offset by benefits that we are able to monetize. Nevertheless, we believe that these volumes represent a reasonable balancing of the statutory factors, including those for which we were unable to provide monetized estimates. In establishing the RFS program, Congress established ambitious renewable fuel volume requirements recognizing that the production and use of renewable fuel was often more costly than using petroleum-based fuels.[189] The waiver authorities provided by Congress authorized reductions of the statutory volumes only when achieving these volumes would cause severe economic harm.[190] Further, while Congress required that the EPA evaluate the impact of the use of renewable fuels on the cost to consumers of transportation fuel and the cost to transport goods, Congress did not require that the consideration of these costs outweigh the consideration of the other statutory factors.[191] Indeed, the D.C. Circuit found that ''[n]othing in the Act or precedent supports a freestanding requirement that EPA balance the quantifiable costs and benefits of the volumes it sets, let alone that EPA may implement the RFS Program only insofar as its benefits—quantified or not—outweigh its costs.'' [192]

While the general approach we are taking to organize our analysis of the statutory factors is consistent with our approach in the Set 1 Rule, which was upheld by the D.C. Circuit in *CBD,* we acknowledge that our balancing of the statutory factors in this rule differs in certain respects from previous rules.[193] In the Set 1 Rule, we emphasized the potential for significant GHG emission reductions, alongside the projected energy security benefits and support for increasing the annual rate of future commercial production of renewable fuels, job creation, and rural economic development, in justifying renewable fuel volume requirements with high costs.[194] In this action we continue to consider all the statutory factors, but, in contrast to previous rules, we are placing less emphasis on the potential impact of this rule on climate change while retaining the general practice of using lifecycle GHG emission reduction estimates as a proxy for this analysis. As explained previously, the ranges of potential GHG emission reductions vary widely from substantial net reductions to very slight net increases. This variability, when coupled with the additional uncertainties involved in commonly used climate change end points, makes it difficult to quantify potential climate change impacts such as changes in global temperature. The potential for net GHG emission reductions is sufficient to consider the climate change factor Congress specified as a relevant environmental consideration, particularly in light of Congress' use of GHG emission reduction thresholds in defining renewable fuels. On the other hand, we have placed greater emphasis on the impact of this rule on other statutory criteria: energy security, job creation, and rural economic development, and have maintained our intent to increase the annual rate of future commercial production of renewable fuels. As a result, we have generally sought to establish volumes that support the domestic production of renewable fuels from domestic feedstocks. This is most apparent in our approach to determining the appropriate volumes for non-cellulosic advanced biofuel. In previous RFS rules our determination of the final volume requirements for non-cellulosic advanced biofuel was based on estimates of the quantity of feedstocks available without diverting feedstock from non-biofuel markets or use in other countries. In this action, the final volume requirements reflect the domestic production capacity for non-cellulosic advanced biofuel, consistent with the policy goal of supporting increased domestic production of these fuels as explained in section III.A of this preamble.

F. Treatment of Carryover RINs

In our assessment of supply-related factors in section III.A of this preamble, we focused on those factors that could directly or indirectly impact the use of renewable fuel in the U.S. and thereby determine the potential number of RINs generated in each year that could be available for compliance with the applicable standards in those same years. However, carryover RINs represent another source of RINs that can be used for compliance. We therefore investigated whether and to what degree carryover RINs should be considered in the context of determining appropriate levels for the final volume requirements.

CAA section 211(o)(5) requires that the EPA establish a credit program as part of its RFS regulations, and that the credits be valid for obligated parties to show compliance for 12 months as of the date of generation. We implemented this requirement through the use of RINs, which are generated for the production of qualifying renewable fuels. Obligated parties can comply by blending renewable fuels into the transportation fuel supply themselves, or by purchasing RINs that represent the renewable fuels that other parties have blended into the supply. RINs can be used to demonstrate compliance for the year in which they are generated or the subsequent compliance year. Obligated parties can obtain more RINs than they need in a given compliance year, allowing them to ''carry over'' these excess RINs for use in the subsequent compliance year, although the RFS regulations limit the use of these carryover RINs to 20 percent of the obligated party's RVO.[195] For the collective supply of carryover RINs to be preserved from one year to the next,

[189] The D.C. Circuit has observed that ''Congress in the RFS Program 'made a policy choice to accept higher fuel prices' in exchange for the benefits of energy security and reduced GHG emissions.'' *CBD,* 141 F.4th at 171 (quoting *Sinclair,* 101 F.4th at 889).

[190] *See generally* CAA section 211(o)(7)(A).

[191] *See* CAA section 211(o)(2)(B)(ii).

[192] *CBD* at 172.

[193] *See FDA* v. *Wages & White Lion Invs., L.L.C.,* 604 U.S. 542, 569–570 (2025).

[194] Additionally, the EPA promulgated the 2020–2022 Rule under its authority in CAA section 211(o)(7)(F), which directs the EPA to conduct the statutory factor analysis under CAA section 211(o)(2)(B)(ii). 87 FR 39600 (July 1, 2022). The D.C. Circuit similarly upheld the EPA's analysis there. *See Sinclair* v. *EPA,* 101 F.4th 871, 887 (2024).

[195] 40 CFR 80.1427(a)(5).

individual carryover RINs are used for compliance before they expire and are essentially replaced with newer vintage RINs that are then held for use in the next year. For example, vintage 2025 carryover RINs must be used for compliance with 2026 compliance year obligations, or they will expire. However, using 2025 vintage RINs to meet 2026 compliance obligations reduces the need to use vintage 2026 RINs, which can then be saved for use toward 2027 compliance.

As noted in past RFS annual rules, carryover RINs are a foundational element of the design and implementation of the RFS program.[196] Carryover RINs play an important role in providing a liquid and well-functioning RIN market upon which success of the entire program depends, and in providing obligated parties compliance flexibility in the face of substantial uncertainties in the transportation fuel marketplace.[197] Carryover RINs enable parties ''long'' on RINs to trade them to those ''short'' on RINs, instead of forcing all obligated parties to comply through physical blending. Carryover RINs also provide flexibility and reduce spikes in compliance costs in the face of a variety of unforeseeable circumstances—including weather-related damage to renewable fuel feedstocks and other circumstances potentially affecting the production and distribution of renewable fuel—that could limit the availability of RINs.

Just as the economy as a whole is able to function efficiently when individuals and businesses prudently plan for unforeseen events by maintaining inventories and reserve money accounts, we believe that the RFS program is best able to function when sufficient carryover RINs are held in reserve for potential use by the RIN holders themselves, or for possible sale to others that may not have established their own carryover RIN reserves. Without sufficient RINs in reserve, even minor disruptions causing shortfalls in renewable fuel production or distribution, or higher-than-expected transportation fuel demand (requiring greater volumes of renewable fuel to comply with the percentage standards that apply to all volumes of transportation fuel, including the unexpected volumes) could result in deficits and/or noncompliance by parties without RIN reserves. Moreover, because carryover RINs are individually and unequally held by market participants, a non-zero but nevertheless small number of available carryover RINs may negatively impact the RIN market, even when the market overall could satisfy the standards. In such a case, market disruptions could force the need for a retroactive waiver of the standards, undermining the market certainty so critical to the RFS program. For all these reasons, carryover RINs provide a necessary programmatic buffer that helps facilitate compliance by individual obligated parties, provides for smooth overall functioning of the program to the benefit of all market participants, and is consistent with the statutory provision requiring the generation and use of credits.

Carryover RINs have also provided flexibility when we have considered the need to use our waiver authorities to lower volumes. For example, in the context of the 2013 RFS rulemaking we noted that an abundance of carryover RINs available in that year, together with possible increases in renewable fuel production and import, justified maintaining the advanced and total renewable fuel volume requirements for that year at the levels specified in the statute.[198]

1. Projected Number of Available Carryover RINs

The projected number of available carryover RINs after compliance with the 2024 standards (*i.e.,* the number of carryover RINs available for compliance with the 2025 standards) is summarized in Table III.F.1–1.[199] This is the most recent year for which complete RFS compliance data was available at the time of this action.

Table III.F.1-1: Projected 2024 Carryover RINs (million RINs)

RFS Standard	RIN Type	Absolute 2024 Carryover RINs[a]	Effective 2024 Carryover RINs[b]
Cellulosic biofuel	D3+D7	70	20
Non-cellulosic advanced biofuel[c]	D4+D5	2,510	2,510
Conventional renewable fuel[d]	D6	1,300	1,070
Total renewable fuel	All D Codes	3,880	3,600

[a] Represents the absolute number of 2024 carryover RINs that are available for compliance with the 2025 standards and does not account for deficits carried forward from 2024 into 2025.

[b] Represents the effective number of 2024 carryover RINs that are available for compliance with the 2025 standards after accounting for deficits carried forward from 2024 into 2025.

[c] Non-cellulosic advanced biofuel is not an RFS standard category but is calculated by subtracting the number of cellulosic RINs from the number of advanced RINs.

[d] Conventional renewable fuel is not an RFS standard category but is calculated by subtracting the number of advanced RINs from the number of total renewable fuel RINs.

Assuming that the market exactly meets the 2025 standards with new RIN generation, these are also the number of carryover RINs that would be available for 2026 and 2027. However, there remains considerable uncertainty surrounding the ultimate number of the carryover RINs that will be available for compliance with the 2026 and 2027 standards for several reasons, including the granting of small refinery exemptions (projected to total 990 million RINs in 2025, as discussed in section IV of this preamble), higher or lower than expected transportation fuel

[196] See, *e.g.,* 72 FR 23904 (May 1, 2007).

[197] See 80 FR 77482–87 (December 14, 2015), 81 FR 89754–55 (December 12, 2016), 82 FR 58493–95 (December 12, 2017), 83 FR 63708–10 (December 11, 2018), 85 FR 7016 (February 6, 2020), 87 FR 39600 (July 1, 2022), 88 FR 44468 (July 12, 2023).

[198] 79 FR 49793–95 (August 15, 2013).

[199] The calculations performed to project the number of available carryover RINs can be found in RIA Chapter 1.8.

demand (requiring greater or lower volumes of renewable fuel to comply with the percentage standards that apply to all volumes of transportation fuel), and the impact of 2025 RFS compliance on the availability of carryover RINs. While we project that the volume requirements in 2025–2027 could be achieved without the use of carryover RINs, there is nevertheless some uncertainty about how the market will choose to meet the applicable standards. The result is that there remains some uncertainty surrounding the ultimate number of carryover RINs that will be available for compliance with the 2026 and 2027 standards.

In addition, we note that there have been enforcement actions in past years that have resulted in the retirement of carryover RINs to make up for the generation and use of invalid RINs and/or the failure to retire RINs for exported renewable fuel. To the extent that there are enforcement actions in the future, they could have similar results and require that obligated parties or renewable fuel exporters settle past enforcement-related obligations in addition to complying with the annual standards. In light of these uncertainties, the number of carryover RINs that will be available for compliance with the 2026 and 2027 standards could be larger or smaller than the number projected in Table III.F.1–1.

2. Treatment of Carryover RINs for 2026 and 2027

We evaluated the number of carryover RINs projected to be available and considered whether we should include any portion of them in the determination of the volume requirements that we are establishing for 2026 and 2027. Doing so would be equivalent to intentionally drawing down the number of available carryover RINs in setting those volume requirements. As part of this consideration, we note that, as further discussed in section IV of this preamble, we are reallocating a portion of the exempted RVOs for the 2023–2025 compliance years to the 2026 and 2027 compliance years, which we intend to be met with carryover RINs attributable to the 2023–2025 exemptions. These reallocated obligations, which total over 2 billion RINs, represent over 50 percent of the number of currently available carryover RINs. Thus, absent the impact of other factors (*e.g.,* higher or lower than expected transportation fuel demand), we would expect that compliance with the SRE reallocated volumes will result in a significant decrease in the number of available carryover RINs over the course of the 2026 and 2027 compliance years.

After due consideration, we do not believe that it would be appropriate to establish final volume requirements that would intentionally draw down the projected number of available carryover RINs any further than will already be required by the SRE reallocation volumes. In reaching this determination, we considered the functions of carryover RINs, the projected number available, the uncertainties associated with this projection, the potential impact of carryover RINs on the production and use of renewable fuel, the ability and need for obligated parties to draw on carryover RINs to comply with their obligations (both on an individual basis and on a market-wide basis), and the impacts of drawing down the number of available carryover RINs on obligated parties and the fuels market more broadly. As previously described, carryover RINs provide important and necessary programmatic functions—including as a cost spike buffer—that will both facilitate individual compliance and provide for smooth overall functioning of the program. We believe that a balanced consideration of the possible role of carryover RINs in achieving the volume requirements, versus maintaining an adequate number of carryover RINs for important programmatic functions, is appropriate when we exercise our discretion under our statutory authorities.

Furthermore, in this action we are prospectively establishing volume requirements for multiple years. This inherently adds uncertainty and makes it more challenging to project with accuracy the number of carryover RINs that will be available for each of these years. Given these factors, and the uneven holding of carryover RINs among obligated parties, we believe that further increasing the volume requirements for 2026 and 2027 with the intent to draw down the number of available carryover RINs could lead to significant deficit carryforwards and noncompliance by some obligated parties. We do not believe this would be a desirable outcome. Therefore, consistent with the approach we have taken in recent annual rules, we are not establishing the 2026 and 2027 volume requirements at levels that will intentionally draw down the projected number of available carryover RINs beyond what will already be required by the SRE reallocation volumes for 2026 and 2027.

We are not determining that the number of carryover RINs projected in Table III.F.1–1 is a bright-line threshold for the number of carryover RINs that provides sufficient market liquidity and allows carryover RINs to play their important programmatic functions. As in past years, we are instead evaluating, on a rule-by-rule basis, the number of available carryover RINs in the context of the RFS standards and the broader transportation fuel market. Based upon this holistic, case-by-case evaluation, we are concluding that it would be inappropriate to intentionally reduce the number of carryover RINs by establishing higher volumes than what we anticipate the market can achieve in 2026 and 2027. Conversely, while a larger number of available carryover RINs may provide greater assurance of market liquidity, we do not believe it would be appropriate to set the standards at levels specifically designed (*i.e.,* low) to increase the number of carryover RINs available to obligated parties.

G. Consideration of Alternative Volumes

When determining the appropriate volumes for 2026 and 2027, we also considered alternative volumes. This section briefly discusses alternative volumes we considered based on the comments we received. As with the final volume requirements, we have structured our discussion of the alternative volumes around the component categories of renewable fuel as these component categories have distinct economic, environmental, technological, and other characteristics relevant to the factors we must analyze under the statute. More detail on each of the analyses discussed in this section can be found in the RIA.

The cellulosic biofuel volume requirements we are finalizing for 2026 and 2027 are equal to the volumes of cellulosic biofuel we project will be used as qualifying transportation fuel in these years. These projections take into account the limited production capacity (in the case of CKF ethanol) and the limited ability for the market to consume cellulosic biofuel as transportation fuel (in the case of renewable CNG/LNG). Establishing higher cellulosic biofuel volume requirements than the market can supply is inconsistent with our statutory authority.[200] Establishing lower cellulosic biofuel volume requirements would be expected to decrease demand for these fuels.[201] Lower demand in turn

[200] For a further discussion of our authority to establish cellulosic biofuel volume requirements in years after 2022, see section II.B of this preamble.

[201] For a discussion of our projection of cellulosic biofuel production and use absent the incentives provided by the RFS program, see RIA Chapter 2.1.

is expected to decrease investment in the technologies needed to expand cellulosic biofuel production and use in future years. Such an action would ultimately forgo the many benefits associated with higher production and use of cellulosic biofuel (see section III.E.1 of this preamble), both in 2026 and 2027 as well as future years.

The non-cellulosic advanced biofuel volume requirements we are finalizing for 2026 and 2027 are approximately equal to the volumes of biodiesel and renewable diesel we project can be supplied by domestic producers, as well as the projected supplies of other advanced biofuels (*e.g.,* advanced CNG/LNG, sugarcane ethanol, renewable naphtha). We acknowledge that higher volumes of these fuels could be supplied to U.S. markets in 2026 and 2027. However, because the non-cellulosic advanced biofuel volumes we are finalizing are based on domestic production capacity, higher required volumes would most likely be met primarily, if not entirely, with imported biofuels.[202] Imported biofuels do not further energy independence, nor do they further the Administration's goal of achieving energy dominance.[203] Imported biofuels are also projected to have few, if any, positive impacts on domestic jobs and rural economic development and are unlikely to be produced from domestic feedstocks.[204] Therefore, increased non-cellulosic advanced biofuel volumes are not projected to materially benefit domestic feedstock suppliers such as soybean farmers or oilseed processors. In addition to lacking these key benefits, higher volumes of non-cellulosic advanced biofuels would be projected to increase fuel costs and the cost to transport goods.

We also considered establishing lower volumes of non-cellulosic advanced biofuels for 2026 and 2027. Our consideration of lower volumes of these fuels was primarily due to the high cost of these fuels, which could suggest that lower volumes are appropriate to minimize the impact of the volume requirements on fuel prices. We project that a majority of the non-cellulosic advanced biofuels supplied in 2026 and 2027 will be produced in the U.S. from domestic feedstocks.[205] Lower volume requirements for these fuels would therefore be expected to result in lower domestic production and decreased demand for domestic feedstocks.[206]

[202] RIA Chapter 7.2.

[203] RIA Chapter 6.

[204] RIA Chapter 9.

[205] RIA Chapter 7.2.

[206] RIA Chapter 2.1.

These decreases in domestic production would negatively impact all parties involved in the biofuel production supply chain (*e.g.,* farmers, oilseed processors, parties that transport feedstocks and finished fuels). Depending on the degree of the reduction in the required volumes for these fuels, it is likely that the decrease in demand due to the RFS would result in the closure of biodiesel and renewable diesel production facilities. To the degree that lower volume requirements in 2026 and 2027 resulted in the closure of biodiesel and renewable diesel production facilities, lower volume requirements could also have negative impacts in future years.

Finally, we also considered whether higher or lower volumes of conventional renewable fuel would be appropriate for 2026 and 2027. In this action, we have maintained the 15-billion-gallon implied conventional renewable fuel volume established for 2023–2025 in the Set 1 Rule and implied in the statutory RFS volumes for years 2015–2022. Based on the most recent data available, we project that ethanol consumption in the U.S. will fall below the 15-billion-gallon implied conventional renewable fuel volume primarily due to the limited availability of higher-level ethanol blends (*e.g.,* E15 and E85) at retail stations.[207] Establishing a higher volume for conventional renewable fuel would therefore be unlikely to result in the increased production and use of ethanol, but would rather increase the production and use of other non-ethanol biofuels such as biodiesel and renewable diesel.[208]

A number of commenters requested that we finalize conventional renewable fuel volumes that are at or below the E10 blendwall in 2026 and 2027. These commenters generally argued that doing so would not have a significant impact on ethanol production and consumption but would result in significantly lower prices for conventional (D6) RINs. Lower D6 RIN prices would in turn, these commenters argued, decrease compliance costs for obligated parties and fuel prices to consumers.

As discussed in previous actions and the Set 2 proposal, maintaining a 15-billion-gallon implied conventional renewable fuel volume provides continued incentives for investment in the distribution and use of ethanol in higher-level ethanol blends. The higher D6 RIN prices that we project would result from maintaining a 15-billion-gallon implied conventional volume

[207] RIA Chapter 7.5.

[208] The impacts of higher volumes of these fuels are discussed earlier in this section.

(relative to an implied conventional volume below the E10 blendwall) provide greater incentives to increase the use of conventional ethanol. In the long term, we project that investments in higher-level ethanol blends are crucial to increase consumption (and by extension the production) of ethanol in the U.S.[209] Increasing ethanol production and use is projected to have similar positive impacts on several of the statutory factors, such as jobs and rural economic development, and energy security. Unlike the majority of non-cellulosic advanced biofuels, ethanol is generally cheaper than the gasoline it displaces on a per gallon basis and increasing ethanol use has the potential to decrease fuel prices.[210]

We do not dispute commenters' claims that finalizing conventional biofuel volumes below the E10 blendwall would result in significantly lower D6 RIN prices. We note, however, that higher D6 RIN prices provide much of the incentives to invest in infrastructure to increase the availability of higher-level ethanol blends at retail stations. Contrary to commenters' claims about the impact of D6 RIN prices on obligated parties, our analysis of the fuels market has demonstrated that, on average at the nationwide scale, obligated parties that acquire RINs recover the cost of these RINs in the sales prices of the gasoline and diesel they produce and are therefore not negatively impacted by higher D6 RIN prices.[211] Finally, our analysis has shown that RINs operate as a cross-subsidy, effectively increasing the price of petroleum-based fuels to retailers and consumers while decreasing the price of renewable fuels to these parties.[212] Higher D6 RIN prices increase the price of fuels with little or no renewable content (such as gasoline that is not blended with ethanol) and decrease the price of fuels with high renewable content (such as E85). Higher D6 RIN prices have little to no impact on E10, which represents approximately 97 percent of the gasoline we project will be sold in 2026 and 2027.[213] Our analysis indicates that reducing the implied conventional renewable fuel volumes would decrease the incentives for higher-level ethanol blends but would not positively impact obligated parties or materially reduce fuel prices for consumers.[214]

[209] RIA Chapter 7.5.

[210] RIA Chapter 10.

[211] RTC Section 9.1.8.

[212] RTC Section 9.1.4.

[213] RTC Section 9.1.4.

[214] For a further discussion of the impacts of lower conventional renewable fuel volumes on RIN

H. Summary of Final Volumes for 2026 and 2027

For the reasons described above, we are finalizing volume requirements for 2026 and 2027 based on the three component categories discussed. The volumes for each of the component categories (sometimes referred to as implied volume requirements) are summarized in Table III.H–1. Table III.H–1 also includes the volume requirements for BBD, which is not a component category of renewable fuel but is based on our evaluation of non-cellulosic advanced biofuel and other considerations described in section III.E.3 of this preamble.

Table III.H-1: Volume Requirements for Component Categories and BBD (billion RINs)

	2026	2027
Cellulosic biofuel	1.36	1.43
Biomass-based diesel	8.86	8.95
Non-cellulosic advanced biofuel	9.46	9.55
Conventional renewable fuel	15.00	15.00

Note: All volumes rounded to the nearest 0.01 billion RINs.

The volumes for each of the four component categories shown in the table above can be combined to produce volume requirements for the four statutory renewable fuel categories on which the applicable percentage standards are based. The results are shown in Table III.H–2.

Table III.H-2: Volume Requirements for Statutory Categories (billion RINs)

	2026	2027
Cellulosic biofuel	1.36	1.43
Biomass-based diesel	8.86	8.95
Advanced biofuel	10.82	10.98
Total renewable fuel	25.82	25.98

Note: All volumes rounded to the nearest 0.01 billion RINs.

We believe that these volume requirements will preserve and substantially build upon the gains made in biofuel production and use in previous years. In particular, these volume requirements would continue to support the domestic renewable fuel industry and help move the U.S. towards greater energy independence and energy security. These volume standards are expected to drive increased employment and economic impact in the U.S. and have the potential to reduce GHG emissions from the transportation sector. The volume requirements will also promote ongoing development within the biofuels and agriculture industries as well as the economies of the rural areas in which biofuels production facilities and feedstock production reside.

IV. SRE Reallocation

In this action, we are adding a new ''SRE reallocation volume'' term in the percentage standard equations for 2026 and 2027 that, taken together, account for the 2023–2025 exempted RVOs. This section describes the EPA's authority to consider the impact of SREs granted for the 2023–2025 compliance years when establishing the RFS standards for 2026 and 2027 and the SRE reallocation volumes we are adding to the volume requirements for 2026 and 2027.

A. Background and Policy Rationale

On August 22, 2025, the EPA issued decisions on 175 SRE petitions in the August 2025 SRE Decisions Action, in which 64 petitions were granted full (100 percent) exemptions, 76 petitions were granted partial (50 percent) exemptions, 28 petitions were denied, and 7 petitions were determined to be ineligible. On September 18, 2025, the EPA proposed in the Set 2 supplemental proposal to reallocate all or a portion of the 2023–2025 exempted RVOs that resulted from the August 2025 SRE Decisions Action—which at the time totaled 1.4 billion RINs—and solicited comment on what amount, if any, to reallocate.[215] On November 7, 2025, the EPA issued decisions on 16 additional SRE petitions in the November 2025 SRE Decisions Action, in which 2 petitions were granted full (100 percent) exemptions, 12 petitions were granted partial (50 percent) exemptions, and 2 petitions were denied, resulting in an additional 2023–2025 exempted RVO of 0.5 billion RINs. The EPA made the SRE decisions in August and November 2025, collectively referred to as the ''2025 SRE Decisions Actions,'' using a consistent policy approach across all SRE petitions under consideration, and we intend to use this same approach going forward.

In this final rule, we are revising the percentage standards equations for 2026 and 2027 to add new volumes we refer to as the ''SRE reallocation volumes,'' which account for a portion of the 2023–2025 exempted RVOs. Specifically, we are adding SRE reallocation volumes that account for 70 percent of: (1) the actual exempted RVOs for the 2023 and 2024 compliance years; and (2) the projected exempted RVOs for the 2025 compliance year.[216] The SRE reallocation volumes correspond to three statutory categories

prices, see RTC Section 6.1.6. The RTC also contains further discussion of the impact of the RFS standards on RIN prices, retail fuel prices, and refiners (RTC Sections 9.1.3, 9.1.4, and 9.1.8, respectively).

[215] 90 FR 45007, 45009 (September 18, 2025). At the time of the Set 2 supplemental proposal, no decisions had been issued for the 2025 compliance year, and additional decisions for 2023 and 2024 petitions were pending. However, we also noted that we intended to update our projection of exempted volumes for the final rule using the most recent available data.

[216] The exact SRE reallocation volumes for 2026 and 2027 are described in section IV.C of this preamble.

of renewable fuel (advanced biofuel, BBD, and renewable fuel), such that there are three SRE reallocation volumes for each year.[217] Each SRE reallocation volume is then added to the corresponding volume requirement in section III of this preamble and the sum of the volumes for each year is used to calculate the percentage standards for 2026 and 2027, as discussed further in section V of this preamble. We are dividing the SRE reallocation volumes across two years to lessen the disruption to the market and the burden on obligated parties. The inclusion of this new term in the percentage standards equations will only be for the 2026 and 2027 compliance years and is linked to the impact of SREs granted for the 2023–2025 compliance years. In the future, we intend to continue our policy of prospectively accounting for exempted volumes of gasoline and diesel such that there will be no need to include SRE reallocation volumes in this manner again.

We received many comments on our authority to implement SRE reallocation volumes, as well as the need for SRE reallocation volumes and the percentage of 2023–2025 exempted RVOs that should be reallocated. Biofuel producers generally argued that we have the legal authority and obligation to reallocate all the 2023–2025 exempted RVOs, while refiners generally argued that we had no legal authority to reallocate any exempted RVOs. We respond fully to these comments in RTC Section 7.3.

The 2025 SRE Decisions Actions resolved a backlog of SRE petitions and exempted significant volumes of gasoline and diesel for the 2023 and 2024 compliance years, resulting in an increased number of RINs available for obligated parties to use for compliance with their RFS obligations. We expect additional SREs will be granted for the 2025 compliance year as well. These RINs represent renewable fuel produced and used in 2023–2025 that obligated parties will no longer need to retire for compliance because of the relieved obligations from SREs. The availability of these RINs—and the ability for obligated parties to use them to comply with their RFS obligations in lieu of RINs generated for renewable fuel produced and used in 2026 and 2027—could reduce RIN demand and RIN prices in future years and may ultimately result in the market failing to produce the volume of renewable fuel anticipated by the volume requirements in section III of this preamble.

The impacts of the SREs granted in the 2025 SRE Decisions Actions on the RIN market are as follows.[218] For the 2023 and 2024 compliance years, we project that 1.9 billion RINs no longer need to be retired for compliance. While the SREs granted for these years have no impact on the volume of renewable fuel actually produced and used in 2023 and 2024—since those years are in the past—the SREs directly increase the supply of RINs available for other obligated parties to use for compliance in future years. As a result, obligated parties will be able to use the RFS program's carryover RIN provisions to roll these RINs forward to the 2025 compliance year and beyond.[219]

CAA section 211(o)(5) requires that the EPA establish a credit program as part of its RFS regulations and that the credits be valid for obligated parties to show compliance for 12 months after the date of generation. We implemented this requirement through the use of RINs, which can be used to demonstrate compliance for the year in which they are generated and the subsequent compliance year. Obligated parties can obtain more RINs than needed in a given compliance year, allowing them to carry over these RINs for use in the subsequent compliance year, although the RFS regulations limit the use of these carryover RINs to 20 percent of the obligated party's RVO. For the total number of available carryover RINs to be preserved from one year to the next, individual carryover RINs are used for compliance before they expire and are replaced with newer vintage RINs that are then held for use in the next year. For example, 2023 carryover RINs must be used for compliance in 2024, or they will expire. However, the use of 2023 RINs to meet up to 20 percent of an obligated party's 2024 RVO increases the number of 2024 RINs that can then be carried over for compliance with the 2025 standards.

While there may have been some impact from the increased number of carryover RINs as a result of the 2023 and 2024 SREs on renewable fuel production and use in 2025 after the 2025 SRE Decisions Actions were issued, the effect of these RINs is likely to be most acute in 2026 and 2027 when obligated parties will be able to choose whether to use carryover RINs to comply with their 2026 and 2027 RVOs in lieu of acquiring renewable fuel produced in those years, which would reduce demand for renewable fuel production and use in those years. Failure to mitigate the market impacts of the increased number of carryover RINs due to these SREs could result in a decrease in demand for renewable fuel produced in 2026 and 2027.

We recognize that while significant quantities of carryover RINs can negatively impact the production and use of renewable fuels, carryover RINs also play an important role in providing a liquid and well-functioning RIN market, as we have stated on multiple occasions.[220] The continued success of the RFS program depends on a functioning RIN market. Carryover RINs provide obligated parties compliance flexibility for substantial uncertainties in the transportation fuel marketplace. In the 2025 SRE Decisions Actions, the EPA granted SREs for multiple years at a single time, representing significant exempted RVOs after the volume requirements for those years had been established and actual production for those years had concluded. The resulting influx of additional RINs in the market could have a deleterious effect on current and future volume requirements without corrective action to address the increased number of carryover RINs due to the 2023–2025 exempted RVOs.

As described above, we are finalizing SRE reallocation volumes for 2026 and 2027 that represent 70 percent of the 2023–2025 exempted RVOs. In determining this value, we weighed the impacts of intentionally drawing down the number of available carryover RINs through SRE reallocation volumes against the need to ensure that the 2026 and 2027 volume requirements are met with renewable fuel use in those years.

We first assessed the ability of the RIN market to manage an intentional drawdown in the number of available carryover RINs through the SRE reallocation volumes over the 2026 and 2027 compliance years. As described in section III.F.1 of this preamble, we project that there are effectively 3.60 billion carryover RINs after compliance

[217] We are not establishing SRE reallocation volumes for cellulosic biofuel for the reasons discussed in section IV.B of this preamble.

[218] The RIN volumes and exemptions discussed in this section are limited to the SRE decisions the EPA issued as of the time of this final rule (*i.e.*, those in the 2025 SRE Decisions Actions), which did not include the 2025 compliance year. However, as discussed in section IV.C of this preamble, we are also projecting exempted volumes for 2025 as part of determining the SRE reallocation volumes for 2026 and 2027.

[219] Contrary to suggestions by some commenters that this ''impermissibly increases the lifespan of RINs,'' we find that this is a wholly permissible compliance mechanism and is how the RIN market has operated since its inception.

[220] *See, e.g.,* 90 FR 25784, 25827 (June 17, 2025); *see also, e.g.,* 88 FR 44468, 44494 (July 12, 2023), 87 FR 39600, 39613 (July 1, 2022), 85 FR 7016, 7021 (February 6, 2020), 83 FR 63704, 63708–10 (December 11, 2018), 82 FR 58486, 58493–95 (December 12, 2017), 81 FR 89746, 89754–55 (December 12, 2016), 80 FR 77420, 77482–87 (December 14, 2015).

with the 2024 RFS standards. In the Set 2 Supplemental proposal, we discussed the fact that some obligated parties may choose to retain some of the RINs associated with the 2023–2025 exempted RVOs as a compliance flexibility. We do not find that it would be appropriate to require the retirement of all RINs associated with the 2023–2025 exempted RVOs because doing so would hinder an existing and statutory compliance flexibility for obligated parties (*i.e.,* the use of carryover RINs). As described in section III.F of this preamble, carryover RINs are a foundational element of the design and implementation of the RFS program. Establishing applicable volumes that would likely result in obligated parties using more carryover RINs than the market can manage in a single year (*i.e.,* drawing down the number of carryover RINs such that the functions of carryover RINs are impaired) could lead to issues such as RIN scarcity or illiquidity in the RIN trading market, resulting in significant instances of noncompliance by obligated parties. In reviewing the historical number of available carryover RINs in RIA Chapter 1.8.3, we observe that the largest drawdown in the number of available carryover RINs was 0.94 billion RINs from 2021 to 2022. We did not observe issues with RIN scarcity or illiquidity during this time period, and thus we believe that the market could handle carryover RIN drawdowns of similar magnitude in 2026 and 2027. Based on this observation and the current number of available carryover RINs currently available, we believe that the market is capable of absorbing a drawdown of approximately 1 billion RINs in each of 2026 and 2027, or a total of approximately 2 billion RINs.

We then evaluated how this volume of carryover RIN drawdown compares to the 2023–2025 exempted RVOs. We find that it is necessary to reallocate the majority of the 2023–2025 exempted RVOs to protect the market-forcing nature of the 2026 and 2027 volume requirements. Without this reallocation, it is likely that a portion of the 2026 and 2027 volume requirements would not be met with new renewable fuel use in the market. As described in section IV.C of this preamble, we project that the total 2023–2025 exempted RVOs will be 2.89 billion RINs. A carryover RIN drawdown of approximately 2 billion RINs represents 70 percent of the 2023–2025 exempted RVOs, which we find is sufficiently significant to ensure that the 2026 and 2027 volume requirements are met with renewable fuel use these years.

We note as well that we are promulgating the 2026 and 2027 SRE reallocation volumes late, and that the 2026 SRE reallocation volumes are partially retroactive in effect. Our consideration of the timing of these actions is discussed in section II.E of this preamble. When the EPA promulgates late rulemakings, including those with retroactive effects, it must consider the benefits and burdens of doing so.[221] In light of the burden on obligated parties, the 70 percent reallocation serves as a means to mitigate the burdens on obligated parties by preserving some amount of carryover RINs associated with the 2023–2025 exempted RVOs and not requiring 100 percent reallocation. We are therefore finalizing SRE reallocation volumes for 2026 and 2027 equal to 70 percent of the 2023–2025 exempted RVOs.

We are not accounting for any SREs granted for compliance years prior to 2023. Pre-2023 vintage RINs that were returned to small refineries that received an SRE for these years in the 2025 SRE Decisions Actions are expired and can only be used to satisfy outstanding, non-exempted pre-2023 obligations by the small refinery. At the time the SREs were granted in the 2025 SRE Decisions Actions, RFS compliance had not yet occurred for 2024. Thus, 2023 and newer vintage RINs were valid for RFS compliance at that time and had value within the RIN market. In contrast, 2022 and older RINs were expired and thus could not be used for compliance with 2024 or later RFS obligations.[222] Therefore, we are finalizing SRE reallocation volumes for 2026 and 2027 that only account for the 2023–2025 exempted RVOs (*i.e.,* the vintage RINs that could still be used for RFS compliance at the time the SREs were granted in ways that may impact the production and use of renewable fuels in 2026 and 2027). Obligated parties could use 2023 RINs to satisfy up to 20 percent of their 2024 obligations, 2024 RINs to satisfy their 2024 or up to 20 percent of their 2025 obligations, and 2025 RINs to satisfy their 2025 or up to 20 percent of their 2026 obligations.

B. Legal Justification

As described in section II.B of this preamble, CAA section 211(o)(2)(B)(ii) provides the statutory factors the EPA is to consider in establishing the volume requirements. We are using this authority to consider the 2023–2025 exempted RVOs and establish RFS volumes for 2026 and 2027 that incorporate the SRE reallocation volumes discussed in this section. In discussing the statutory conditions in CAA section 211(o)(2)(B)(iii) and (v) in section II.B of this preamble, we have assessed the total applicable volumes, including the SRE reallocation volumes.

As also discussed in section II.B of this preamble, CAA section 211(o)(2)(B)(iv) requires that the EPA set the cellulosic biofuel standard based on the assumption that the Administrator will not need to waive the volume using the cellulosic waiver authority. The cellulosic waiver authority at CAA section 211(o)(7)(D) requires that the EPA reduce the cellulosic biofuel volume in circumstances where the projected volume of cellulosic biofuel production is less than the cellulosic biofuel volume requirement. In these circumstances, under the cellulosic waiver authority, the EPA must reduce the volume to the ''projected volume available.'' As described in section III of this preamble, we are establishing cellulosic biofuel volumes at the ''projected volume available'' to satisfy the CAA section 211(o)(2)(B)(iv) condition. We recognize the D.C. Circuit's holding that the ''projected volume available'' excludes carryover RINs, and its indication that any ''projection of cellulosic biofuel production'' would likely also exclude any carryover RINs.[223] Therefore, we are not establishing SRE reallocation volumes associated with cellulosic biofuel exempted RVOs. This is primarily due to the statutory conditions on cellulosic biofuel volume requirements, which we do not read as allowing the EPA to set the total applicable volume of cellulosic biofuel at a volume that is greater than the projected volume available, and which necessarily excludes cellulosic carryover RINs.

In establishing these SRE reallocation volumes under CAA section 211(o)(2)(B)(ii), we also analyzed the statutory factors and a review of implementation of the program. As noted in the Set 2 supplemental proposal, we have considered the impact of the volume of RINs associated with the 2023–2025 exempted RVOs on the future rate of production of renewable fuels and concluded that without an SRE reallocation volume, the future rate of production of renewable fuels would be reduced by an amount as large as 1.9 billion RINs (the RINs associated with the 2023–2025 exempted RVOs). Because we project that the SRE reallocation volumes will be met with carryover RINs attributable to the 2023–2025 exempted RVOs, we

[221] *See e.g., CBD,* 141 F.4th at 165.

[222] 40 CFR 80.1428(c).

[223] *Sinclair,* 101 F.4th at 883–84.

do not expect the SRE reallocation volumes to increase the production and use of renewable fuel beyond the volumes described in section III of this preamble. Our analysis of all other factors is therefore not impacted by the SRE reallocation volumes. This includes air quality, climate change, conversion of wetlands, ecosystems, wildlife habitat, water quality and supply, energy security, infrastructure, job creation, the prices and supply of agricultural commodities, rural economic development, or food prices.

Our assessment of the other statutory factors drove the selection of the 2026 and 2027 volume requirements, and that is not affected by the use of carryover RINs in 2026 and 2027. For example, we analyze the infrastructure required for production distribution with the 2026 and 2027 renewable fuel volumes by looking at the volumes for 2026 and 2027 and the existing and future infrastructure for product distribution in light of those renewable fuel volumes. Because we are establishing SRE reallocation volumes at the level necessary to avoid erosion of the 2026 and 2027 renewable fuel volumes, it is appropriate to only look at the renewable fuel volumes, without considering the additional volume of carryover RINs required to be retired to meet the SRE reallocation volumes. Two statutory factors that may be impacted by our decision to include the SRE reallocation volumes in the applicable volume (rather than the volume of renewable fuel produced and used in 2026 and 2027) are the cost to consumers of transportation fuel and the cost to transport goods. In assessing those factors, we have utilized higher percentage standards to calculate the impacts of the SRE reallocation volumes, along with the renewable fuel volume requirements to quantify the effects. Our consideration of the impact of the SRE reallocation volumes on these factors is discussed in the RIA Chapter 10.5.4.

Some commenters suggested that the EPA's review of implementation of the program, and consideration of the exempted RVOs from SREs as part of that review, extended beyond the terms of the statute that requires the EPA to review implementation of the program for the calendar years in the statute (*i.e.,* through 2012 for the BBD standard, and through 2022 for all other renewable fuel types). The statutory text does refer to the years identified in the statutory tables. However, our consideration of the years identified in the statutory tables, including our own experience implementing the program during that timeframe and the impacts of carryover RINs on the renewable fuels market in those past years, informs our evaluation in this action. As described in the Set 2 supplemental proposal, recent SRE decisions resulted in increased carryover RINs available for obligated parties as a compliance mechanism with future (*i.e.,* 2026 and 2027) volume requirements. These carryover RINs have the potential to be used in lieu of new renewable fuel, thus decreasing demand for renewable fuel. Even absent consideration of years beyond 2022, we would conclude that the SRE reallocation volumes are appropriate given the impacts on the future rate of commercial production and other statutory factors.

C. SRE Reallocation Volumes

In this final rule, we are establishing new SRE reallocation volumes for 2026 and 2027 equivalent to 70 percent of the 2023–2025 exempted RVOs. These final SRE reallocation volumes reflect consideration of public comments, including data and argumentation, received in response to the Set 2 supplemental proposal, in which we sought comment on what an appropriate SRE reallocation volume would be if the Agency were to finalize SRE reallocation volumes for 2026 and 2027.[224] Commenters provided a variety of perspectives on the appropriate level for SRE reallocation. The 70 percent reallocation finalized in this action reflects our analysis of the comments submitted and endeavors to achieve an appropriate balance among relevant statutory considerations.

Since we issued decisions for all the 2023 and 2024 SRE petitions that were before the Agency and obligated parties have submitted compliance reports for these years, we are able to determine the actual exempted RVOs for the 2023 and 2024 compliance years. Specifically, we used information from EMTS compliance data to calculate the actual total exempted gasoline and diesel volumes for 2023 and 2024. In turn, we used these exempted volumes, together with the previously established percentage standards for 2023 and 2024, to calculate the actual exempted RVOs for these years.

However, we have not yet issued any SRE decisions for 2025. In order to develop a projection of the 2025 exempted RVOs, we used data on the volumes of exempted gasoline and diesel for previous years. Consistent with the approach that the EPA first advanced in the 2020 RFS Rule (in which the EPA projected future exempted fuel volumes),[225] we believe it is appropriate to use average volumes of exempted gasoline and diesel over a three-year period as our projection of future exempted volumes of gasoline and diesel in 2025, rather than the volumes of gasoline and diesel that were exempted in any single year. This helps to average the effects of unique events or market circumstances that occurred in individual years that may or may not occur in 2025, and thus serves as a better predictor of the volume of gasoline and diesel that will ultimately be exempted in 2025.[226] Thus, we used information from 2022–2024 SRE petitions to calculate the annual average volumes of exempted gasoline and diesel and used those volumes to represent our projection of the exempted volumes of gasoline and diesel in 2025, as shown in Table IV.C–1.

[224] 90 FR 45007, 45011 (September 18, 2025).

[225] 85 FR 7016, 7051–53 (February 6, 2020). We note that while we projected exempted volumes of gasoline and diesel in the 2020 final rule, we later revised the 2020 percentage standards via rulemaking, including adjusting our projection of exempted volume from SREs. 87 FR 39600 (July 1, 2022) (''Reset Rule'').

[226] 84 FR 57677 (October 28, 2019); 85 FR 7016 (February 6, 2020).

Table IV.C-1: Exempted Fuel Volumes for 2022–2025 Compliance Years (billion gallons)

Compliance Year	Exempted Fuel		
	Gasoline	Diesel	Total
2022	3.97	3.08	7.06
2023	4.58	3.22	7.79
2024	4.50	3.29	7.78
2025	4.35	3.20	7.55

Note: Volumes for 2022–2024 are actual exempted fuel volumes. Volumes for 2025 are projected based on the three-year average exempted fuel volumes for 2022–2024.

Using these exempted fuel volumes and multiplying them by the RFS percentage standards in 40 CFR 80.1405(a), we calculated the 2023–2025 exempted RVOs, as shown in Table IV.C–2.

Table IV.C-2: Exempted RVOs for 2023–2025 Compliance Years (million RINs)

Category	Percentage Standards			Exempted RVOs			
	2023	2024	2025	2023	2024	2025	Total
Cellulosic biofuel	0.48%	0.59%	0.71%	40	50	50	140
Biomass-based diesel	2.58%	2.82%	3.15%	200	220	240	660
Advanced biofuel	3.39%	3.79%	4.31%	260	300	330	890
Total renewable fuel	11.96%	12.50%	13.13%	930	970	990	2,890

Note: RVOs for 2023 and 2024 are actual exempted RVOs. RVOs for 2025 are projected based on the three-year average exempted fuel volumes for 2022–2024.

As discussed in section IV.B of this preamble, we are not establishing SRE reallocation volumes for cellulosic biofuel. In making this decision, we have considered that there are very few 2024 cellulosic carryover RINs available to meet the 2025 compliance obligations.[227] In the Set 2 supplemental proposal, we requested comment on our treatment of the advanced biofuel and total renewable fuel SRE reallocation volumes if we chose not to establish an SRE reallocation volume for cellulosic biofuel. We noted that, given the nested nature of the standards, the total renewable fuel and advanced biofuel SRE reallocation volumes would include some amount of RINs associated with the 2023–2025 exempted cellulosic biofuel RVOs, unless we made corresponding reductions in the total renewable fuel and advanced biofuel SRE reallocation volumes.

In this final rule, we find that it is appropriate to require the full total renewable fuel and advanced biofuel SRE reallocation volumes for 2026 and 2027. As discussed in section III.F of this preamble, there are currently over 2.5 billion non-cellulosic advanced carryover RINs and nearly 1.1 billion conventional carryover RINs, whereas the 2023–2025 cellulosic biofuel exempted RVOs total 140 million RINs (which would be reduced to 100 million RINs after multiplying by 70 percent). Thus, we find that there are sufficient conventional and advanced carryover such that the full SRE reallocation volumes for 2026 and 2027 can be met without reducing the total renewable fuel and advanced biofuel SRE reallocation volumes by the amount of the 2023–2025 cellulosic biofuel exempted RVOs. Declining to reduce the total renewable fuel and advanced biofuel SRE reallocation volumes by the amount of 2023–2025 cellulosic biofuel exempted RVOs would better serve the purpose of the SRE reallocation volumes, which is to require the use of carryover RINs that resulted from the 2023–2025 exempted RVOs and realize the renewable fuel volumes through renewable fuel production in 2026 and 2027. This will mean that, given the nested nature of the standards, the advanced biofuel SRE reallocation volumes will be used to satisfy a portion of the 2023–2025 cellulosic biofuel exempted RVOs.

We then multiplied the 2023–2025 exempted RVOs for BBD, advanced biofuel, and total renewable fuel in Table IV.C–2 by 70 percent and used those reduced values to determine the SRE reallocation volumes for 2026 and 2027. Specifically, we are establishing SRE reallocation volumes for 2026 equivalent to all the reduced 2023 exempted RVOs and half of the reduced 2024 exempted RVOs, and for 2027 equivalent to the remaining half of the reduced 2024 exempted RVOs and all the projected reduced 2025 exempted RVOs. The resulting SRE reallocation volumes are shown in Table IV.C–3.

[227] As described in RIA Chapter 1.8.1, we project that there effectively fewer than 20 million cellulosic carryover RINs available for compliance with the 2025 standards. This represents approximately 1 percent of the revised 2025 cellulosic biofuel volume requirement of 1.21 billion RINs.

Table IV.C-3: SRE Reallocation Volumes for 2026 and 2027 (million RINs)

Category	2026	2027	Total
Biomass-based diesel	210	250	460
Advanced biofuel	280	340	620
Total renewable fuel	990	1,040	2,030

Note: All volumes are rounded to the nearest 10 million RINs. To avoid overestimating, volumes ending in five were rounded down for 2026 and rounded up for 2027.

V. Total Applicable Volumes and Percentage Standards for 2026 and 2027

The EPA implements the nationally applicable volume requirements by establishing percentage standards that apply to obligated parties.[228] The obligated parties to which the percentage standards apply are producers and importers of gasoline and diesel, as defined by 40 CFR 80.2. Each obligated party multiplies the percentage standards by the sum of all non-renewable gasoline and diesel they produce or import to determine their RVOs. The RVOs are the number of RINs that the obligated party is responsible for procuring to demonstrate compliance with the applicable standards for that year. Since there are four categories of renewable fuel under the RFS program, there are likewise four RVOs applicable to each obligated party for each year. As described in section II.D of this preamble, the EPA establishes applicable percentage standards for multiple future years after 2022 in a single action for as many years as it establishes volume requirements.

A. Total Applicable Volumes for 2026 and 2027

For 2026 and 2027, the total applicable volumes are the sum of the renewable fuel volumes requirements (discussed in section III of this preamble) and the SRE reallocation volumes (discussed in section IV of this preamble). These volumes are shown in Table V.A–1.

Table V.A-1: Total Applicable Volumes for 2026 and 2027 (billion RINs)

	Renewable Fuel Volume Requirement		SRE Reallocation Volume		Total Applicable Volume	
	2026	2027	2026	2027	2026	2027
Cellulosic biofuel	1.36	1.43	0	0	1.36	1.43
Biomass-based diesel	8.86	8.95	0.21	0.25	9.07	9.20
Advanced biofuel	10.82	10.98	0.28	0.34	11.10	11.32
Total renewable fuel	25.82	25.98	0.99	1.04	26.81	27.02

We find that the total applicable volumes—including both the renewable fuel volume requirements and the SRE reallocation volumes—are achievable in the market through a combination of both new production of renewable fuel and the use of carryover RINs. As described in section III of this preamble (renewable fuel volume requirements) and section IV of this preamble (SRE reallocation volumes), each component of the total applicable volumes is justified for the reasons described therein. While we have assumed that each component will be met with new renewable fuel production or carryover RINs, in practice carryover RINs or RINs representing renewable fuel production in 2026 and 2027 can be used to meet both volume components, and compliance demonstrations will be identical to past years. We find that the overall applicable volumes are also appropriate and justified, as they balance the need to address the 2023–2025 exempted RVOs and the continued growth of renewable fuel use in the U.S. in 2026 and 2027. We have used these volumes together to calculate the percentage standards for 2026 and 2027.

B. Calculation of Percentage Standards

The formulas used to calculate the percentage standards applicable to obligated parties are provided in 40 CFR 80.1405. In this action, we are revising the percentage standard equations in 40 CFR 80.1405 such that the numerator in the percentage standard equations for 2026 and 2027 is the sum of the annual volume requirement (RFV) and SRE reallocation volume (SRERV). Consistent with previous RFS rulemakings, we also account for a projection of the gasoline and diesel volumes exempted through SREs in 2026 and 2027 in the denominator of the percentage standard equations for 2026 and 2027. These equations incorporating the SRE reallocation volume will only be used for the 2026 and 2027 percentage standards. In the future, we intend to continue our policy of prospectively accounting for exempted volumes of gasoline and diesel such that there will be no need to include SRE reallocation volumes in this manner again.

In addition to the required volumes of renewable fuel, the formulas also require estimates of the volumes of non-renewable gasoline and diesel, for both highway and nonroad uses, that are projected to be used in the year in which the standards will apply. Consistent with previous RFS rulemakings, we are using fuel projections provided by EIA—specifically AEO2025. However, these projections include volumes of renewable fuel (*e.g.,* ethanol, biodiesel, renewable diesel) used in gasoline and

[228] *See* 40 CFR 80.1407 and 75 FR 14670 (March 26, 2010). As discussed in the Set 1 Rule, we determined that continuing to use percentage standards as the implementing mechanism for years after 2022 was effective and reasonable. 88 FR 44519 (July 12, 2023).

diesel. Since the percentage standards apply only to the non-renewable portions of gasoline and diesel, the volumes of renewable fuel are subtracted out of the EIA fuel projections as part of the percentage standard equations.[229]

C. Treatment of Small Refinery Volumes

The percentage standard equations also require projections of the exempted volumes of gasoline and diesel.[230] As discussed in section IV of this preamble, we have already developed a projection of exempted gasoline and diesel volumes for 2025 using a three-year average of the actual exempted gasoline and diesel volumes from 2022–2024 (4.35 billion gallons of gasoline and 3.20 billion gallons of diesel). We believe this projection is an appropriate estimate of exempted gasoline and diesel for 2026 and 2027 as well and are using this projection of exempted gasoline and diesel volume for 2025 to inform our projection of exempted gasoline and diesel within the percentage standard equations. We note, however, that we do not plan to revise the percentage standards for 2026 and 2027 to account for any subsequent changes to our approach to evaluating SRE petitions or other inaccuracies in the projection of exempt volumes of gasoline and diesel.[231]

D. Percentage Standards

The formulas used to calculate the percentage standards applicable to obligated parties as a function of their gasoline and diesel fuel production or importation are provided in 40 CFR 80.1405.[232] Using the total applicable volumes shown in Table V.A–1, we have calculated the percentage standards for 2026 and 2027, as shown in Table V.D–1.[233] These percentage standards are included in the regulations at 40 CFR 80.1405(a) and apply to producers and importers of gasoline and diesel.

Table V.D-1: Percentage Standards for 2026 and 2027

	2026	2027
Cellulosic biofuel	0.79%	0.84%
Biomass-based diesel	5.24%	5.37%
Advanced biofuel	6.42%	6.61%
Renewable fuel	15.50%	15.78%

VI. Partial Waiver of the 2025 Cellulosic Biofuel Volume Requirement

In the Set 1 Rule, the EPA promulgated RFS volume requirements and percentage standards for 2023–2025 and projected that 1.38 billion cellulosic RINs would be available for compliance in 2025. Consequently, we used that volume to establish the 2025 cellulosic biofuel percentage standard of 0.81 percent.[234] In the Set 2 proposal, we proposed to partially waive the 2025 cellulosic biofuel volume requirement and revise the associated 2025 cellulosic biofuel percentage standard due to a projected shortfall in 2025 cellulosic biofuel production. In this action, we are finalizing a partial waiver of the 2025 cellulosic biofuel requirement. Based on cellulosic RIN generation and retirement data for 2025, we now project that only 1.21 billion cellulosic RINs will be available for compliance in 2025, which is 0.17 billion fewer than the 1.38 billion RINs projected in the Set 1 Rule. Due to this shortfall and reasons further explained below, we are finalizing a partial waiver of the 2025 cellulosic biofuel volume requirement to 1.21 billion RINs (the projected cellulosic RINs available for compliance in 2025) using the CAA section 211(o)(7)(D) ''cellulosic waiver authority.'' Use of the cellulosic waiver authority also triggers the availability of CWCs for 2025 as an additional compliance flexibility for obligated parties.

We currently project that the supply of advanced biofuel and total renewable fuel in 2025 will exceed the required volumes, despite the projected shortfall in cellulosic biofuel. Given the projected surplus of 2025 advanced RINs, we are not waiving the volume requirements for any of the other categories of renewable fuel (*i.e.,* BBD, advanced biofuel, and total renewable fuel).

A. Cellulosic Waiver Authority Statutory Background

The cellulosic waiver authority at CAA section 211(o)(7)(D)(i) provides that ''[f]or any calendar year for which the projected volume of cellulosic biofuel production is less than the minimum applicable volume established under [CAA section 211(o)](2)(B)], as determined by the Administrator based on the estimate provided under [CAA section 211(o)](3)(A),'' the EPA ''shall reduce the applicable volume of cellulosic biofuel required under [CAA section 211(o)](2)(B) to the projected volume available during that calendar year'' and that this reduction is to be made ''not later than November 30 of the preceding calendar year.'' For those years in which the EPA ''makes such a reduction,'' the statute further provides that the EPA ''may also reduce the applicable volume of renewable fuel and advanced biofuels requirement . . . by the same or a lesser volume.'' As such, even when the EPA exercises its cellulosic waiver authority, the determination of whether to correspondingly reduce the total renewable fuel or advanced biofuel requirements is discretionary.

When we determine that the projected volume of cellulosic biofuel production for a given year will be less than the annual applicable volume established under CAA section 211(o)(2)(B), we are then required to reduce the applicable volume of cellulosic biofuel for that calendar year. Pursuant to this

[229] Further adjustments of these projections, including the AEO2025 adjustment factors, are discussed in ''AEO2025 Adjustment Factors for Set 2 Final Rule,'' and ''Calculation of Final 2026 and 2027 RFS Percentage Standards,'' available in the docket for this action.

[230] The D.C. Circuit upheld the EPA's change to the regulatory formula for percentage standards to account for future exempted volumes in *Sinclair,* 101 F.4th at 892–93 (challenge to the Reset Rule). *See also* 40 CFR 80.1405(c).

[231] For further discussion on our approach if the actual volume of exempt gasoline and diesel differs from our projection, see 2020–2022 RFS Rule RTC Section 7.1.

[232] As described in section VIII.C of this preamble, we are revising and clarifying the percentage standard equations.

[233] ''Calculation of Final 2026 and 2027 RFS Percentage Standards,'' available in the docket for this action. As discussed in section II.G of this preamble, the 2026 and 2027 percentage standards without the SRE reallocation volumes are presented in ''Calculation of 2026 and 2027 RFS Percentage Standards Without SRE Reallocation Volumes,'' also available in the docket for this action.

[234] 40 CFR 80.1405(a).

provision, we established the cellulosic biofuel volume requirement lower than the CAA section 211(o)(2)(B)(i)(III) statutory volumes enumerated by Congress for each year from 2010–2022, and again for the 2024 compliance year. Legal challenges to our interpretation of this statutory provision ensued, leading the D.C. Circuit to evaluate various aspects of our implementation of the cellulosic waiver authority.[235] In 2013 in *API,* the court held that the EPA must take a ''neutral aim at accuracy'' in determining the projected volume of cellulosic biofuel available.[236] In *API* and *Alon Refining Krotz Springs, Inc.* v. *EPA,* the D.C. Circuit upheld the EPA's decision to use EIA's projected volume of cellulosic biofuel production to inform the EPA's projection, without requiring ''slavish adherence by EPA to the EIA estimate.'' [237] In *Sinclair Wyoming Refining Co. LLC, et al.* v. *EPA,* the D.C. Circuit upheld the EPA's reading of the statutory phrase ''projected volume available'' to exclude carryover RINs.[238]

In this action, we recognize that we are implementing the cellulosic waiver authority to reduce the 2025 cellulosic biofuel volume after the deadline articulated in the statute; CAA section 211(o)(7)(D)(i) directs the EPA to act ''by November 30 of the preceding calendar year'' to determine whether cellulosic biofuel production is likely to fall short of the volume requirements in a given year, and then reduce the standard to the projected volume available. The statute is silent about the consequences of the EPA missing this procedural deadline, which the Supreme Court and the D.C. Circuit have both declined to interpret as Congress intending an agency to lose authority to act in other contexts, including related provisions in CAA section 211(o).[239] Although we have implemented the cellulosic waiver authority to reduce the cellulosic biofuel volume after the November 30 deadline on several occasions,[240] no party has specifically challenged the EPA's use of the cellulosic waiver authority after the November 30 deadline and so no court has weighed in on the EPA's authority to issue a delayed cellulosic waiver. However, Congress has directed the EPA to waive the cellulosic biofuel volume in specific circumstances that have been met for 2025. Furthermore, the compliance deadline for 2025 has not yet passed, suggesting it is still appropriate to partially waive the 2025 cellulosic biofuel volume requirement. We read the statute as allowing the EPA to retain authority to waive the volume requirements for a given year even when the November 30 deadline in the preceding year has passed, as it has in this instance.

CAA section 211(o)(7)(D)(i) also refers to the ''projected volume of cellulosic biofuel production'' and the ''projected volume available,'' which some parties have suggested is another indication that the provision should or could only be used prospectively. We believe the best reading of the statute is instead that there are projections necessary to determine the ''volume of . . . production'' and the ''volume available,'' both when the EPA acts in a timely manner by November 30 of the preceding year and when the EPA waives the volume requirement after the November 30 date. The use of the term ''projected'' in the statute does contemplate the need for forward-looking estimates; however, it does not follow that the statutory language prohibits the EPA from acting after November 30.[241] Instead, the language is consistent with the relevant circumstances when the statutory deadline of November 30 is met.

We note that the statutory language indicates that the use of the cellulosic waiver authority is mandatory. That is, whenever the projected volume of cellulosic biofuel production is less than the minimum applicable volume established under CAA section (o)(2)(B), CAA section 211(o)(7)(D)(i) provides that the EPA ''shall reduce the applicable volume of cellulosic biofuel required under paragraph (2)(B) to the projected volume available during that calendar year.'' We implemented this provision for every year from 2010–2022 and again in 2024 to reduce the cellulosic biofuel volume consistent with the statutory directive that the EPA shall reduce the volume when the requisite conditions are met.[242] As discussed further in RTC Section 8.1, we are acting consistent with this mandatory provision, which prescribes both when the EPA must issue a waiver and to what volume the EPA must reduce the cellulosic biofuel standard and does not provide the EPA discretion in either circumstance.

In addition, CAA section 211(o)(7)(D)(ii) directs the EPA to make CWCs available whenever it reduces the cellulosic biofuel volume under CAA section 211(o)(7)(D). CWCs—which are offered for sale to obligated parties at a price established by regulation [243] per CAA section 211(o)(7)(D)(iii)—provide compliance flexibility for obligated parties. However, it should be noted that CWCs only satisfy an obligated party's cellulosic biofuel obligation; unlike a cellulosic RIN, a CWC cannot be used to satisfy an obligated party's advanced biofuel or total renewable fuel obligation.[244] To obtain the same compliance value as a cellulosic RIN, an obligated party using a CWC for compliance with the cellulosic biofuel standard needs to also acquire an advanced or BBD RIN to use towards meeting its advanced biofuel and total renewable fuel obligations. When CWCs are made available, they generally limit or cap the price of cellulosic RINs.[245]

CAA section 211(o)(7)(D) provides that the EPA may reduce the applicable volume of total renewable fuel and advanced biofuel in years when the EPA reduces the applicable volume of cellulosic biofuel under that provision.

[235] *See, e.g., American Petroleum Institute (API)* v. *EPA,* 706 F.3d 474, 479 (D.C. Cir. 2013) (interpreting the ''projected volume available'' and indicating that ''the most natural reading of the provision is to call for a projection that aims at accuracy, not at deliberately indulging a greater risk of overshooting than undershooting'' in projecting the available cellulosic biofuel volume); *ACE,* 864 F.3d at 730 (determining the EPA's use of the cellulosic waiver authority to reduce advanced and total renewable fuel was reasonable); *Sinclair,* 101 F.4th at 883 (rejecting biofuels producers' challenge that the EPA must include carryover cellulosic RINs in its determination of ''projected volume available during that calendar year'').

[236] *API,* 706 F.3d at 476.

[237] *Alon Refining Krotz Springs, Inc.* v. *EPA,* 396 F.3d 628, 660 (D.C. Cir. 2019); *API,* 607 F.3d at 478.

[238] *Sinclair,* 101 F.4th at 883–86.

[239] *See ACE,* 864 F.3d at 721; *Monroe Energy,* 750 F.3d at 919–21; *National Petrochemical Manufacturers* v. *EPA,* 630 F.3d 145, 152–158 (D.C. Cir. 2010) (citing *Barnhart* v. *Peabody Coal Co.,* 537 U.S. 149 (2003)).

[240] *See, e.g.,* 79 FR 25025 (May 2, 2014) (direct final rule reducing the 2013 cellulosic biofuel volume in May 2014), 80 FR 77420 (December 14, 2015) (final rule reducing the 2014 and 2015 cellulosic biofuel volumes in December 2015), 87 FR 39600 (July 1, 2022) (final rule reducing the 2020 and 2021 volumes in July 2022). The EPA has also waived the statutory volume requirements under CAA section 211(o)(7)(F)—the ''reset'' authority—after the deadline prescribed in the statute for such a waiver. 87 FR 39600 (July 1, 2022). *See also* CAA section 211(o)(7)(F), providing that the EPA shall waive the volume under the provision ''within 1 year'' after the triggering event. The EPA waived the volumes several years after the first statutory trigger, and approximately two years after the second statutory trigger.

[241] *See Loper Bright Enterprises* v. *Raimondo,* 603 U.S. 369, 400 (2024) (in overruling *Chevron* deference, the Court observed that it ''makes no sense to speak of a 'permissible' interpretation [of a statute] that is not the one the court, after applying all relevant interpretive tools, concludes is best. In the business of statutory interpretation, if it is not the best, it is not permissible.'').

[242] The EPA acknowledges that it did not waive the 2023 cellulosic biofuel volume requirement. *https://www.epa.gov/renewable-fuel-standard-program/epa-denial-petition-partial-waiver-2023-cellulosic-biofuel.*

[243] 40 CFR 80.1456.

[244] 72 FR 14726–27 (March 26, 2010).

[245] *See, e.g.,* 85 FR 7025 (February 6, 2020); 87 FR 39616 (July 1, 2022).

That reduction must be less than or equal to the reduction in cellulosic biofuel. The D.C. Circuit explained:

> There is no requirement to reduce these latter quotas, nor does the statute prescribe any factors that EPA must consider in making its decision. . . . In the absence of any express or implied statutory directive to consider particular factors, EPA reasonably concluded that it enjoys broad discretion regarding whether and in what circumstances to reduce the advanced biofuel and total renewable fuel volumes under the cellulosic waiver provision.[246]

Using this discretion, we have, in the past, declined to reduce the advanced biofuel and total renewable fuel volumes in certain circumstances.[247] In other circumstances, we have reduced the advanced biofuel and total renewable fuel volumes using this authority.[248] It is worth noting that the EPA's practice of reducing the advanced biofuel and total renewable fuel volumes utilizing the cellulosic waiver authority in past years served to carry through the partial waiver necessitated by the shortfall in cellulosic biofuel to the other nested renewable fuel categories when reducing the statutory cellulosic biofuel volumes established by Congress in 2007. In many cases, reductions to the advanced biofuel and total renewable fuel volumes were necessary to enable compliance by obligated parties. For example, we reduced the cellulosic biofuel volume by over 15 billion gallons for 2022. Had we not also reduced the 2022 advanced biofuel and total renewable fuel volumes, these requirements would have been 15 billion gallons higher, far exceeding the market's ability to supply qualifying renewable fuels, even after considering available carryover RINs. In contrast, for 2025, a year for which we set the volume requirements using our set authority, the partial waiver of the cellulosic biofuel volume requirement is significantly smaller than in prior years (0.17 billion RINs). The starting point of a waiver in years prior to 2023 was the statutory table volumes set by Congress in 2007, which were perhaps overly optimistic for production in years further out in the future. The EPA itself established the 2025 volume requirements in 2023 based on projection of cellulosic biofuel production and use in 2025 using the best data and information available at the time the projections were made. As discussed further in section VI.B of this preamble, we are not adjusting the 2025 total renewable fuel and advanced biofuel volumes because those volumes are likely to be achieved in the market.

We received comments on various aspects of CAA section 211(o)(7)(D) and our proposed use of the cellulosic waiver authority. Some commenters suggested that the provision cannot be used in these circumstances given that there is not a shortfall in production. Some commenters suggested that using the cellulosic waiver authority to waive the 2025 volume is not permitted after November 30, 2024. Other commenters supported our proposed waiver of the 2025 cellulosic biofuel requirement and our reading of the statutory requirements. We respond fully to these comments in RTC Section 8.1.

B. Assessment of Cellulosic RINs Available for Compliance in 2025

Based on the actual cellulosic RIN data available at the time of this writing, we estimate that 1.21 billion cellulosic RINs will be available for compliance in 2025. We determined this quantity by taking the total number of cellulosic RINs generated in 2025 through the date of this analysis (1.29 billion cellulosic RINs),[249] and subtracting the number of cellulosic RINs retired for reasons other than demonstrating annual compliance (0.08 billion RINs).[250] As described in section VI.C of this preamble, we believe this volume represents the projected volume of cellulosic biofuel production in 2025.

We recognize that this analysis differs from our assessment of cellulosic biofuel availability in 2024 because both the RFS regulations and the timing have changed. For 2024, we determined the total number of cellulosic RINs available for compliance with the 2024 cellulosic biofuel standard, based on the ''Total Net Generation RIN'' dataset—that is, all cellulosic RINs generated in 2024, excluding those retired due to generation errors (invalid RINs).[251] This approach reflects how cellulosic RIN generation operated in 2024, particularly for biogas-derived renewable fuel. Under the RFS regulations in place for 2024, cellulosic RINs for biogas-derived renewable fuel could only be generated once the cellulosic RIN generator obtained documentation that showed that a specified volume of biogas-derived renewable fuel had been produced and used as transportation fuel. Because cellulosic RIN generation was tied to actual use of biogas-derived renewable fuel as transportation fuel, it was reasonable to project that all cellulosic RINs that were generated in 2024 (and not retired due to generation errors) would be available for obligated parties to demonstrate compliance with their 2024 cellulosic biofuel obligations. Additionally, the partial wavier of the 2024 cellulosic biofuel volume requirement occurred six months after the end of the 2024 compliance year. Thus, by mid-2025, when we finalized the partial waiver of the 2024 cellulosic biofuel volume requirement, the ''Total Net Generation'' RIN dataset was an appropriate determination of the 2024 cellulosic RINs available for compliance.

In contrast, the biogas regulatory reform revisions from the Set 1 Rule that took effect in 2025 decoupled cellulosic RIN generation from the demonstration that the biogas-derived renewable fuel is used as transportation fuel. In short, cellulosic RINs for biogas-derived renewable fuel (*i.e.,* RNG RINs) are now generated prior to use as a transportation fuel, and such RINs are not separated—and thus made available for compliance—until the RNG RIN separator obtains documentation demonstrating that the volume of renewable CNG/LNG was used as transportation fuel.[252] Such RIN separation must occur by December 31 of the subsequent calendar year after the RNG RIN was separated; otherwise the RIN is expired and must be retired.[253] For example, an RNG RIN generated on January 1, 2025, can be separated until December 31, 2026.[254] Thus, while we are able to know the number of cellulosic RINs generated for 2025 shortly after the end of the 2025 compliance year, there remains some uncertainty regarding the actual number of these RINs that will be separated and made available for compliance in 2025 since there are still many months left until these RINs must be separated (or else will expire).

Given this regulatory shift and the timing of this action, we must instead make a projection of 2025 cellulosic RIN availability. Accordingly, we projected that the cellulosic RINs available for compliance in 2025 is the total number

[246] *Monroe,* 750 F.3d at 915; *see also ACE,* 864 F.3d at 721.

[247] *See, e.g.,* 78 FR 49794, 49811 (August 15, 2013).

[248] *See, e.g.,* 80 FR 77420 (December 14, 2015). 81 FR 89746 (December 12, 2016).

[249] See ''Available RINs to date from January 2026'' RIN data file available at: *https://www.epa.gov/fuels-registration-reporting-and-compliance-help/spreadsheet-available-rins-date-renewable-fuel.*

[250] See ''RIN retirement data from January 2026'' RIN data file available at: *https://www.epa.gov/fuels-registration-reporting-and-compliance-help/spreadsheet-rin-retirement-data-renewable-fuel.*

[251] 90 FR 29755 (July 7, 2025).

[252] 40 CFR 80.125(d) and (e).

[253] *Id.*

[254] Pursuant to 40 CFR 80.125(d)(5), RNG RINs generated in 2025 will expire if they are not separated by December 31, 2026.

of cellulosic RINs generated in 2025 at the time of this analysis, minus those RINs retired for reasons other than demonstrating annual compliance. This calculation intentionally excludes RINs retired for non-transportation purposes from our projection of available cellulosic RINs, and that exclusion is significant: retirements in this category grew from 0.4 million RINs in 2024 to 74.5 million in 2025—an increase we anticipated given the consumption constraints expected to affect the cellulosic biofuel market.[255] Excluding these retirements, we project that the remaining cellulosic RINs that were generated in 2025 will ultimately be separated and available for use toward 2025 compliance.

Finally, we note that if, for the partial waiver of the 2024 cellulosic biofuel volume requirement, we had used the same methods in this action (*i.e.,* excluding all cellulosic RINs retired for reasons other than demonstrating annual compliance) rather than excluding only those cellulosic RINs retired due to generation errors (invalid RINs), then the partial waiver of the 2024 cellulosic biofuel requirement would not have been materially different.[256] Together with the 2024 regulations governing cellulosic RIN generation for biogas-derived renewable fuel, this confirms that our previous approach to estimating the RINs available for compliance was appropriate for the time.

We intend to utilize the approach described in this action going forward, both in projecting the volume of cellulosic biofuel that will be used (as described in section III of this preamble) and in evaluating any future waivers under CAA section 211(o)(7)(D).

C. Implementation of the Cellulosic Waiver Authority

The cellulosic waiver authority is specific regarding when it is available and how the volume reduction should be determined when acting under the authority, as discussed in section VI.A of this preamble. We have determined that ‘‘the projected volume of cellulosic biofuel production is less than the minimum applicable volume’’ for 2025. In the Set 1 Rule, we established the ‘‘minimum applicable volume’’ of cellulosic biofuel for 2025 to be 1.38 billion RINs and used that volume to calculate the 2025 cellulosic biofuel percentage standard of 0.81 percent.[257] The actual number of cellulosic RINs that obligated parties will ultimately need to retire for compliance with the current standard will not be known until after the 2025 compliance deadline, which will be determined after the promulgation of the 2026 percentage standards in this action,[258] when obligated parties report to the EPA their 2025 gasoline and diesel production and import volumes.[259] However, for the purpose of making a decision to partially waive the 2025 cellulosic biofuel volume requirement, we have assumed that the actual total 2025 cellulosic biofuel obligation, if not reduced, will be 1.38 billion RINs.[260]

We currently estimate that only 1.21 billion 2025 cellulosic RINs are projected to be generated and separated.[261] To qualify as cellulosic biofuel, a fuel must be produced from qualifying renewable biomass, derived from cellulose, hemi-cellulose, or lignin, and have lifecycle GHG emissions that are at least 60 percent less than the baseline GHG emissions. Fuels that meet these criteria (along with other relevant statutory and regulatory provisions) qualify to generate cellulosic RINs. RIN-generating fuels must also be used in the covered location to replace or reduce the quantity of fossil fuel present in transportation fuel, heating oil, or jet fuel and such fuels that meet this criterion are generally eligible to be separated. Thus, only fuels for which cellulosic RINs have been generated and separated fully meet the requirements to qualify as cellulosic biofuel and thus are ‘‘available.’’ We therefore believe our estimate of the number of 2025 cellulosic RINs that have been generated and separated represents the projected volume of cellulosic biofuel production in 2025. This projected volume (1.21 billion gallons) is 0.17 billion fewer RINs than the 1.38 billion RINs needed to comply with the original 2025 cellulosic biofuel standard, a shortfall of approximately 13 percent. We therefore find that the shortfall in the projected volume of cellulosic biofuel production in 2025 relative to the required volume triggers the need for implementation of the cellulosic waiver authority for 2025.

When the EPA determines that a waiver of the cellulosic biofuel volume requirement is appropriate under CAA section 211(o)(7)(D)(i), the EPA must then reduce the required cellulosic biofuel volume to ‘‘the projected volume available.’’ We have previously interpreted the phrase ‘‘projected volume available’’ to exclude carryover RINs when determining the volume adjustment to be made; this interpretation was affirmed by the D.C. Circuit in *Sinclair*.[262] We have consistently interpreted the ‘‘projected volume available’’ as ‘‘the volume of qualifying cellulosic biofuel projected to be produced or imported and available for use as transportation fuel in the U.S. in that year.’’ [263] In determining the ‘‘projected volume available,’’ the EPA must take a ‘‘neutral aim at accuracy.’’ [264]

As discussed in section VI.B of this preamble, the projected volume of cellulosic biofuel available in 2025 is 1.21 billion RINs. Thus, when the cellulosic waiver authority is applied, we are only able to reduce the 2025 cellulosic biofuel volume to the projected volume available of 1.21 billion RINs. However, in accordance with the statute, we are also required to make CWCs available to obligated parties, which can be used—along with additional BBD or advanced RINs—to cover any remaining shortfall.[265] With the waiver of the cellulosic biofuel requirement for 2025, we are making CWCs available to obligated parties at a price of $1.91.[266] The availability of CWCs helps ensure RFS program stability by reducing the likelihood that obligated parties may be forced into non-compliance with their RFS obligations; any obligated party that is

[255] We discuss future consumption constraints in further detail in section III of this preamble and RIA Chapter 7.

[256] In our assessment of cellulosic biofuel availability in the rule for the partial waiver of the 2024 cellulosic biofuel volume requirement, we projected that only 1.01 billion cellulosic RINs were generated and available in 2024. 90 FR 29755 (July 7, 2025). If we were to have calculated that figure using the same methodology described in this action, there would still have been 1.01 billion cellulosic RINs.

[257] 88 FR 44470–71 (July 12, 2023).

[258] The compliance deadline for the 2025 standards will be the first quarterly reporting deadline after the 2026 standards are effective. 40 CFR 80.1451(f)(1)(i)(A).

[259] 40 CFR 80.1451 and 80.1427(a).

[260] Because the compliance obligation is calculated on a percentage basis, if the actual gasoline and diesel volumes reported by obligated parties differ from the projected gasoline and diesel volumes that were used to derive the percentage standard, then the actual number of RINs required for compliance will differ from the projected volume that was used to calculate the percentage standard. Although we rely on the 1.38-billion-RIN projection for 2025 in the Set 1 Rule that was the basis for the 2025 cellulosic biofuel percentage standard, we would reach the same conclusion to waive the 2025 cellulosic biofuel volume requirement, for the reasons stated below, using a higher RIN obligation (*i.e.,* a higher gasoline and diesel projection).

[261] RIA Chapter 7.1.3.

[262] *Sinclair,* 101 F.4th at 883–86.

[263] *See, e.g.,* 87 FR 39600 (July 1, 2022); *see also Sinclair,* 101 F.4th at 883–86.

[264] *API,* 706 F.3d at 479.

[265] Pursuant to 40 CFR 80.1405(d), the CWC price is calculated using the methodology specified in 40 CFR 80.1456(d) and posted on the EPA's website at: *https://www.epa.gov/renewable-fuel-standard-program/cellulosic-waiver-credits-under-renewable-fuel-standard-program.*

[266] See ‘‘Cellulosic Waiver Credit Price Calculation for 2025,’’ available in the docket for this action.

unable to acquire sufficient cellulosic RINs to comply with their 2025 cellulosic biofuel obligations—plus any cellulosic RIN deficit carried from 2024—will be able to purchase CWCs to cover the shortfall.[267]

Given that ''the projected volume of cellulosic biofuel production is less than the minimum applicable volume'' for 2025, we are implementing the cellulosic waiver authority to waive the 2025 cellulosic biofuel volume requirement to 1.21 billion RINs, a reduction of 0.17 billion RINs from the original volume requirement of 1.38 billion RINs. This volume requirement matches the projected 1.21 billion cellulosic RINs available for 2025.

Finally, CAA section 211(o)(7)(D) provides that the EPA may reduce the applicable volume of total renewable fuel and advanced biofuel in years when the EPA reduces the applicable volume of cellulosic biofuel under that provision. That reduction must be less than or equal to the reduction in cellulosic biofuel. The D.C. Circuit concluded that the cellulosic waiver authority provides the EPA ''broad discretion'' to consider a variety of factors in determining whether to reduce the total renewable fuel and advanced biofuel volumes under this provision.[268] RIN generation data from EMTS indicates that there will likely be a sufficient supply of RINs to meet the advanced biofuel and total renewable fuel volume requirements in 2025. Advanced and total RIN generation in 2025 (8.57 billion RINs and 23.23 billion RINs, respectively) exceeded the 2025 volume requirements (7.33 billion RINs and 22.33 billion RINs, respectively).[269] These RIN generation numbers indicate that the market is capable of meeting the 2025 advanced biofuel and total renewable volume requirements even with the projected shortfall in cellulosic biofuel. Further, the significant oversupply of RINs in previous years indicates that there will be sufficient carryover RINs to facilitate compliance.

We believe reductions to the 2025 advanced biofuel and total renewable fuel volumes are not necessary or warranted based on the available supply data, given that the market has provided volumes of these fuels in excess of the requirements established in the Set 1 Rule. Reductions in these volume requirements at this time would only serve to increase the number of advanced and total carryover RINs. Historically, we have declined to take actions that would inflate the number of available carryover RINs.[270]

D. Calculation of 2025 Cellulosic Biofuel Percentage Standard

As described in section VI.C of this preamble, we are implementing the cellulosic waiver authority to partially waive the 2025 cellulosic biofuel volume requirement from 1.38 billion RINs to 1.21 billion RINs. As described in section V of this preamble, the formula used to calculate the cellulosic biofuel percentage standard applicable to obligated parties as a function of their gasoline and diesel fuel production or importation is provided in 40 CFR 80.1405. Using the same values from the Set 1 Rule for the variables in this formula other than RFV_{CB} (the cellulosic biofuel volume),[271] we have calculated the revised cellulosic biofuel percentage standard for 2025 to be 0.71 percent, down from 0.81 percent.[272] This percentage standard is included in the regulations at 40 CFR 80.1405(a) and applies to producers and importers of gasoline and diesel.

VII. Removal of Renewable Electricity From the RFS Program

The EPA previously promulgated regulations permitting RIN generation for renewable electricity (commonly referred to as eRINs). In the Set 2 proposal, the EPA proposed to remove renewable electricity as a qualifying renewable fuel under the RFS program, and in this action we are finalizing the removal. We do so under a new, better interpretation of the statute, consistent with our proposal, that finds that renewable electricity is not a qualifying renewable fuel.

A. Historical Treatment of Renewable Electricity in the RFS Program

The statutory definition of ''renewable fuel'' in CAA section 211(o)(1)(J) requires that renewable fuel be produced from renewable biomass and used to replace or reduce the quantity of fossil fuel present in a transportation fuel. CAA section 211(o)(1)(B)(ii)(B) further indicates that the definition of renewable fuel may include certain non-liquid biofuels, such as biogas produced through the conversion of organic matter from renewable biomass. We have permitted RIN generation for non-liquid biofuels from biogas that are produced through the conversion of organic matter from renewable biomass, such as renewable CNG/LNG. Thus, renewable fuels under the RFS program can be broadly categorized as either liquid biofuels (*e.g.,* ethanol and biodiesel) or non-liquid biofuels (*e.g.,* renewable CNG/LNG that is produced from qualifying biogas), so long as these fuels are used as transportation fuel. Non-liquid biofuels have played a part in the RFS program since the RFS2 Rule was promulgated in 2010. In that rule, we specified that electricity, as well as natural gas and propane, produced from renewable biomass could be a RIN-generating renewable fuel under the RFS program. However, we stipulated that electricity could only be a RIN-generating renewable fuel if it could be demonstrated that specific quantities of electricity ''are actually used as a transportation fuel[ ].'' [273] The record for the RFS2 Rule did not further elaborate on how renewable electricity (*i.e.,* electricity that is derived from renewable biomass) satisfies the statutory definition of renewable fuel or is consistent with other applicable statutory requirements.

Pursuant to the mistaken determination that renewable electricity is, in certain circumstances, a qualifying renewable fuel, in the RFS2 Rule we also established regulatory provisions governing the generation of RINs representing renewable electricity in anticipation of a future action that would provide a RIN-generating pathway for electricity produced from renewable biomass and used as transportation fuel. In doing so, we discussed the relevant differences between liquid and non-liquid biofuels and established regulatory provisions for renewable electricity that recognized those distinctions.[274] In a separate action also in 2010, we promulgated a definition of ''renewable electricity'' to ''clarify that electricity must meet the definition of renewable fuel in order to qualify for RINs.'' [275]

[267] Unlike cellulosic RINs—which apply towards an obligated party's cellulosic biofuel, advanced biofuel, and total renewable fuel obligations—CWCs only apply towards an obligated party's cellulosic biofuel obligation and not toward their nested advanced biofuel and total renewable fuel obligation. Obligated parties that satisfy their cellulosic biofuel obligations with CWCs would therefore also have to purchase additional BBD or advanced RINs to meet their associated advanced biofuel and total renewable fuel obligations.

[268] *ACE,* 864 F.3d at 730–34; *see also Monroe,* 750 F.3d 909.

[269] See ''Total Net Generation'' RIN data table at: *https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rins-generated-transactions.*

[270] 87 FR 39600, 39621 (July 1, 2022) (''While EPA has previously set the RFS standards at what the market actually used (like for 2014 and 2015 in the 2014–2016 rule), we have never intentionally reduced the standards with the express intent to inflate the size of the carryover RIN bank.''); 2020–2022 RFS Rule RTC Section 2.6.1.

[271] 88 FR 44519–21 (July 12, 2023).

[272] ''Calculation of Final 2025 Cellulosic Biofuel Percentage Standard,'' available in the docket for this action.

[273] 74 FR 14670, 14686 (March 26, 2010).

[274] 75 FR 14670, 14729 (March 26, 2010).

[275] 75 FR 26026, 26031 (May 10, 2010).

In 2014, we established novel RIN-generating pathways for electricity produced from biogas from landfills and waste digesters.[276] In the same 2014 rulemaking, we updated the regulations governing RIN generation for renewable electricity.[277] In general, the regulatory requirements were intended to ensure that any RINs generated correspond to electricity that meets the statutory criteria to qualify as renewable fuel. For example, the electricity must be produced from renewable biomass under an approved pathway (demonstrating it meets the required GHG reduction threshold), the electricity must be sold for use as transportation fuel and for no other purpose (and the RIN generator must provide documentation to support its use as transportation fuel), and it must be the case that no other party relied on the renewable electricity for the generation of RINs.

Although renewable electricity has been part of the RFS program since 2010, and a pathway has existed since 2014 for renewable electricity produced from biogas, the EPA has never registered a party to generate RINs for renewable electricity. We intended our proposed updates to the ''eRIN'' regulatory program for renewable electricity as part of the Set 1 proposal in December 2022 to revise the existing regulations governing renewable electricity to allow RIN generation under the existing pathways.[278] However, the Set 1 Rule was ultimately finalized without the proposed eRIN regulatory program, leaving the previously existing, inadequate regulations governing renewable electricity in place.

B. Statutory Basis for Removal of Renewable Electricity From the RFS Program

In this final rule, and consistent with the Set 2 proposal, we are reversing the determination in the RFS2 Rule that renewable electricity is eligible to generate RINs because the statute does not permit renewable electricity to generate RINs under the RFS program. As such, we are finalizing the removal of renewable electricity as a qualifying renewable fuel under the RFS program. This decision marks a change in position from the Agency's prior interpretations discussed above but is well within our authority to review and revise prior policies by acknowledging the change, offering a reasoned explanation for the change, and considering reliance interests, if any, that counsel against the change.[279] Given the regulatory history of the eRIN regulatory program, we do not believe that significant and cognizable reliance interests have arisen in the renewable electricity interpretation set out in these prior actions. As discussed in section VII.A of this preamble, although we previously determined that electricity could qualify as a renewable fuel under the RFS program and promulgated regulations for the generation of RINs for renewable electricity, the EPA has not registered any parties to generate RINs for renewable electricity and no RINs representing renewable electricity have ever been generated. As explained further below, this change is supported by the best reading of the statute that engages fully with relevant interpretive tools. We have repeatedly acknowledged the difficulties in formulating a workable eRIN regulatory program, including when we decided not to finalize additional regulations as part of the Set 1 Rule. In this final rule, we conclude that CAA section 211(o)(1)(J), read in context and considering the structure of the statute as a cohesive whole, does not authorize such a program. This explains, in part, the difficulty in implementing such a program given the applicable requirements and structure of the statute.

We are removing renewable electricity from the RFS program on the grounds that, under the best reading of the statute, renewable electricity is not a renewable fuel. Congress defined renewable fuel in CAA section 211(o)(1)(J) as ''fuel that is produced from renewable biomass and that is used to replace or reduce the quantity of fossil fuel present in a transportation fuel.'' Congress further defined transportation fuel in CAA section 211(o)(1)(L) as ''fuel for use in motor vehicles, motor vehicle engines, nonroad vehicles, or nonroad engines.'' We have consistently interpreted ''renewable fuel'' to encompass three key components: (1) there must be a fuel; (2) the fuel must be produced from renewable biomass; and (3) the fuel must be used to replace or reduce fossil fuel present in a transportation fuel.[280] While we previously, in 2010, assumed that renewable electricity could meet this definition, we have revisited the statutory analysis based on the text of the statute and consistent with intervening Supreme Court decisions on standards for statutory interpretation.[281]

Our analysis focuses on the last component of the renewable fuel definition—that the fuel must be used to replace or reduce the quantity of fossil fuel present in a transportation fuel. The best reading of this language is that a renewable fuel must physically displace a volume of fossil fuel that is present in a motor vehicle or motor vehicle engine. The statutory definition uses the phrases ''quantity of fossil fuel'' and ''present in a transportation fuel.'' The plain meanings of ''present'' include ''now existing or in progress,'' ''being in view or at hand,'' ''existing in something mentioned or under consideration,'' and ''constituting the one actually involved, at hand, or being considered.''[282] Each of these definitions indicates that for something to be ''present,'' it must physically and actively be involved or at hand. The word ''quantity'' in the definition of renewable fuel reinforces that there must be a measurable physical unit of fossil fuel involved that is replaced or reduced.

The definition of transportation fuel provides that the relevant scale at which renewable fuel must replace or reduce fossil fuel is in a motor vehicle, motor vehicle engine, nonroad vehicle, or nonroad engine (hereinafter ''motor vehicle''), as opposed to in the U.S. transportation fuel supply overall. It is not sufficient for a biofuel to be capable of reducing or replacing fossil fuel in the abstract—it must replace or reduce a measurable, physical volume of fossil fuel that is actually at hand in a fuel in a motor vehicle.

Electricity cannot replace or reduce a volume of fossil fuel that is present in a motor vehicle or motor vehicle engine. Rather, to the extent it does replace or reduce fossil fuel, it does so at the level of the national, aggregate transportation fuel supply. But it is not fungible with fossil fuel that is present in a motor vehicle and, therefore, does not meet the statutory definition of renewable fuel.

In contrast, biogas that is cleaned up into RNG (and then compressed into renewable CNG/LNG) can replace and reduce fossil natural gas that is used in a motor vehicle. That is, natural gas that is used in a motor vehicle powered by CNG/LNG is a fossil fuel, and renewable

[276] Rows Q and T of Table 1 to 40 CFR 80.1426. 79 FR 42128 (July 18, 2014).

[277] 40 CFR 80.1426(f)(10)(i) and (f)(11)(i).

[278] 87 FR 80582 (December 30, 2022).

[279] *See FDA* v. *Wages & White Lion Invs., L.L.C.,* 604 U.S. 542, 567–69 (2025); *FCC* v. *Fox Television Stations, Inc.,* 556 U.S. 502, 514 (2009); *Motor Vehicle Mfrs. Ass'n of U.S., Inc.* v. *State Farm Mut. Auto. Ins. Co.,* 463 U.S. 29, 43 (1983).

[280] 87 FR 80582, 80634 (December 30, 2022); 87 FR 73956–57 (December 2, 2022) (discussing what fuels can generate RINs).

[281] *Loper Bright,* 603 U.S. 369; *see also West Virginia* v. *EPA,* 597 U.S. 697 (2022).

[282] Merriam Webster online, definition of ''present,'' *https://www.merriam-webster.com/dictionary/present,* last accessed January 26, 2026.

CNG/LNG can replace or reduce the physical volume of fossil fuel in that motor vehicle. CNG/LNG produced from qualifying biogas is therefore a renewable fuel. But because electricity cannot physically displace fossil fuel present in a motor vehicle, it is not a renewable fuel. While it is true that electricity produced from biogas does, or may, replace or reduce electricity that would have been produced from fossil fuels, such displacement occurs in an electric generating unit, not in a motor vehicle. Renewable electricity does not replace or reduce fossil fuel that is present in a transportation fuel in a motor vehicle. Said a different way, electricity is not a fossil fuel but is rather produced from fossil fuels. Renewable biomass may be swapped for fossil fuels in an electric generating unit, but not in a motor vehicle.

Additionally, we note that ''electricity'' is not mentioned in CAA section 211(o), in contrast to over fifty references to liquid fuels. The RFS program statutory language in CAA section 211(o) speaks to ''volumes'' and ''gallons'' of renewable fuel. The fact that the CAA explicitly references physical units implies that the RFS program was intended to measure, and thus include, only quantities of liquid or gaseous fuels. To this end, when Congress amended the RFS program in 2007, it revised the definition of ''renewable fuel'' and elaborated the types of fuels that are included under this definition.[283] When it did so, Congress was aware that electricity was being used to power motor vehicles.[284] And although it explicitly referenced biogas in the list of fuels eligible for consideration as advanced biofuel, it declined to include electricity in this list, or to reference electricity in any other way in CAA section 211(o). This is further evidence that Congress did not intend for electricity to qualify as a renewable fuel under the RFS program.

We received comments both in support of and in opposition to our proposed interpretation and determination. Many commenters in support of the proposed removal of renewable electricity agreed that electricity cannot be a renewable fuel because it does not physically replace fossil fuel in a motor vehicle, and that if Congress had intended for the EPA to include electricity in the RFS program, it would have explicitly stated so. Some commenters also cited policy reasons for excluding electricity from the RFS program, including impacts on the economy and competition for feedstocks. Commenters opposed to the proposed removal of renewable electricity argued, among other things, that Congress deliberately drafted the statutory definitions of renewable fuel and transportation fuel to be broad enough to encompass electricity. Reasons for opposing the proposed removal of renewable electricity on policy grounds included support for biogas markets and for domestic manufacturing. We respond to these and all other significant comments in RTC Section 10.

In addition, some commenters noted that, despite having included renewable electricity regulations under the RFS program since 2010,[285] the EPA has been unable to implement those regulations. Indeed, as early as 2016 the EPA stated that those regulations ''created an untenable environment for the approval of any single registration request by the EPA.'' [286] The Agency further explained that the RIN generation regulations for renewable electricity were inadequate to prevent double counting of electricity claimed for transportation use, which is fundamental to ensuring RIN integrity and the volume requirements under the RFS program.[287] Specifically, because the regulations allowed any party that could demonstrate compliance with the applicable requirements to be the RIN generator, it was possible under those regulations for multiple parties to claim RIN generation for the same quantity of renewable electricity. But if RINs do not correspond to the actual volume of renewable fuel, the credit mechanism breaks down.[288] Thus, even if the EPA was not finalizing the complete removal of renewable electricity from all RFS regulations because it does not meet the definition of ''renewable fuel'' under CAA section 211(o), it would remove the implementing regulations for renewable electricity because they are unworkable. That is, in addition to and as an alternative to the final action the Agency is taking here to interpret the statute to exclude renewable electricity from the RFS program, the EPA is removing the implementing regulations for renewable electricity in 40 CFR part 80, subpart M, on the basis that those regulations fail to adequately implement the RFS program with integrity.[289]

C. Implementation of Removal of Renewable Electricity From the RFS Program

Our determination that electricity is not a renewable fuel is effectuated by removing all regulatory provisions associated with renewable electricity from 40 CFR part 80, subparts A and M. First, we are removing the definition of ''renewable electricity'' from the definitions in 40 CFR 80.2. Second, we are removing the regulations associated with generating RINs for renewable electricity. These actions include removing the renewable electricity pathways in table 1 to 40 CFR 80.1426, the renewable electricity equivalence value in 40 CFR 80.1415(b), the renewable electricity RIN generation requirements in 40 CFR 80.1426(f)(10) and (11), the renewable electricity RIN separation requirements in 40 CFR 80.1429(b)(5), and all associated registration, reporting, and recordkeeping requirements in 40 CFR 80.1450(b)(1), 80.1451(b)(1), and 80.1454(k) and (l).

D. Withdrawal of December 2022 Proposal Regarding Renewable Electricity

We previously proposed to restructure the regulatory provisions for renewable electricity in the December 2022 Set 1 proposal.[290] We received a wide variety of comments on all aspects of our proposal, with stakeholder positions ranging from strong support to strong opposition. In light of the significant number and complexity of comments received, we did not finalize the proposed revisions to the electricity provisions with the rest of the Set 1 Rule in July 2023.[291]

We are now withdrawing the December 2022 proposal pertaining to renewable electricity. The primary reason for doing so is that we are removing renewable electricity from the RFS program on the basis that CAA section 211(o) does not allow for it. This action renders our December 2022 proposal moot. We are formally

[283] *Compare* Public Law 109–58 § 1501(a)(2) (2005), *with* 42 U.S.C. 7545(o)(1).

[284] *See, e.g.,* Public Law 110–140, sec. 206 (2007) (directing the EPA to conduct a study of credits for use of renewable electricity in electric vehicles).

[285] The EPA significantly updated the renewable electricity regulations in 2014, including by adding the pathways for renewable electricity that would have, in theory, allowed for RIN generation. 79 FR 42128 (July 18, 2014).

[286] 81 FR 80828, 80891 (November 16, 2016); *see also* EPA Final Brief defending decision to not include renewable electricity volumes in 2019 Annual Volumes Rule, *Growth Energy* v. *EPA,* D.C. Cir. No. 19–1023, Doc. # 1831996 at 74–77 (filed March 5, 2020).

[287] 81 FR 80891 (November 16, 2016).

[288] *See* CAA section 211(o)(5)(A) (providing that the EPA's regulations under CAA section 211(o)(2)(A) shall provide for the generation of an appropriate amount of credits).

[289] These implementing regulations include the pathway, equivalence value, RIN generation, RIN separation, registration, reporting, and recordkeeping requirements for renewable electricity.

[290] 87 FR 80582 (December 30, 2022).

[291] 88 FR 44468, 44471 (July 12, 2023).

withdrawing this proposal to avoid any potential confusion about its status.

VIII. Other Changes to RFS Regulations

This section describes the other regulatory changes beyond those already discussed that we are finalizing for the fuel quality and RFS programs. We address comments related to these regulatory changes in RTC Section 12.

A. Renewable Diesel, Naphtha, and Jet Fuel Equivalence Values

In this action, we are finalizing revisions to the equivalence values for renewable diesel, naphtha, and jet fuel to account for the non-renewable portion of these fuels, as they are all typically produced using a hydrotreating process. Due to an oversight when initially establishing the equivalence values for these fuels, the existing equivalence values for these fuels do not take into consideration the fact that a portion of the hydrogen in these fuels originates from the hydrogen used in the hydrotreating process, nearly all of which is produced from fossil natural gas. Equivalence values dictate the number of RINs a renewable fuel producer or importer can generate per gallon of fuel they produce (*e.g.,* a party who produces a renewable fuel with an equivalence value of 1.5 can generate 1.5 RINs for every gallon of qualifying fuel they produce). By not accounting for the hydrogen produced from fossil natural gas in these fuels, the current equivalence values are artificially high and effectively allow these hydrotreated fuels to generate RINs for non-renewable content. This conflicts not only with the statutory direction that fuels must be produced from renewable biomass to be eligible under the RFS program, but also with the approach EPA has taken for other biofuels that contain non-renewable content (*e.g.,* biodiesel, which by standard practice is generally comprised partially of fossil fuel-based methanol).[292]

In the Set 2 proposal, we proposed to reduce the equivalence value for renewable diesel to 1.6 and establish equivalence values of 1.6 for renewable jet fuel and 1.4 for renewable naphtha. Stakeholders submitted comments on multiple aspects of the proposed revisions, including comments on the EPA's technical analysis supporting the proposed equivalence values and policy arguments for why higher or lower equivalence values for these fuels may be appropriate. Some of these comments are discussed briefly in this section, and we respond fully to comments in RTC Section 11.1.

In this action, we are finalizing equivalence values for renewable diesel and renewable jet fuel that are lower than was proposed and finalizing the equivalence value for renewable naphtha as proposed. Specifically, we are reducing the equivalence value for renewable diesel specified in 40 CFR 80.1415(b) from 1.7 to 1.5 and specifying equivalence values of 1.4 for renewable naphtha and 1.5 for renewable jet fuel. Equivalence values for renewable naphtha and renewable jet fuel were not previously specified in 40 CFR 80.1415(b), but were instead determined on a facility-by-facility basis using an equation specified in 40 CFR 80.1415(c). Previously approved equivalence values for naphtha ranged from 1.4 to 1.5 with the majority approved at 1.5, and for renewable jet fuel ranged from 1.6 to 1.7, with the majority approved at 1.6.[293] These equivalence values properly account for the fossil-derived hydrogen found in most renewable diesel, renewable naphtha, and renewable jet fuel. The final equivalence values for renewable diesel and renewable jet fuel differ from the proposed equivalence values for the reasons discussed below.

The equivalence values for renewable diesel, renewable naphtha, and renewable jet fuel are based on our technical assessment of the proportion of these fuels that are derived from renewable biomass and the average energy content of these fuels. The equivalence values we are establishing in this action better align the equivalence values of these fuels with the approach used for other biofuels that contain non-renewable content described above.[294]

When we proposed to modify the equivalence values for renewable diesel, renewable naphtha, and renewable jet fuel, we provided documentation of our technical evaluation of the proportion of these fuels derived from renewable biomass and their average energy content. Our proposal was consistent with the EPA's longstanding practice of calculating equivalence values based on these factors.[295] We received several comments on this technical evaluation and have revised our analysis based on these comments, along with additional data. Consistent with our initial analysis, our updated analysis demonstrates that the proportion of each of these fuels derived from renewable biomass varies slightly depending on the feedstocks used to produce these fuels. Further, the energy content of the fuels produced can vary depending on a variety of factors, including the feedstocks used to produce the fuels, the operating conditions of the renewable fuel production facility, the age of the catalyst used in the production process, and other factors.

Based on our updated technical analysis, we have estimated the average renewable content of renewable diesel (93.9 percent), renewable jet fuel produced using distillation and hydrocracking technologies (96.2 percent and 92.1 percent, respectively), and renewable naphtha (91.7 percent).[296] These estimates are based on a representative mix of feedstocks that are used to produce these fuels. We then used these estimates of the average proportion of these fuels that is derived from renewable biomass together with our estimates of the average energy content of these fuels as the basis for calculating the appropriate equivalence values for these fuels.[297] Based on our updated analysis, we are finalizing equivalence values of 1.5 for renewable diesel, 1.5 for renewable jet fuel, and 1.4 for renewable naphtha.

We believe that the equivalence values we are finalizing in this action reflect the appropriate equivalence value for the vast majority of renewable jet fuel and naphtha. However, our analysis indicates that the appropriate equivalence value for renewable diesel could be either 1.5 or 1.6, depending on the renewable content and energy content of the renewable diesel. The equivalence value we are finalizing in this action for renewable diesel (1.5) is therefore slightly conservative, as we expect that renewable diesel with relatively high renewable content or energy content could qualify for an equivalence value of 1.6. We believe establishing a slightly conservative equivalence value for renewable diesel is appropriate since renewable diesel producers that believe their fuel should qualify for a higher equivalence value are able to apply for a higher equivalence value under 40 CFR 80.1415. This application process

[292] See ''Calculation of Equivalence Values for renewable fuels under the RFS program,'' Docket Item No. EPA–HQ–OAR–2005–0161–0046.

[293] See ''Feedstock Summary'' RIN data table at: *https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rins-generated-transactions.*

[294] See ''Calculation of Equivalence Values and Energy Content for Renewable Diesel, Naphtha, and Jet Fuel for the Set 2 FRM,'' available in the docket for this action.

[295] See 40 CFR 80.1415. Equivalence values in the RFS program have been based on the energy content and portion of the fuel derived from renewable biomass since RFS2 Rule.

[296] See ''Calculation of Equivalence Values and Energy Content for Renewable Diesel, Naphtha, and Jet Fuel for the Set 2 FRM,'' available in the docket for this action.

[297] *Id.*

allows renewable diesel with a sufficiently high energy content or renewable content to qualify for an equivalence value of 1.6 without over-crediting other renewable diesel that does not meet the necessary thresholds. Were we to establish a higher default equivalence value, some quantity of renewable diesel would continue to be over-credited.

We are not changing the regulations governing the application process for equivalence values in this action, and we note that this application process is available to any producer or importer of any renewable fuel—including renewable jet fuel and naphtha—who has reason to believe that an equivalence value that differs from the default equivalence value is warranted. In these applications, renewable diesel producers may use the average renewable content for renewable diesel we have estimated for this action (93.9 percent) or may provide justification for an alternative renewable content. Renewable diesel producers that choose to base their application on the average renewable content will only need to submit testing results of the energy content of their renewable diesel in their application. At this time, consistent with the regulations in 40 CFR 80.1415, we are not requiring renewable diesel producers to submit testing information supporting their equivalence value petitions on an ongoing (*e.g.,* quarterly) basis. However, if we become aware of information that suggests the testing results we receive through this application process are not representative of the renewable fuel actually produced for commercial scale, we may add regular testing requirements to the regulations in a future action.

We recognize that changing the equivalence values for these fuels in the middle of a compliance year has the potential to cause confusion for renewable fuel producers that generate RINs and obligated parties that are required to acquire RINs for compliance. We also recognize that it may take some time for renewable diesel producers that could qualify for an equivalence value of 1.6 to submit an application and for the EPA to process those applications. We are therefore delaying the effective date for the new equivalence values in this action for renewable diesel (1.5), renewable jet fuel (1.5), and renewable naphtha (1.4) to January 1, 2027. Furthermore, we anticipate that we will be able to process any applications for a higher equivalence value that are submitted in a timely manner before January 1, 2027.

Stakeholders submitted comments on several aspects of the proposed equivalence value changes. Several of these comments are discussed briefly below, and we respond fully to these comments in RIA Chapter 11.1. Several commenters provided input on our technical analysis of the average energy content and renewable content of renewable diesel, jet fuel, and naphtha. As discussed previously, we have considered these comments in our updated analysis for this final rule.

Some commenters suggested that, in order to achieve desired policy outcomes, we should establish equivalence values that are not strictly based on the energy content and renewable content of renewable diesel, jet fuel, and naphtha. For example, several commenters stated that we should establish higher equivalence values for renewable jet fuel to support this relatively new industry, while other commenters stated that we should establish an equivalence value of 1.5 for renewable diesel (or alternatively increase the equivalence value for biodiesel to 1.6) to provide parity in the number of RINs generated per gallon of biodiesel and renewable diesel. At this time, we do not believe it would be appropriate to deviate from our longstanding practice of calculating equivalence values in the RFS program based on the energy content and renewable content of the renewable fuel. Such a change would invite requests for higher (or lower) equivalence values to support a wide range of policy goals. We believe any such changes should only be considered holistically, and with adequate notice and opportunity for public comment.

Finally, some commenters suggested that renewable diesel, renewable jet fuel, and renewable naphtha producers should be required to regularly test the energy content of their fuel and that its equivalence value should be based on these testing results. At this time, it is unclear whether the requested regular testing is necessary to ensure that such renewable fuel production is credited appropriately. We will continue to review the available data and may consider adopting regular testing requirements in the future if data indicates that this type of testing is necessary.

B. RIN-Related Provisions

1. RIN Generation and Assignment

Since we finalized the biogas regulatory reform provisions in the Set 1 Rule, we have received a significant number of questions from stakeholders regarding when RINs for RNG must be generated and assigned. In response to these inquiries, we proposed to specify when RINs must be generated and assigned both for renewable fuel and for RNG. We are finalizing these provisions largely as proposed, with additional clarifications added in response to comments from stakeholders. For most renewable fuels (not including RNG or renewable CNG/LNG), we are specifying in 40 CFR 80.1426(f)(18) that RINs must be generated at:

- For domestic renewable fuel producers, the point of production or point of sale.
- For RIN-generating foreign producers, the point of production or when the renewable fuel is loaded onto a vessel or other transportation mode for transport to the covered location.
- For RIN-generating importers of renewable fuel, upon importation into the covered location.

We are also specifying in 40 CFR 80.1426(f)(18) that RINs for RNG and renewable fuels that are gaseous at standard temperature and pressure (STP) (*e.g.,* renewable CNG/LNG) must be generated no later than five business days after all applicable requirements for RIN generation under 40 CFR 80.125(b), 80.130(b), and 80.1426(f), as applicable, have been met. An exception would be for foreign produced RIN-less RNG, in which RINs must be generated no later than when title is transferred from the foreign producer to the RIN-generating importer.

Furthermore, we are specifying in 40 CFR 80.1426(e) that, except for renewable fuels that are gaseous at STP, RINs generated at the point of production or the point of importation into the covered location must be assigned to a volume of renewable fuel when the renewable fuel leaves the renewable fuel production or import facility, while RINs generated at the point of sale or when the renewable fuel was loaded onto a vessel or other transportation mode for transport to the covered location must be assigned prior to the transfer of ownership of the renewable fuel. We are also requiring that RINs for renewable fuels that are gaseous at STP must be assigned to a volume of renewable fuel at the same time the RIN is generated.

Several commenters expressed confusion regarding the proposed changes to 40 CFR 80.1426(e) and (f). Our intent was to improve consistency of data submissions related to RIN generation for all types of fuel, including RNG. To help clarify this intent, we are adding additional language to 40 CFR 1426(f)(18). As proposed, 40 CFR 80.1426(f)(18)(i) and (ii) clarify the RIN generation event (also known as ''fuel production date'' in EMTS), while newly added 40 CFR 80.1426(f)(18)(iii) describes when the RIN generator must submit this information via EMTS. To improve consistency, we also added additional references in 40 CFR 80.1426(f)(18)(ii) to 40 CFR 80.125 and 80.130.

The regulation at 40 CFR 80.1426(f)(18)(ii) only provides clarification on existing procedures. When the RNG producer is able to meet the applicable requirements in 40 CFR 80.125(b), 80.130(b), and 80.1426(f), the RIN generation event has occurred and the RNG producer then has 5 business days to submit this information to EMTS.

Using a hypothetical example to illustrate 40 CFR 80.1426(f)(18)(ii), an RNG producer continuously measures and injects RNG into the commercial pipeline from April 1 to April 30. The RNG producer receives the first pipeline statement on May 15 showing values from April 1 to April 15, and a second pipeline statement on June 15 covering values from April 16 to April 30. The RNG producer then combines the two statements to reflect the full calendar month of production for April. The associated biogas producer submits the monthly biogas batch in EMTS (''biogas token'') on May 31 and then transfers the biogas batch tokens in EMTS to the RNG producer, which provides necessary information on the pathway and the total volume of biogas. The RNG producer has all the required inputs for calculating the RNG batch volume described in 40 CFR 80.110(j)(4) on June 15, including the biogas batch and the pipeline injection statements. The RNG producer is now able to calculate the RNG volume from April 1 to April 30 and uses April 30 as the ''Fuel Production Date'' for purposes of RIN generation. The RNG producer then has up to five business days from June 15 to submit the RIN generation event in EMTS.

2. Renewable Fuel Used for Process Heat or Electricity Generation

This rule aims to ensure that renewable fuel producers do not generate RINs for renewable fuel used for process heat or electricity generation—and that they retire any RINs generated for renewable fuel that the producer has reason to know is used for process heat or electricity generation—as these RINs are invalid because Congress did not include such uses as qualifying under the RFS program. In the Set 2 proposal, we proposed changing the definition of heating oil to state that pure biodiesel (*i.e.,* B100) or neat biodiesel (*i.e.,* B99) used for process heat or power generation is not heating oil. After considering the comments received, we are instead finalizing a prohibition on RIN generation for fuel that is used for process heat or electricity generation, for the reasons described below and in RTC Section 11.2.2.

Additionally, in the Set 2 proposal, we referred to ''power generation'' instead of ''electricity generation'' in the context of this proposed amendment. In this final rule, we instead now refer to ''electricity generation'' to reduce ambiguity. The EPA has never allowed RINs to be generated for renewable fuel used for electricity generation under the RFS program. Indeed, the only RIN-generating use of electricity previously permitted under the RFS program was renewable electricity generated from biogas and used as transportation fuel.[298] However, under this section we use the term ''electricity generation'' to refer to the production of electrical power by a utility for generalized use by the public; it does not refer to the renewable electricity pathway described in section VII of this preamble.

a. Statutory and Regulatory History

The CAA only permits credit (*i.e.,* RIN) generation for renewable fuel, which is limited to fuel that replaces or reduces the quantity of fossil fuel present in transportation fuel, home heating oil, or jet fuel. EPAct initially limited the definition of ''renewable fuel'' to motor vehicle fuel only, and we subsequently promulgated RFS program regulations to implement Congress's mandates.[299] Separately, we initially defined heating oil as ''any #1, #2, or non-petroleum diesel blend that is sold for use in furnaces, boilers, stationary diesel engines, and similar applications and which is commonly or commercially known or sold as heating oil, fuel oil, and similar trade names, and that is not jet fuel, kerosene, or MVNRLM diesel fuel.'' [300]

In 2007, Congress added the definition of ''additional renewable fuel'' in EISA, which expanded the scope of renewable fuel qualifying for the RFS program to include home heating oil and jet fuel.[301] Process heat and electricity generation were not included in EISA's expanded qualifying uses. In 2010, we subsequently modified ''the regulatory requirements to allow RINs assigned to renewable fuel blended into heating oil or jet fuel in addition to highway and nonroad transportation fuels to continue to be valid for compliance purposes.'' [302]

Additionally, we added a second definition of heating oil in the RFS regulations in 2013 (the ''Heating Oil Rule''), which expanded the definition of heating oil to include ''[a]ny fuel oil that is used to heat or cool interior spaces of homes or buildings to control ambient climate for human comfort.'' [303] The Heating Oil Rule explicitly prohibited RIN generation on fuel oils used to generate process heat, electricity, or other functions under the newly added definition, because those fuels did not fall within the scope of ''home heating oil'' as the term is used in EISA.[304] We also stated that the first definition of heating oil would remain unaffected: ''All fuels previously included in the definition of heating oil continue to be included as heating oil under 40 CFR 80.1401 for purposes of the RFS program.'' [305] To the extent that renewable fuel producers believed that renewable fuel used for process heat or electricity generation qualified as heating oil under the first definition, this final rule clarifies that it does not.

b. Changes From the Set 2 Proposal

In the Set 2 proposal, we proposed revising the definition of heating oil under 40 CFR 80.2 to state that ''pure biodiesel (*i.e.,* B100) or neat biodiesel (*i.e.,* B99) that is used for process heat or power generation is not heating oil.'' After considering the comments we received on our proposal and the goals of this clarification, we are instead adding a new prohibited act in 40 CFR 80.1460(b) to prohibit the generation of a RIN for fuel that is used for process heat or electricity generation, except as specified in 40 CFR 80.1426(f)(12). Consistent with this change, we are also clarifying in 40 CFR 80.1431(a) that RINs generated for a prohibited act are invalid RINs.

Rather than revising the definition of heating oil to exclude only certain concentrations of biodiesel, we are instead prohibiting RIN generation on any renewable fuel that is used for

[298] As discussed in section VII of this preamble, we are removing renewable electricity as a qualifying renewable fuel under the RFS program in this action.

[299] Public Law 109–58, 119 Stat. 594, 1068.

[300] 71 FR 25706, 25716 (May 1, 2006). The reference to ''stationary diesel engines'' was removed from the definition in 40 CFR 80.2(ccc) as part of the EPA's final rule concerning oceangoing vessels. 75 FR 22896 (April 30, 2010).

[301] EISA, H.R. 6, 110th Cong., sec. 201 (2007); 42 U.S.C. 7545(o)(1)(A).

[302] 75 FR 14670, 14687 (March 26, 2010).

[303] 78 FR 62462, 62470 (October 22, 2013); 40 CFR 80.2.

[304] 78 FR 62462, 62463–64, 68 (October 22, 2013). Although the Heating Oil Rule preamble uses the word ''power,'' we are using ''electricity'' throughout this final rule to reduce ambiguity, as previously explained.

[305] *Id.* at 62463–64.

process heat or electricity generation. First, as several commenters pointed out, because the EPA has expressly stated that blends of biodiesel above B80 fall under the definition of "heating oil," it makes little sense to distinguish blends above B80 from B99 or B100. Additionally, we have decided to expand the prohibition beyond biodiesel to all renewable fuels because, although most other renewable fuels are unlikely to meet the first definition of heating oil at 40 CFR 80.2, process heat and electricity generation are not qualifying uses for the RFS program as contemplated by Congress in the CAA.

Further, we have determined that this clarification is better conveyed by adding a prohibited act, rather than changing the definition of heating oil. Adding a new prohibited act is the clearest way for the EPA to ensure that RINs are only generated for qualifying renewable fuel under the RFS program. While amending the definition of heating oil may have been one way to accomplish that goal, clarifying that the practice is "prohibited" is the most direct way of communicating this to stakeholders. Additionally, clarifying that RINs generated for a prohibited act are invalid provides a more complete picture of the consequences to stakeholders, as the existing RIN retirement regulations already state that any invalid RIN must be retired.[306]

c. Additional Clarifications

First, several commenters pointed to one of our responses in the RTC document for the Heating Oil Rule, in which we stated that the "inclusion of the new heating oil provision for fuel oils does not impact the current definition and use of biodiesel as heating oil, even where that biodiesel is used for process heat, power generation, or in stationary sources. EPA confirms that biodiesel producers can (and must) separate the RINs from wet gallons when used by the producer as heating oil or for process heat or power." [307] Commenters on the Set 2 proposal appear to have interpreted our prior response to mean that, under the first definition of heating oil, renewable fuel producers were allowed to generate RINs on biodiesel that was used for process heat or electricity generation, and that the EPA was reminding producers to separate RINs from wet gallons of biodiesel when doing so. While this errant response to comment is part of the rulemaking record, its language was not incorporated into the text of the regulation. Indeed, the interpretation of this response by commenters on the Set 2 proposal is contrary to the CAA. If Congress had intended any reduction or replacement of fossil-based fuels by renewable fuels to qualify for RIN generation, it would have either said so explicitly or refrained from specifying particular uses.

Second, we recognize that for renewable fuels meeting the first definition of heating oil, no tracking or documentation of end use is required, and some heating oils that meet the original definition could end up being used for other purposes. In the Heating Oil Rule, we explained that renewable fuel qualifying as heating oil under the first definition must have the physical or other characteristics that make it the type of fuel oil normally used to heat homes, and that products qualifying as heating oil under the second definition will be identified not by their chemical specifications but instead by their actual use to control indoor climates for human comfort.[308] As a result, we adopted registration, recordkeeping, product transfer document (PTD), and reporting requirements for fuel oils qualifying as heating oil under the second definition.

While this final rule requires renewable fuel producers to determine in good faith whether their product is eventually used for process heat or electricity generation, this does not add significant documentation burdens. Given the fungible nature of the heating oil delivery market, we understand that tracking the end use for products that fall under the first definition of heating oil would likely be sufficiently difficult and potentially expensive so as to discourage the generation of RINs. However, the PTDs accompanying fuel shipments already require the producer to designate RIN-generating renewable fuel for a qualifying use.[309] As we previously stated in the QAP Rule, "parties designating fuel for a qualifying use who know or have reason to know that the fuel would likely not be" used as such would be in violation of the regulation.[310] As an example, a renewable fuel producer that uses its own product for process heat or electricity generation will be the end user and tracking its end use will not be a significant burden. Likewise, if a renewable fuel producer sells its product to a utility company for electricity generation, that producer will be able to track the portion of the product being sold to that customer.

This final rule does not require renewable fuel producers that generate RINs immediately upon production to change their RIN generation practices. Producers of renewable fuel that falls under the first definition of heating oil are not required to track end use, so they may be more likely to generate RINs at the time of renewable fuel production. For producers that fall into this category, we are clarifying in 40 CFR 80.1431(a) that RINs generated for a prohibited act are invalid. When combined with the existing RIN retirement regulation at 40 CFR 80.1434(a)(8), this additional clarification informs producers that such RINs must be retired. As stated above, we do not anticipate that this will impose significant documentation burdens on renewable fuel producers, because as the end user themselves, they will be in a position to know the renewable fuel's final use.

Finally, this prohibition on RIN generation does not apply to de minimis or incidental volumes of renewable fuel used as heating oil in emergency backup generators for mission critical functions during power outages. We are not imposing additional documentation burdens on producers of heating oil meeting the first definition and those producers are not expected to determine whether their renewable fuel is ultimately used in backup diesel-powered generators. We also recognize the importance of such backup forms of power to mission critical functions such as hospitals and 911 call centers during power outages. Therefore, we are not requiring additional documentation for instances when a small or incidental volume of renewable fuel is ultimately used in such emergency situations.

C. Percentage Standard Equations

In the Set 2 proposal, we proposed several changes to the percentage standard equations in 40 CFR 80.1405(c), including to: (1) clarify that the volume requirements used to calculate the percentage standards for cellulosic biofuel, advanced biofuel, and total renewable fuel are based on the number of "gallon-RINs"; (2) change the BBD volume requirement to be expressed in gallon-RINs; and (3) clarify, revise, or remove certain terms of the percentage standard equations. Commenters were generally supportive of these changes, although several commenters raised concerns about our proposed change to express the BBD volume requirement in gallon-RINs instead of physical gallons. After consideration of those comments, we

[306] 40 CFR 80.1434(a)(8).

[307] EPA, "Regulation of Fuel and Fuel Additives: Modifications to Renewable Fuel Standard Program, Response to Comments," EPA–420–R–13–010, September 2013, at 13–14.

[308] 78 FR 62462, 62466 (October 22, 2013).

[309] 40 CFR 80.1453(a)(12).

[310] 79 FR 42078, 42104 (July 18, 2014).

are finalizing the changes to the percentage standard equations as proposed with minor clerical revisions to the proposed language.[311] We address the specific concerns raised by commenters in RTC Section 11.3.

First, consistent with our long-standing practice, we are clarifying that the volume requirements used to calculate the percentage standards for cellulosic biofuel, advanced biofuel, and total renewable fuel ($RFV_{CB,i}$, $RFV_{AB,i}$, and $RFV_{RF,i}$, respectively) are based on the number of ''gallon-RINs'' of each fuel, rather than simply ''gallons'' as previously specified. As described in the RFS2 Rule, we have interpreted these volume requirements as being on an energy-equivalent basis (rather than wet or physical gallons of liquid fuel) and that when the volume requirements are used to calculate the applicable percentage standards, it would be through the use of the equivalence value for RIN generation (the ''Equivalence Value'' approach).[312] This energy-equivalent basis for using the volume requirements to calculate the percentage standards is expressed through the use of gallon-RINs, and thus we believe these terms should be defined as such in the regulations.

Second, we are changing the BBD volume requirement ($RFV_{BBD,i}$) from being expressed in physical gallons to gallon-RINs, consistent with the methodology used to specify the other three renewable fuel volume requirements. Since the BBD volume requirement was first established in the RFS2 Rule, we have interpreted the statutory BBD volume requirements as being in physical gallons.[313] Thus, while the percentage standard equations for cellulosic biofuel, advanced biofuel, and total renewable fuel were established on a gallon-RINs basis, the BBD percentage standard was established on a physical gallon basis. Because the BBD standard was assumed in the RFS2 Rule to be met exclusively with biodiesel, and biodiesel generated 1.5 RINs per gallon, we applied a 1.5 multiplier (the ''BBD conversion factor'') to the BBD percentage standard equation to convert from the number of BBD physical gallons in the statutory volume requirements to the equivalent number of gallon-RINs. Since the RFS2 Rule, we have continued to use the energy-equivalent (or gallon-RIN) approach in establishing the cellulosic biofuel, advanced biofuel, and total renewable fuel volume requirement and associated percentage standards. However, the BBD volume requirement has continued to be expressed in physical gallons and then converted to a gallon-RIN equivalent in the BBD percentage standard equation by multiplying the BBD volume requirement by the BBD conversion factor (either 1.5 (from 2010–2022) or 1.6 (from 2023–2025)).

As discussed in section III of this preamble, since the promulgation of the RFS2 Rule, fuels other than biodiesel, most prominently renewable diesel, have become significant contributors to the BBD volume requirement. This increased contribution from renewable diesel to the BBD pool, along with an equivalence value of 1.7 for renewable diesel [314]—compared to an equivalence value of 1.5 for biodiesel—resulted in the average equivalence value for BBD increasing from 1.51 in 2012 to nearly 1.59 in 2022.[315] The shifting equivalence value has led to confusion among stakeholders regarding the correct way to interpret the BBD volume requirement and a perceived lack of clarity regarding how the BBD percentage standard is calculated.

Acknowledging that the BBD volume requirement is now being met with a more complex mixture of fuels than we anticipated in the RFS2 Rule, we are now revising the definition of $RFV_{BBD,i}$ to specify that the BBD volume requirement is expressed in gallon-RINs rather than physical gallons. We believe that specifying the BBD volume requirement in gallon-RINs reduces confusion among stakeholders regarding how to interpret the BBD volume requirement and how the BBD percentage standard is calculated. We acknowledge that this is a change in our approach to the BBD volume requirement. In 2010, we believed that Congress intended the BBD volume mandate to be treated as volumes rather than in terms of gallon-RINs.[316] However, Congress did not specify BBD volume requirements for any years after 2012. Subsequent experience implementing the RFS program has compelled us to revisit this interpretation, as well as the facts that the EPA has broad discretion to establish the BBD volume requirements after 2012 (based on a review of the implementation of the RFS program to date and the statutory factors) and the increasingly complex mix of renewable fuels that are used to meet the BBD volume requirement.

We now believe that the BBD volume requirement is best read as requiring BBD volumes to be specified in gallon-RINs, consistent with the other three renewable fuel categories under the RFS program. Under CAA section 211(o)(B)(i), the tables listing the statutory volume requirements for all four categories of renewable fuel (cellulosic biofuel, BBD, advanced biofuel, and total renewable fuel) specify the units as being ''in billions of gallons.'' There is no indication in the statutory text that the units of the BBD volume requirement should be treated differently than the other renewable fuel categories. The reason we gave in 2010 for differentiating BBD—that we believed the BBD volume requirements set by Congress through 2012 were best interpreted as physical gallons rather than RIN-gallons—is no longer relevant since Congress did not provide BBD volume requirements for years after 2012.

In addition, we note that there is no practical effect on regulated parties by specifying the BBD volume requirement in gallon-RINs rather than physical gallons. Whether the EPA specifies the BBD volume requirement in gallon-RINs or physical gallons, ultimately the numerator in the BBD percentage standard equation—and thus the BBD percentage standard itself—would be the same. Since 2010, obligated parties have used the BBD percentage standards to determine their BBD RVOs in gallon-RINs, rather than in physical gallons. This was clear in the multiplier (initially 1.5, revised to 1.6 for 2023–2025) used in the BBD percentage standard equation, which was unique to BBD. The purpose of this multiplier was to ensure that the percentage standards

[311] Our changes to the percentage standard formulas are limited to the changes here and in sections IV and V of this preamble that establish SRE reallocation volumes for 2026 and 2027. We have not reopened any other aspects of the percentage standard formulas, including the factors that project exempt volumes of gasoline and diesel due to small refinery exemptions.

[312] 75 FR 14709–10, 16–18 (March 26, 2010).

[313] In the RFS2 rule, we stated that ''we are finalizing the energy content approach to Equivalence Values for the cellulosic biofuel, advanced biofuel, and total renewable fuel standards. However, the biomass-based diesel standard is based on the volume of biodiesel. In order to align both of these approaches simultaneously, biodiesel will continue to generate 1.5 RINs per gallon as in RFS1, and the biomass-based diesel volume mandate from EISA is then adjusted upward by the same 1.5 factor.'' 75 FR 14716 (March 26, 2010).

[314] While we acknowledge that we are revising the specified equivalence value for renewable diesel from 1.7 to 1.5 in this action, our decision here to specify the BBD volume requirement in gallon-RINs rather than physical gallons is independent from our decision to revise the equivalence value for renewable diesel. In addition, we expect that many renewable diesel producers will petition for a greater equivalence value, as discussed in section VIII.A of this preamble.

[315] For additional discussion of the BBD conversion factor, see our discussion on this topic in the Set 1 Rule in which we revised the BBD conversion factor from 1.5 to 1.6. 88 FR 44545–47 (July 12, 2023).

[316] 75 FR 14710 (March 26, 2010).

represented obligations in gallon-RINs rather than physical gallons.

Were we to still specify the BBD volume requirement in physical gallons, we would first determine the intended increase in the BBD volume requirement in RINs and then divide by 1.6 to calculate the necessary BBD volume requirement in physical gallons. This conversion would then be reversed in the numerator of the BBD percentage standard equation, where the BBD physical gallon volume requirement would be multiplied by 1.6 to convert from physical gallons back to RINs. Ultimately, the BBD volume requirement is simply an input into the BBD percentage standard equation, not a standalone or otherwise enforceable requirement itself. By specifying the BBD volume requirement in gallon-RINs in the first place, we avoid a confusing and unnecessary step in the calculation of the BBD percentage standard (*i.e.,* the requirement with which obligated parties actually have to comply) and ensure consistency with the other three renewable fuel categories.

Consistent with this clarification, we are also revising the BBD percentage standard to remove the 1.6 conversion factor. By specifying the BBD volume requirement in gallon-RINs, the BBD conversion factor is no longer necessary to convert from physical gallons of BBD to gallon-RINs. This also eliminates the need to track the average equivalence value of BBD to adjust the BBD conversion factor in the future. For example, we recently revised from 1.5 to 1.6 in the Set 1 Rule due to increased production volumes of renewable diesel relative to biodiesel; [317] such adjustments will no longer be necessary.

We are also removing the terms GS_i, DS_i, RGS_i, and RDS_i from the percentage standard equations. These terms relate to the use of gasoline, diesel, and renewable fuels contained in gasoline and diesel in Alaska or a U.S. territory if the State or territory opts into the RFS program. However, if Alaska or a U.S. territory were to opt into the RFS program in the future, we would instead account for gasoline, diesel, and renewable fuel use in the State or territory under the existing G_i, D_i, RG_i, and RD_i terms. These terms refer to the amounts of gasoline, diesel, or renewable fuel used in gasoline or diesel in the covered location, which is defined as ''the contiguous 48 states, Hawaii, and any state or territory that has received an approval from the EPA to opt-in to the RFS program under § 80.1443.'' [318] Thus, there is no need to have separate terms in the percentage standards just for Alaska or a U.S. territory that opts into the RFS program in the future.

Finally, we are revising the definitions of RG_i and RD_i (the projected amounts of renewable fuel in gasoline and diesel, respectively) to clarify that these projections are for the amounts of renewable fuel contained within the projections of G_i and D_i themselves (the amounts of gasoline and diesel, respectively, projected to be used in the U.S.), rather than a projection of the absolute amount of renewable fuel contained in gasoline and diesel. While the EIA projections that the EPA uses to calculate the percentage standards have historically contained some volume of renewable fuel (*e.g.,* ethanol in gasoline, biodiesel and renewable diesel in diesel), EIA has recently changed their STEO projection methodology to provide separate projections of petroleum-based distillate and renewable fuels blended into distillate (*e.g.,* biodiesel and renewable diesel). Thus, were we to use these projections to calculate the percentage standards, we would use the petroleum-based distillate projection for D_i and a value of zero for RD_i, as the D_i projection does not contain any renewable fuel.[319] We believe this clarification makes clear how we would calculate the percentage standards under this potential future scenario.

D. Renewable Fuel Pathways

In the Set 2 proposal, we proposed changes to the table of approved renewable fuel pathways in order to clarify the parameters for certain pathways. In particular, we proposed to revise references to ''any'' in the production process requirements of table 1 to 40 CFR 80.1426 (hereinafter ''Table 1'') with more precise descriptions. These revisions are intended to more accurately describe the production processes that we evaluated when we approved these pathways as satisfying the statutory requirements for lifecycle emissions reductions. In the Set 2 proposal, we also proposed to add biogenic waste fats, oils, and greases as a feedstock for producing renewable naphtha and liquefied petroleum gas (LPG). In this action, we are finalizing many of the proposed changes with modifications based on our consideration of the public comments.

Table 1 lists generally applicable fuel pathways that have been approved for the RFS program. Fuel producers that produce fuel through a pathway (*i.e.,* a unique combination of a fuel, feedstock, and production process) described in Table 1 may submit a registration application to the EPA.[320] Table 1 lists an applicable RIN D code for each approved pathway based on the statutory criteria, including the type of fuel produced, the feedstock used to produce the fuel, and whether it satisfies the statutory 20 percent, 50 percent, or 60 percent lifecycle emissions reduction threshold. In section VIII.D.1 of this preamble, we are finalizing clarifications to the parameters of certain pathways in Table 1. In section VIII.D.2 of this preamble, we are finalizing the addition of pathways to Table 1 for naphtha and LPG produced from biogenic waste fats, oils, and greases. These amendments to Table 1 are summarized in Table VIII.D–1.[321] We are finalizing these changes largely as proposed, but with certain modifications based on our consideration of the comments.

[317] 88 FR 44545–47 (July 12, 2023).

[318] 40 CFR 80.2.

[319] Note that the percentage standards in this action are calculated using projections from AEO2025, which does include renewable fuels in its projections of gasoline and distillate.

[320] Note that an individual row in Table 1 can include multiple fuel pathways.

[321] The reasons for these regulatory amendments are described in section X.D of the Set 2 proposal (90 FR 25845–49; June 17, 2025).

Table VIII.D-1: Summary of Amendments to Renewable Fuel Pathways

Row in Table 1 to 40 CFR 80.1426	D Code	Summary of Amendments in This Action
I	5	Add "biogenic waste oils/fats/greases" feedstock.
K	3	Replace "any process" with specific production processes.
L	7	Replace "any process" with specific production processes; Move purpose-grown crop feedstocks to Row U.
M	3	Replace "any process" with specific production processes; Move purpose-grown crop feedstocks to Row N.
N	3	Add additional fuels and purpose-grown crop feedstocks; Add direct biochemical conversion as a process and associated conditions.
P	5	Replace "any process" with specific production processes.
Q	3	Replace "any process" with specific production processes.
T	5	Replace "any process" with specific production processes.
U	7	New row with purpose-grown crop feedstocks and production processes.

1. Table 1 Pathways That Include ''Any'' Production Process

In addition to requiring that renewable fuel be produced from renewable biomass and used to reduce or replace the quantity of fossil fuel in transportation fuel,[322] the CAA also requires that qualifying biofuels meet the lifecycle emissions reduction threshold specified for the applicable category of renewable fuel.[323] The CAA further requires the EPA to determine the lifecycle emissions for renewable fuels.[324] We have evaluated the lifecycle emissions associated with a wide range of fuel pathways and listed those pathways that satisfy the statutory emissions reduction criteria and other statutory criteria in Table 1. To do so, we evaluate particular feedstocks that are put through particular production processes to produce particular fuels. Thus, an approved pathway in Table 1 signifies that we have determined that the specific combination of elements we evaluated—feedstock, process, and fuel—meets the applicable lifecycle emissions reduction threshold.

For certain pathways that were promulgated in the RFS2 Rule, we believed, based on the fuel production process data available at the time, that the use of any process would result in emissions for the resulting fuel that meet the applicable lifecycle emissions reduction threshold.[325] However, since that time, we have observed the emergence and development of fuel production processes that vary from those assumed in the original lifecycle assessments underlying the approved pathways in Table 1. These developments have resulted in processes that differ much more than we anticipated was possible in the RFS2 Rule. Indeed, some of the fuel production processes that parties are now interested in registering under ''any'' pathways bear little resemblance to the processes we evaluated as the basis for including a given pathway in Table 1. In some cases, the lifecycle emissions performance of such new processes may be significantly worse than the processes we analyzed in the RFS2 Rule or the notional processes we anticipated might be developed in the future. These new processes may therefore not meet the applicable statutory lifecycle emissions reduction threshold. For example, we have received petitions for thermochemical cellulosic biofuel production technologies that would use a large amount of conventional natural gas and grid electricity per unit of fuel produced, whereas our 2010 analysis assumed that this type of process would use practically zero fossil fuel or grid electricity, relying instead on combustion of char, coke, and syngas derived from the cellulosic renewable biomass feedstock for process energy.[326]

Given the possibility that some pathways nominally fitting the description in Table 1 might not actually meet the corresponding statutory lifecycle emissions reduction requirement, we believe it is inappropriate to continue listing ''any'' production process under certain approved pathways in Table 1. Therefore, we are finalizing changes to clarify certain approved pathways in Table 1 by replacing the ''any'' terminology with more precise language that reflects the fuel production processes that we have determined satisfy the applicable lifecycle emissions reduction thresholds.

Specifically, to further clarify the scope of approved pathways in Table 1, we are replacing the term ''any'' with more precise language in the production technology requirements column of Rows K, L, M, P, Q, and T. Previously, Rows K and L listed the production process requirements as ''Any process that converts cellulosic biomass to fuel,'' Row M included ''any process utilizing biogas and/or biomass as the only process energy sources which

[322] CAA section 211(o)(1)(J).

[323] CAA sections 211(o)(1)(B), (D), (E); 211(o)(2)(A)(i).

[324] CAA section 211(o)(1)(H).

[325] *See, e.g.,* our discussion of ''assessments of similar feedstocks sources'' at 75 FR 14792–14797 (March 26, 2010).

[326] See Table 2.4–59 of the RFS2 Rule RIA (EPA–HQ–OAR–2021–0427–0115) (March 26, 2010).

converts cellulosic biomass to fuel,'' and Rows P, Q, and T listed the production process requirements as ''Any.'' As discussed below, we are replacing some or all of the current language in each of these rows with a description of the production process and associated parameters that we evaluated for the corresponding lifecycle assessment and that we determined meet the applicable lifecycle emissions reduction threshold. Furthermore, we are making related changes to Row N and adding a new Row U so that the full set of previously evaluated and approved pathways are listed in Table 1. Renewable fuel production facilities that do not satisfy the production process requirements in Table 1 may petition the EPA pursuant to 40 CFR 80.1416 to request our evaluation of the lifecycle emissions associated with their fuel.

As discussed further in section VIII.D.1.h of this preamble, we are adding two provisions in the regulations at 40 CFR 80.1426(f)(1) to clarify the implementation of pathways in Table 1. First, we are adding a paragraph to clarify that the amendments to Table 1 in this action do not affect renewable fuel producers with an existing pathway registration. Second, we are adding a paragraph that specifies the criteria the EPA applies to determine whether a feedstock, fuel, or production process qualifies for an approved pathway in Table 1.

Stakeholders provided comments on these proposed changes. Some commenters were neutral and provided specific recommendations for modifying the proposed changes to Rows Q and T. One commenter was generally opposed to the changes, saying they were unnecessary, but did not provide specific reasons. Other commenters questioned the need for changes to specific rows, and in some cases these comments recommended specific alternatives. We discuss some of these specific comments and our response in the subsections below, and more detail is contained in RTC Section 11.4.1.

a. Row K

Row K includes pathways for ethanol produced from certain cellulosic feedstocks to qualify for D3 RINs. We are finalizing revisions to Row K as proposed but with modifications based on consideration of comments and further review of the processes that we evaluated in prior RFS rulemakings. As proposed, we are revising Row K to specify that the approved production processes include biochemical conversion, thermochemical conversion, and dry mill processes that satisfy certain conditions. In response to comments that requested additional clarity, we are modifying the proposed text in Row K that specifies the production process requirements, and we are describing these processes in more detail in this section. Below, we describe the production processes evaluated and the associated criteria specified for each of these production processes in Row K.

Biochemical conversion refers to processes that involve the fermentation, or other biological conversion, of sugars liberated from the breakdown of cellulosic biomass. A biochemical conversion process to produce ethanol from cellulosic biomass includes the following main steps: feedstock pretreatment, hydrolysis, saccharification, fermentation, dehydration, and lignin recovery.[327] Feedstock physical pretreatment involves reducing the feedstock's particle size by grinding, shredding, or chopping. Following physical pretreatment, the feedstock undergoes chemical pretreatment, enzymatic hydrolysis, and saccharification to break down the cellulose and hemicellulose into simple sugars such as glucose and xylose. Chemical pretreatment and hydrolysis include treating the feedstock with hot water, dilute acid, alkaline, organic solvent, ammonia, sulfur dioxide, carbon dioxide, or other chemicals to make the biomass more digestible by enzymes. Saccharification breaks down the polysaccharides into simple sugars via enzymatic or acidic methods. The resulting sugars are then fermented to ethanol with yeast, nutrients, and enzymes. Following fermentation, the mixture undergoes dehydration to remove water, carbon dioxide, and other materials. Biochemical conversion processes are unable to produce fuel from the lignin portion of cellulosic biomass feedstocks. During the processing steps described above, the lignin portion of the renewable biomass is isolated for combustion. The biochemical conversion processes we evaluated for this pathway combust the lignin onsite to provide all the thermal and electrical process energy needs for fuel production processes at the facility.

We are specifying in Row K that the biochemical conversion process must use lignin from the renewable biomass feedstock (*i.e.,* the feedstock(s) listed in Row K) to provide all thermal and electrical process energy. For example, this means that a biochemical conversion process using corn stover feedstock must combust the lignin that remains after the cellulose and hemicellulose portions of the corn stover are converted to ethanol to provide heat and power for all the fuel production processes at the facility, such that no grid electricity or other fuels are purchased to supply heat and power for these processes. We have determined that these process requirements are necessary to ensure that the pathways in Row K conform with the biochemical conversion processes that we evaluated and determined satisfy the statutory criteria for cellulosic biofuel.

Thermochemical conversion refers to processes that break down cellulosic biomass into intermediates using heat and then upgrade the intermediates to transportation fuel. A thermochemical conversion process to produce ethanol from cellulosic biomass includes the following main steps: feedstock pretreatment, gasification, syngas cleanup and conditioning, fuel synthesis, and separation.[328] Feedstock pretreatment includes drying and particle size reduction for proper feeding into the gasifier. The biomass is gasified to syngas with an exothermic partial oxidation (directly heated) gasifier or an indirect gasifier using steam and heat transfer. The syngas cleanup and conditioning step involves removing impurities such as tar, sulfur, nitrogen oxides, alkali metals, and particulates. The syngas conditioning step includes sulfur polishing to remove trace levels of hydrogen sulfide and water-gas shift to adjust the final ratio of hydrogen to carbon monoxide. The clean syngas, comprised of carbon monoxide and hydrogen, is converted to ethanol through either a catalytic process or a fermentation process. During the alcohol separation step, ethanol, methanol, and other alcohols are separated with molecular sieves or distillation. The gasification step produces char and coke solid byproducts that are combusted to provide heat and power for the process. Unreacted gases and slipstreams of syngas from the gas conditioning through separation stages can also be combusted to provide process energy. The thermochemical conversion processes that we evaluated for this pathway combust the char, coke, and syngas onsite to provide all the thermal

[327] For additional information on the processes the EPA evaluated, see: 75 FR 14782 (March 26, 2010); RFS2 Rule RIA at 101–107 and 433–435; and Tao and Aden (2009) (Docket Item No. EPA–HQ–OAR–2005–0161–0844).

[328] For additional information on the processes the EPA evaluated, see: 75 FR 14782 (March 26, 2010); RFS2 Rule RIA at 107–111 and 433–435; and Aden (2009) (Docket Item No. EPA–HQ–OAR–2005–0161–3034).

and electrical process energy needs for fuel production processes at the facility.

We are specifying in Row K that the thermochemical conversion process must use char, coke, or syngas derived from the renewable biomass feedstock (*i.e.,* the feedstock(s) listed in Row K) to provide all thermal and electrical process energy. For example, this means that a thermochemical conversion process using corn stover feedstock must combust the char, coke, or syngas byproducts from gasification of the corn stover to provide heat and power for all the fuel production processes at the facility, such that no grid electricity or other fuels are purchased to supply heat and power for these processes. We have determined that these process requirements are necessary to ensure that the pathways in Row K conform with the thermochemical conversion processes that we evaluated and determined satisfy the statutory criteria for cellulosic biofuel.

Dry mill crop residue conversion refers to the conversion of the cellulosic crop residue portion of grain ethanol feedstocks at a dry mill ethanol plant via in-situ or offline technologies. A dry mill ethanol production process to produce ethanol from cellulosic biomass includes the following main steps: grinding, pretreatment, fermentation, distillation, and dehydration.[329] Grain feedstocks are milled into a coarse flour known as meal. The meal is pretreated (*e.g.,* cooking, liquefaction, hydrolysis) with the addition of water and enzymes to produce a mixture called mash. The mash is fermented with the addition of yeast, nutrients, and enzymes to produce ethanol, carbon dioxide, and solids from the grain and yeast, known as fermented mash. The fermented mash is distilled to produce a mixture of ethanol and water, and a residue of non-fermentable solids known as stillage. The mixture of ethanol and water is dehydrated to produce 200-proof ethanol. Co-products from the dry mill process include distillers grains, and may also include carbon dioxide, solubles syrup, and distillers oil. Grain feedstocks often have a fiber layer on the outside of the kernel that is predominantly composed of cellulosic biomass. We have determined that this fibrous layer on the outside of grain feedstocks (*i.e.,* barley, corn, oats, rice, rye, grain sorghum, and wheat) qualify as crop residue.[330] While this fiber traditionally ends up in the stillage and is sold with the distillers grains as animal feed, additional ethanol can be produced by converting the kernel fiber to ethanol via in-situ or offline technologies. In-situ technologies perform the fiber and starch conversion simultaneously with minimal changes to the traditional ethanol process; these processes involve pretreatment of the stillage and the addition of specialized enzymes. Offline processes perform the fiber conversion separately from the starch conversion; these processes involve separate process trains to pretreat the stillage and then ferment the fiber portions. The dry mill crop residue conversion processes that we evaluated for this pathway use natural gas, biogas, or crop residue for all thermal process energy.

We are specifying in Row K that the dry mill crop residue conversion process must use natural gas, biogas, or crop residue for all thermal process energy. Thermal process energy refers to heat energy needed for all the processes at dry mill ethanol plants that are associated with ethanol and distillers grains production. The dry mill processes that we evaluated also use grid electricity to satisfy electrical process energy needs. We have determined that these process requirements are necessary to ensure that the pathways in Row K conform with the dry mill crop residue conversion processes that we evaluated and determined satisfy the statutory criteria for cellulosic biofuel.

b. Row L

Row L includes pathways for cellulosic diesel, cellulosic jet fuel, and cellulosic heating oil produced from certain cellulosic feedstocks to qualify for D7 RINs. We proposed to leave the feedstocks in Row L unchanged and revise the production process requirements from ''Any process that converts cellulosic biomass to fuel,'' to ''Fischer-Tropsch process that converts cellulosic biomass to transportation fuel or heating oil; only includes processes that use a portion of the feedstock for over 99% of thermal and electrical process energy.'' We are finalizing more substantial revisions to Row L than proposed based on consideration of comments and further review of the processes that we evaluated in prior RFS rulemakings.

One commenter stated that Row L should not be limited to Fischer-Tropsch conversion processes. Upon further review, we agree with this commenter as we have previously evaluated several other production processes (*i.e.,* the set of production processes included in Row M) to produce cellulosic diesel from corn stover and determined that these pathways satisfy the 60 percent lifecycle emissions reduction threshold. Thus, we are finalizing a broader set of process technologies in Row L that matches the set of technologies included in Row M. To include this broader set of process technologies in Row L while ensuring the fuels produced satisfy the statutory criteria for lifecycle emissions, we are also revising the set of feedstocks included in Row L. Specifically, we are removing purpose-grown crop feedstocks from Row L and moving them to a new Row U and pairing them with a more limited set of production processes.[331] We are moving the purpose-grown crop feedstocks because they are associated with emissions related to crop production (*e.g.,* fertilizer application, feedstock harvesting) that are not present for the other feedstocks in Row L, which are residue and waste feedstocks. In this section, we describe the finalized pathways in Row L and the associated criteria for each of the specified production processes.

In the RFS2 Rule and the Pathways I Rule, we evaluated biochemical and thermochemical processes that convert lignocellulosic feedstocks to hydrocarbon fuels such as renewable diesel, gasoline, and jet fuel. We found that hydrocarbon fuels produced from cellulosic feedstocks qualify for the 60 percent lifecycle emissions reduction criteria when certain criteria are satisfied. Below, we describe the production processes evaluated and the associated criteria specified for each of these production processes in Row L.

Thermochemical conversion refers to processes that break down cellulosic biomass into intermediates using heat and then upgrade the intermediates to transportation fuel. Gasification is a thermochemical process that partially combusts biomass and makes syngas intermediate. Pyrolysis is a thermochemical process that heats biomass under high temperature and pressure in the absence of oxygen and makes bio-oil intermediates. Gasification processes can convert cellulosic biomass to ethanol or hydrocarbons, whereas pyrolysis is used to produce hydrocarbons.

A gasification and upgrading process to produce hydrocarbon fuels from cellulosic biomass includes the following main steps: feedstock pretreatment, gasification, syngas cleanup and conditioning, fuel

[329] For additional information on the processes the EPA evaluated, see: 79 FR 42145–51 (July 18, 2014).

[330] 79 FR 42150–42151 (July 18, 2014).

[331] Row U is discussed in section VIII.D.1.e of this preamble.

synthesis, upgrading, and separation.[332] Feedstock pretreatment includes drying and particle size reduction for proper feeding into the gasifier. The biomass is gasified to syngas with an exothermic partial oxidation (directly heated) gasifier or an indirect gasifier using steam and heat transfer. The syngas cleanup and conditioning step involves removing impurities such as tar, sulfur, nitrogen oxides, metals, and particulates. The syngas conditioning step includes polishing to remove hydrogen sulfide and water-gas shift to adjust the final ratio of hydrogen to carbon monoxide. A slipstream of clean syngas is sent to a pressure swing adsorption unit to provide hydrogen for downstream hydroprocessing. The cleaned and water-shifted syngas is sent to a reactor (*e.g.,* Fischer-Tropsch) where the carbon monoxide and hydrogen are reacted over catalyst creating a synthetic crude oil (''syncrude''). The syncrude from the reactor is sent to a distillation column where it is separated into various hydrocarbon fuels such as naphtha, distillates, and wax, and the heavier compounds can be hydrocracked to maximize the production of diesel. The wax undergoes hydroprocessing to upgrade it to fuel-range-material, and diesel fuel is often finished with a hydrotreating step. The gasification step produces char and coke byproducts that are combusted to provide heat and power for the process. Unreacted gases and slipstreams of syngas from the gas conditioning through separation stages can be combusted to provide process energy. The thermochemical conversion processes that we evaluated for this pathway combust the char, coke, and syngas onsite to provide all the thermal and electrical process energy needs for fuel production processes at the facility.

A pyrolysis and upgrading process to produce hydrocarbon fuels from cellulosic biomass includes the following main steps: feedstock pretreatment, pyrolysis, upgrading, separation, and distillation.[333] The feedstock pretreatment step includes biomass drying and size reduction and normalization. The biomass is fed to the pyrolysis reactor where it is rapidly heated in the absence of oxygen and thermally decomposed to pyrolysis vapor, water vapor, non-condensable product gases, char, coke, and ash. The pyrolysis vapor is cooled and condensed to liquid bio-oil. The bio-oil is upgraded via hydroprocessing with the addition of hydrogen to remove oxygen, sulfur, nitrogen, olefins, and metals. The upgraded bio-oil is separated into off-gas, wastewater, and stabilized oil streams. The stabilized oil is distilled into gasoline, diesel, and other hydrocarbon products. This pyrolysis step generates char, coke, and product gas that can be combusted to provide process energy. The pyrolysis and upgrading processes that we evaluated for this pathway combust the char, coke, and product gas onsite to provide all the thermal and electrical process energy needs for fuel production processes at the facility, other than the use of natural gas to produce hydrogen via steam methane reforming for the upgrading step. The pyrolysis and upgrading processes that we evaluated consume no more than 0.5 Btu of natural gas per Btu of finished fuel.

A biochemical conversion and upgrading process to produce hydrocarbon fuels from cellulosic biomass includes the following main steps: feedstock pretreatment, hydrolysis, and aqueous phase catalytic reforming to selectively upgrade intermediates to liquid hydrocarbon fuels.[334] Feedstock pretreatment involves drying and size reduction by grinding, shredding, or chopping. Following pretreatment, the feedstock undergoes hydrolysis to break down the cellulose and hemicellulose into aqueous intermediates including simple sugars and platform chemicals derived from these sugars. The aqueous phase catalytic reforming step is a form of upgrading to convert sugars into hydrocarbon fuels. This form of upgrading requires hydrogen as an input and involves substantial chemical transformations and multiple reactions involving oxygen removal (*e.g.,* dehydration, hydrogenation, hydrogenolysis) combined with carbon-to-carbon coupling (*e.g.,* aldol condensation, ketonization, oligomerization). Biochemical conversion processes are unable to produce fuel from the lignin portion of cellulosic biomass feedstocks. During the processing steps described above, the lignin portion of the renewable biomass is isolated for combustion. The biochemical conversion and upgrading processes that we evaluated for this pathway combust the lignin onsite to provide all the thermal and electrical process energy needs for fuel production processes at the facility, other than natural gas needed to produce hydrogen for upgrading. The biochemical conversion and upgrading processes that we evaluated consume no more than 0.5 Btu of natural gas per Btu of finished fuel.

A direct biochemical conversion process to produce hydrocarbon fuels from cellulosic biomass includes the following main steps: feedstock pretreatment, hydrolysis, saccharification, fermentation with enhanced microorganisms, and lignin recovery. The process is similar to the biochemical conversion to ethanol process, with the major difference being that the fermentation step utilizes organisms enhanced through synthetic biology to produce hydrocarbons instead of ethanol. Direct biochemical conversion processes are unable to produce fuel from the lignin portion of cellulosic biomass feedstocks. During the processing steps described above, the lignin portion of the renewable biomass is isolated for combustion. The direct biochemical conversion processes we evaluated for this pathway combust the lignin onsite to provide all the thermal and electrical process energy needs for fuel production processes at the facility.

We are specifying in Row L the following feedstocks: crop residue; slash, pre-commercial thinnings, and tree residue; separated yard waste; biogenic components of separated MSW; and cellulosic components of separated food waste. We are specifying in Row L the following production processes that use lignin, char, or syngas derived from the renewable biomass feedstock to provide all the thermal and electrical process energy: gasification and upgrading; and direct biochemical conversion. We are also specifying in Row L the following production processes that use lignin, char, or syngas derived from the renewable biomass feedstock to provide all the thermal and electrical process energy other than natural gas to produce hydrogen for upgrading (maximum 0.5 Btu of natural gas per Btu of finished fuel): pyrolysis and upgrading; and biochemical conversion and upgrading. We have determined that these process requirements are necessary to ensure that the pathways in Row L conform with the processes that we evaluated and determined satisfy the statutory criteria for cellulosic biofuel.

Relative to the revisions proposed for Row L, we are finalizing a broader set of production processes and a narrower set of feedstocks. We analyzed the

[332] For additional information on the processes the EPA evaluated, see: 75 FR 14782 (March 26, 2010); 78 FR 14208 (March 5, 2013); RFS2 Rule RIA at 101–113 and 433–435; and Davis (2009) (Docket Item No. EPA–HQ–OAR–2005–0161–3035).

[333] For additional information on the processes the EPA evaluated, see: 78 FR 14208–09 (March 5, 2013); RFS2 Rule RIA at 112; and Kinchin (2011) (Docket Item No. EPA–HQ–OAR–2011–0542–0007).

[334] For additional information on the processes the EPA evaluated, see: 78 FR 14209–10 (March 5, 2013).

lifecycle emissions associated with renewable fuel produced from corn stover and switchgrass via each of the production processes described above.[335] We determined that when corn stover is used as feedstock, these pathways satisfy the 60 percent lifecycle emissions reduction criteria to qualify as cellulosic biofuel. However, when switchgrass is used as feedstock, not all the production processes listed in Row L would satisfy the 60 percent lifecycle emissions reduction criteria. We extended the corn stover estimates to other waste and residue feedstocks, and we extended the switchgrass estimates to other purpose-grown crop feedstocks including other energy grasses and annual cover crops. These revisions clarify the eligible pathways in Row L. As mentioned above, we are moving the purpose-grown crop feedstocks to a new Row U, which includes a narrower set of production processes.

c. Row M

Row M includes pathways for renewable gasoline, renewable gasoline blendstock, and co-processed cellulosic diesel, jet fuel, and heating oil produced from certain cellulosic feedstocks to qualify for D3 RINs. These pathways were originally evaluated and approved as part of the Pathways I Rule.[336] The production process requirements listed in Row M were not described as ‘‘any’’ production process, but they were listed without a great deal of specificity. We are finalizing the revisions to Row M as proposed but with modifications based on consideration of comments and further review of the processes that we evaluated in prior RFS rulemakings.

In response to comments that requested additional clarity, we are modifying the production process requirements in Row M to provide additional specificity. For example, the revisions clarify that the approved gasification and upgrading and direct biochemical conversion processes do not use any fossil fuels for process energy, whereas the pyrolysis and upgrading and biochemical conversion and upgrading processes can use up to a specific amount of natural gas to produce hydrogen for upgrading per unit of fuel produced. These revisions align the production process requirements in Row M with the production processes that we evaluated and approved in the Pathways I Rule.[337]

We are also moving ‘‘cellulosic components of annual cover crops’’ from Row M to Row N. As discussed in section VIII.D.1.b of this preamble, when we evaluated hydrocarbon fuels produced from switchgrass through the pyrolysis and upgrading and biochemical conversion and upgrading processes, we found that these pathways did not satisfy the 60 percent lifecycle emissions reduction criteria. We extended the switchgrass estimates to other purpose-grown crop feedstocks because they are associated with emissions related to crop production (*e.g.,* fertilizer application, feedstock harvesting) that are not present for the other feedstocks in Row L. Thus, as discussed in section VIII.D.1.d of this preamble, to further align the pathways approved under Row M with our prior evaluations, we are moving ‘‘cellulosic components of annual cover crops’’ to Row N.

After these modifications, the production process requirements and feedstocks for Rows L and M are now the same. See section VIII.D.1.b of this preamble for further discussion of the production processes and feedstocks approved under Rows L and M and the reasons for the revisions in this action.

d. Row N

Row N currently includes pathways for naphtha produced from switchgrass and other energy grasses through a gasification and upgrading process to qualify for D3 RINs.[338] As discussed in section VIII.D.1.c of this preamble, we also previously determined that a wider range of hydrocarbon fuels (*e.g.,* renewable gasoline, co-processed cellulosic diesel) produced from specific energy grasses or the cellulosic components of annual cover crops produced through a gasification and upgrading process or a direct biochemical conversion satisfies the 60 percent lifecycle emissions reduction criteria provided that specific production process requirements are met.[339] In this action, we are moving specific feedstocks from Row M to Row N to ensure that the correct pairings of fuels, feedstocks, and production processes qualify for D3 RINs based on our prior lifecycle analyses. We are also adding fuels to Row N to ensure that the complete set of pathways that we previously determined satisfy the statutory criteria are listed in Table 1. We did not receive any comments opposing these amendments.

e. Row U

As discussed in section VIII.D.1.b of this preamble, we are moving specific pathways from Row L to a new Row U to ensure that the correct pairings of fuels, feedstocks, and production processes qualify for D7 RINs based on our prior lifecycle analyses. Specifically, Row U includes pathways for the production of cellulosic diesel, renewable jet fuel, and heating oil from specific energy grasses and cellulosic components of annual cover crops through gasification and upgrading or direct biochemical conversion that uses lignin, char, coke, or syngas derived from the renewable biomass feedstock to provide all thermal and electrical process energy. We previously evaluated these pathways in the RFS2 Rule and the Pathways I Rule and determined that they satisfy the statutory criteria for D7 RINs.[340] We are creating Row U to ensure that the complete set of pathways that we previously determined satisfy the statutory criteria are listed in Table 1. We did not receive any comments opposing these amendments.

f. Row P

We are finalizing the revisions to Row P as proposed for the reasons described in the Set 2 proposal.[341] Specifically, we are revising the production processes in Row P to include: fermentation using natural gas, biogas, or crop residue for thermal energy; hydrotreating; and transesterification.[342] We did not receive any comments opposing these amendments.

g. Rows Q and T

Rows Q and T include pathways for renewable CNG/LNG produced from biogas. Row Q includes pathways for D3 RINs for renewable CNG/LNG produced from: biogas from landfills, municipal wastewater treatment facility digesters, agricultural digesters, and separated MSW digesters; and biogas from the cellulosic components of biomass processed in other waste digesters. The pathways in Row Q qualify for D3 RINs. Row T includes pathways for D5 RINs

[335] For additional information on the EPA’s analysis of the emissions associated with producing and transporting these feedstocks, see: 75 FR 14791–95 (March 26, 2010); and RFS2 Rule RIA Section 2.4.

[336] 78 FR 14205–13 (March 5, 2013).

[337] *Id.*

[338] The current pathways in Row N were approved based on the evaluation described at 78 FR 14208 (March 5, 2013).

[339] 78 FR 14205–13 (March 5, 2013).

[340] For additional information on the gasification and upgrading pathways, see: 75 FR 14782 (March 26, 2010) and 78 FR 14208 (March 5, 2013). For additional information on the direct biochemical conversion pathways, see: 78 FR 14210 (March 5, 2013).

[341] 90 FR 25848 (June 17, 2025).

[342] For background on the EPA’s evaluation of these pathways, see: 75 FR 14792–95 (March 26, 2010); and RFS2 Rule RIA Section 2.4.

for renewable CNG/LNG produced from biogas from waste digesters.[343]

We are finalizing changes to Rows Q and T with revisions relative to what we proposed based on our consideration of the comments. In the production process requirements for Rows Q and T, we proposed to replace ''Any'' with ''The following processes that occur in North America: CNG production from treated biogas via compression; LNG production from treated biogas via liquefaction.'' Commenters stated that it could be problematic to reference the fuels (CNG/LNG) in the production process requirements, and that CNG/LNG can also be produced from biogas and RNG. Based on our consideration of these comments, we are describing the production processes as ''Treatment and compression'' and ''Treatment and liquefaction.'' Based on our consideration of comments, we are also replacing the condition that the production processes ''occur in North America'' with a condition that the production process ''do[es] not transport RNG or renewable CNG/LNG by ocean-going vessel.'' These modifications are discussed below.

Treatment and compression refers to the process of upgrading biogas to RNG and subsequent compression to produce renewable CNG for use in CNG vehicles. Treatment and liquefaction refers to the process of upgrading biogas to renewable LNG for use in LNG vehicles. Treatment begins with moisture and particulate removal from raw biogas, followed by advanced cleaning technologies that remove carbon dioxide, non-methane organic compounds and a variety of other contaminants including sulfur compounds. Treatment technologies include the use of pressure swing adsorption, water scrubbing, chemical absorption, membrane separation, or other technologies to remove additional components so the gas is suitable for injection into the natural gas commercial pipeline system. The RNG is then transported and distributed to refueling stations via the natural gas pipeline system, or potentially in a tube as compressed gas or liquefied in a tank. Final compression or liquefaction of the RNG at a refueling station depends on how the gas will be used as a vehicle fuel. Compression is the physical compression of RNG to produce renewable CNG, while liquefaction is the physical conversion of RNG into a liquid state by cooling it to low temperatures to produce renewable LNG.

As noted above, a commenter disagreed with the proposed condition limiting the processes in Rows Q and T to ''processes that occur in North America.'' In the Set 2 proposal, we explained that this condition was appropriate because there could be CNG/LNG transportation and distribution scenarios associated with high GHG emissions that we did not consider in the lifecycle analyses that formed the basis for Rows Q and T. We specifically discussed long-duration LNG transportation with associated boil-off emissions as a scenario that the underlying evaluation for Rows Q and T did not consider; we estimated that transporting LNG is associated with boil-off emissions of approximately 0.10 to 0.15 percent per day.[344] Pursuant to the definition of ''lifecycle greenhouse gas emissions,'' [345] we always evaluate emissions associated with transport of feedstocks and fuels in our lifecycle emissions calculations. In the case of LNG transportation in particular, the transport emissions have the potential to be dispositive in terms of meeting the statutory emissions reduction criteria to qualify for D3 or D5 RINs, so it is appropriate to condition the pathway on this basis. Thus, the proposed condition that CNG/LNG production processes ''occur in North America'' was intended to exclude long international transportation of LNG that could result in large boil-off or other sources of emissions that could be results in the production process (including transportation and distribution) not meeting the 50 percent or 60 percent emissions reduction threshold.

However, based on our consideration of the public comments, the restriction to North America raised other questions, such as whether renewable CNG/LNG produced and used in Hawaii or other covered locations would qualify for the Row Q and T pathways.[346] Given that our primary concern is long-duration international transportation and distribution scenarios that would likely involve marine transport of renewable CNG/LNG, we are instead finalizing a condition that the production processes under Rows Q and T, ''do not transport RNG, or renewable CNG/LNG by ocean-going vessel.'' [347] We believe this change more directly addresses our primary concern of long-duration transportation scenarios. We note that renewable fuel producers seeking to transport renewable CNG/LNG on ocean-going vessels can still petition the EPA to evaluate a new pathway using the petition process specified at 40 CFR 80.1416.

h. Other Associated Regulatory Changes

The revisions described in this section VIII.D.1 of this preamble do not affect existing pathway registrations and we are adding language to 40 CFR 80.1426(f)(1) to clarify that a renewable fuel producer may continue to use an existing registration that was under a pathway in Table 1 that previously specified ''Any'' or ''Any process that converts cellulosic biomass to fuel'' as its production process requirement if the pathway was in the renewable fuel facility's registration that was accepted by EPA prior to the effective date of this rule. Producers with an existing pathway registration that satisfies the above criteria do not need to update or modify their registrations due to the Table 1 amendments in this action, nor will any existing pathway registrations be deactivated. Any modifications to the renewable fuel production facility's registration after the effective date of this action must meet an approved pathway.[348] These provisions are appropriate as prior registrations were reviewed and accepted by the EPA based on our engineering judgement and interpretation of the fuel pathways in Table 1, including our consideration of the parameters of the lifecycle analyses that formed the basis for the approved pathways.

To provide additional clarity going forward regarding the criteria the EPA will apply to determine whether a feedstock, fuel, or production process qualifies for an approved pathway in Table 1, we are adding the following language to 40 CFR 80.1426(f)(1): ''For purposes of identifying the appropriate approved pathway, the fuel must be produced, distributed, and used in a manner consistent with the pathway EPA evaluated when it determined that the pathway satisfies the applicable lifecycle emissions reduction requirement.'' One commenter stated that this language was unnecessary and unhelpful, but based on our experience

[343] For background on the EPA's evaluation of these pathways, see: 79 FR 42140–44 (July 18, 2014).

[344] 90 FR 25848 (June 17, 2025).

[345] ''The term 'lifecycle greenhouse gas emissions' . . . include[es] all stages of fuel and feedstock production and distribution, from feedstock generation or extraction through the distribution and delivery and use of the finished fuel to the ultimate consumer. . . .'' CAA section 211(o)(1)(H).

[346] Covered location is defined as ''the contiguous 48 states, Hawaii, and any state or territory that has received an approval from EPA to opt-in to the RFS program.'' 40 CFR 80.2.

[347] Ocean-going vessel is defined as ''vessels that are equipped with engines meeting the definition of 'Category 3' in 40 CFR 1042.901.'' 40 CFR 80.2.

[348] An approved pathway is defined as ''a pathway listed in table 1 to § 80.1426 or in a petition approved under § 80.1416 that is eligible to generate RINs of a particular D code.'' 40 CFR 80.2.

implementing the RFS program we believe adding this provision to the regulations will improve program implementation and clarify how to handle situations that have arisen in the past where a production process appeared to meet the production process requirements in Table 1 but did not actually satisfy the statutory criteria.

i. Conclusion

We believe the revisions to Table 1 discussed in this section will improve implementation of the RFS program in accordance with the statutory criteria. Although we have strived to describe the pathways in Table 1 in a manner that aligns with the lifecycle analysis that supports each pathway, we recognize there will likely still be some cases where it is not clear whether a particular production process qualifies for a particular pathway. Renewable fuel producers seeking to determine if their fuel fits within the bounds of a pathway listed in Table 1 can contact the EPA through the pathway screening tool for clarification.[349] The pathway screening tool process was designed for the express purpose of providing a means for renewable fuel producers to seek input on whether a fuel fits an existing pathway in Table 1 or whether a new renewable fuel pathway petition, pursuant to 40 CFR 80.1416, is needed prior to registering to generate RINs.

2. Adding Waste Fats, Oils, and Greases as Feedstock for Producing Renewable Naphtha and LPG

As discussed in the Set 2 proposal, we are adding new pathways to Row I for renewable naphtha and LPG produced from biogenic waste oils, fats, and greases through a hydrotreating process to qualify for D5 RINs.[350] Specifically, we are adding ''Biogenic waste oils/fats/greases'' as a feedstock in Row I. As discussed in the Set 2 proposal, we are adding these pathways based on our finding that these pathways satisfy the statutory 50 percent lifecycle emission reduction criteria to qualify for D5 RINs. We did not receive any comments opposing these amendments.

E. Updates to Definitions

1. New Definitions

The RFS regulations previously did not define the terms ''renewable fuel producer,'' ''renewable fuel oil,'' ''renewable naphtha,'' and ''renewable jet fuel''; however, all these terms are used within the RFS regulations. To provide regulatory clarity, we proposed to define each of these terms in the Set 2 proposal. Commenters were generally supportive of defining these terms but suggested minor revisions to improve clarity and accuracy of the definitions. We have incorporated these suggestions into our final definitions described below.

We are defining a renewable fuel producer as ''any person that owns, leases, operates, controls, or supervises a facility where renewable fuels are produced.'' This definition is consistent with other definitions of regulated parties under the RFS program. We are defining renewable fuel oil as ''heating oil that is renewable fuel and that meets paragraph (2) of the definition of heating oil,'' renewable naphtha as ''naphtha that is renewable fuel,'' and renewable jet fuel as ''jet fuel that is renewable fuel and that meets ASTM D1655 or ASTM D7566.'' These definitions are consistent with other definitions of renewable fuels under the RFS program.

We believe these definitions will provide more clarity to both the regulated community and the public.

2. Revised Definitions

Given the complex nature of global supply chains, we are updating the definitions of foreign renewable fuel producers and importers as proposed in the Set 2 proposal. These revisions will also provide clarity to regulated parties regarding which entities qualify as foreign renewable fuel producers or importers.

Under 40 CFR 80.2, a foreign renewable fuel producer was previously defined as ''a person from a foreign country or from an area outside the covered location who produces renewable fuel for use in transportation fuel, heating oil, or jet fuel for export to the covered location. Foreign ethanol producers are considered foreign renewable fuel producers.'' This definition was unclear because renewable fuel produced at a facility in the United States could arguably be considered produced by a ''foreign renewable fuel producer'' if the corporation that produced the renewable fuel is incorporated in a foreign country. We are instead defining a foreign renewable fuel producer as ''any person that owns, leases, operates, controls, or supervises a facility outside the covered location where renewable fuel is produced.'' This revised definition is consistent with how foreign biogas producers and foreign RNG producers have been defined under the RFS regulations.

Further, under 40 CFR 80.2 an importer was previously defined as ''any person who imports transportation fuel or renewable fuel into the covered location from an area outside of the covered location.'' To provide greater clarity to the regulated community as to which entities can be considered an importer, we are revising the definition of importer to include ''the importer of record or an authorized agent acting on their behalf, as well as the actual owner, the consignee, or the transferee, if the right to withdraw merchandise from a bonded warehouse has been transferred.''

Finally, we are adding a provision in the liability provisions at 40 CFR 80.1461 that specifies that each person meeting the definition of an importer of renewable fuel under the RFS regulations is jointly and severally liable for any violations of the RFS requirements, including the new import RIN reduction provisions. The change is consistent with the liability framework for other parties participating in the RFS program and the liability framework that applies in our fuel quality program under 40 CFR part 1090. These provisions are also necessary to ensure that importers who import non-qualifying renewable fuel or renewable fuel feedstocks can be held liable.

3. New Biointermediates

In the 2020–2022 RFS Rule, we established provisions for biointermediates to be used to produce qualifying renewable fuels. At the same time, we listed in the regulations the specific biointermediates that are allowed under the RFS program.[351] We also stated that new biointermediates would be brought into the RFS program via notice-and-comment rulemaking. In the Set 1 Rule, we added biogas as a biointermediate and in the Set 2 proposal we proposed to add two more biointermediates: activated sludge and converted oils. These new biointermediates were requested in two separate petitions for rulemaking submitted to the EPA in 2023 and 2024.[352] We are finalizing the addition of these two new biointermediates in this action.

First, we are adding activated sludge, which is waste sludge from a secondary wastewater treatment process involving oxygen and microorganisms. One petitioner suggested that activated

[349] EPA, ''Renewable Fuel Pathway Screening Tool.'' *https://www.epa.gov/renewable-fuel-standard-program/forms/renewable-fuel-pathway-screening-tool.*

[350] 90 FR 25848–49 (June 17, 2025).

[351] 87 FR 39600 (July 1, 2022).

[352] ''Agresti Energy Petition to Add Potential Biointermediates to the Regulatory Definition,'' October 12, 2023; ''DS Dansuk Petition for Addition of New Biointermediate Produced via a New Production Process,'' November 26, 2024. Both petitions are available in the docket for this action.

sludge could initially be used to produce renewable CNG, potentially followed by other fuels such as LNG, ethanol, biobutanol, and methanol in the future. Second, we are adding converted oils, which are glycerides such as monoglycerides and diglycerides that are produced through the glycerolysis of waste oils, fats, or greases with glycerol. Converted oils must exclusively consist of glycerides with fatty acid alkyl groups that originate from qualifying biogenic waste oils, fats, or greases during the conversion process. One petitioner suggested that converted oils could be used to produce biodiesel, renewable diesel, or jet fuel.

We are finalizing these changes as proposed. Several commenters supported the proposed changes, while one commenter expressed concern about considering activated sludge a biointermediate rather than simply as an approved feedstock. In response to this comment, we want to clarify that biogas from municipal wastewater treatment facility digesters is already an approved feedstock in Rows Q and T, and such pathways may involve the production of biogas from activated sludge at the same facility where the activated sludge is produced. Furthermore, biogas used to make a renewable fuel other than renewable CNG/LNG is also a biointermediate.[353] In cases where the activated sludge is produced at one facility and used to produce renewable fuel at a second facility, the activated sludge would need to be a biointermediate. This is because activated sludge is produced from primary sludge, which has been substantially altered through anaerobic and aerobic treatment. Thus, by adding activated sludge as a new biointermediate, we are facilitating the production of qualifying fuel from this material.

F. Compliance Reporting, Recordkeeping, and Registration Provisions

1. Exempt Small Refinery Compliance Reporting

Under the RFS program, small refineries are eligible to petition for and receive an exemption from their RFS obligations for a given compliance year. The RFS regulations do not, however, exempt these small refineries from having to submit an annual compliance report. In the Set 2 proposal, we proposed to clarify that such exempt small refineries must file an annual compliance report. Commenters were generally supportive of this change and we are finalizing this clarification as proposed.

While an exempt small refinery does not have to retire RINs to comply with an RVO, it still produces gasoline or diesel that is used as transportation fuel in the United States and thus this fuel is included in EIA's projections of nationwide fuel consumption. We use these projections as the basis for calculating the annual RFS percentage standards and, as described in the Set 1 Rule, we have recently discovered a discrepancy between the volumes of gasoline and diesel reported by obligated parties in their annual compliance reports and EIA's reported actual volumes of gasoline and diesel consumed.[354] In order for the EPA to have a complete picture of the actual volume of gasoline and diesel that was produced by refiners—including fuel produced by exempt small refineries—that would otherwise be reported as obligated fuel in a given compliance year, it is necessary that all refiners submit an annual compliance report regardless of whether they received an exemption from their RFS obligations for the given compliance year. Having this data will improve the accuracy of our gasoline and diesel projections in future standard-setting actions and better ensure that there is not overcompliance by obligated parties. Without gasoline and diesel production volumes from exempt small refineries, we are more likely to underestimate the actual amount of gasoline and diesel expected to be used in a given compliance year. This would result in overly stringent percentage standards, and thus more RINs would need to be retired than necessary to comply with the annual volume requirements. Therefore, we are clarifying under 40 CFR 80.1441(e)(2) and 80.1442(h) that exempt small refineries and small refiners are still subject to RFS reporting requirements under 40 CFR 80.1451(a) and must submit an annual compliance report by the annual compliance reporting deadline. Such exempt small refineries will need to report their actual annual production of gasoline and diesel that would otherwise be obligated fuel.

In addition, we also proposed to clarify under 40 CFR 80.1441(e)(2) and 80.1442(h) that a small refinery or small refiner that receives an exemption for a given compliance year is not exempt from having to comply with any deficit RVOs that were carried forward from the previous compliance year. Several small refinery commenters objected to this clarification and claimed that this proposed change would negate the intent behind both the deficit carryforward provision and small refinery hardship relief. We disagree with these commenters and are finalizing this clarification as proposed, consistent with our long-standing interpretation and implementation of an exemption under the SRE program. We address the specific concerns raised by commenters in RTC Section 11.6.1.

2. Compliance Report Updates

We are finalizing several changes to requirements related to compliance reports. Generally, these changes are intended to reduce burden, support implementation, and improve the quality of information submitted to the EPA under 40 CFR 80.1449, 80.1451, and 80.1452. Commenters were generally supportive of these changes.

First, we are sunsetting the reporting requirement specific to how each entity owning RINs must calculate the volume of renewable fuel (in gallons) owned at the end of each quarter and report this on a quarterly basis. The general requirements for RIN distribution specify that the number of assigned RINs owned must be less than or equal to the amount of renewable fuel owned multiplied by 2.5. However, since 2010 there have been no documented compliance issues with entities meeting the distribution requirement for assigned RINs. To reduce reporting burden, we are removing as proposed this quarterly reporting requirement under 40 CFR 80.1451 and also updating the associated requirement under 40 CFR 80.1428(a)(4).

Next, we are simplifying the "production outlook report" and its associated requirements as proposed. Renewable fuel producers were required to submit an annual "production outlook report" that previously included a monthly or annual projection in future years; we are now only requiring annual projections. Reducing this reporting requirement to annual projections will reduce burden while maintaining a minimum level of reporting needed to assess future production. We are also updating or removing other outdated language under 40 CFR 80.1449.

Additionally, producers or importers of biogas used for transportation fuel were required to report on a quarterly basis the total energy produced and supplied for use as transportation fuel, as well as where the fuel is sold for use as a transportation fuel. These quarterly reporting requirements under 40 CFR 80.1451(b)(1)(ii)(P) were similar to other existing reporting requirements under

[353] 40 CFR 80.2.

[354] Set 1 RIA, Chapter 1.11.

40 CFR 80.140. We are therefore removing this separate quarterly reporting requirement as proposed to further reduce reporting burden.

Finally, we are taking steps to improve the quality of information when entities generate RINs in EMTS. Currently, each reporting party must enter a ''reason code'' whenever they are reporting a buy, sell, separate or retire transaction in EMTS, as described in 40 CFR 80.1452. This information is then used for implementation, compliance, and public data postings on our website. As proposed, we are now adding a ''reason code'' for RIN generation to directly improve implementation. For example, commenters noted long delays by the EPA in processing report corrections in EMTS and we will first use this new field to automate processing report corrections submitted by renewable fuel producers (*e.g.,* under-generation of RINs). We will initially utilize a transition period that only requires entities submitting report corrections to complete this new element followed by full implementation starting on January 1, 2027. We will also post additional information specific to compliance assistance and technical support material on our website while gradually phasing in this new field and closely monitoring feedback towards improving implementation and automation.

3. Third-Party Auditor Registration Renewal

We are changing the frequency with which independent third-party auditors are required to renew their registrations. Previously, a third-party auditor's registration expired each year on December 31. However, we have found that there is significant burden on both the EPA and auditors to review and approve these registrations every year. We believe that it is not necessary to require auditors to renew their registrations annually and that a two-year registration period is more appropriate. This length of time still ensures that we are regularly reviewing auditor registrations, while also reducing burden on the EPA and auditors. Commenters were generally supportive of this change. Thus, we are specifying that a third-party auditor's registration will expire on December 31 every other year.

4. Engineering Review Site Visits

Under 40 CFR 80.1450(b)(2), renewable fuel production facilities are required to undergo an independent third-party engineering review prior to registration. As part of that engineering review, the independent third-party engineer is required to conduct a site visit. However, the previous regulations did not specify when such site visits need to occur. Recently, we have received some engineering reviews where the site visit was over a year old. In the Set 2 proposal, we proposed to specify that engineering review site visits must be conducted within six months prior to submitting a registration request in order to ensure that the site visit is reflective of the current operation of the facility. Several commenters expressed concern about the limited number of qualified engineers to conduct such reviews. However, we believe that it is critical that the engineering review site visit accurately reflects the current operations of the facility. We are therefore finalizing the requirement for engineering review site visits to be conducted within six months prior to submitting a registration request, as proposed.

5. Biogas Batch Period of Production

As part of the biogas regulatory reform provisions in the Set 1 Rule, a batch of biogas was specified as the volume of biogas measured for a calendar month, with the last day of the month as the production date.[355] Stakeholders have subsequently provided feedback to the EPA that allowing biogas producers to produce batches for time periods of less than a month would improve implementation of the biogas regulations. To provide additional flexibility for biogas producers, in the Set 2 proposal we proposed to change the period of production such that a biogas batch may be ''up to'' a calendar month, allowing for more frequent biogas batches as indicated by the business practices of the biogas producer. This change also provides additional flexibility to RNG producers that use the biogas batches as part of their RNG RIN generation. Commenters were generally supportive of this change, and we are therefore finalizing this flexibility as proposed.

G. New Approved Measurement Protocols

In the Set 2 proposal, we proposed to add measurement protocols to the list of approved methods for measuring the volume of RNG or treated biogas. Commenters were generally supportive of adding these methods to the regulations and suggested additional methods that could be added. We agree with commenters and have included these additional methods in the list of approved methods, as we have already accepted all these methods through alternative measurement protocols.[356] The methods we are adding under 40 CFR 80.155(a) are the following: AGA Report No. 3; AGA Report No. 7; AGA Report No. 9; AGA Report No. 11; ASME MFC–3M; ASME MFC–5.1; ASME MFC–11; ASME MFC–12M; ASME MFC–21.2; ANSI B109.3; API MPMS 14.9; ISO 5167–1 and ISO 5167–2, ISO 5167–4, or ISO 5167–5; ISO 10790; ISO 14511; ISO 17089–1; and ISO 17089–2.

We also proposed to add methods for the measurement of biogas and RNG samples under 40 CFR 80.155(b)(2). Commenters were generally supportive of adding these methods to the regulations and suggested additional methods that could be added. We agree with commenters and have included these additional methods in the list of approved methods. For methane, carbon dioxide, nitrogen, and oxygen, we are adding ASTM D1945, ASTM D1946, and ASTM D7833; previously, the only specified method was EPA Method 3C. For hydrogen sulfide and total sulfur, we are adding ASTM D6228 and ASTM D6968; previously the only specified method was ASTM D5504. For moisture, we are adding ASTM D1142, ASTM D5454, and ASTM D7904; previously, the only specified method was ASTM D4888. For hydrocarbon analysis, we are adding ASTM D1945, ASTM D1946, ASTM D7833, and EPA Method TO–15; previously, the only specified method was EPA Method 18.

H. Biodiesel and Renewable Diesel Requirements

We did not propose and are not finalizing any changes to the sulfur standards for biodiesel or renewable diesel in this action. However, we are taking this opportunity to reiterate that biodiesel and renewable diesel producers must comply with all of our regulatory requirements for diesel producers in 40 CFR part 1090 for the biodiesel and renewable diesel they produce (referred to as ''nonpetroleum diesel fuel'' in 40 CFR part 1090), including demonstrating homogeneity for each batch of biodiesel and renewable diesel and testing each batch for sulfur content to ensure the fuel meets the 15 ppm standard.[357] This also

[355] 40 CFR 80.105(j)(1) and 80.140(b)(2).

[356] EPA, ''Alternative Measurement Protocols for Biogas and Renewable Natural Gas,'' *https://www.epa.gov/fuels-registration-reporting-and-compliance-help/alternative-measurement-protocols-biogas-and-0.*

[357] We have previously made clear that biodiesel producers must comply with all our regulatory requirements for diesel producers. *See* EPA, ''Guidance for Biodiesel Producers and Biodiesel Blenders/Users,'' EPA–420–B–07–019, November 2007; *see also* EPA ''Am I required to register

includes the requirement that all sulfur test results must be obtained by the producer before shipping biodiesel or renewable diesel from the facility. Requiring measurement before shipping provides assurance of compliance prior to the fuel being mixed and comingled in the fungible distribution system.

To further make clear that all the above requirements apply to biodiesel and renewable diesel, we proposed to clarify the language at 40 CFR 1090.300(a), 1090.305(a), 1090.1310(b)(1), and 1090.1337(e). Commenters were generally supportive of these clarifications, and we are finalizing these changes as proposed with minor clerical revisions to the proposed language.

I. Extension of RFS Compliance Reporting Deadlines

In 2022, we finalized changes to the way the RFS compliance and attest engagement reporting deadlines are determined.[358] Prior to that action, the compliance and attest engagement reporting deadlines for a given compliance year were March 31 and June 1 of the subsequent year, respectively, even if the applicable RFS standards for that year had not yet been established. Any change to these deadlines required the EPA to undertake a notice-and-comment rulemaking process to revise the RFS regulations on a case-by-case basis. However, under the new provisions finalized in 2022, the annual compliance reporting deadline is the latest date of the following: [359]

• March 31st of the subsequent calendar year;

• The next quarterly reporting deadline after the effective date of the subsequent compliance year's standards (typically 60 days after publication of the final rule in the **Federal Register**); or

• The next quarterly reporting deadline under 40 CFR 80.1451(f)(2) after the annual compliance reporting deadline for the prior compliance year.

In December 2024, we proposed to add a new provision that would automatically extend the annual compliance reporting deadline for a given compliance year if we propose to revise an existing RFS standard for that year.[360] Some commenters supported the certainty that this change would provide to stakeholders when EPA proposes to revise an existing RFS standard, while other commenters expressed concern that these provisions were unnecessary and could undermine RFS program integrity. On balance, we find that the benefits of the proposed new compliance date extension provisions outweigh the concerns raised by some commenters and we are finalizing the provisions as proposed. We address the specific concerns raised by commenters in RTC Section 11.9.

Under this approach, the publication of a document in the **Federal Register** proposing to revise a renewable fuel standard in 40 CFR 80.1405(a) will automatically extend the annual compliance reporting deadline for that year to the next quarterly reporting deadline after either: (1) The effective date of the final rule that revises the existing standard (typically 60 days after publication of the final rule in the **Federal Register**); or (2) 60 days after the publication of a document in the **Federal Register** withdrawing the proposed revision. However, if we do not either finalize or withdraw the proposed revision within 12 months after the proposed rule is published, we are limiting the extension in this specific circumstance to no more than the next quarterly reporting deadline that is 12 months after the date of publication of the proposed rule.[361] We believe that this provides sufficient time for the EPA to either finalize or withdraw the proposed revision to an existing RFS standard and do not want to indefinitely extend the compliance reporting deadline for a compliance year with already established RFS standards.

Essentially, this new provision means that the mere proposal—as opposed to a final action—by the EPA to change an existing RFS standard would change the associated compliance reporting deadline for that compliance year. This change is being made because by the time the need is evident to extend the compliance deadline, there is often inadequate time to both propose and finalize a rulemaking to do so. And even when we have undertaken rulemakings to extend compliance deadlines, these actions have required significant time and resources by EPA staff that could have been dedicated to other Agency priorities. By further automating the extension of compliance deadlines when we propose to revise an existing RFS standard, EPA staff will have more time to work on the final rulemaking to revise the existing RFS standard. This will likely result in the final rule being completed sooner than it would otherwise if the same EPA staff had to work on a separate final rule to first extend the associated compliance deadline before then revising the existing RFS standard.

As an example, under this approach, if the 2026 compliance deadline was originally established as March 31, 2027, but then we proposed to revise the 2026 cellulosic biofuel standard on November 30, 2026, the 2026 compliance reporting deadline would be automatically extended until the first quarterly reporting deadline after the effective date of the final rule establishing the revised 2026 cellulosic biofuel standard. We would not have to separately propose to extend the 2026 compliance reporting deadline in that same action, because the deadline would be automatically extended by operation of law. If we then finalized the proposed revision to the 2026 cellulosic biofuel standard on February 15, 2027, with an effective date of April 16, 2027, the 2026 compliance reporting deadline would be June 1, 2027 (*i.e.,* the next quarterly reporting deadline after the effective date of the final rule). Alternatively, if we chose not to finalize the proposed revision to the 2026 cellulosic biofuel standard and instead published a document in the **Federal Register** to withdraw the proposed revision on April 30, 2027, the 2026 compliance reporting deadline would be September 1, 2027 (*i.e.,* the next quarterly reporting deadline that is at least 60 days after publication of that document in the **Federal Register**). Finally, if we took no action after proposing to revise the 2026 cellulosic biofuel standard, the 2026 compliance deadline would be December 1, 2027 (*i.e.,* the next quarterly reporting deadline that is 12 months after the date of publication of the proposed rule).

This approach will provide regulatory certainty for obligated parties by clearly establishing future compliance deadlines when we propose to change a previously established RFS standard, thereby preventing unnecessary burden on obligated parties to prepare, submit, and then possibly retract and revise compliance reports for deadlines that were later extended. This approach is consistent with our prior rules extending RFS compliance reporting deadlines in different factual

biodiesel? How would I do that?'' April 1, 2025. *https://www.epa.gov/fuels-registration-reporting-and-compliance-help/am-i-required-register-biodiesel-how-would-i-do.*

[358] 87 FR 5696 (February 2, 2022).

[359] 40 CFR 80.1451(f)(1)(i)(A).

[360] 89 FR 100442 (December 12, 2024).

[361] We note that under any of these scenarios, the applicable compliance reporting deadline in 40 CFR 80.1451(f)(1)(i)(A) or (B) of this section would apply if it were later than the proposed extension (*e.g.,* the deadline would be no earlier than March 31 of the subsequent calendar year or the next quarterly reporting deadline after the annual compliance reporting deadline for the prior compliance year).

circumstances[362] and with D.C. Circuit's decisions on this issue.[363]

J. Biogas Regulations

In December 2024, we proposed minor revisions to two main areas of the RFS program's biogas regulations that were identified after the EPA and market participants began implementing the regulations promulgated in the Set 1 Rule.[364] First, we proposed to clarify and provide flexibility for how biogas, RNG, and renewable CNG/LNG are measured, sampled, and tested to demonstrate compliance. Second, we proposed several clarifying technical amendments to the biogas regulations. Commenters were generally supportive of all these changes, with several suggesting minor revisions or additions to our proposed language. As described in more detail below, we are finalizing these clarifications largely as proposed with mostly minor clerical revisions to the proposed language. We address stakeholders' specific comments on these changes in RTC Section 11.10.

1. Measurement, Sampling, and Testing

We are finalizing revisions to align the testing frequency of pipeline-specified components for RNG with the reporting frequency for those pipeline specification components. Previously, RNG producers needed to annually sample and test their RNG to demonstrate that the RNG production facility was producing RNG that met applicable pipeline specifications,[365] and they needed to submit these results as part of their three-year registration updates.[366] Stakeholders have highlighted the disconnect between the annual testing requirement and the three-year reporting requirement. Since we only collect this information as part of the three-year engineering review update, we believe it appropriate to only require sampling and testing of RNG once every three years, rather than each year, and are revising 40 CFR 80.110(f)(2)(iii) to this end. We are further clarifying that such sampling and testing is required beginning with three-year engineering review updates submitted on or after January 1, 2027.

We are also finalizing clarifications to the regulations to reinforce that we may approve alternative test methods for testing components of RNG and that we may exempt the testing of a component that is not required under the RNG producer's applicable pipeline specifications. Specifically, we are revising 40 CFR 80.135(d)(6), which contains the information related to RNG quality that RNG producers must provide (including certificates of analysis for RNG components), to allow alternatives to the test methods for individual RNG components that are specified at 40 CFR 80.155(b). We will assess alternative test methods based on whether the requested alternative test method provides results that are reasonably accurate to the results provided by the method specified at 40 CFR 80.155(b). While under 40 CFR 80.135(d)(6)(v) RNG producers can already request alternative methods and exemption from non-specified parameters, we believe that adding further clarification will help alleviate stakeholder confusion concerning the sampling and testing requirements for RNG.

In order to streamline the alternative measurement protocol approval and registration acceptance process, we are finalizing the removal of the requirement that biogas and RNG production facilities must demonstrate that their facility is incapable of using certain specified meters in order to receive an alternative measurement protocol. After promulgation of the biogas regulatory reform provisions in the Set 1 Rule, we have received dozens of alternative measurement protocol submissions and issued guidance for the application of the criterion that a facility demonstrate that it is incapable of using the specified meters.[367] We have determined that many of these meters are as accurate and precise as those specified in the regulations, and have also received a number of registration submissions for facilities that have demonstrated the appropriateness of using such meters.[368] Based on our review of the alternative measurement protocol and registration submissions and the new information we have obtained in the course of this review, we believe that the first criterion whereby a facility must demonstrate that they cannot use the specified meters is not necessary to ensure the accurate and precise measurement of biogas and RNG under the RFS program.[369] We are also removing the associated requirement that biogas producers and RNG producers demonstrate at registration that they are unable to use the meters specified.[370]

Finally, we note that due to the numerous changes to the provisions of 40 CFR 80.155(a) in this action, we are restructuring 40 CFR 80.155(a) to ensure that the measurement requirements for biogas, treated biogas, RNG, and renewable CNG/LNG are clearly enumerated.

2. Other Amendments

We are finalizing clarifications to the provisions surrounding the annual attest engagement procedures for biogas producers, RNG producers, and RNG RIN separators at 40 CFR 80.165. These changes clarify that annual attest engagements are only required for parties that engage in activities regulated under biogas regulatory reform in a given compliance year (*e.g.,* an RNG RIN separator only needs to obtain an annual attest engagement if they separate RNG RINs in a compliance year).

We are also clarifying that any party transferring RINs assigned to a volume of RNG is deemed to also be transferring a corresponding volume of RNG for the purposes of 40 CFR part 80 (*i.e.,* the RFS program). The original language in 40 CFR 80.125(c)(3) led to confusion among stakeholders as to whether physical volumes of RNG were required to be exchanged when transferring assigned RNG RINs. We are replacing this language with text that makes clear that when a party transfers title of an assigned RNG RIN to another party, they are deemed to have also transferred a corresponding volume of RNG to the transferee. We are also clarifying under 40 CFR 80.1460(a)(4) that, while it need not be the same volume of RNG used for RIN generation, the transferee taking title to the assigned RNG RINs must also acquire a corresponding volume of RNG.

We are clarifying that all biogas production facilities registered under the previous biogas provisions (*i.e.,* registered under 40 CFR 80.1450(b) to generate RINs under 40 CFR 80.1426(f)(10) or (11)) do not need updated engineering reviews as part of registering for the new biogas provisions. In the Set 1 Rule, we intended to allow all previously

[362] 86 FR 17073 (April 1, 2021); 87 FR 5696 (February 2, 2022).

[363] *Wynnewood Refining Co., LLC, et al.* v. *EPA,* 77 F.4th 767, 779 (D.C. Cir. 2023) (''Thus, rather than task EPA with overseeing a fixed compliance schedule, the Act gives EPA flexibility to craft and adjust a compliance regime in service of the Act's core mandate: to ensure the Act's annual renewable fuel volumes are met.''). *See also ACE,* 864 F.3d at 718–21; *Monroe Energy, LLC* v. *EPA,* 750 F.3d 909, 919–20 (D.C. Cir. 2014); *Nat'l Petrochemical & Refiners Ass'n* v. *EPA,* 630 F.3d 145, 154–58) (D.C. Cir. 2010).

[364] 89 FR 100442 (December 12, 2024).

[365] 40 CFR 80.110(f)(2)(iii).

[366] 40 CFR 80.135(d)(6).

[367] EPA, ''Biogas Regulatory Reform Rule Criteria for Qualifying for an Alternative Measurement Protocol Guidance,'' EPA–420–B–24–014, March 2024.

[368] A list of approved alternative measurement protocols can be found at: *https://www.epa.gov/fuels-registration-reporting-and-compliance-help/alternative-measurement-protocols-biogas-and-0.*

[369] 40 CFR 80.155(a)(3)(i).

[370] 40 CFR 80.135(c)(3)(iii)(A) and (d)(3)(iii)(A).

registered biogas production facilities that did not undergo changes as a result of the new biogas provisions to rely on their existing engineering reviews until their next three-year engineering review is due. However, after promulgation of the new biogas provisions, stakeholders noted that the language in the regulations appears to limit this allowance to only those biogas production facilities in a biogas closed distribution system. Therefore, we are revising 40 CFR 80.135(b)(2)(ii) to make it clear that all previously registered biogas production facilities can use their existing engineering review until the next one is due. We note, however, that if changes to the facility are needed that would otherwise require a new engineering review, the new engineering review must be submitted regardless of this flexibility.

We are also making two changes to the registration requirements for RNG RIN separators under 40 CFR 80.135(f). First, we are requiring that, as part of the information submitted at registration, RNG RIN separators must provide the location on the natural gas commercial pipeline system where the RNG is withdrawn, which is information we already require to be reported in periodic reports under 40 CFR 80.140(e)(1). In addition, as part of the forms and procedures established for those reports, we require that the RNG RIN separator include an EPA-issued facility registration system identification (FRS ID) number. While most withdrawal points have previously assigned FRS ID numbers, some do not. Due to how the EPA's registration system is designed, the only way to obtain those new FRS ID numbers is at the point of registration. Therefore, to aid in the timely submittal of reports, we are clarifying that RNG RIN separators must supply the withdrawal locations at registration.

Second, we are removing the limitation at 40 CFR 80.115(b) that a CNG/LNG dispensing location may only be part of one RNG RIN separator's registration at a time. Based on our experience implementing the program, it is difficult for parties to know which RNG RIN separator has registered for a particular CNG/LNG dispensing location. Under the previous framework, there was a perverse incentive for an RNG RIN separator to register for a CNG/LNG dispensing location in order to block another party from registering that location and prevent that party from separating RNG RINs for transportation fuel dispensed at that location—even though the registering party does not maintain an actual relationship to that location. Removing this restriction will allow a dispensing location to be in multiple parties' registrations, thereby avoiding the situation where one party that does not intend to actually dispense renewable CNG/LNG can block another party that does intend to dispense renewable CNG/LNG from separating RINs at that location. However, we are maintaining the limitation at 40 CFR 80.125(d)(2)(v) that only one party may actually separate RINs for a given CNG/LNG dispensing location during a calendar month. We continue to believe that this restriction is necessary to preclude double counting of RINs because it is the limitation that only one party can separate RINs for a volume dispensed at a station during a given month that avoids double-counting, not whether multiple parties reflect that station in their registration information on file with the EPA.

K. Technical Amendments

We are finalizing numerous technical amendments to the RFS regulations. These amendments are being made to correct minor inaccuracies and clarify the current regulations. These changes are described in Table VIII.K–1.

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Table VIII.K-1: Miscellaneous Technical Corrections and Clarifications to RFS Regulations

Part and Section of Title 40	Description of Revision
§ 63.10042	Updating the definition of "clean fuel" to reference 40 CFR part 1090, subpart D, instead of 40 CFR part 80, subpart I.
§§ 80.2, 80.1425(a)(3), 80.1426(e)(3), 80.1428(a)(3), 80.1429(c), 80.1460(b)(4)	Clarifying the definition of "Assigned RIN" and implementing regulations that assigned RINs for RNG have a K code of 3.
§ 80.2	Clarifying the definition of "Biodiesel" to state that it must be renewable fuel.
§ 80.2	Clarifying the definition of "Diesel fuel" by adding renewable diesel as an example of a non-distillate diesel fuel.
§ 80.2	Clarifying that parties must use ASTM D86 to measure T90 in the definition of "MVNRLM diesel fuel".
§§ 80.2, 80.1426(f)(17), 80.1450(b)(1)(xii), 80.1451(b)(1)(ii)(T), 80.1454(l)	Removing the definition of "Non-ester renewable diesel" and replacing it with a definition of "Renewable diesel".
§§ 80.1426(c)(7), 80.1450(b)(1)(xi), 80.1453(d), 80.1454(b)(8), 80.1460(g)	Replacing text in existing regulations to use the new definition of "renewable fuel oil."
§ 80.1426(f)(17), table 1 to § 80.1426, §§ 80.1450(b)(1)(xii), 80.1451(b)(1)(ii)(T), 80.1454(l)	Replacing text in existing regulations to use the new definition of "renewable jet fuel."
§§ 80.2, 80.1454, 80.1469, 80.1470, 80.1471, 80.1472, 80.1473, 80.1474, 80.1477, 80.1479	Removing expired Option A and Option B QAP provisions.
§§ 80.12 and 1090.95	Updating numerous ASTM standards and methods to the latest versions (see Section XI.J for list of methods).
§§ 80.105(j)(3), 80.110(j)(3), and 80.1476(h)(1)	Clarifying that batch numbers for biogas, RNG, biogas-derived renewable fuel, and biointermediates do not need to be numbered sequentially but must be unique in a compliance period.

Part and Section of Title 40	Description of Revision
§ 80.125(e)(2)	Clarifying when assigned RINs for a volume of RNG must be retired.
§ 80.135(c)(10)(vi)(A)(*5*)	Clarifying that biogas is "produced," not "generated."
§ 80.1426(f)(8)	Clarifying that the batch volume standardization equations apply to liquid renewable fuels and liquid biointermediates.
Table 1 to § 80.1426, § 80.1453(a)(12)(v)	Replacing text in existing regulations to use the new definition of "renewable naphtha."
§ 80.1449(a)(4)(i)	Replacing existing and planned production capacity with nameplate and permitted production capacity.
§ 80.1452(b) and (c)	Clarifying that we may allow a party to submit RIN assignment or transaction information to EMTS outside the applicable 5- or 10-business-day deadline.
§ 80.1454(b)(3)(ix)	Clarifying that records must be kept for all calculations under § 80.1426.
§ 1090.80	Replacing references to "NP diesel fuel" with "nonpetroleum diesel fuel."
§ 1090.80	Clarifying the definition of "Responsible corporate officer (RCO)" by removing "operations manager" as an example of an RCO.
§ 1090.215(b)(3)(ii)	Removing Ohio from the list of areas excluded from the 1-psi waiver in table 2 to § 1090.215(b)(3)(ii). EPA approved Ohio's request under 40 CFR 1090.297 to reinstate the 1-psi waiver on February 4, 2026 (91 FR 5108) and this action ministerially updates our regulations to reflect this action.
§ 1090.215(b)(3)(ii)	Correcting table 2 to § 1090.215(b)(3)(ii) to reflect 2026 effective date for nine counties in South Dakota.
§§ 80.2, 80.3, 80.1405, 80.1407, 80.1415, 80.1426, 80.1429, 80.1435, 80.1444, 80.1450, 80.1451, 80.1452, 80.1453, 80.1454, 80.1469	Correcting typographical, grammatical, and consistency errors.

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IX. Set 1 Remand

On June 20, 2025, the D.C. Circuit issued an opinion in *CBD,* a challenge by multiple petitioners to the Set 1 Rule. The majority opinion held that the EPA had reasonably considered and balanced the statutory factors to determine the required volumes of renewable fuel, with one exception concerning the consideration of climate change impacts.

CAA section 211(o)(2)(B)(ii) states that the basis for setting applicable renewable fuel volumes after 2022 under the RFS program 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.'' Accordingly, we conducted an analysis of the potential climate change impacts of the 2023–2025 standards finalized under the Set 1 Rule. Our climate change analysis for the Set 1 Rule relied on two distinct and sequential analytical steps:

1. We conducted a broad review of lifecycle GHG emissions analyses published in peer reviewed literature and government reports for biofuels affected by the RVO standards and for the fossil fuels that those biofuels are intended to displace.[371] This review produced ranges of published lifecycle GHG emissions estimates for each fuel type.

2. We used a subset of the studies identified in the literature review described above to construct two scenarios illustrating a range of potential monetized GHG emissions impacts associated with the RVO standards.[372]

In *CBD,* the D.C. Circuit noted that, in general, the EPA used the high- and low-end estimates of GHG emissions to construct the best- and worst-case scenarios of monetized GHG emissions

[371] Studies identified and associated ranges of lifecycle GHG emissions estimates for each fuel pathway are discussed in Set 1 RIA Chapters 4.2.2.2 through 4.2.2.12 and summarized in Set 1 RIA Chapter 4.2.2.13.

[372] Ranges of lifecycle GHG emissions estimates used for monetization of potential impacts of the Set 1 volume standards and monetized impacts estimates are presented, respectively, in Set 1 RIA Chapters 4.2.3 and 4.2.4.

impacts. However, the Court also stated that the EPA took a different approach for the category of biofuels produced from crops; specifically, that the Agency relied on just a subset of studies that did not represent the full range of GHG emissions when monetizing the impacts of crop-based biofuels. The Court then held that the EPA had failed to articulate a rational explanation for limiting the calculation of monetized impacts for crop-based biofuels to only a subset of the LCA studies identified in the EPA's literature review. The Court stated that ''EPA's unexplained decision to generally rely on [ranges of GHG emissions estimates from credible publications] for every other fuel category and to disregard them for crop-based renewable fuels in favor of ranges derived from its dated 2010 study was arbitrary and capricious.'' [373] The Court raised concerns with the EPA's justification for relying on the EPA's 2010 analyses of crop-based fuels in the monetization of GHG emissions impacts and remanded these issues back to the EPA for further explanation.[374] We intend the discussion below to fulfill our obligation to provide further explanation in response to this remand.

First, the Court noted that the EPA had made conflicting statements in the Agency's justification for why it relied on only the 2010 analyses for crop-based fuels, as opposed to the full range of GHG emissions estimates from the literature. The Court stated that the EPA had explained that the 2010 analyses provided the only estimates of GHG emissions reported on an annual basis.[375] However, the Court pointed out that the EPA had also stated that ''[t]he majority of the land use change GHG estimates in the literature—*i.e.,* not all of them—do not report an annual stream [of GHG emissions impacts].'' [376] Thus, the Court understood the EPA to have belied its assertion that ''only'' the 2010 analyses were a sufficient basis for monetizing the GHG emissions impacts of crop-based biofuels. That is, it appears the Court believed there were additional studies the Agency could have relied on for this purpose.

The EPA is clarifying here that its statement in the Set 1 RIA that ''[t]he majority of the land use change GHG estimates in the literature do not report an annual stream'' meant that all the land use change GHG estimates in the literature except EPA's 2010 analyses did not report annual streams of emissions. That is, for the crop-based fuels assessed in the Set 1 RIA—corn ethanol and soy biodiesel—the EPA's 2010 analyses were the only studies within the literature review which provided emissions estimates that were suitable for estimating monetized emissions impacts. No other analyses were identified in the literature review that the EPA could have used to estimate annual streams of emissions impacts.

Second, the Court stated that the EPA justified using only the Agency's 2010 analyses of crop-based fuels in the monetized impacts calculation by arguing that the full range of estimates in the literature systematically overestimates GHG emissions from land use changes. The Court then noted that ''that assertion of systemic skew is contradicted by EPA's own figures showing that GHG emissions estimates drawn from the literature review were effectively identical to those included in the 2010 study for all crop-based renewable fuel—except corn-based ethanol.'' [377]

We are clarifying and reinforcing here that our sole reliance on the 2010 analyses to monetize the GHG emissions impacts of crop-based fuels was because these were the only studies available that were suitable for such a calculation for the reason discussed above; the only studies within the literature review with annual emissions estimates were our 2010 analyses. We did not argue in the Set 1 Rule that estimates identified in the literature review systematically overestimated emissions from land use change, nor would we agree with such a statement in general. To the contrary, the Set 1 RIA explicitly states that the EPA did not adjudicate relative strengths or appropriateness of the various studies and that the literature review was designed to be inclusive of all published comparable estimates.[378]

As noted by the Court, the range of corn ethanol emissions estimates identified in the Set 1 Rule literature review (38 to 116 gCO_2e/MJ) was wider than the range of emissions estimates of the studies used in the monetized impacts calculation (49 to 91 gCO_2e/MJ). Relatedly, the Court raised concerns that this ''unexplained discrepancy is particularly problematic for EPA because [corn ethanol] plays an outsized role in the program overall. Corn-based ethanol is by volume the largest category of renewable fuel produced in the United States—and it drives the largest aggregate portion of GHG emissions attributable to renewable fuels. If EPA improperly relied on a lower high-end emission estimate for corn-based ethanol, it lacks support for its climate conclusion that 'on average [corn-based ethanol] provides some GHG reduction in comparison to gasoline.' '' [379]

As explained above, we considered all available GHG emissions estimates identified in the literature that were suitable for the monetized impacts calculation. The only studies of crop-based fuels that met these criteria were the EPA's 2010 analyses of those fuels. We also note that it is not necessarily the case that using a larger range of emissions estimates (higher and lower) would have resulted in higher and lower monetized GHG emissions impacts. Due to complexities in the timing and relative magnitude of GHG emissions associated with crop-based biofuels (*e.g.,* there may be large pulses of emissions early in the time period analyzed followed by smaller amounts of emissions, or even negative emissions, later on in the time period analyzed), monetized impacts do not necessarily scale linearly with emissions. This is why annualized estimates are needed to monetize emissions—an annual average or net emissions estimate alone does not provide the necessary timing and magnitude information required for monetization. Additionally, while corn ethanol does represent the largest category of biofuel generating credits under the RFS program, it represented only 15 percent of the difference in total biofuel use associated with the fuel volumes that we modeled to be

[373] *CBD* at 173.

[374] Analyses of crop-based fuels conducted for the RFS2 Rule are discussed in Section 2.6.1 of the RFS2 Rule RIA (EPA, ''RFS2 Regulatory Impact Analysis,'' EPA–420–R–10–006, February 2010). Annual estimates used in the monetization calculation were included in the docket for the RFS2 Rule (EPA–HQ–OAR–2005–0161).

[375] Annualized GHG emissions estimates were necessary to monetize the impacts of those emissions under the guidance that was in place at the time of the Set 1 rulemaking. The methodology used to monetize estimated GHG emissions impacts in the Set 1 Rule was based on the guidance provided by the February 2021 Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990, available to the docket in the Set 1 Rule (EPA–HQ–OAR–2021–0427–0339). That guidance provided factors expressed as dollars-per-ton of emissions in each individual year. Thus, to appropriately use the guidance on monetizing emissions impacts, it was necessary for emissions estimates to be projected for each individual year being assessed.

[376] *CBD,* 141 F.4th at 174.

[377] *CBD,* 141 F.4th at 174.

[378] *See* Set 1 RIA at 125 (June 2023, EPA–420–R–23–015): ''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 . . . Our review is intentionally broad and inclusive, and is informed by our experience conducting LCA evaluations of transportation fuels for the RFS program.''

[379] *CBD,* 141 F.4th at 174.

attributable to the Set 1 rule, relative to a scenario in which there were no RFS standards for 2023, 2024, and 2025.[380] Thus, while it is not possible to accurately monetize the impacts of the full range of GHG emissions estimates from the full literature review, any discrepancy is limited to a small minority (15 percent by energy content) of the total volumes of fuels assessed.

X. Administrative Actions

A. Assessment of the Domestic Aggregate Compliance Approach

The RFS regulations specify an ''aggregate compliance'' approach for demonstrating that planted crops and crop residue from the U.S. comply with the ''renewable biomass'' requirements that address lands from which qualifying feedstocks may be harvested.[381] In the RFS2 Rule, we established a baseline number of acres for U.S. agricultural land in 2007 (the year of EISA's enactment) and determined that as long as this baseline number of acres is not exceeded, it is unlikely, based on our assessment of historical trends and economic considerations, that new land outside of the 2007 baseline is being devoted to crop production for renewable fuel production. The regulations specify, therefore, that renewable fuel producers using planted crops or crop residue from the U.S. as feedstock in renewable fuel production need not undertake individual recordkeeping and reporting related to documenting that their feedstocks come from qualifying lands, unless the EPA determines through one of its annual evaluations that the 2007 baseline acreage of 402 million acres of agricultural land has been exceeded. The RFS regulations require the EPA to make an annual finding concerning whether the 2007 baseline amount of U.S. agricultural land has been exceeded in a given year. If the baseline is found to have been exceeded, then producers using U.S. planted crops and crop residue as feedstocks for renewable fuel production would be required to comply with individual recordkeeping and reporting requirements to verify that their feedstocks are renewable biomass.

USDA provided the EPA with data from the discontinued Grassland Reserve Program (GRP) and Wetlands Reserve Program (WRP) as well as the Agricultural Land Easements (ACEP–ALE) and the Wetlands Reserve Easements (ACEP–WRE) programs. Based on data from reduced cropland based on historic programs, WRE and GRP, estimated cropland reached approximately 372.4 million acres in 2024 and thus did not exceed the 2007 baseline acreage of 402 million acres.[382] We will continue to monitor total agricultural land annually to determine if national agricultural land acreage increases above this 2007 national aggregate baseline, as specified in the RFS2 Rule.[383]

B. Assessment of the Canadian Aggregate Compliance Approach

The RFS regulations specify a petition process through which we may approve the use of an aggregate compliance approach for planted crops and crop residue from foreign countries.[384] On September 29, 2011, we approved such a petition from the Government of Canada.[385] The 2007 baseline acreage for Canadian agricultural land is 122.1 million acres. The total agricultural land in Canada in 2025 is estimated at 115.4 million acres. This total agricultural land area includes 94.6 million acres of cropland and summer fallow, 11.0 million acres of pastureland, and 9.8 million acres of agricultural land under conservation practices. This acreage estimate is based on the same methodology used to set the 2007 baseline acreage for Canadian agricultural land in our response to Canada's petition. This 2025 acreage does not exceed the 2007 baseline acreage of 122.1 million acres.[386] We will continue to monitor total agricultural land annually to determine if Canadian agricultural land acreage increases above its 2007 aggregate baseline, as specified in the RFS2 Rule.[387]

XI. Statutory and Executive Order Reviews

Additional information about these statutes and Executive orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders.*

A. Executive Order 12866: Regulatory Planning and Review

This action is a significant regulatory action as defined under section 3(f)(1) of Executive Order 12866. Accordingly, it was submitted to the Office of Management and Budget (OMB) for review. Any changes made in response to OMB recommendations have been documented in the docket. We prepared an analysis of the potential costs and benefits associated with this action. This analysis is presented in RIA Chapter 10.6, available in the docket for this action.

B. Executive Order 14192: Unleashing Prosperity Through Deregulation

This action is considered an Executive Order 14192 regulatory action. For regulatory accounting purposes, the estimated present value and annualized value of the costs of this rule are $31.1 billion and $2.18 billion, respectively (7% discount rate, 2024$, 2026 present value year, perpetuity time horizon). Details on the estimated costs of this final rule can be found in EPA's analysis of the potential costs and benefits associated with this action.

C. Paperwork Reduction Act (PRA)

The information collection activities in this rule have been submitted for approval to the Office of Management and Budget (OMB) under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 7804.02, OMB Control Number 2060–0767. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

The volume standards and associated percentage standards for 2026 and 2027 do not add to the burdens already estimated under existing, approved ICRs for the RFS program. This final rule creates reporting for RIN generators to identify a generation protocol code. We anticipate the increase in burden related to this code to be very small because the parties already provide reports for the RFS program, generally. General recordkeeping and reporting for the RFS

[380] The impact on corn ethanol consumption volumes attributable to the RFS program is discussed in Set 1 RIA Chapters 2.1.1 and 3.2.

[381] 40 CFR 80.1454(g). We established the ''aggregate compliance'' approach in the 2010 RFS2 rule and has applied it for the U.S. in annual RFS rulemakings since then. 75 FR 14701–04 (March 26, 2010). In this final rule, we have not reexamined or reopened this policy, including the regulations at 40 CFR 80.1454(g) and 80.1457. Similarly, as further explained below, we have applied this approach for Canada since our approval of Canada's petition to use aggregate compliance in 2011. In this final rule, we have also not reexamined or reopened our decision on that petition. Any comments we received on these issues are beyond the scope of this rulemaking.

[382] For additional analysis and the underlying USDA data, see ''Assessment of Domestic Aggregate Compliance Approach 2024,'' available in the docket for this action.

[383] 75 FR 14701 (March 26, 2010).

[384] 40 CFR 80.1457.

[385] ''EPA Decision on Canadian Aggregate Compliance Approach Petition'' (Docket Item No. EPA–HQ–OAR–2011–0199–0015).

[386] The data used to make this calculation can be found in ''Changes to the Renewable Fuel Standard Program Aggregate Compliance for Canadian Crops and Crop Residues- Data Analysis and Justification for 2025,'' available in the docket for this action.

[387] 75 FR 14701 (March 26, 2010).

program is contained in the Renewable Fuel Standard program ICR, OMB Control Number 2060–0725 (extended pending OMB decision).

Respondents/affected entities: Renewable fuel producers, obligated parties, RIN owners, third party auditors (attest engagements), QAP auditors.

Respondent's obligation to respond: Mandatory, under 40 CFR part 80.

Estimated number of respondents: 3,689.

Frequency of response: Quarterly, annual, on occasion/as needed.

Total estimated burden: 11,483 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $24,512 (per year), includes $0 annualized capital or operation & maintenance costs.

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

D. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA.

With respect to the amendments to the RFS regulations, this action makes minor corrections and modifications to those regulations. As such, we do not anticipate that there will be any significant adverse economic impact on directly regulated small entities as a result of these revisions.

The small entities directly regulated by the annual percentage standards associated with the RFS volumes are small refiners that produce gasoline or diesel fuel, which are defined at 13 CFR 121.201. We believe that there are currently 6 refiners (owning 7 refineries) producing gasoline and/or diesel that meet the definition of small entity by having 1,500 employees or fewer. To evaluate the impacts of the 2026 and 2027 volume requirements on small entities, we have conducted a screening analysis to assess whether we should make a finding that this action will not have a significant economic impact on a substantial number of small entities.[388]

This action does not change the compliance flexibilities currently offered to small entities under the RFS program and currently available information shows that the impact on small entities from implementation of this rule will not be significant. We have reviewed and assessed the available information, which shows that obligated parties, in general on a nationwide scale, are able to recover the cost of acquiring the RINs necessary for compliance with the RFS standards through higher sales prices of the petroleum products they sell than would be expected in the absence of the RFS program.[389] This is true whether they acquire RINs by purchasing renewable fuels with attached RINs or purchasing separated RINs. The costs of the RFS program are thus being passed on to consumers in a highly competitive marketplace. Even if we were to assume that the cost of acquiring RINs was not recovered by obligated parties, a cost-to-sales ratio test shows that the costs to small entities of the RFS standards established in this action are less than 1 percent of the value of their sales.[390]

While the screening analysis described above supports a certification that this rule will not have a significant economic impact on small refiners, we continue to believe that it is more appropriate to consider the 2026 and 2027 standards as a part of our ongoing implementation of the overall RFS program. When considered this way, the impacts of the RFS program as a whole on small entities were addressed in the RFS2 Rule, which was the rule that implemented the entire program as required by EISA 2007.[391] As such, the Small Business Regulatory Enforcement Fairness Act (SBREFA) panel process that took place prior to the 2010 rule was also for the entire RFS program and looked at impacts on small refiners through the full implementation of the statutory volume targets.

For the SBREFA process for the RFS2 Rule, we analyzed the potential impacts of the RFS regulations on small entities. As a part of this analysis, we convened a Small Business Advocacy Review Panel (SBAR Panel, or ''the Panel''). During the Panel process, we gathered information and recommendations from Small Entity Representatives (SERs) on how to reduce the impact of the rule on small entities, and those comments are detailed in the Final Panel Report.[392] We also conducted an analysis of the potential impacts of the RFS program on all refiners, including small refiners, and found that the program would not have a significant economic impact on a substantial number of small entities.[393] For small refiners subject to the RFS program, the analysis included a cost-to-sales ratio test, a ratio of the estimated annualized compliance costs to the value of sales per company. From this test, we estimated that all directly regulated small entities would have compliance costs that are less than one percent of their sales over the full implementation of the statutory volume targets.[394] Furthermore, the EPA conducted a section 610 review of the RFS program in May 2020, in which the Agency was required to determine whether the RFS program should continue without change or should be rescinded or amended, consistent with the stated objectives of the CAA, to minimize any significant economic impact of the rule upon a substantial number of small entities.[395] Following a review of relevant evidence, the EPA did not identify any such potential changes that would reduce burden on a substantial number of small entities in a manner consistent with the stated objectives of the CAA or EISA and concluded that no changes to the RFS program were warranted.[396]

We have determined that this final rule will not impose any additional requirements on small entities beyond those already analyzed, since the impacts of this rule are not greater or fundamentally different than those already considered in the analysis for

[388] RIA Chapter 11.

[389] For a further discussion of the ability of obligated parties to recover the cost of RINs, *see, e.g.,* EPA, ''Denial of Petitions for Rulemaking to Change the RFS Point of Obligation,'' EPA–420–R–17–008, November 2017. *See also* Gerveni, Maria, Todd Hubbs, Scott H. Irwin, and James H. Stock. ''The Biofuels Blueprint: Understanding the U.S. Renewable Fuel Standard,'' January 12, 2026. *See also CBD* at 188, finding that the EPA properly considered RIN cost passthrough in setting the volume requirements in the Set 1 Rule, and acknowledging the ''central premise'' that ''refineries are able to pass RIN costs along to consumers'' as generally true.

[390] A cost-to-sales ratio of 1 percent represents a typical agency threshold for determining the significance of the economic impact on small entities. ''Final Guidance for EPA Rulewriters: Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act,'' November 2006.

[391] 75 FR 14670 (March 26, 2010).

[392] EPA, ''Final Report of the Small Business Advocacy Review Panel on EPA's Planned Proposed Rule Regulation of Fuels and Fuel Additives: Renewable Fuel Standard Program,'' September 8, 2008, Docket Item No. EPA–HQ–OAR–2005–0161–0457.

[393] 75 FR 14858–62 (March 26, 2010).

[394] 75 FR 14862 (March 26, 2010).

[395] EPA, ''Results of EPA's Section 610 Review of the Final Rule for Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program,'' May 2020, Docket Item No. EPA–HQ–OAR–2019–0168–0022.

[396] *Id.*

the RFS2 final rule assuming full implementation of the statutory volume targets. While in this action we are establishing volumes through our Set authority rather than reducing the statutory volumes through our waiver authorities (as was the case through 2022), the magnitude of the cellulosic biofuel, advanced biofuel, and total renewable fuel volume requirements established in this action nonetheless remain significantly below the statutory volume targets analyzed in the RFS2 Rule.[397] Compared to the burden that would be imposed under the volumes that we assessed in the analysis for the RFS2 Rule (*i.e.,* the volumes specified in the CAA), the volume requirements in this rule reduce burden on small entities. Regarding the BBD standard, it is a nested standard within the advanced biofuel category, and as discussed in section III of this preamble, the BBD volume requirements for 2026 and 2027 are below the volume of BBD that is anticipated to be produced and used to satisfy the advanced biofuel and total renewable fuel requirements. In other words, the volume of BBD actually used in 2026 and 2027 will be driven not by the 2026 and 2027 BBD standards, but rather by the 2026 and 2027 advanced biofuel and total renewable fuel standards. The net result of the standards being promulgated in this action is a reduction in burden as compared to implementation of the statutory volume targets assumed in the RFS2 Rule analysis.

Furthermore, to the degree that small entities may be impacted by this action, these impacts are mitigated by the existing compliance flexibilities in the RFS program that are available to small entities, which we are not changing in this rule. These flexibilities include being able to comply through RIN trading rather than renewable fuel blending, 20 percent RIN rollover allowance (up to 20 percent of an obligated party's RVO can be met using previous-year RINs), and deficit carry-forward (the ability to carry over a deficit from a given year into the following year, provided that the deficit is satisfied together with the next year's RVO). Additionally, as required by CAA section 211(o)(9)(B), the RFS regulations include a hardship relief provision that allows for a small refinery to petition for an extension of its small refinery exemption at any time based on a showing that the refinery is experiencing a ''disproportionate economic hardship.''[398] The RFS regulations provide the same relief to small refiners that are not eligible for small refinery relief.[399] In the RFS2 Rule, we discussed other potential small entity flexibilities that had been suggested by the SBAR Panel or through comments, but we did not adopt them, in part because we had serious concerns regarding our legal authority to do so.[400]

In sum, this rule will not change the compliance flexibilities currently offered to small entities under the RFS program and available information shows that the impact on small entities from implementation of this rule will not be significant. We have therefore concluded that this action will not have any significant adverse economic impact on directly regulated small entities.

E. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million (adjusted annually for inflation) or more (in 1995 dollars) as described in UMRA, 2 U.S.C. 1531–1538, for State, local, or Tribal governments, and does not significantly or uniquely affect small governments. This action imposes no enforceable duty on any State, local, or Tribal governments. This action contains a Federal mandate under UMRA that may result in expenditures of $100 million (adjusted annually for inflation) or more (in 1995 dollars) for the private sector in any one year. Accordingly, the costs associated with this rule are discussed in section III of this preamble and RIA Chapter 10.

This action is not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments.

F. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the National Government and the States, or on the distribution of power and responsibilities among the various levels of government.

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

This action does not have Tribal implications as specified in Executive Order 13175. This action will be implemented at the Federal level and affects transportation fuel refiners, blenders, marketers, distributors, importers, exporters, and renewable fuel producers and importers. Tribal governments will be affected only to the extent they produce, purchase, or use regulated fuels. Thus, Executive Order 13175 does not apply to this action.

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

Executive Order 13045 directs Federal agencies to include an evaluation of the health and safety effects of the planned regulation on children in Federal health and safety standards and explain why the regulation is preferable to potentially effective and reasonably feasible alternatives. This action is subject to Executive Order 13045 because it is an economically significant regulatory action under Executive Order 12866, and we believe that the environmental health or safety risks of the pollutants impacted by this action may have a disproportionate effect on children. The 2021 Policy on Children's Health also applies to this action.[401] An assessment of the environmental impacts from this rule is included in RIA Chapter 4.

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

This action is not a ''significant energy action'' because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. This action establishes the required renewable fuel content of the transportation fuel supply for 2026 and 2027 pursuant to the CAA. The RFS program and this rule are designed to achieve positive effects on the nation's transportation fuel supply by increasing energy independence and security. These positive impacts are described in section III of this preamble and RIA Chapter 6.

J. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51

This action involves technical standards. Except for the standards discussed in this section, the standards included in the regulatory text as incorporated by reference were all previously approved for incorporation by reference (IBR) and no change is included in this action.

[397] The statutory volume targets analyzed in the RFS2 Rule were 16 billion gallons of cellulosic biofuel, 21 billion gallons of advanced biofuel, and 36 billion gallons of total renewable fuel.

[398] 40 CFR 80.1441(e)(2).

[399] 40 CFR 80.1442(h).

[400] 75 FR 14858–62 (March 26, 2010).

[401] EPA, ''2021 Policy on Children's Health,'' October 5, 2021. *https://www.epa.gov/system/files/documents/2021-10/2021-policy-on-childrens-health.pdf.*

In accordance with the requirements of 1 CFR 51.5, we are incorporating by reference the use of certain standards and test methods from the American Gas Association (AGA), American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), ASTM International (ASTM), International Organization for Standardization (ISO), and the EPA. The standards and test methods may be obtained through the AGA website (*www.aga.org*) or by calling AGA at (202) 824–7000; the ANSI website (*www.ansi.org*) or by calling ANSI at (202) 293–8020; the API website (*www.api.org*) or by calling API at (202) 682–8000; the ASME website (*www.asme.org*) or by calling ASME at (800) 843–2763; the ASTM website (*www.astm.org*) or by calling ASTM at (877) 909–2786; the ISO website (*www.iso.org*) or by calling ISO at +41–22–749–01–11; and the EPA website (*www.epa.gov*) or by calling the EPA at (202) 272–0167. We are incorporating by reference the following standards:

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Organization and Standard or Test Method	Part and Section of Title 40	Summary
AGA Report No. 3 Part 1, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters Part 1: General Equations and Uncertainty Guidelines, 4th Edition, including Errata July 2013, Reaffirmed, July 2022	§§ 80.12 and 80.155(a)	This standard describes engineering equations, installation requirements, and uncertainty estimations of square-edged orifice meters in measuring the flow of natural gas and similar fluids.
AGA Report No. 3 Part 2, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters Part 2: Specification and Installation Requirements, 5th Edition, March 2016	§§ 80.12 and 80.155(a)	This standard describes design and installation of square-edged orifice meters for measuring flow of natural gas and similar fluids.
AGA Report No. 3 Part 3, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters Part 3: Natural Gas Applications, 4th Edition, Reaffirmed, June 2021	§§ 80.12 and 80.155(a)	This standard describes applications using square-edged orifice meters for measuring flow of natural gas and similar fluids.
AGA Report No. 3 Part 4, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters Part 4—Background, Development, Implementation Procedure, and Example Calculations, 4th Edition, October 2019	§§ 80.12 and 80.155(a)	This standard describes the development of equations for coefficient of discharge, including a calculation procedure, for square-edged orifice meters measuring flow of natural gas and similar fluids.
AGA Report No. 7, Measurement of Natural Gas by Turbine Meters, Revised February 2006	§§ 80.12 and 80.155(a)	This standard describes procedures and guidelines for measuring natural gas by turbine meters.
AGA Report No. 9, Measurement of Gas by Multipath Ultrasonic Meters, 2nd Edition, April 2007	§§ 80.12 and 80.155(a)	This standard describes procedures and guidelines for measuring natural gas by ultrasonic meters.
AGA Report No. 11, Measurement of Natural Gas by Coriolis Meter, 2nd Edition, February 2013 (co-published with API MPMS 14.9-2013)	§§ 80.12 and 80.155(a)	This standard describes procedures and guidelines for measuring natural gas by Coriolis meters.

Organization and Standard or Test Method	Part and Section of Title 40	Summary
ANSI B109.3-2019 (R2024), Rotary-Type Gas Displacement Meters, Fifth Edition, ANSI-approved February 5, 2019 (Reaffirmed April 26, 2024)	§§ 80.12 and 80.155(a)	This document describes a basic standard for safe operation, substantial and durable construction, and acceptable performance for rotary-type gas displacement meters.
API MPMS 14.9-2013, Measurement of Natural Gas by Coriolis Meter, 2nd Edition, February 2013 (co-published with AGA Report No. 11, 2013)	§§ 80.12 and 80.155(a)	This standard describes procedures and guidelines for measuring natural gas by Coriolis meters.
ASME MFC-3M-2004 (R2017), Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi, including ASME MFC-3M—2004 Addenda, Reaffirmed 2017	§§ 80.12 and 80.155(a)	This standard specifies the geometry and method of use for pressure differential devices (including, but not limited to, orifice plates, nozzles, and venturi tubes) when installed in a closed conduit running full and use to determine the flow-rate of the fluid flowing in the conduit.
ASME MFC-5.1-2011 (R2024), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters, Reaffirmed 2024	§§ 80.12 and 80.155(a)	This standard describes procedures and guidelines for measuring liquid flow by ultrasonic flowmeters.
ASME MFC-11-2006 (R2014), Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters, Reaffirmed 2014	§§ 80.12 and 80.155(a)	This standard gives guidelines for the selection, installation, calibration, and operation of Coriolis flowmeters for the determination of mass flow, density, volume flow, and other related parameters of flowing fluids.
ASME MFC-12M–2006 (R2014), Measurement of Fluid Flow in Closed Conduits Using Multiport Averaging Pitot Primary Elements, Reaffirmed 2014	§§ 80.12 and 80.155(a)	This standard provides information on the use of multiport averaging Pitot head-type devices used to measure liquids and gases.
ASME MFC-21.2-2010 (R2018), Measurement of Fluid Flow by Means of Thermal Dispersion Mass Flowmeters, Reaffirmed 2018	§§ 80.12 and 80.155(a)	This standard describes guidelines for the quality, description, principle of operation, selection, installation, and flow calibration of thermal dispersion flowmeters for the measurement of the mass flow rate and volumetric flow rate of the flow of a fluid in a closed conduit.

Organization and Standard or Test Method	Part and Section of Title 40	Summary
ASTM D86-23ae2, Standard Test Method for Distillation of Petroleum Products and Liquid Fuels at Atmospheric Pressure, approved December 1, 2023	§§ 80.2, 80.12, 1090.95, and 1090.1350(b)	This standard describes how to perform distillation measurements for gasoline and other petroleum products.
ASTM D287-22, Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method), approved December 1, 2022	§§ 1090.95 and 1090.1337(d)	This standard describes how to measure the density of fuels and other petroleum products, expressed in terms of API gravity.
ASTM D975-24a, Standard Specification for Diesel Fuel, approved August 1, 2024	§§ 80.2 and 80.12	This standard describes the characteristic values for several parameters to be considered suitable as diesel fuel.
ASTM D976-21e1, Standard Test Method for Calculated Cetane Index of Distillate Fuels, approved November 1, 2021	§§ 1090.95 and 1090.1350(b)	This standard describes how to calculate cetane index for a sample of diesel fuel and other distillate fuels.
ASTM D1142-95 (Reapproved 2021), Standard Test Method for Water Vapor Content of Gaseous Fuels by Measurement of Dew-Point Temperature, approved July 1, 2021	§§ 80.12 and 80.155(b)	This standard covers the determination of the water vapor content of gaseous fuels by measurement of the dew-point temperature and the calculation therefrom of the water vapor content.
ASTM D1298-24, Standard Test Method for Density, Relative Density, or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method, approved November 1, 2024	§§ 1090.12 and 1090.1337(d)	This standard describes how to measure the density of fuels and other petroleum products, which can be expressed in terms of API gravity.
ASTM D1655-25, Standard Specification for Aviation Turbine Fuels, approved October 1, 2025	§§ 80.2 and 80.12	This standard describes the characteristic values for several parameters to be considered suitable as jet fuel.
ASTM D1945-25, Standard Test Method for Analysis of Natural Gas by Gas Chromatography, approved August 1, 2025	§§ 80.12 and 80.155(b)	This standard describes how to determine the chemical composition of natural gas using gas chromatography.
ASTM D1946-24, Standard Practice for Analysis of Gaseous Fuels by Gas Chromatography, approved December 1, 2024	§§ 80.12 and 80.155(b)	This standard covers the determination of the chemical composition of gaseous fuels using gas chromatography.

Organization and Standard or Test Method	Part and Section of Title 40	Summary
ASTM D2622-24a, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-ray Fluorescence Spectrometry, approved December 1, 2024	§§ 1090.95, 1090.1350(b), 1090.1360(d), and 1090.1375(c)	This standard describes how to measure the sulfur content in gasoline, diesel fuel, and other petroleum products.
ASTM D3231-25, Standard Test Method for Phosphorus in Gasoline, approved May 1, 2025	§§ 1090.12 and 1090.1350(b)	This standard describes how to measure the phosphorus content of gasoline.
ASTM D3588-98 (Reapproved 2024)e1, Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels, approved May 1, 2024	§§ 80.12 and 80.155(b) and (f)	This standard describes the calculation protocol for aggregate properties of gaseous fuels from compositional measurements.
ASTM D3606-24a, Standard Test Method for Determination of Benzene and Toluene in Spark Ignition Fuels by Gas Chromatography, approved November 1, 2024	§§ 1090.95 and 1090.1360(c)	This standard describes how to measure the benzene content of gasoline and similar fuels.
ASTM D4057-22, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, approved May 1, 2022	§§ 80.8(a) and 80.12	This standard describes procedures for drawing samples of fuel and other petroleum products from storage tanks and other containers using manual procedures.
ASTM D4177-22e1, Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, approved July 1, 2022	§§ 80.8(b) and 80.12	This standard describes procedures for using automated procedures to draw fuel samples for testing.
ASTM D4442-20 (Reapproved 2025), Standard Test Methods for Direct Moisture Content Measurement of Wood and Wood-Based Materials, approved August 1, 2025	§§ 80.12 and 80.1426(f)	This standard describes how to determine the moisture content of wood samples.
ASTM D4444-25, Standard Test Method for Laboratory Standardization and Calibration of Hand-Held Moisture Meters, approved August 1, 2025	§§ 80.12 and 80.1426(f)	This standard describes how to determine the moisture content of wood samples.
ASTM D4737-21, Standard Test Method for Calculated Cetane Index by Four Variable Equation, approved November 1, 2021	§§ 1090.95 and 1090.1350(b)	This standard describes how to calculate cetane index for a sample of diesel fuel and other distillate fuels.
ASTM D4806-25, Standard Specification for Denatured Fuel Ethanol, approved April 1, 2025	§§ 1090.95 and 1090.1395(a)	This standard describes the characteristic values for several parameters to be considered suitable as denatured fuel ethanol for blending with gasoline.

Organization and Standard or Test Method	Part and Section of Title 40	Summary
ASTM D4814-25a, Standard Specification for Automotive Spark-Ignition Engine Fuel, approved December 15, 2025	§§ 1090.80, 1090.95, and 1090.1395(a)	This standard describes the characteristic values for several parameters to be considered suitable as gasoline.
ASTM D5134-21 (Reapproved 2025), Standard Test Method for Detailed Analysis of Petroleum Naphthas through n-Nonane by Capillary Gas Chromatography, approved October 1, 2025	§§ 1090.95 and 1090.1350(b)	This standard describes how to measure benzene in butane, pentane, and other light-end petroleum compounds.
ASTM D5453-25, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Spark Ignition Engine Fuel, Diesel Engine Fuel, and Engine Oil by Ultraviolet Fluorescence, approved July 1, 2025	§§ 1090.95 and 1090.1350(b)	This standard describes how to measure the sulfur content of neat ethanol and other petroleum products.
ASTM D5454-11 (Reapproved 2020), Standard Test Method for Water Vapor Content of Gaseous Fuels Using Electronic Moisture Analyzers, approved January 1, 2020	§§ 80.12 and 80.155(b)	This standard covers the determination of the water vapor content of gaseous fuels by the use of electronic moisture analyzers.
ASTM D5769-25, Standard Test Method for Determination of Benzene, Toluene, and Total Aromatics in Finished Gasolines by Gas Chromatography/Mass Spectrometry, approved October 1, 2025	§§ 1090.95, 1090.1350(b), and 1090.1360(d)	This standard describes how to determine the volume percent of benzene, toluene, and total aromatics in gasoline by gas chromatography/mass spectrometry.
ASTM D5842-23, Standard Practice for Sampling and Handling of Fuels for Volatility Measurement, approved October 1, 2023	§§ 80.8(c), 80.12, 1090.95, and 1090.1335(d)	This standard describes procedures for drawing samples of gasoline and other fuels from storage tanks and other containers using manual procedures to prepare samples for measuring vapor pressure.
ASTM D5854-25, Standard Practice for Mixing and Handling of Liquid Samples of Petroleum and Petroleum Products, approved July 1, 2025	§§ 80.8(d), 80.12, 1090.95, and 1090.1315(a)	This standard describes procedures for handling, mixing, and conditioning procedures to prepare representative composite samples.
ASTM D6228-19, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection, approved April 1, 2019	§§ 80.12 and 80.155(b)	This standard describes how to determine sulfur compounds in gaseous fuels by gas chromatography with a flame photometric detector or a pulsed flame photometric detector.

Organization and Standard or Test Method	Part and Section of Title 40	Summary
ASTM D6259-23, Standard Practice for Determination of a Pooled Limit of Quantitation for a Test Method, approved May 1, 2023	§§ 1090.95 and 1090.1355(b)	This standard describes procedures to determine how to evaluate parameter measurements at very low levels, including a laboratory limit of quantitation that applies for a given facility.
ASTM D6299-25a, Standard Practice for Applying Statistical Quality Assurance and Control Charting Techniques to Evaluate Analytical Measurement System Performance, approved July 1, 2025	§§ 1090.95, 1090.1300(d), 1090.1370(c), 1090.1375(a), (b), (c), and (d), and 1090.1450(c)	This standard establishes procedures to evaluate measurement system performance relative to statistical criteria for ensuring reliable measurements.
ASTM D6550-25, Standard Test Method for Determination of Olefin Content of Gasolines by Supercritical-Fluid Chromatography, approved October 1, 2025	§§ 1090.95 and 1090.1350(b)	This standard describes how to determine the total amount of olefins in blended motor gasolines and gasoline blending stocks by supercritical-fluid chromatography.
ASTM D6708-24, Standard Practice for Statistical Assessment and Improvement of Expected Agreement Between Two Test Methods that Purport to Measure the Same Property of a Material, approved March 1, 2024	§§ 1090.95, 1090.1360(c), 1090.1365(d) and (f), and 1090.1375(c)	This standard describes statistical criteria to evaluate whether an alternative test method provides results that are consistent with a reference procedure.
ASTM D6729-25, Standard Test Method for Determination of Individual Components in Spark Ignition Engine Fuels by 100 Metre Capillary High Resolution Gas Chromatography, approved October 1, 2025	§§ 1090.95 and 1090.1350(b)	This standard describes how to determine the benzene content of butane and pentane.
ASTM D6730-22, Standard Test Method for Determination of Individual Components in Spark Ignition Engine Fuels by 100-Metre Capillary (with Precolumn) High-Resolution Gas Chromatography, approved November 1, 2022	§§ 1090.95 and 1090.1350(b)	This standard describes how to determine the benzene content of butane and pentane.
ASTM D6751-24, Standard Specification for Biodiesel Fuel Blendstock (B100) for Middle Distillate Fuels, approved March 1, 2024	§ 1090.300(a)	This standard describes the characteristics of biodiesel.
ASTM D6792-25, Standard Practice for Quality Management Systems in Petroleum Products, Liquid Fuels, and Lubricants Testing Laboratories, approved November 1, 2025	§§ 1090.95 and 1090.1450(c)	This standard describes principles for ensuring quality for laboratories involved in parameter measurements for fuels and other petroleum products.

Organization and Standard or Test Method	Part and Section of Title 40	Summary
ASTM D6866-24a, Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis, approved December 1, 2024	§§ 80.12, 80.155(b), 80.1426(f), and 80.1430(e)	This standard describes the radiocarbon dating test method to determine the renewable content of biogas and RNG.
ASTM D6968-03 (Reapproved 2015), Standard Test Method for Simultaneous Measurement of Sulfur Compounds and Minor Hydrocarbons in Natural Gas and Gaseous Fuels by Gas Chromatography and Atomic Emission Detection, approved June 1, 2015	§§ 80.12 and 80.155(b)	This standard describes how to determine sulfur compounds and minor hydrocarbons in gaseous fuels by gas chromatography with a flame photometric detector and atomic emission detection.
ASTM D7566-25a, Standard Specification for Aviation Turbine Fuel Containing Synthesized Hydrocarbons, approved November 15, 2025	§§ 80.2 and 80.12	This standard describes the characteristic values for several parameters to be considered suitable as jet fuel.
ASTM D7717-11 (Reapproved 2021), Standard Practice for Preparing Volumetric Blends of Denatured Fuel Ethanol and Gasoline Blendstocks for Laboratory Analysis, approved October 1, 2021	§§ 1090.95 and 1090.1340(b)	This standard describes the procedures for blending denatured fuel ethanol with gasoline to prepare a sample for testing.
ASTM D7777-24, Standard Test Method for Density, Relative Density, or API Gravity of Liquid Petroleum by Portable Digital Density Meter, approved July 1, 2024	§§ 1090.95 and 1090.1337(d)	This standard describes how to measure the density of fuels and other petroleum products, expressed in terms of API gravity.
ASTM D7833-20, Standard Test Method for Determination of Hydrocarbons and Non-Hydrocarbon Gases in Gaseous Mixtures by Gas Chromatography, approved June 1, 2020	§§ 80.12 and 80.155(b)	This standard covers the determination of non-condensed hydrocarbon gases in gaseous samples using gas chromatography.
ASTM D7904-21, Standard Test Method for Determination of Water Vapor (Moisture Concentration) in Natural Gas by Tunable Diode Laser Spectroscopy (TDLAS), approved November 1, 2021	§§ 80.12 and 80.155(b)	This standard covers the online determination of vapor phase moisture concentration in natural gas using a tunable diode laser absorption spectroscopy analyzer.
ASTM E711-23e1, Standard Test Method for Gross Calorific Value of Refuse-Derived Fuel by the Bomb Calorimeter, approved April 1, 2023	§§ 80.12 and 80.1426(f)	This standard describes the procedures for determination of the gross calorific value of a prepared analysis sample of solid forms of refuse-derived fuel by the bomb calorimeter method.

Organization and Standard or Test Method	Part and Section of Title 40	Summary
ASTM E870-24, Standard Test Methods for Analysis of Wood Fuels, approved October 1, 2024	§§ 80.12 and 80.1426(f)	This standard describes the proximate analysis, ultimate analysis, and the determination of the gross caloric value of wood fuels.
ISO 5167-1:2022(E), Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full—Part 1: General principles and requirements, Third edition, June 2022	§§ 80.12 and 80.155(a)	This standard establishes the general principles for methods of measurement and computation of the flow rate of fluid flowing in a conduit by means of pressure differential devices when they are inserted into a circular cross-section conduit running full.
ISO 5167-2:2022(E), Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full—Part 2: Orifice plates, Second edition, June 2022	§§ 80.12 and 80.155(a)	This standard specifies the geometry and method of use of orifice plates when they are inserted in a conduit running full to determine the flow rate of the fluid flowing in the conduit.
ISO 5167-4:2022(E), Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full—Part 4: Venturi tubes, Second edition, June 2022	§§ 80.12 and 80.155(a)	This standard specifies the geometry and method of use of Venturi tubes when they are inserted in a conduit running full to determine the flow rate of the fluid flowing in the conduit.
ISO 5167-5:2022(E), Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full—Part 5: Cone meters, Second edition, October 2022	§§ 80.12 and 80.155(a)	This standard specifies the geometry and method of use of cone meters when they are inserted in a conduit running full to determine the flow rate of the fluid flowing in the conduit.
ISO 10790:2015(E), Measurement of fluid flow in closed conduits – Guidance to the selection, installation and use of Coriolis flowmeters (mass flow, density and volume flow measurements), Third edition, April 1, 2015	§§ 80.12 and 80.155(a)	This standard gives guidelines for the selection, installation, calibration, performance, and operation of Coriolis flowmeters for the measurement of mass flow and density.
ISO 14511:2019(E), Measurement of fluid flow in closed conduits – Thermal mass flowmeters, Second edition, January 2019	§§ 80.12 and 80.155(a)	This standard gives guidelines for the specification, testing, inspection, installation, operation and calibration of thermal mass gas flowmeters for the metering of gases and gas mixtures.

Organization and Standard or Test Method	Part and Section of Title 40	Summary
ISO 17089-1:2019(E), Measurement of fluid flow in closed conduits – Ultrasonic meters for gas— Part 1: Meters for custody transfer and allocation measurement, Second edition, August 2019	§§ 80.12 and 80.155(a)	This standard specifies requirements and recommendations for ultrasonic gas flowmeters, which utilize the transit time of acoustic signals to measure the flow of single-phase homogenous gases in closed conduits.
ISO 17089-2:2012(E), Measurement of fluid flow in closed conduits – Ultrasonic meters for gas— Part 2: Meters for industrial applications, First edition, October 1, 2012	§§ 80.12 and 80.155(a)	This standard specifies requirements and recommendations for ultrasonic gas meters, which utilize acoustic signals to measure the flow in the gaseous phase in closed conduits.
EPA Compendium Method TO-15, Determination Of Volatile Organic Compounds (VOCs) In Air Collected In Specially-Prepared Canisters And Analyzed By Gas Chromatography/Mass Spectrometry (GC/MS), (as published in /625/R-96/010b, Compendium of Methods for the Determination of Toxic Organic Compounds in Ambient Air, Second Edition), January 1999	§§ 80.12 and 80.155(b)	This standard specifies sampling and analytical procedures for identifying and measuring VOCs using gas chromatography/mass spectrometry.

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K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action meets the criteria set forth in 5 U.S.C. 804(2).

XII. Amendatory Instructions

Amendatory instructions are the standard terms that the Office of the Federal Register (OFR) uses to give specific instructions to agencies on how to change the CFR. OFR's historical guidance was to include amendatory instructions accompanying each individual change that was being made (*e.g.,* each sentence or individual paragraph). The piecemeal amendments served as an indication of changes we were making. Due to the extensive number of technical and conforming amendments included in this action, however, we are utilizing OFR's new amendatory instruction ''revise and republish'' for revisions finalized in this action.[402] Therefore, instead of the past practice of piecemeal amendments for revisions to the CFR, we are using the ''revise and republish'' instruction to both revise regulatory text and republish in their entirety certain sections of 40 CFR part 80 that contain the regulatory text being revised. To indicate those portions of provisions where changes are being revised, we have created a red-line version of 40 CFR part 80 that incorporates the changes. This red-line version is available in the docket for this action. This red-line version provides further context to assist the public in reviewing the regulatory text changes. As previously noted, we did not reopen those unchanged provisions for comment. Republishing provisions that are unchanged in this action is consistent with guidance from OFR.

[402] OFR's Document Drafting Handbook (Chapter 2, 2–38) explains that agencies ''[u]se [r]epublish to set out unchanged text for the convenience of the reader, often to provide context for your regulatory changes.'' *https://www.archives.gov/federal-register/write/handbook.* Additional information on OFR's mandatory use of ''revise and republish'' is available at *https://www.archives.gov/federal-register/write/ddh/revise-republish.*

XIII. Statutory Authority

Statutory authority for this action comes from sections 114, 203–05, 208, 211, 301, and 307 of the Clean Air Act, 42 U.S.C. 7414, 7522–24, 7542, 7545, 7601, and 7607.

List of Subjects

40 CFR Part 63

Administrative practice and procedure, Air pollution control.

40 CFR Part 80

Environmental protection, Administrative practice and procedure, Air pollution control, Diesel fuel, Fuel additives, Gasoline, Imports, Incorporation by reference, Oil imports, Petroleum, Renewable fuel.

40 CFR Part 1090

Environmental protection, Administrative practice and procedure, Air pollution control, Diesel fuel, Fuel additives, Gasoline, Imports, Incorporation by reference, Oil imports, Petroleum, Renewable fuel.

Lee Zeldin,

Administrator.

For the reasons set forth in the preamble, EPA amends 40 CFR parts 63, 80, and 1090 as follows:

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

■ 1. The authority citation for part 63 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

■ 2. Amend § 63.10042 by revising the definition for ''Clean fuel'' to read as follows:

§ 63.10042 What definitions apply to this subpart?

* * * * *

Clean fuel means natural gas, synthetic natural gas that meets the specification necessary for that gas to be transported on a Federal Energy Regulatory Commission (FERC) regulated pipeline, propane, distillate oil, synthesis gas that has been processed through a gas clean-up train such that it could be used in a system's combustion turbine, or ultra-low-sulfur diesel (ULSD) fuel, including those fuels meeting the requirements of part 1090, subpart D of this chapter.

* * * * *

PART 80—REGULATION OF FUELS AND FUEL ADDITIVES

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

Authority: 42 U.S.C. 7414, 7521, 7542, 7545, and 7601(a).

Subpart A—General Provisions

■ 4. Amend § 80.2 by:

■ a. Adding, in alphabetical order, a definition for ''Activated sludge'';

■ b. Removing the definition for ''A–RIN'';

■ c. Revising definitions for ''Assigned RIN'' and ''Biodiesel'';

■ d. In the definition for ''Biointermediate'', adding paragraphs (5)(x) and (xi);

■ e. In the definition for ''Biomass-based diesel'', revising paragraph (1)(ii);

■ f. Removing the definition for ''B–RIN'';

■ h. In the definition for ''Continuous measurement'', in paragraph (2), removing the text ''flow meters'' and adding, in its place, the text ''flowmeters'';

■ i. Adding, in alphabetical order, a definition for ''Converted oils'';

■ j. In the definition for ''Co-processed cellulosic diesel'', revising paragraph (1)(ii);

■ k. In the definition for ''Diesel fuel'', revising paragraph (1)(ii);

■ l. Revising definitions for ''Foreign renewable fuel producer'' and ''Importer'';

■ m. Removing the definition for ''Interim period'';

■ n. Revising the definition for ''MVNRLM diesel fuel'';

■ o. Removing the definition for ''Non-ester renewable diesel or renewable diesel'';

■ p. In the definition for ''Permitted capacity'', removing the text ''renewable fuel facility'' and adding, in its place, the text ''renewable fuel production facility'';

■ q. Adding, in alphabetical order, a definition for ''Renewable diesel'';

■ r. Removing the definition for ''Renewable electricity'';

■ s. Adding, in alphabetical order, definitions for ''Renewable fuel oil'', ''Renewable fuel producer'', and ''Renewable jet fuel'';

■ t. Revising the definition for ''Renewable liquefied natural gas or renewable LNG''; and

■ u. Adding, in alphabetical order, a definition for ''Renewable naphtha''.

The revisions and additions read as follows:

§ 80.2 Definitions.

* * * * *

Activated sludge means the waste sludge from a secondary wastewater treatment process involving oxygen and microorganisms.

* * * * *

Assigned RIN means a RIN assigned to a volume of renewable fuel or RNG pursuant to § 80.1426(e) or § 80.125(c), respectively, with a K code of 1 for renewable fuel or 3 for RNG.

* * * * *

Biodiesel means diesel fuel that is renewable fuel and that meets ASTM D6751 (incorporated by reference, see § 80.12).

* * * * *

Biointermediate * * *

(5) * * *

(x) Activated sludge.

(xi) Converted oils.

* * * * *

Biomass-based diesel * * *

(1) * * *

(ii) Meets the definition of either biodiesel or renewable diesel.

* * * * *

Converted oils means glycerides such as monoglycerides and diglycerides that are produced through the glycerolysis of biogenic waste oils/fats/greases with glycerol. Converted oils must exclusively consist of glycerides with fatty acid alkyl groups that originate from biogenic waste oils/fats/greases during the conversion process.

* * * * *

Co-processed cellulosic diesel * * *

(1) * * *

(ii) Meets the definition of either biodiesel or renewable diesel.

* * * * *

Diesel fuel * * *

(1) * * *

(ii) A non-distillate fuel other than residual fuel with comparable physical and chemical properties (*e.g.,* biodiesel, renewable diesel).

* * * * *

Foreign renewable fuel producer means any person that owns, leases, operates, controls, or supervises a facility outside the covered location where renewable fuel is produced.

* * * * *

Importer means any person who imports transportation fuel or renewable fuel into the covered location from an area outside of the covered location. This includes the importer of record or an authorized agent acting on their behalf, as well as the actual owner, the consignee, or the transferee, if the right to withdraw merchandise from a bonded warehouse has been transferred.

* * * * *

MVNRLM diesel fuel means any diesel fuel or other distillate fuel that is used, intended for use, or made available for use in motor vehicles or motor vehicle engines, or as a fuel in any nonroad diesel engines, including locomotive and marine diesel engines, except the following: Distillate fuel with a T90, as determined using ASTM D86 (incorporated by reference, see § 80.12), at or above 700 °F that is used only in Category 2 and 3 marine engines is not MVNRLM diesel fuel, and ECA marine fuel is not MVNRLM diesel fuel (note that fuel that conforms to the requirements of MVNRLM diesel fuel is excluded from the definition of ''ECA marine fuel'' in this section without regard to its actual use).

(1) Any diesel fuel that is sold for use in stationary engines that are required to meet the requirements of 40 CFR 1090.300, when such provisions are applicable to nonroad engines, is considered MVNRLM diesel fuel.

(2) [Reserved]

* * * * *

Renewable diesel means diesel fuel that is renewable fuel and that is one or more of the following:

(1) A fuel or fuel additive that meets the Grade No. 1–D or No. 2–D specification in ASTM D975 (incorporated by reference, see § 80.12).

(2) A fuel or fuel additive that is registered under 40 CFR part 79.

* * * * *

Renewable fuel oil means heating oil that is renewable fuel and that meets paragraph (2) of the definition for heating oil.

Renewable fuel producer means any person that owns, leases, operates, controls, or supervises a facility where renewable fuels are produced.

* * * * *

Renewable jet fuel means jet fuel that is renewable fuel and that meets ASTM D1655 or ASTM D7566 (both incorporated by reference, see § 80.12).

Renewable liquefied natural gas or *renewable LNG* means biogas, treated biogas, or RNG that is liquefied (*i.e.,* it is cooled below its boiling point) for use as transportation fuel and meets the definition of renewable fuel.

Renewable naphtha means naphtha that is renewable fuel.

* * * * *

■ 5. Amend § 80.3 by revising entry LNG to read as follows:

§ 80.3 Acronyms and abbreviations.

* * * * *

LNG .... Liquefied natural gas.

* * * * *

■ 6. Revise and republish § 80.12 to read as follows:

§ 80.12 Incorporation by reference.

Certain material is incorporated by reference into this part with the approval of the Director of the Federal Register under 5 U.S.C. 552(a) and 1 CFR part 51. All approved incorporation by reference (IBR) material is available for inspection at the U.S. EPA and at the National Archives and Records Administration (NARA). Contact the U.S. EPA at: U.S. EPA, Air and Radiation Docket and Information Center, WJC West Building, Room 3334, 1301 Constitution Ave. NW, Washington, DC 20460; (202) 566–1742; *a-and-r-Docket@epa.gov.* For information on the availability of this material at NARA, visit *www.archives.gov/federal-register/cfr/ibr-locations* or email *fr.inspection@nara.gov.* The material may be obtained from the following sources:

(a) American Gas Association (AGA), 400 North Capitol Street NW, Suite 450, Washington, DC 20001; (202) 824–7000; *www.aga.org.*

(1) AGA Report No. 3 Part 1, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters Part 1: General Equations and Uncertainty Guidelines, 4th Edition, including Errata July 2013, Reaffirmed, July 2022; IBR approved for § 80.155(a).

(2) AGA Report No. 3 Part 2, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters Part 2: Specification and Installation Requirements, 5th Edition, March 2016; IBR approved for § 80.155(a).

(3) AGA Report No. 3 Part 3, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters Part 3: Natural Gas Applications, 4th Edition, Reaffirmed, June 2021; IBR approved for § 80.155(a).

(4) AGA Report No. 3 Part 4, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters Part 4—Background, Development, Implementation Procedure, and Example Calculations, 4th Edition, October 2019; IBR approved for § 80.155(a).

(5) AGA Report No. 7, Measurement of Natural Gas by Turbine Meters, Revised February 2006; IBR approved for § 80.155(a).

(6) AGA Report No. 9, Measurement of Gas by Multipath Ultrasonic Meters, 2nd Edition, April 2007; IBR approved for § 80.155(a).

(7) AGA Report No. 11, Measurement of Natural Gas by Coriolis Meter, 2nd Edition, February 2013; IBR approved for § 80.155(a).

(8) ANSI B109.3–2019 (R2024), Rotary-Type Gas Displacement Meters, Fifth Edition, ANSI-approved, February 5, 2019 (Reaffirmed April 16, 2024) (ANSI B109.3); IBR approved for § 80.155(a).

Note 1 to paragraph (a)(8): ANSI B109.3 is also available from the American National Standards Institute (*www.ansi.org*).

(b) American Petroleum Institute (API), 200 Massachusetts Avenue NW, Suite 1100, Washington, DC 20001–5571; (202) 682–8000; *www.api.org.*

(1) API MPMS 14.1–2016, Manual of Petroleum Measurement Standards Chapter 14—Natural Gas Fluids Measurement Section 1—Collecting and Handling of Natural Gas Samples for Custody Transfer, 7th Edition, May 2016 (API MPMS 14.1); IBR approved for § 80.155(b).

(2) API MPMS 14.3.1–2012, Manual of Petroleum Measurement Standards Chapter 14.3.1—Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters Part 1: General Equations and Uncertainty Guidelines, 4th Edition, including Errata July 2013, Reaffirmed, July 2022 (API MPMS 14.3.1); IBR approved for § 80.155(a).

(3) API MPMS 14.3.2–2016, Manual of Petroleum Measurement Standards Chapter 14.3.2—Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters Part 2: Specification and Installation Requirements, 5th Edition, March 2016 (API MPMS 14.3.2); IBR approved for § 80.155(a).

(4) API MPMS 14.3.3–2013, Manual of Petroleum Measurement Standards Chapter 14.3.3—Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters Part 3: Natural Gas Applications, 4th Edition, Reaffirmed, June 2021 (API MPMS 14.3.3); IBR approved for § 80.155(a).

(5) API MPMS 14.3.4–2019, Manual of Petroleum Measurement Standards Chapter 14.3.4—Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters Part 4—Background, Development, Implementation Procedure, and Example Calculations, 4th Edition, October 2019 (API MPMS 14.3.4); IBR approved for § 80.155(a).

(6) API MPMS 14.9–2013, Measurement of Natural Gas by Coriolis Meter, 2nd Edition, February 2013 (API MPMS 14.9); IBR approved for § 80.155(a).

(7) API MPMS 14.12–2017, Manual of Petroleum Measurement Standards Chapter 14—Natural Gas Fluid Measurement Section 12—Measurement of Gas by Vortex Meters, 1st Edition, March 2017 (API MPMS 14.12); IBR approved for § 80.155(a).

Note 2 to paragraph (b): API MPMS 14.3.1, 14.3.2, 14.3.3, and 14.3.4, are co-published as AGA Report 3, Parts 1, 2, 3, and 4, respectively. API MPMS 14.9 is co-published as AGA Report No. 11.

(c) American Public Health Association (APHA), 1015 15th Street NW, Washington, DC 20005; (202) 777–2742; *www.standardmethods.org.*

(1) SM 2540, Solids, revised June 10, 2020; IBR approved for § 80.155(c).

(2) [Reserved]

(d) American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016–5990; (800) 843–2763; *www.asme.org.*

(1) ASME MFC–3M–2004 (R2017), Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi, including ASME MFC–3M—2004 Addenda, Reaffirmed 2017 (ASME MFC–3M); IBR approved for § 80.155(a).

(2) ASME MFC–5.1–2011 (R2024), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters, Reaffirmed 2024 (ASME MFC–5.1); IBR approved for § 80.155(a).

(3) ASME MFC–11–2006 (R2014), Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters, Reaffirmed 2014 (ASME MFC–11); IBR approved for § 80.155(a).

(4) ASME MFC–12M–2006 (R2014), Measurement of Fluid Flow in Closed Conduits Using Multiport Averaging Pitot Primary Elements, Reaffirmed 2014 (ASME MFC–12M); IBR approved for § 80.155(a).

(5) ASME MFC–21.2–2010 (R2018), Measurement of Fluid Flow by Means of Thermal Dispersion Mass Flowmeters, Reaffirmed 2018 (ASME MFC–21.2); IBR approved for § 80.155(a).

(e) ASTM International (ASTM), 100 Barr Harbor Dr., P.O. Box C700, West Conshohocken, PA 19428–2959; (877) 909–2786; *www.astm.org.*

(1) ASTM D86–23ae2, Standard Test Method for Distillation of Petroleum Products and Liquid Fuels at Atmospheric Pressure, approved December 1, 2023 (ASTM D86); IBR approved for § 80.2.

(2) ASTM D975–24a, Standard Specification for Diesel Fuel, approved August 1, 2024 (ASTM D975); IBR approved for § 80.2.

(3) ASTM D1142–95 (Reapproved 2021), Standard Test Method for Water Vapor Content of Gaseous Fuels by Measurement of Dew-Point Temperature, approved July 1, 2021 (ASTM D1142); IBR approved for § 80.155(b).

(4) ASTM D1250–19e1, Standard Guide for the Use of the Joint API and ASTM Adjunct for Temperature and Pressure Volume Correction Factors for Generalized Crude Oils, Refined Products, and Lubricating Oils: API MPMS Chapter 11.1, approved May 1, 2019 (ASTM D1250); IBR approved for § 80.1426(f).

(5) ASTM D1655–25, Standard Specification for Aviation Turbine Fuels, approved October 1, 2025 (ASTM D1655); IBR approved for § 80.2.

(6) ASTM D1945–25, Standard Test Method for Analysis of Natural Gas by Gas Chromatography, approved August 1, 2025 (ASTM D1945); IBR approved for § 80.155(b).

(7) ASTM D1946–24, Standard Practice for Analysis of Gaseous Fuels by Gas Chromatography, approved December 1, 2024 (ASTM D1946); IBR approved for § 80.155(b).

(8) ASTM D3588–98 (Reapproved 2024)e1, Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels, approved May 1, 2024 (ASTM D3588); IBR approved for § 80.155(b) and (f).

(9) ASTM D4057–22, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, approved May 1, 2022 (ASTM D4057); IBR approved for § 80.8(a).

(10) ASTM D4177–22e1, Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, approved July 1, 2022 (ASTM D4177); IBR approved for § 80.8(b).

(11) ASTM D4442–20 (Reapproved 2025), Standard Test Methods for Direct Moisture Content Measurement of Wood and Wood-Based Materials, approved August 1, 2025 (ASTM D4442); IBR approved for § 80.1426(f).

(12) ASTM D4444–25, Standard Test Method for Laboratory Standardization and Calibration of Hand-Held Moisture Meters, approved August 1, 2025 (ASTM D4444); IBR approved for § 80.1426(f).

(13) ASTM D4888–20, Standard Test Method for Water Vapor in Natural Gas Using Length-of-Stain Detector Tubes, approved December 15, 2020 (ASTM D4888); IBR approved for § 80.155(b).

(14) ASTM D5454–11 (Reapproved 2020), Standard Test Method for Water Vapor Content of Gaseous Fuels Using Electronic Moisture Analyzers, approved January 1, 2020 (ASTM D5454); IBR approved for § 80.155(b).

(15) ASTM D5504–20, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, approved November 1, 2020 (ASTM D5504); IBR approved for § 80.155(b).

(16) ASTM D5842–23, Standard Practice for Sampling and Handling of Fuels for Volatility Measurement, approved October 1, 2023 (ASTM D5842); IBR approved for § 80.8(c).

(17) ASTM D5854–25, Standard Practice for Mixing and Handling of Liquid Samples of Petroleum and Petroleum Products, approved July 1, 2025 (ASTM D5854); IBR approved for § 80.8(d).

(18) ASTM D6228–19, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection, approved April 1, 2019 (ASTM D6228); IBR approved for § 80.155(b).

(19) ASTM D6751–24, Standard Specification for Biodiesel Fuel Blendstock (B100) for Middle Distillate Fuels, approved March 1, 2024 (ASTM D6751); IBR approved for § 80.2.

(20) ASTM D6866–24a, Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis, approved December 1, 2024 (ASTM D6866); IBR approved for §§ 80.155(b); 80.1426(f); 80.1430(e).

(21) ASTM D6968–03 (Reapproved 2015), Standard Test Method for Simultaneous Measurement of Sulfur Compounds and Minor Hydrocarbons in Natural Gas and Gaseous Fuels by Gas Chromatography and Atomic Emission Detection, approved June 1, 2015 (ASTM D6968); IBR approved for § 80.155(b).

(22) ASTM D7164–21, Standard Practice for On-line/At-line Heating Value Determination of Gaseous Fuels by Gas Chromatography, approved April 1, 2021 (ASTM D7164); IBR approved for § 80.155(a).

(23) ASTM D7566–25a, Standard Specification for Aviation Turbine Fuel Containing Synthesized Hydrocarbons, approved November 15, 2025 (ASTM D7566); IBR approved for § 80.2.

(24) ASTM D7833–20, Standard Test Method for Determination of Hydrocarbons and Non-Hydrocarbon Gases in Gaseous Mixtures by Gas Chromatography, approved June 1, 2020 (ASTM D7833); IBR approved for § 80.155(b).

(25) ASTM D7904–21, Standard Test Method for Determination of Water Vapor (Moisture Concentration) in Natural Gas by Tunable Diode Laser Spectroscopy (TDLAS), approved November 1, 2021 (ASTM D7904); IBR approved for § 80.155(b).

(26) ASTM D8230–19, Standard Test Method for Measurement of Volatile Silicon-Containing Compounds in a Gaseous Fuel Sample Using Gas Chromatography with Spectroscopic Detection, approved June 1, 2019 (ASTM D8230); IBR approved for § 80.155(b).

(27) ASTM E711–23e1, Standard Test Method for Gross Calorific Value of Refuse-Derived Fuel by the Bomb Calorimeter, approved April 1, 2023 (ASTM E711); IBR approved for § 80.1426(f).

(28) ASTM E870–24, Standard Test Methods for Analysis of Wood Fuels, approved October 1, 2024 (ASTM E870); IBR approved for § 80.1426(f).

(f) European Committee for Standardization (CEN), Rue de la Science 23, B–1040 Brussels, Belgium; + 32 2 550 08 11; *www.cencenelec.eu.*

(1) EN 17526:2021(E), Gas meter—Thermal-mass flow-meter based gas meter, approved July 11, 2021 (EN 17526); IBR approved for § 80.155(a).

(2) [Reserved]

(g) International Organization for Standardization (ISO), Chemin de Blandonnet 8, CP 401, 1214 Vernier, Geneva, Switzerland; +41 22 749 01 11; *www.iso.org.*

(1) ISO 5167–1:2022(E), Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full—Part 1: General principles and requirements, Third edition, June 2022 (ISO 5167–1); IBR approved for § 80.155(a).

(2) ISO 5167–2:2022(E), Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full—Part 2: Orifice plates, Second edition, June 2022 (ISO 5167–2); IBR approved for § 80.155(a).

(3) ISO 5167–4:2022(E), Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full—Part 4: Venturi tubes, Second edition, June 2022 (ISO 5167–4); IBR approved for § 80.155(a).

(4) ISO 5167–5:2022(E), Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full—Part 5: Cone meters, Second edition, October 2022 (ISO 5167–5); IBR approved for § 80.155(a).

(5) ISO 10790:2015(E), Measurement of fluid flow in closed conduits—Guidance to the selection, installation and use of Coriolis flowmeters (mass flow, density and volume flow measurements), Third edition, April 1, 2015 (ISO 10790); IBR approved for § 80.155(a).

(6) ISO 14511:2019(E), Measurement of fluid flow in closed conduits—Thermal mass flowmeters, Second edition, January 2019 (ISO 14511); IBR approved for § 80.155(a).

(7) ISO 17089–1:2019(E), Measurement of fluid flow in closed conduits—Ultrasonic meters for gas—Part 1: Meters for custody transfer and allocation measurement, Second edition, August 2019 (ISO 17089–1); IBR approved for § 80.155(a).

(8) ISO 17089–2:2012(E), Measurement of fluid flow in closed conduits—Ultrasonic meters for gas—Part 2: Meters for industrial applications, First edition, October 1, 2012 (ISO 17089–2); IBR approved for § 80.155(a).

(h) U.S. Environmental Protection Agency (EPA), 1200 Pennsylvania Avenue NW, Washington, DC 20460; (202) 272–0167; *www.epa.gov.*

(1) EPA Compendium Method TO–15, Determination Of Volatile Organic Compounds (VOCs) In Air Collected In Specially-Prepared Canisters And Analyzed By Gas Chromatography/Mass Spectrometry (GC/MS), (as published in/625/R–96/010b, Compendium of Methods for the Determination of Toxic Organic Compounds in Ambient Air, Second Edition), January 1999 (EPA Method TO–15); IBR approved for § 80.155(b).

(2) [Reserved]

Subpart E—Biogas-Derived Renewable Fuel

■ 7. Amend § 80.105 by revising paragraphs (j)(1) and (3) and adding paragraph (j)(4) to read as follows:

§ 80.105 Biogas producers.

* * * * *

(j) * * *

(1) Except for biogas produced from a mixed digester, the batch volume of biogas is the volume of biogas measured under paragraph (f) of this section for a single batch pathway at a single facility for up to a calendar month, in Btu HHV.

* * * * *

(3) The biogas producer must assign a number (the ‘‘batch number’’) to each batch of biogas consisting of their EPA-issued company registration number, the EPA-issued facility registration number, the last two digits of the compliance year in which the batch was produced, and a unique number for the batch during the compliance year (*e.g.,* 4321–54321–25–000001).

(4) The production date for a batch of biogas is the last day of the time period that the batch represents. For example, the production date for a batch of biogas for the month of January would be January 31, while the production date for a batch of biogas for February 1–14 would be February 14.

* * * * *

■ 8. Amend § 80.110 by revising paragraphs (f)(2)(iii) introductory text and (j)(1) and (3) to read as follows:

§ 80.110 RNG producers, RNG importers, and biogas closed distribution system RIN generators.

* * * * *

(f) * * *

(2) * * *

(iii) As part of three-year engineering review updates required under § 80.135(b)(3) submitted on or after January 1, 2027, an RNG producer that injects RNG from an RNG production facility into a natural gas commercial pipeline system must sample and test a representative sample of all the following at least once every three years, as applicable:

* * * * *

(j) * * *

(1) A batch of RNG is the total volume of RNG injected into a natural gas commercial pipeline system from an RNG production facility under a single batch pathway for the calendar month, in Btu LHV, as determined under paragraph (j)(4) of this section.

* * * * *

(3) The RNG producer, RNG importer, or biogas closed distribution system RIN generator must assign a number (the ‘‘batch number’’) to each batch of RNG or biogas-derived renewable fuel consisting of their EPA-issued company registration number, the EPA-issued facility registration number, the last two digits of the compliance year in which the batch was produced, and a unique number for the batch during the compliance year (*e.g.,* 4321–54321–25–000001).

* * * * *

■ 9. Amend § 80.115 by revising paragraph (b) to read as follows:

§ 80.115 RNG RIN separators.

* * * * *

(b) *Registration.* The RNG RIN separator must register with EPA under §§ 80.135 and 80.1450 and 40 CFR part 1090, subpart I, as applicable.

* * * * *

■ 10. Amend § 80.125 by:

■ a. In paragraphs (b)(6) and (7), removing the text ‘‘§ 80.1415(b)(5)’’ and adding, in its place, the text ‘‘§ 80.1415(b)’’;

■ b. Revising paragraphs (c)(3) and (d)(4);

■ c. Adding paragraph (d)(5); and

■ d. Revising paragraphs (e)(1) and (2).

The revisions and addition read as follows:

§ 80.125 RINs for RNG.

* * * * *

(c) * * *

(3) For purposes of this part, each party that transfers title of an assigned RIN for RNG is deemed to have transferred a corresponding volume of RNG to the transferee.

(d) * * *

(4) A party must only separate a number of RINs equal to the total volume of RNG (where the Btu LHV are converted to gallon-RINs using the conversion specified in § 80.1415(b)) that the party demonstrates is used as renewable CNG/LNG under paragraph (d)(2) of this section.

(5) An assigned RIN for RNG must be separated by December 31 of the subsequent calendar year after the RIN for RNG was generated. Any RINs for RNG not separated by this date are expired.

(e) * * *

(1) A party must retire RINs for RNG if any of the conditions specified in § 80.1434(a) apply and must comply with § 80.1434(b).

(2) A party must retire any expired RINs for RNG under paragraph (d)(5) of this section by March 31 of the subsequent calendar year after the RINs expired. For example, if an RNG producer assigns RINs for RNG in 2025, the RINs expire if they are not separated under paragraph (d) of this section by December 31, 2026, and must be retired by March 31, 2027.

* * * * *

■ 11. Amend § 80.135 by:

■ a. Revising paragraph (b)(2)(ii);

■ b. Revising and republishing paragraph (c)(3);

■ d. Revising paragraph (c)(10)(vi)(A)(*5*);

■ e. Revising and republishing paragraph (d)(3);

■ f. Revising paragraphs (d)(5) and (d)(6)(i) and (ii);

■ g. Adding paragraph (d)(6)(vi); and

■ h. Revising paragraphs (d)(7)(ii) and (f).

The revisions, republications, and addition read as follows:

§ 80.135 Registration.

* * * * *

(b) * * *

(2) * * *

(ii) A biogas closed distribution system RIN generator or biogas producer does not need to submit an updated engineering review for any facility before the next three-year engineering review update is due as specified in § 80.1450(d)(3).

* * * * *

(c) * * *

(3) The following information related to biogas measurement:

(i) A description of how biogas will be measured, including the specific standards under which the meters are operated.

(ii) A description of the biogas production process, including a process flow diagram that includes metering type(s) and location(s).

(iii) For an alternative measurement protocol under § 80.155(a)(2), all the following:

(A) A description of how measurement is conducted.

(B) Any standards or specifications that apply.

(C) A description of all routine maintenance and the frequency that such maintenance will be conducted.

(D) A description of the frequency of all measurements and how often such measurements will be recorded under the alternative measurement protocol.

(E) A comparison between the accuracy, precision, and reliability of the alternative measurement protocol and the requirements specified in § 80.155(a)(1), including any supporting data.

* * * * *

(10) * * *

(vi) * * *

(A) * * *

(*5*) A demonstration that no biogas produced from non-cellulosic biogas feedstocks could be used to generate RINs for a batch of renewable fuel with a D code of 3 or 7. EPA may reject this demonstration if it is not sufficiently protective.

* * * * *

(d) * * *

(3) The following information related to RNG measurement:

(i) A description of how RNG will be measured, including the specific standards under which the meters are operated.

(ii) A description of the RNG production process, including a process flow diagram that includes metering type(s) and location(s).

(iii) For an alternative measurement protocol under § 80.155(a)(2), all the following:

(A) A description of how measurement is conducted.

(B) Any standards or specifications that apply.

(C) A description of all routine maintenance and the frequency that such maintenance will be conducted.

(D) A description of the frequency of all measurements and how often such measurements will be recorded under the alternative measurement protocol.

(E) A comparison between the accuracy, precision, and reliability of the alternative measurement protocol and the requirements specified in § 80.155(a)(1), as applicable, including any supporting data.

* * * * *

(5) A description of the natural gas specifications for the natural gas commercial pipeline system into which the RNG will be injected, including information on all parameters regulated by the pipeline (*e.g.,* hydrogen sulfide, total sulfur, carbon dioxide, oxygen, nitrogen, heating content, moisture, siloxanes, etc.).

(6) * * *

(i) A certificate of analysis from an independent laboratory for a representative sample of the biogas produced at the biogas production facility as specified in § 80.155(b).

(ii) A certificate of analysis from an independent laboratory for a representative sample of the RNG prior to addition of non-renewable components as specified in § 80.155(b).

* * * * *

(vi) Except as specified in § 80.155(b)(2)(vii), an RNG producer does not need to test for a parameter specified in § 80.155(b)(2) if the parameter is not included in the pipeline specifications submitted at registration under paragraph (d)(5) of this section.

(7) * * *

(ii) A diagram showing the locations of flowmeters, gas analyzers, and in-line GC meters used in the allocation procedure.

* * * * *

(f) *RNG RIN separator.* In addition to the information required under paragraph (b) of this section, an RNG RIN separator must submit all the following information:

(1) A list of locations of any dispensing stations where the RNG RIN separator supplies or intends to supply renewable CNG/LNG for use as transportation fuel.

(2) A list of the names and locations of each point where RNG will be withdrawn from the natural gas commercial pipeline system.

* * * * *

■ 12. Amend § 80.140 by revising paragraph (b)(2) and paragraph (e)(2) introductory text to read as follows:

§ 80.140 Reporting.

* * * * *

(b) * * *

(2) Production date.

* * * * *

(e) * * *

(2) An RNG RIN separator must submit monthly reports to EPA containing all the following information for each month's renewable CNG/LNG dispensing activity:

* * * * *

■ 13. Amend § 80.155 by:

■ a. Revising and republishing paragraphs (a) and (b)(2);

■ b. Adding paragraph (b)(3); and

■ c. Revising paragraph (f)(2) introductory text.

The revisions, republications, and addition read as follows:

§ 80.155 Sampling, testing, and measurement.

(a) *Continuous measurement*—(1) *Biogas, treated biogas, and RNG measurement.* Except as specified in paragraph (a)(3) of this section, any party required to measure the volume of biogas, treated biogas, or RNG under this subpart must continuously measure using meters as specified in paragraphs (a)(1)(i) and (ii) of this section or have an accepted alternative measurement protocol as specified in paragraph (a)(2) of this section.

(i) In-line GC meters compliant with ASTM D7164 (incorporated by reference, see § 80.12), including sections 9.2, 9.3, 9.4, 9.5, 9.7, 9.8, and 9.11 of ASTM D7164.

(ii) Flowmeters compliant with one of the following:

TABLE 1 TO PARAGRAPH (a)(1)(ii)—FLOWMETER METHODS

Flowmeter type	Method [1]
Cone	ISO 5167–1 and ISO 5167–5.
Coriolis	AGA Report No. 11; API MPMS 14.9; ASME MFC–11; ISO 10790.
Orifice plate	AGA Report No. 3 Parts 1, 2, 3, and 4; API MPMS 14.3.1, API MPMS 14.3.2, API MPMS 14.3.3, and API MPMS 14.3.4; ASME MFC–3M; ISO 5167–1 and ISO 5167–2.
Pitot tube	ASME MFC–12M.
Rotary	ANSI B109.3.
Thermal dispersion	ASME MFC-21.2.
Thermal mass	EN 17526 compatible with gas type H; ISO 14511.
Turbine	AGA Report No. 7.
Ultrasonic	AGA Report No. 9; ASME MFC–5.1; ISO 17089–1; ISO 17089–2.

TABLE 1 TO PARAGRAPH (a)(1)(ii)—FLOWMETER METHODS—Continued

Flowmeter type	Method [1]
Venturi	ISO 5167–1 and ISO 5167–4.
Vortex	API MPMS 14.12.

[1] Methods are incorporated by reference, see § 80.12).

(2) *Alternative measurement protocols.* EPA may accept an alternative measurement protocol if the party demonstrates that the alternative measurement protocol is at least as accurate and precise as the methods specified in paragraph (a)(1) of this section. An alternative measurement protocol may include less frequent measurement or recording than specified in the definition of continuous measurement.

(3) *RNG RIN separator measurement.* An RNG RIN separator must measure natural gas or renewable CNG/LNG using one of the following:

(i) A method specified in paragraph (a)(1) or (2) of this section.

(ii) Documentation (*e.g.,* pipeline or utility statements, scale tickets, or bills of lading) that establishes the volume of natural gas or renewable CNG/LNG. Documentation must be specified in Btu LHV or converted as specified in paragraph (f) of this section.

(b) * * *

(2) Perform all the following measurements on each representative sample:

(i) Methane, carbon dioxide, nitrogen, and oxygen using EPA Method 3C (see appendix A–2 to 40 CFR part 60), ASTM D1945, ASTM D1946, or ASTM D7833 (all incorporated by reference, see § 80.12).

(ii) Hydrogen sulfide and total sulfur using ASTM D5504, ASTM D6228, or ASTM D6968 (all incorporated by reference, see § 80.12).

(iii) Siloxanes using ASTM D8230 (incorporated by reference, see § 80.12).

(iv) Moisture using ASTM D1142, ASTM D4888, ASTM D5454, or ASTM D7904 (all incorporated by reference, see § 80.12).

(v) Hydrocarbon analysis using EPA Method 18 (see appendix A–6 to 40 CFR part 60), ASTM D1945, ASTM D1946, ASTM D7833, or EPA Method TO–15 (all incorporated by reference, see § 80.12).

(vi) Heating value and relative density using ASTM D3588 (incorporated by reference, see § 80.12).

(vii) If the RNG producer blends non-renewable components into RNG, carbon-14 analysis using ASTM D6866 (incorporated by reference, see § 80.12).

(3) EPA may approve a party's request to use a method other than those specified in paragraph (b)(2) of this section if the party demonstrates one of the following:

(i) The alternative analysis provides information that is reasonably accurate to that determined by the applicable method specified in paragraph (b)(2) of this section.

(ii) The alternative analysis is required by pipeline specifications or has been approved to be used by a State or Federal government agency.

* * * * *

(f) * * *

(2) A party with documentation under paragraph (a)(3) of this section that is not specified in Btu must convert to Btu LHV as follows:

* * * * *

■ 14. Amend § 80.165 by revising paragraph (a)(1) to read as follows:

§ 80.165 Attest engagements.

(a) * * *

(1) The following parties must arrange for annual attestation engagement using agreed-upon procedures:

(i) Biogas producers that supplied biogas to produce RNG or a biogas-derived renewable fuel within the compliance year.

(ii) RNG producers that generated RINs within the compliance year.

(iii) RNG importers that generated RINs within the compliance year.

(iv) Biogas closed distribution system RIN generators that generated RINs within the compliance year.

(v) RNG RIN separators that separated RINs from RNG within the compliance year.

(vi) Renewable fuel producers that use RNG as a feedstock within the compliance year.

* * * * *

Subpart M—Renewable Fuel Standard

■ 15. Amend § 80.1405 by:

■ a. In table 1 to paragraph (a), revising entry 2025 and adding entries 2026 and 2027 in numerical order; and

■ b. Revising paragraphs (b) through (d).

The revisions and additions read as follows:

§ 80.1405 What are the Renewable Fuel Standards?

(a) * * *

TABLE 1 TO PARAGRAPH (a)—ANNUAL RENEWABLE FUEL STANDARDS

Year	Cellulosic biofuel standard (%)	Biomass-based diesel standard (%)	Advanced biofuel standard (%)	Renewable fuel standard (%)	Supplemental total renewable fuel standard (%)
* * *	*	*	*	*	*
2025	0.71	3.15	4.31	13.13	n/a
2026	0.79	5.24	6.42	15.50	n/a
2027	0.84	5.37	6.61	15.78	n/a

(b) Except as specified in paragraph (c) of this section, EPA will calculate the annual renewable fuel percentage standards using the following equations:

$$Std_{CB,i} = 100 * \frac{RFV_{CB,i}}{(G_i - RG_i) - GE_i + (D_i - RD_i) - DE_i}$$

$$Std_{BBD,i} = 100 * \frac{RFV_{BBD,i}}{(G_i - RG_i) - GE_i + (D_i - RD_i) - DE_i}$$

$$Std_{AB,i} = 100 * \frac{RFV_{AB,i}}{(G_i - RG_i) - GE_i + (D_i - RD_i) - DE_i}$$

$$Std_{RF,i} = 100 * \frac{RFV_{RF,i}}{(G_i - RG_i) - GE_i + (D_i - RD_i) - DE_i}$$

Where:

$Std_{CB,i}$ = Cellulosic biofuel standard for year i, in percent.

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

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

$Std_{RF,i}$ = Renewable fuel standard for year i, in percent.

$RFV_{CB,i}$ = Annual volume of cellulosic biofuel required by 42 U.S.C. 7545(o)(2)(B) for year i, or volume as adjusted pursuant to 42 U.S.C. 7545(o)(7)(D), in gallon-RINs.

$RFV_{BBD,i}$ = Annual volume of biomass-based diesel required by 42 U.S.C. 7545(o)(2)(B) for year i, in gallon-RINs.

$RFV_{AB,i}$ = Annual volume of advanced biofuel required by 42 U.S.C. 7545(o)(2)(B) for year i, in gallon-RINs.

$RFV_{RF,i}$ = Annual volume of renewable fuel required by 42 U.S.C. 7545(o)(2)(B) for year i, in gallon-RINs.

G_i = Amount of gasoline projected to be used in the covered location for year i, in gallons.

D_i = Amount of diesel projected to be used in the covered location for year i, in gallons.

RG_i = Amount of renewable fuel projected to be contained in the projection of G_i for year i, in gallons.

RD_i = Amount of renewable fuel projected to be contained in the projection of D_i for year i, in gallons.

GE_i = Amount of gasoline projected to be exempt for year i, in gallons, per §§ 80.1441 and 80.1442.

DE_i = Amount of diesel fuel projected to be exempt for year i, in gallons, per §§ 80.1441 and 80.1442.

(c) For the 2026 and 2027 compliance years, EPA will calculate the annual renewable fuel percentage standards using the following equations:

$$Std_{CB,i} = 100 * \frac{RFV_{CB,i}}{(G_i - RG_i) - GE_i + (D_i - RD_i) - DE_i}$$

$$Std_{BBD,i} = 100 * \frac{RFV_{BBD,i} + SRERV_{BBD,i}}{(G_i - RG_i) - GE_i + (D_i - RD_i) - DE_i}$$

$$Std_{AB,i} = 100 * \frac{RFV_{AB,i} + SRERV_{AB,i}}{(G_i - RG_i) - GE_i + (D_i - RD_i) - DE_i}$$

$$Std_{RF,i} = 100 * \frac{RFV_{RF,i} + SRERV_{RF,i}}{(G_i - RG_i) - GE_i + (D_i - RD_i) - DE_i}$$

Where:

$Std_{CB,i}$ = Cellulosic biofuel standard for year i, in percent.

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

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

$Std_{RF,i}$ = Renewable fuel standard for year i, in percent.

$RFV_{CB,i}$ = Annual volume of cellulosic biofuel required by 42 U.S.C. 7545(o)(2)(B) for year i, or volume as adjusted pursuant to 42 U.S.C. 7545(o)(7)(D), in gallon-RINs.

$RFV_{BBD,i}$ = Annual volume of biomass-based diesel required by 42 U.S.C. 7545(o)(2)(B) for year i, in gallon-RINs.

$RFV_{AB,i}$ = Annual volume of advanced biofuel required by 42 U.S.C. 7545(o)(2)(B) for year i, in gallon-RINs.

$RFV_{RF,i}$ = Annual volume of renewable fuel required by 42 U.S.C. 7545(o)(2)(B) for year i, in gallon-RINs.

$SRERV_{BBD,i}$ = Small refinery exemption reallocation volume for biomass-based diesel for year i, in gallon-RINs.

$SRERV_{AB,i}$ = Small refinery exemption reallocation volume for advanced biofuel for year i, in gallon-RINs.

$SRERV_{RF,i}$ = Small refinery exemption reallocation volume for renewable fuel for year i, in gallon-RINs.

G_i = Amount of gasoline projected to be used in the covered location for year i, in gallons.

D_i = Amount of diesel projected to be used in the covered location for year i, in gallons.

RG_i = Amount of renewable fuel projected to be contained in the projection of G_i for year i, in gallons.

RD_i = Amount of renewable fuel projected to be contained in the projection of D_i for year i, in gallons.

GE_i = Amount of gasoline projected to be exempt for year i, in gallons, per §§ 80.1441 and 80.1442.

DE_i = Amount of diesel fuel projected to be exempt for year i, in gallons, per §§ 80.1441 and 80.1442.

(d) The price for cellulosic biofuel waiver credits will be calculated in accordance with § 80.1456(d) and published on EPA's website.

■ 16. Amend § 80.1407 by revising paragraph (f)(5) to read as follows:

§ 80.1407 How are the Renewable Volume Obligations calculated?

* * * * *

(f) * * *

(5) Gasoline or diesel fuel exported for use outside the covered location.

* * * * *

■ 17. Effective January 1, 2027, amend § 80.1415 by revising paragraphs (a), (b), and (c)(1) to read as follows:

§ 80.1415 How are equivalence values assigned to renewable fuel?

(a) *General.* (1) Each gallon (or gallon-equivalent) of a renewable fuel must be assigned an equivalence value by the producer or importer pursuant to paragraph (b) or (c) of this section, as applicable.

(2) The equivalence value is a number that is used to determine how many gallon-RINs can be generated for a gallon of renewable fuel according to § 80.1426.

(b) *Assigned equivalence values.* (1) Equivalence values for certain renewable fuels are assigned as follows:

TABLE 1 TO PARAGRAPH (b)(1)—EQUIVALENCE VALUES FOR CERTAIN RENEWABLE FUELS

Fuel	Amount	Equivalence value
Biodiesel	1 gallon	1.5
Butanol	1 gallon	1.3
Denatured ethanol	1 gallon	1.0
Fuels that are gaseous at STP (*e.g.,* RNG, renewable CNG/LNG)	77,000 Btu LHV	1.0
Renewable diesel	1 gallon	1.5
Renewable jet fuel	1 gallon	1.5
Renewable naphtha	1 gallon	1.4

(2) For all other renewable fuels, a producer or importer must submit an application to EPA for an equivalence value following the provisions of paragraph (c) of this section. A producer or importer may also submit an application for an alternative equivalence value pursuant to paragraph (c) of this section if the renewable fuel is listed in this paragraph (b), but the producer or importer has reason to believe that a different equivalence value than that listed in this paragraph (b) is warranted.

(c) * * *

(1) The equivalence value for renewable fuels described in paragraph (b)(2) of this section must be calculated using the following formula:

$$EqV = (R/0.972) * (EC/77{,}000)$$

Where:

EqV = Equivalence Value for the renewable fuel, rounded to the nearest tenth.

R = Renewable content of the renewable fuel. This is a measure of the portion of a renewable fuel that came from renewable biomass, expressed as a fraction, on an energy basis.

EC = Energy content of the renewable fuel, in Btu LHV per gallon.

* * * * *

■ 18. Amend § 80.1425 by adding paragraph (a)(3) to read as follows:

§ 80.1425 Renewable Identification Numbers (RINs).

* * * * *

(a) * * *

(3) K has the value of 3 when the RIN is assigned to a volume of RNG pursuant to §§ 80.125(c) and 80.1426(e).

* * * * *

■ 19. Amend § 80.1426 by:

■ a. Revising paragraphs (b)(2), (c)(7), and (e);

■ b. In paragraphs (f)(1)(v)(A) and (B), removing the text "D-code" and adding, in its place, the text "D code";

■ c. Adding paragraphs (f)(1)(vii) and (viii);

■ d. Revising paragraphs (f)(8) introductory text, (f)(8)(iii), and (f)(10), (11), and (17);

■ e. Adding paragraph (f)(18); and

■ f. Revising table 1 to the section.

The revisions and additions read as follows:

§ 80.1426 How are RINs generated and assigned to batches of renewable fuel?

* * * * *

(b) * * *

(2) If EPA approves a petition of Alaska or a United States territory to opt-in to the renewable fuel program under the provisions in § 80.1443, then the requirements of paragraph (b)(1) of this section shall also apply to renewable fuel produced or imported for use as transportation fuel, heating oil, or jet fuel in that state or territory beginning in the next calendar year.

(c) * * *

(7) For renewable fuel oil, renewable fuel producers and importers must not generate RINs unless they have received affidavits from the final end user or users of the fuel oil as specified in § 80.1451(b)(1)(ii)(T)(*2*).

* * * * *

(e) *Assignment of RINs to batches.* (1)(i) Except as specified in paragraphs (e)(1)(ii) and (g) of this section, the producer or importer of renewable fuel must assign all RINs generated to volumes of renewable fuel as follows:

(A) If RINs were generated for the renewable fuel at the point of production or upon importation into the covered location, RINs must be assigned when such volumes leave the renewable fuel production or import facility.

(B) If RINs were generated for the renewable fuel at the point of sale or when the renewable fuel was loaded onto a vessel or other transportation mode for transport to the covered location, RINs must be assigned prior to the transfer of ownership of the renewable fuel.

(ii) For renewable fuels that are gaseous at STP, RINs must be assigned to a volume of renewable fuel at the same time the RIN is generated.

(iii) For RNG, RINs must be assigned as specified in § 80.125(c).

(2) A RIN is assigned to a volume of renewable fuel when ownership of the RIN is transferred along with the transfer of ownership of the volume of renewable fuel, pursuant to § 80.1428(a).

(3) All assigned RINs must have a K code value of 1 for RINs assigned to renewable fuel or 3 for RINs assigned to RNG.

(f) * * *

(1) * * *

(vii) For purposes of identifying the appropriate approved pathway, the fuel must be produced, distributed, and used in a manner consistent with the pathway EPA evaluated when it determined that the pathway satisfies the applicable lifecycle emissions reduction requirement.

(viii) A renewable fuel producer may continue to use an existing registration that was under a pathway in table 1 to this section that previously specified ''Any'' or ''Any process that converts cellulosic biomass to fuel'' as its production process requirement if the pathway was in the renewable fuel production facility's registration that was accepted by EPA prior to June 1, 2026. Any modifications to the renewable fuel production facility's registration after this date must meet an approved pathway.

* * * * *

(8) *Standardization of volumes.* In determining the standardized volume of a batch of liquid renewable fuel or liquid biointermediate under this subpart, the batch volume must be adjusted to a standard temperature of 60 °F as follows:

* * * * *

(iii) For other renewable fuels and biointermediates, an appropriate formula commonly accepted by the industry must be used to standardize the actual volume to 60 °F. Formulas used must be reported to EPA and may be determined to be inappropriate.

* * * * *

(10) *Renewable CNG/LNG produced from biogas distributed via a closed distribution system.* RIN generators may only generate RINs for renewable CNG/LNG produced from biogas that is distributed via a closed, private, non-commercial system if all the following requirements are met:

(i) The renewable CNG/LNG was produced from renewable biomass under an approved pathway.

(ii) The RIN generator has entered into a written contract for the sale or use of a specific quantity of renewable CNG/LNG for use as transportation fuel, or has obtained affidavits from all parties selling or using the renewable CNG/LNG as transportation fuel.

(iii) The renewable CNG/LNG was used as transportation fuel and for no other purpose.

(iv) The biogas was introduced into the closed, private, non-commercial system no later and the renewable CNG/LNG produced from the biogas was used as transportation fuel no later than December 31, 2024.

(v) RINs may only be generated on biomethane content of the renewable CNG/LNG used as transportation fuel.

(11) *Renewable CNG/LNG produced from RNG distributed via a commercial distribution system.* RINs for renewable CNG/LNG produced from RNG that is introduced into a commercial distribution system may only be generated if all the following requirements are met:

(i) The renewable CNG/LNG was produced from renewable biomass and qualifies for a D code in an approved pathway.

(ii) The RIN generator has entered into a written contract for the sale or use of a specific quantity of RNG, taken from a commercial distribution system (*e.g.,* physically connected pipeline, barge, truck, rail), for use as transportation fuel, or has obtained affidavits from all parties selling or using the RNG taken from a commercial distribution system as transportation fuel.

(iii) The renewable CNG/LNG produced from the RNG was sold for use as transportation fuel and for no other purpose.

(iv) The RNG was injected into and withdrawn from the same commercial distribution system.

(v) The RNG was withdrawn from the commercial distribution system in a manner and at a time consistent with the transport of the RNG between the injection and withdrawal points.

(vi) The volume of RNG injected into the commercial distribution system and the volume of RNG withdrawn are measured by continuous metering.

(vii) The volume of renewable CNG/LNG sold for use as transportation fuel corresponds to the volume of RNG that was injected into and withdrawn from the commercial distribution system.

(viii) No other party relied upon the volume of biogas, RNG, or renewable CNG/LNG for the generation of RINs.

(ix) The RNG was introduced into the commercial distribution system no later than December 31, 2024, and the renewable CNG/LNG was used as transportation fuel no later than December 31, 2024.

(x) RINs may only be generated on biomethane content of the biogas, treated biogas, RNG, or renewable CNG/LNG.

(xi)(A) On or after January 1, 2025, RINs may only be generated for RNG injected into a natural gas commercial pipeline system for use as transportation fuel as specified in subpart E of this part.

(B) RINs may be generated for RNG as specified in subpart E of this part prior to January 1, 2025, if all applicable requirements under this part are met.

* * * * *

(17) *Qualifying use demonstration for certain renewable fuels.* For purposes of this section, any renewable fuel other than ethanol, biodiesel, renewable gasoline, renewable jet fuel, or renewable diesel that meets paragraph (1) of the definition for renewable diesel is considered renewable fuel and the producer or importer may generate RINs for such fuel only if all the following apply:

(i) The fuel is produced from renewable biomass and qualifies to generate RINs under an approved pathway.

(ii) The fuel producer or importer maintains records demonstrating that the fuel was produced for use as a transportation fuel, heating oil, or jet fuel by any of the following:

(A) Blending the renewable fuel into gasoline or distillate fuel to produce a transportation fuel, heating oil, or jet fuel that meets all applicable standards under this part and 40 CFR part 1090.

(B) Entering into a written contract for the sale of the renewable fuel, which specifies the purchasing party must blend the fuel into gasoline or distillate fuel to produce a transportation fuel, heating oil, or jet fuel that meets all applicable standards under this part and 40 CFR part 1090.

(C) Entering into a written contract for the sale of the renewable fuel, which specifies that the fuel must be used in its neat form as a transportation fuel, heating oil, or jet fuel that meets all applicable standards.

(iii) The fuel was sold for use in or as a transportation fuel, heating oil, or jet fuel, and for no other purpose.

(18) *RIN generation timing.* A RIN generator must generate RINs as follows:

(i) Except as specified in paragraph (f)(18)(ii) of this section, RINs must be generated at:

(A) For domestic renewable fuel producers, the point of production or point of sale.

(B) For RIN-generating foreign producers, the point of production or when the renewable fuel is loaded onto a vessel or other transportation mode for transport to the covered location.

(C) For RIN-generating importers of renewable fuel, the point of importation into the covered location.

(ii)(A) Except as specified in paragraph (f)(18)(ii)(B) of this section, for RNG and renewable fuels that are gaseous at STP, RINs must be generated no later than 5 business days after the RIN generator has met all applicable requirements for the generation of RINs under §§ 80.125(b) and 80.130(b) and this paragraph (f), as applicable.

(B) For foreign produced RIN-less RNG, RINs must be generated no later than when title is transferred from the foreign producer to the RIN-generating importer.

(iii) After the RIN generation event has occurred, the RIN generator must submit the required information to EPA following the procedures and reporting deadline specified in § 80.1452(b).

* * * * *

TABLE 1 TO § 80.1426—APPLICABLE D CODES FOR EACH FUEL PATHWAY FOR USE IN GENERATING RINS

Row	Fuel type	Feedstock	Production process requirements	D code
A	Ethanol	Corn starch	All the following: Dry mill process, using natural gas, biomass, or biogas for process energy and at least two advanced technologies from table 2 to this section.	6
B	Ethanol	Corn starch	All the following: Dry mill process, using natural gas, biomass, or biogas for process energy and at least one of the advanced technologies from table 2 to this section plus drying no more than 65% of the distillers grains with solubles it markets annually.	6
C	Ethanol	Corn starch	All the following: Dry mill process, using natural gas, biomass, or biogas for process energy and drying no more than 50% of the distillers grains with solubles it markets annually.	6
D	Ethanol	Corn starch	Wet mill process using biomass or biogas for process energy.	6
E	Ethanol	Starches from crop residue and annual cover crops.	Fermentation using natural gas, biomass, or biogas for process energy.	6
F	Biodiesel; Renewable diesel; Renewable jet fuel; Heating oil.	Soybean oil; Oil from annual cover crops; Oil from algae grown photosynthetically; Biogenic waste oils/fats/greases; *Camelina sativa* oil; Distillers corn oil; Distillers sorghum oil; Commingled distillers corn oil and sorghum oil.	The following processes that do not co-process renewable biomass and petroleum: Transesterification with or without esterification pre-treatment; Esterification; Hydrotreating.	4
G	Biodiesel; Renewable diesel; Renewable jet fuel; Heating oil.	Canola/Rapeseed oil	The following processes that do not co-process renewable biomass and petroleum: Transesterification using natural gas or biomass for process energy; Hydrotreating.	4
H	Biodiesel; Renewable diesel; Renewable jet fuel; Heating oil.	Soybean oil; Oil from annual cover crops; Oil from algae grown photosynthetically; Biogenic waste oils/fats/greases; *Camelina sativa* oil; Distillers corn oil; Distillers sorghum oil; Commingled distillers corn oil and sorghum oil; Canola/Rapeseed oil.	The following processes that co-process renewable biomass and petroleum: Transesterification with or without esterification pre-treatment; Esterification; Hydrotreating.	5
I	Renewable naphtha; LPG.	*Camelina sativa* oil; Distillers sorghum oil; Distillers corn oil; Commingled distillers corn oil and distillers sorghum oil; Canola/Rapeseed oil; Biogenic waste oils/fats/greases.	Hydrotreating	5
J	Ethanol	Sugarcane	Fermentation	5
K	Ethanol	Crop residue; Slash, pre-commercial thinnings, and tree residue; Switchgrass; Miscanthus; Energy cane; *Arundo donax; Pennisetum purpureum;* Separated yard waste; Biogenic components of separated MSW; Cellulosic components of separated food waste; Cellulosic components of annual cover crops.	Biochemical conversion process that uses lignin from the renewable biomass feedstock to provide all thermal and electrical process energy; Thermochemical conversion process that uses char, coke, or syngas derived from the renewable biomass feedstock to provide all thermal and electrical process energy; Dry mill crop residue conversion process that uses natural gas, biogas, or crop residue for all thermal process energy.	3
L	Cellulosic diesel; Renewable jet fuel; Heating oil.	Crop residue; Slash, pre-commercial thinnings, and tree residue; Separated yard waste; Biogenic components of separated MSW; Cellulosic components of separated food waste.	The following processes that use lignin, char, coke, or syngas derived from the renewable biomass feedstock to provide all thermal and electrical process energy other than natural gas to produce hydrogen for upgrading (maximum 0.5 Btu of natural gas per Btu of finished fuel): Pyrolysis and upgrading; Biochemical conversion and upgrading. The following processes that use lignin, char, coke, or syngas derived from the renewable biomass feedstock to provide all thermal and electrical process energy: Gasification and upgrading; Direct biochemical conversion.	7

TABLE 1 TO § 80.1426—APPLICABLE D CODES FOR EACH FUEL PATHWAY FOR USE IN GENERATING RINS—Continued

Row	Fuel type	Feedstock	Production process requirements	D code
M	Renewable gasoline; Renewable gasoline blendstock; Co-processed cellulosic diesel; Co-processed renewable jet fuel; Co-processed heating oil.	Crop residue; Slash, pre-commercial thinnings, and tree residue; Separated yard waste; Biogenic components of separated MSW; Cellulosic components of separated food waste.	The following processes that use lignin, char, coke, or syngas derived from the renewable biomass feedstock to provide all thermal and electrical process energy other than natural gas to produce hydrogen for upgrading (maximum 0.5 Btu of natural gas per Btu of finished fuel): Pyrolysis and upgrading; Biochemical conversion and upgrading. The following processes that use lignin, char, coke, or syngas derived from the renewable biomass feedstock to provide all thermal and electrical process energy: Gasification and upgrading; Direct biochemical conversion.	3
N	Renewable naphtha; Renewable gasoline; Renewable gasoline blendstock; Co-processed cellulosic diesel; Co-processed renewable jet fuel; Co-processed heating oil.	Switchgrass; Miscanthus; Energy cane; *Arundo donax; Pennisetum purpureum;* Cellulosic components of annual cover crops.	Gasification and upgrading process that uses lignin, char, coke, or syngas derived from the renewable biomass feedstock to provide all thermal and electrical process energy.	3
O	Butanol	Corn starch	Fermentation; Dry mill process using natural gas, biomass, or biogas for process energy.	6
P	Ethanol; Renewable diesel; Renewable jet fuel; Heating oil; Renewable naphtha.	Non-cellulosic portions of separated food waste; Non-cellulosic components of annual cover crops.	Fermentation using natural gas, biogas, or crop residue for thermal energy; Hydrotreating; Transesterification.	5
Q	Renewable CNG; Renewable LNG.	Biogas from landfills, municipal wastewater treatment facility digesters, agricultural digesters, and separated MSW digesters; Biogas from the cellulosic components of biomass processed in other waste digesters.	The following processes that do not transport RNG or renewable CNG/LNG by ocean-going vessel: Treatment and compression; Treatment and liquefaction.	3
R	Ethanol	Grain sorghum	Dry mill process using natural gas or biogas from landfills, waste treatment plants, or waste digesters for process energy.	6
S	Ethanol	Grain sorghum	Dry mill process using only biogas from landfills, waste treatment plants, or waste digesters for process energy and for on-site production of all electricity used at the site other than up to 0.15 kWh of electricity from the grid per gallon of ethanol produced, calculated on a per batch basis.	5
T	Renewable CNG; Renewable LNG.	Biogas from waste digesters	The following processes that do not transport RNG or renewable CNG/LNG by ocean-going vessel: Treatment and compression; Treatment and liquefaction.	5
U	Cellulosic diesel; Renewable jet fuel; Heating oil.	Switchgrass; Miscanthus; Energy cane; *Arundo donax; Pennisetum purpureum;* Cellulosic components of annual cover crops.	The following processes that use lignin, char, coke, or syngas derived from the renewable biomass feedstock to provide all thermal and electrical process energy: Gasification and upgrading; Direct biochemical conversion.	7

* * * * *

■ 20. Amend § 80.1428 by revising paragraph (a) to read as follows:

§ 80.1428 General requirements for RIN distribution.

(a) *RINs assigned to volumes of renewable fuel or RNG.*

(1) Except as provided in §§ 80.1429 and 80.125(d), no person can separate a RIN that has been assigned to a volume of renewable fuel or RNG pursuant to §§ 80.1426(e) and 80.125(c), as applicable.

(2) An assigned RIN with a K code of 1 cannot be transferred to another person without simultaneously transferring a volume of renewable fuel to that same person.

(3) Assigned gallon-RINs with a K code of 1 or 3 can be transferred to another person based on the following:

(i) No more than 2.5 assigned gallon-RINs with a K code of 1 can be transferred to another person with every gallon of renewable fuel transferred to that same person.

(ii) For RNG, the transferor of assigned RINs with a K code of 3 must transfer RINs under § 80.125(c).

(4) Any transfer of ownership of assigned RINs must be documented on product transfer documents generated pursuant to § 80.1453.

(i) The RIN must be recorded on the product transfer document used to transfer ownership of the volume of renewable fuel or a volume of RNG to another person; or

(ii) The RIN must be recorded on a separate product transfer document transferred to the same person on the same day as the product transfer document used to transfer ownership of the volume of renewable fuel or a volume of RNG.

* * * * *

■ 21. Amend § 80.1429 by revising paragraphs (b)(5)(i), (b)(5)(ii)(B), and (c) to read as follows:

§ 80.1429 Requirements for separating RINs from volumes of renewable fuel or RNG.

* * * * *

(b) * * *

(5)(i) Any party that produces, imports, owns, sells, or uses a volume of biogas for which RINs have been generated in accordance with § 80.1426(f) must separate any RINs that have been assigned to that volume of biogas if all the following conditions are met:

(A) The party designates the biogas as transportation fuel.

(B) The biogas is used as transportation fuel.

(ii) * * *

(B) Only an RNG RIN separator may separate the RINs that have been assigned to a volume of RNG after meeting all applicable requirements in § 80.125(d)(2).

* * * * *

(c) The party responsible for separating a RIN from a volume of renewable fuel or RNG must change the K code in the RIN from a value of 1 or 3, as applicable, to a value of 2 prior to transferring the RIN to any other party.

* * * * *

■ 22. Amend § 80.1431 by revising paragraph (a)(1)(ix) and adding paragraph (a)(1)(xi) to read as follows:

§ 80.1431 Treatment of invalid RINs.

(a) * * *

(1) * * *

(ix) Was generated for a prohibited act under § 80.1460(b).

* * * * *

(xi) Was otherwise improperly generated.

* * * * *

§ 80.1435 [Amended]

■ 23. Amend § 80.1435 by, in paragraph (b)(2)(ii), removing the text ''RIN gallons'' and adding, in its place, the text ''gallon-RINs''.

■ 24. Amend § 80.1441 by adding paragraphs (e)(2)(iv) and (v) to read as follows:

§ 80.1441 Small refinery exemption.

* * * * *

(e) * * *

(2) * * *

(iv) A refinery that is granted a small refinery exemption under this section must still submit reports under § 80.1451(a) for the compliance year for which it was granted an exemption, including annual compliance reports. Such exempt small refineries must submit annual compliance reports containing all the information specified in § 80.1451(a)(1) by the applicable compliance deadline specified in § 80.1451(f)(1)(i).

(v) A refinery that is granted a small refinery exemption under this section must still comply with any deficit RVOs carried forward from the previous compliance year.

* * * * *

■ 25. Amend § 80.1442 by adding paragraphs (h)(6) and (7) to read as follows:

§ 80.1442 What are the provisions for small refiners under the RFS program?

* * * * *

(h) * * *

(6) A refiner that is granted a small refiner exemption under this section must still submit reports under § 80.1451(a) for the compliance year for which it was granted an exemption, including annual compliance reports. Such exempt small refiners must submit annual compliance reports containing all the information specified in § 80.1451(a)(1) by the applicable compliance deadline specified in § 80.1451(f)(1)(i).

(7) A refiner that is granted a small refiner exemption under this section must still comply with any deficit RVOs carried forward from the previous compliance year.

* * * * *

§ 80.1444 [Amended]

■ 26. Amend § 80.1444 by, in paragraph (b), removing the text ''in § 80.1401''.

■ 27. Amend § 80.1449 by:

■ a. Revising paragraphs (a) introductory text, (a)(1), (a)(4)(i) and (iii), and (b);

■ b. Removing paragraph (d); and

■ c. Redesignating paragraph (e) as paragraph (d).

The revisions read as follows:

§ 80.1449 What are the Production Outlook Report requirements?

(a) By June 1 of each year, a registered renewable fuel producer or importer must submit and an unregistered renewable fuel producer may submit all of the following information for each of its facilities, as applicable, to EPA:

(1) If currently registered, any planned changes to the type, or types, of renewable fuel expected to be produced or imported at each facility owned by the renewable fuel producer or importer.

* * * * *

(4) * * *

(i) Nameplate production capacity and, if applicable, permitted production capacity.

* * * * *

(iii) If currently registered, any planned changes to feedstocks, biointermediates, and production processes to be used at each production facility.

* * * * *

(b) The information listed in paragraph (a) of this section must include the reporting party's best annual projection estimates for the five following calendar years.

* * * * *

■ 28. Amend § 80.1450 by:

■ a. Revising the last sentence in paragraph (a); and

■ b. Revising paragraphs (b)(1)(iv)(A)(*2*), (b)(1)(v) introductory text, (b)(1)(v)(A), (b)(1)(v)(B)(*1*) introductory text, (b)(1)(v)(D) introductory text, (b)(1)(v)(D)(*1*), (b)(1)(vi)(B), (b)(1)(xi), (b)(1)(xii) introductory text, (b)(1)(xii)(A), (b)(2) introductory text, (g)(10) introductory text, and (g)(10)(i).

The revisions read as follows:

§ 80.1450 What are the registration requirements under the RFS program?

(a) * * * Registration information must be submitted and accepted by EPA at least 60 days prior to RIN ownership.

(b) * * *

(1) * * *

(iv) * * *

(A) * * *

(*2*) The name and address of the company supplying each process heat fuel to the renewable fuel production facility, foreign ethanol production facility, or biointermediate production facility.

* * * * *

(v) The following records that support the facility's baseline volume or, for foreign ethanol production facilities, their production volume:

(A) For all facilities except those described in paragraph (b)(1)(v)(B) of this section, copies of the most recent applicable air permits issued by the U.S. Environmental Protection Agency, state, local air pollution control agencies, or foreign governmental agencies and that govern the construction and/or operation of the renewable fuel or foreign ethanol production facility.

(B) * * *

(*1*) Applicable air permits issued by EPA, state, local air pollution control agencies, or foreign governmental agencies that govern the construction and/or operation of the renewable fuel production facility that were:

* * * * *

(D) For all facilities producing renewable fuel from biogas, submit all relevant information in § 80.1426(f)(10) or (11), including:

(*1*) Copies of all contracts or affidavits, as applicable, that follow the track of the biogas/CNG/LNG from its original source, to the producer that processes it into renewable fuel, and finally to the end user that will actually use the renewable CNG/LNG for transportation purposes.

* * * * *

(vi) * * *

(B) Applicable air permits issued by the U.S. Environmental Protection Agency, state, local air pollution control agencies, or foreign governmental agencies that governed the construction and/or operation of the renewable fuel production facility during construction and when first operated.

* * * * *

(xi) For a producer of renewable fuel oil:

(A) An affidavit from the producer of the renewable fuel oil stating that the renewable fuel oil for which RINs have been generated will be sold for the purposes of heating or cooling interior spaces of homes or buildings to control ambient climate for human comfort, and no other purpose.

(B) Affidavits from the final end user or users of the renewable fuel oil stating that the renewable fuel oil is being used or will be used for purposes of heating or cooling interior spaces of homes or buildings to control ambient climate for human comfort, and no other purpose, and acknowledging that any other use of the renewable fuel oil would violate EPA regulations and subject the user to civil and/or criminal penalties under the Clean Air Act.

(xii) For a producer or importer of any renewable fuel other than ethanol, biodiesel, renewable gasoline, renewable jet fuel, renewable diesel that meets paragraph (1) of the definition for *renewable diesel,* biogas-derived renewable fuel, or RNG, all the following:

(A) A description of the renewable fuel and how it will be blended to into gasoline or diesel fuel to produce a transportation fuel, heating oil, or jet fuel that meets all applicable standards.

* * * * *

(2) An independent third-party engineering review and written report and verification of the information provided pursuant to paragraph (b)(1) of this section and § 80.135, as applicable. The report and verification must be based upon a review of relevant documents and a site visit conducted within the six months prior to submission of the registration information. The report and verification must separately identify each item required by paragraph (b)(1) of this section, describe how the independent third-party evaluated the accuracy of the information provided, state whether the independent third-party agrees with the information provided, and identify any exceptions between the independent third-party's findings and the information provided.

* * * * *

(g) * * *

(10) *Registration renewal.* Registrations for independent third-party auditors expire December 31 of every other calendar year. Previously approved registrations will renew automatically if all the following conditions are met:

(i) The independent third-party auditor resubmits all information, updated as necessary, described in paragraphs (g)(1) through (7) of this section no later than October 31 before the calendar year that their registration expires.

* * * * *

■ 29. Amend § 80.1451 by:

■ a. Revising paragraph (b)(1)(ii)(L);

■ b. Removing and reserving paragraph (b)(1)(ii)(P);

■ c. Revising paragraph (b)(1)(ii)(Q) and paragraph (b)(1)(ii)(T) introductory text;

■ d. Removing paragraph (c)(2)(ii)(D)(*14*);

■ e. Revising paragraph (f)(1)(i)(A) introductory text;

■ f. Adding paragraph (f)(1)(i)(C); and

■ g. In paragraph (g)(1)(viii), removing the text ''D-code'' and adding, in its place, the text ''D code''.

The revisions and addition read as follows:

§ 80.1451 What are the reporting requirements under the RFS program?

* * * * *

(b) * * *

(1) * * *

(ii) * * *

(L) Each process, feedstock, and biointermediate used and proportion of renewable volume attributable to each process, feedstock, and biointermediate, as applicable.

* * * * *

(Q) Producers or importers of renewable fuel produced at facilities that use biogas for process heat as described in § 80.1426(f)(12), shall report the total energy supplied to the renewable fuel production facility, in MMBtu based on metering of gas volume.

* * * * *

(T) Producers or importers of any renewable fuel other than ethanol, biodiesel, renewable gasoline, renewable jet fuel, renewable diesel that meets paragraph (1) of the definition for *renewable diesel,* biogas-derived renewable fuel, or RNG, must report, on a quarterly basis, all the following for each volume of fuel:

* * * * *

(f) * * *

(1) * * *

(i) * * *

(A) Except as specified in paragraphs (f)(1)(i)(B) and (C) of this section, obligated parties must submit annual compliance reports by whichever of the following dates is latest:

* * * * *

(C) If EPA publishes a document in the **Federal Register** that proposes to revise a renewable fuel standard in § 80.1405(a), annual compliance reports for that compliance year must be submitted by the following date, as applicable:

(*1*) If EPA publishes a document in the **Federal Register** that finalizes the proposed revision to the renewable fuel standard in § 80.1405(a), whichever of the following dates is latest:

(*i*) The next quarterly reporting deadline under paragraph (f)(2) of this section after the date the revised renewable fuel standard becomes effective in § 80.1405(a).

(*ii*) The applicable compliance reporting deadline under paragraph (f)(1)(i)(A) or (B) of this section.

(*2*) If EPA publishes a document in the **Federal Register** that withdraws the proposed revision to the renewable fuel standard in § 80.1405(a), whichever of the following dates is latest:

(*i*) The next quarterly reporting deadline under paragraph (f)(2) of this section that is 60 days after the date the withdrawal is published in the **Federal Register**.

(*ii*) The applicable compliance reporting deadline under paragraph (f)(1)(i)(A) or (B) of this section.

(*3*) If EPA does not publish a document in the **Federal Register** that either finalizes or withdraws the proposed revision to the renewable fuel standard in § 80.1405(a) within 12 months after the date the proposed rule was published in the **Federal Register**, whichever of the following dates is latest:

(*i*) The next quarterly reporting deadline under paragraph (f)(2) of this section that is 12 months after the date the proposed rule was published in the **Federal Register**.

(*ii*) The applicable compliance reporting deadline under paragraph (f)(1)(i)(A) or (B) of this section.

* * * * *

■ 30. Amend § 80.1452 by:

■ a. Revising paragraphs (a), (b) introductory text, and (b)(1), (2), (4), and (11);

■ b. Redesignating paragraph (b)(18) as paragraph (b)(19) and adding new paragraph (b)(18); and

■ c. Revising paragraph (c) introductory text.

The revisions and addition read as follows:

§ 80.1452 What are the requirements related to the EPA Moderated Transaction System (EMTS)?

(a) Each party required to submit information under this section must establish an account with the EPA Moderated Transaction System (EMTS) at least 60 days prior to engaging in any RIN transactions.

(b) Each time a RIN generator assigns RINs to a batch of renewable fuel or RNG pursuant to §§ 80.125(c) and 80.1426(e), as applicable, all the following information must be submitted to EPA via the submitting party's EMTS account within five (5) business days of the date of RIN assignment. EPA in its sole discretion may allow a RIN generator to submit information under this paragraph (b) outside the 5-business-day deadline.

(1) The name of the RIN generator.

(2) The EPA company registration number of the renewable fuel producer, RNG producer, or foreign ethanol producer, as applicable.

* * * * *

(4) The EPA facility registration number of the facility at which the renewable fuel producer, RNG producer, or foreign ethanol producer produced the batch, as applicable.

* * * * *

(11) The volume of ethanol denaturant, if applicable, and applicable equivalence value of each batch.

* * * * *

(18) Starting January 1, 2027, the type of RIN generation protocol used when assigning RINs to the associated renewable fuel volume.

* * * * *

(c) Each time any party sells, separates, or retires RINs, all the following information must be submitted to EPA via the submitting party's EMTS account within five (5) business days of the reportable event. Each time any party purchases RINs, all the following information must be submitted to EPA via the submitting party's EMTS account within ten (10) business days of the reportable event. The reportable event for a RIN purchase or sale occurs on the date of transfer per § 80.1453(a)(4). The reportable event for a RIN separation or retirement occurs on the date of separation or retirement as described in § 80.1429 or § 80.1434. EPA in its sole discretion may allow a party to submit information under this paragraph (c) outside the applicable 5- or 10-business-day deadline.

* * * * *

■ 31. Amend § 80.1453 by revising paragraphs (a)(12)(v) and (vii) and (d) to read as follows:

§ 80.1453 What are the product transfer document (PTD) requirements for the RFS program?

(a) * * *

(12) * * *

(v) Renewable naphtha. ''This volume of neat or blended renewable naphtha is designated and intended for use as transportation fuel or jet fuel in the 48 U.S. contiguous states and Hawaii. This naphtha may only be used as a gasoline blendstock, E85 blendstock, or jet fuel. Any person exporting this fuel is subject to the requirements of 40 CFR 80.1430.''.

* * * * *

(vii) Renewable fuels other than ethanol, biodiesel, heating oil, renewable diesel, naphtha, or butanol. ''This volume of neat or blended renewable fuel is designated and intended to be used as transportation fuel, heating oil, or jet fuel in the 48 U.S. contiguous states and Hawaii. Any person exporting this fuel is subject to the requirements of 40 CFR 80.1430.''.

* * * * *

(d) For renewable fuel oil, the PTD of the renewable fuel oil shall state: ''This volume of renewable fuel oil is designated and intended to be used to heat or cool interior spaces of homes or buildings to control ambient climate for human comfort. Do NOT use for process heat or cooling or any other purpose, as these uses are prohibited pursuant to 40 CFR 80.1460(g).''.

* * * * *

■ 32. Amend § 80.1454 by:

■ a. Revising paragraphs (a) introductory text, (b) introductory text, (b)(3)(ix), (b)(8), and (c)(1) introductory text;

■ b. In paragraph (d)(4)(ii)(B), removing the text ''renewable fuel facility'' and adding, in its place, the text ''renewable fuel production facility'';

■ c. In paragraph (g) introductory text, removing the text ''U.S. agricultural land as defined in § 80.1401'' and adding, in its place, the text ''agricultural land'';

■ d. In paragraph (g)(2)(ii)(B), removing the text ''renewable fuel facility'' and adding, in its place, the text ''renewable fuel production facility'';

■ e. Revising and republishing paragraph (k)(1);

■ f. Revising paragraphs (k)(2) introductory text, (l) introductory text, (l)(2), and (l)(3)(iv);

■ g. Removing paragraph (m)(8); and

■ h. Redesignating paragraphs (m)(9) through (11) as paragraphs (m)(8) through (10).

The revisions read as follows:

§ 80.1454 What are the recordkeeping requirements under the RFS program?

(a) *Requirements for obligated parties and exporters of renewable fuel.* Any obligated party or exporter of renewable fuel must keep all the following records:

* * * * *

(b) *Requirements for all producers of renewable fuel.* In addition to any other applicable records a renewable fuel producer must maintain under this section, any domestic or RIN-generating foreign producer of a renewable fuel must keep all the following records:

* * * * *

(3) * * *

(ix) All facility-determined values used in the calculations under § 80.1426 and the data used to obtain those values.

* * * * *

(8) A producer of renewable fuel oil must keep copies of all contracts which describe the renewable fuel oil under contract with each end user.

* * * * *

(c) * * *

(1) Any RIN-generating foreign producer or importer of renewable fuel must keep records of feedstock purchases and transfers associated with renewable fuel for which RINs are generated, sufficient to verify that feedstocks used are renewable biomass.

* * * * *

(k) * * *

(1) *Pathways involving feedstocks other than grain sorghum.* A renewable fuel producer that generates RINs for renewable CNG/LNG pursuant to § 80.1426(f)(10) or (11), or that uses process heat from biogas to produce renewable fuel pursuant to § 80.1426(f)(12) must keep all the following additional records:

(i) Documentation recording the sale of renewable CNG/LNG for use as transportation fuel relied upon in § 80.1426(f)(10) or (11), or for use of biogas for process heat to make renewable fuel as relied upon in § 80.1426(f)(12), and the transfer of title of the biogas/CNG/LNG from the point of biogas production to the facility that sells or uses the fuel for transportation purposes.

(ii) Documents demonstrating the volume and energy content of biogas/CNG/LNG relied upon under § 80.1426(f)(10) that was delivered to the facility that sells or uses the fuel for transportation purposes.

(iii) Documents demonstrating the volume and energy content of biogas/CNG/LNG relied upon under § 80.1426(f)(11), or biogas relied upon under § 80.1426(f)(12) that was placed into the commercial distribution.

(iv) Documents demonstrating the volume and energy content of biogas relied upon under § 80.1426(f)(12) at the point of distribution.

(v) Affidavits, EPA-approved documentation, or data from a real-time electronic monitoring system, confirming that the amount of the biogas/CNG/LNG relied upon under § 80.1426(f)(10) and (11) was used for transportation purposes only, and for no other purpose. The RIN generator must obtain affidavits, or monitoring system data under this paragraph (k), at least once per calendar quarter.

(vi) The biogas producer's Compliance Certification required under Title V of the Clean Air Act.

(vii) Any other records as requested by EPA.

(2) *Pathways involving grain sorghum as feedstock.* A renewable fuel producer that produces fuel pursuant to a pathway that uses grain sorghum as a feedstock must keep all the following additional records, as appropriate:

* * * * *

(l) *Additional requirements for producers or importers of any renewable fuel other than ethanol, biodiesel, renewable gasoline, renewable diesel, biogas-derived renewable fuel, or RNG.* A renewable fuel producer that generates RINs for any renewable fuel other than ethanol, biodiesel, renewable gasoline, renewable jet fuel, renewable diesel that meets paragraph (1) of the definition for *renewable diesel,* biogas-derived renewable fuel, or RNG must keep all the following additional records:

* * * * *

(2) Contracts and documents memorializing the sale of renewable fuel to parties who blend the fuel into gasoline or diesel fuel to produce a transportation fuel, heating oil, or jet fuel, or who use the renewable fuel in its neat form for a qualifying fuel use.

(3) * * *

(iv) A description of the finished fuel, and a statement that the fuel meets all applicable standards and was sold for use as a transportation fuel, heating oil, or jet fuel.

* * * * *

■ 33. Amend § 80.1460 by:
■ a. Revising paragraph (b)(4);
■ b. Adding paragraph (b)(9); and
■ c. Revising paragraph (g).

The revisions and addition read as follows:

§ 80.1460 What acts are prohibited under the RFS program?

* * * * *

(b) * * *

(4)(i) Transfer to any person an assigned RIN with a K code of 1 without transferring an appropriate volume of renewable fuel to the same person on the same day.

(ii) Take title to an assigned RIN with a K code of 3 without taking title to a corresponding volume of RNG.

* * * * *

(9) Generate a RIN for fuel that is used for process heat or electricity generation, except as specified in § 80.1426(f)(12).

* * * * *

(g) *Failing to use a renewable fuel oil for its intended use.* No person shall use renewable fuel oil for which RINs have been generated in an application other than to heat or cool interior spaces of homes or buildings to control ambient climate for human comfort.

* * * * *

■ 34. Amend § 80.1461 by adding paragraph (g) to read as follows:

§ 80.1461 Who is liable for violations under the RFS program?

* * * * *

(g) *Importer joint and several liability.* Any person meeting the definition of an importer under this subpart is jointly and severally liable for any violation of this subpart.

■ 35. Amend § 80.1469 by:
■ a. Removing paragraphs (a) and (b);
■ b. Redesignating paragraphs (c) through (f) as paragraphs (a) through (d); and
■ c. Revising newly redesignated paragraphs (a) introductory text, (a)(1)(vii), (a)(3)(vii), (a)(5), (c)(1), (d)(1) introductory text, and (d)(2).

The revisions read as follows:

§ 80.1469 Requirements for Quality Assurance Plans.

* * * * *

(a) *QAP Requirements.* All components specified in this paragraph (a) require quarterly monitoring, except for paragraph (a)(4)(iii) of this section which must be done annually.

(1) * * *

(vii) Feedstock(s) and biointermediate(s) are not renewable fuel for which RINs were previously generated unless the RINs were generated under § 80.1426(c)(6). For renewable fuels that have RINs generated under § 80.1426(c)(6), verify that renewable fuels used as a feedstock meet all applicable requirements of this paragraph (a)(1).

* * * * *

(3) * * *

(vii) Verify that appropriate RIN generation calculations are being followed under § 80.1426.

* * * * *

(5) *Representative sampling.* Independent third-party auditors may use a representative sample of batches of renewable fuel or biointermediate in accordance with the procedures described in 40 CFR 1090.1805 for all components of this paragraph (a) except for paragraphs (a)(1)(ii) and (iii), (a)(2)(ii), (a)(3)(vi), and (a)(4)(ii) and (iii) of this section. If a facility produces both a renewable fuel and a biointermediate, the independent third-party auditor must select separate representative samples for the renewable fuel and biointermediate.

* * * * *

(c) * * *

(1) Each independent third-party auditor must annually submit a general and at least one pathway-specific QAP to the EPA which demonstrates adherence to the requirements of paragraphs (a) and (b) of this section and request approval on forms and using procedures specified by EPA.

* * * * *

(d) * * *

(1) A new QAP must be submitted to EPA according to paragraph (c) of this section and the independent third-party auditor must update their registration according to § 80.1450(g)(9) whenever any of the following changes occur at a renewable fuel or biointermediate production facility audited by an independent third-party auditor and the auditor does not possess an appropriate pathway-specific QAP that encompasses the change:

* * * * *

(2) A QAP ceases to be valid as the basis for verifying RINs or a biointermediate under a new pathway until a new pathway-specific QAP, submitted to the EPA under this paragraph (d), is approved pursuant to paragraph (c) of this section.

§ 80.1470 [Removed and Reserved]

■ 36. Remove and reserve § 80.1470.

■ 37. Amend § 80.1471 by revising paragraphs (b)(3), (e), and (f) to read as follows:

§ 80.1471 Requirements for QAP auditors.

* * * * *

(b) * * *

(3) The independent third-party auditor must not own, buy, sell, or otherwise trade RINs unless required to replace an invalid RIN pursuant to § 80.1474.

* * * * *

(e) The independent third-party auditor must identify RINs generated from a renewable fuel producer or foreign renewable fuel producer as having been verified under a QAP.

(1) For RINs verified under a QAP pursuant to § 80.1469, RINs must be designated as Q–RINs and must be identified as having been verified under a QAP in EMTS.

(2) The independent third-party auditor must not identify RINs generated from a renewable fuel producer or foreign renewable fuel producer as having been verified under a QAP if a revised QAP must be submitted to and approved by the EPA under § 80.1469(d).

(3) The independent third-party auditor must not identify RINs generated for renewable fuel produced using a biointermediate as having been verified under a QAP unless the biointermediate used to produce the renewable fuel was verified under an approved QAP pursuant to § 80.1477.

(f)(1) Auditors may only verify RINs that have been generated after the audit required under § 80.1472 has been completed. Auditors may only verify biointermediates that were produced after the audit required under § 80.1472 has been completed. Auditors must only verify RINs generated from renewable fuels produced from biointermediates after the audit required under § 80.1472 has been completed for both the biointermediate production facility and the renewable fuel production facility.

(2) Verification of RINs or biointermediates may continue for no more than 200 days following an on-site visit or 380 days after an on-site visit if a previously EPA-approved remote monitoring system is in place at the renewable fuel production facility.

* * * * *

■ 38. Revise and republish § 80.1472 to read as follows:

§ 80.1472 Requirements for quality assurance audits.

(a) *General requirements.* (1) An audit must be performed by an auditor who meets the requirements of § 80.1471.

(2) An audit must be based on a QAP per § 80.1469.

(3) Each audit must verify every element contained in an applicable and approved QAP.

(4) Each audit must include a review of documents generated by the renewable fuel producer or biointermediate producer.

(b) *On-site visits.* (1) As applicable, the independent third-party auditor must conduct an on-site visit at the renewable fuel production facility, foreign ethanol production facility, or biointermediate production facility:

(i) At least two times per calendar year; or

(ii) In the event an auditor uses a remote monitoring system approved by the EPA, at least one time per calendar year.

(2) An on-site visit specified in paragraph (b)(1)(i) of this section must occur no more than:

(i) 200 days after the previous on-site visit. The 200-day period must start the day after the previous on-site visit ends; or

(ii) 380 days after the previous on-site visit if a previously approved (by EPA) remote monitoring system is in place at the renewable fuel production facility, foreign ethanol production facility, or biointermediate production facility, as applicable. The 380-day period must start the day after the previous on-site visit ends.

(3) An on-site visit must include verification of all QAP elements that require inspection or evaluation of the physical attributes of the renewable fuel production facility, foreign ethanol production facility, or biointermediate production facility, as applicable.

(4) The on-site visit must be overseen by a professional engineer, as specified in § 80.1450(b)(2)(i)(A) and (B).

■ 39. Amend § 80.1473 by:

■ a. Revising paragraph (a);

■ b. Removing paragraphs (c) and (d);

■ c. Redesignating paragraphs (e) and (f) as paragraphs (c) and (d);

■ d. Revising newly redesignated paragraphs (c) introductory text, (c)(1), and (d).

The revisions read as follows:

§ 80.1473 Affirmative defenses.

(a) *Criteria.* Any person who engages in actions that would be a violation of the provisions of either § 80.1460(b)(2) or (c)(1), other than the generator of an invalid RIN, will not be deemed in violation if the person demonstrates that the criteria under paragraph (c) of this section are met.

* * * * *

(c) *Asserting an affirmative defense for invalid Q–RINs.* To establish an affirmative defense to a violation of § 80.1460(b)(2) or (c)(1) involving invalid Q–RINs, the person must meet the notification requirements of paragraph (d) of this section and prove by a preponderance of evidence all the following:

(1) The RIN in question was verified through a quality assurance audit pursuant to § 80.1472 using an approved QAP as specified in § 80.1469.

* * * * *

(d) *Notification requirements.* A person asserting an affirmative defense to a violation of § 80.1460(b)(2) or (c)(1), arising from the transfer or use of an invalid Q–RIN must submit a written report to the EPA via the EMTS support line (*fuelsprogramsupport@epa.gov*), including all pertinent supporting documentation, demonstrating that the requirements of paragraph (c) of this section were met. The written report must be submitted within 30 days of the person discovering the invalidity.

■ 40. Amend § 80.1474 by:

■ a. Removing paragraphs (a)(1) and (2);

■ b. Redesignating paragraphs (a)(3) and (4) as paragraphs (a)(1) and (2);

■ c. Revising paragraphs (b)(5) and (d)(2);

■ d. Removing paragraph (e);

■ e. Redesignating paragraphs (f) and (g) as paragraphs (e) and (f).

The revisions read as follows:

§ 80.1474 Replacement requirements for invalidly generated RINs.

* * * * *

(b) * * *

(5) Within 60 days of receiving a notification from the EPA that a PIR generator has failed to perform a corrective action required pursuant to this section, the party that owns the invalid RIN is required to do one of the following:

(i) Retire the invalid RIN.

(ii) If the invalid RIN has already been used for compliance with an obligated party's RVO, correct the RVO to subtract the invalid RIN.

* * * * *

(d) * * *

(2) The number of RINs retired must be equal to the number of PIRs or invalid RINs being replaced, subject to paragraph (e) of this section if applicable.

* * * * *

■ 41. Amend § 80.1476 by revising paragraph (h)(1) to read as follows:

§ 80.1476 Requirements for biointermediate producers.

* * * * *

(h) * * *

(1) Each biointermediate producer must assign a number (the ''batch number'') to each batch of biointermediate consisting of their EPA-issued company registration number,

the EPA-issued facility registration number, the last two digits of the compliance year in which the batch was produced, and a unique number for the batch during the compliance year (*e.g.,* 4321–54321–25–000001).

* * * * *

■ 42. Amend § 80.1477 by revising paragraphs (b) and (c) to read as follows:

§ 80.1477 Requirements for QAPs for biointermediate producers.

* * * * *

(b) QAPs approved by EPA to verify biointermediate production must meet the requirements in § 80.1469, as applicable.

(c) Quality assurance audits, when performed, must be conducted in accordance with the requirements in § 80.1472.

* * * * *

■ 43. Amend § 80.1479 by revising paragraphs (c)(2) to read as follows:

§ 80.1479 Alternative recordkeeping requirements for separated yard waste, separated food waste, separated MSW, and biogenic waste oils/fats/greases.

* * * * *

(c) * * *

(2) The independent third-party auditor must conduct a site visit of each feedstock aggregator's establishment as specified in § 80.1471(f). Instead of verifying RINs with a site visit of the feedstock aggregator's establishment every 200 days as specified in § 80.1471(f)(2), the independent third-party auditor may verify RINs with a site visit every 380 days.

* * * * *

PART 1090—REGULATION OF FUELS, FUEL ADDITIVES, AND REGULATED BLENDSTOCKS

■ 44. The authority citation for part 1090 continues to read as follows:

Authority: 42 U.S.C. 7414, 7521, 7522–7525, 7541, 7542, 7543, 7545, 7547, 7550, and 7601.

Subpart A—General Provisions

■ 45. Amend § 1090.80 by:

■ a. In the definition for ''Diesel fuel'', revising paragraph (2);

■ b. Removing the definition for ''Nonpetroleum (NP) diesel fuel'' and adding, in its place, a definition for ''Nonpetroleum diesel fuel''; and

■ c. In the definition for ''Responsible corporate officer (RCO)'', revising the last sentence.

The revisions and addition read as follows:

§ 1090.80 Definitions.

* * * * *

Diesel fuel * * *

(2) Any fuel (including nonpetroleum diesel fuel or a fuel blend that contains nonpetroleum diesel fuel) that is intended or used to power a vehicle or engine that is designed to operate using diesel fuel.

* * * * *

Nonpetroleum diesel fuel means renewable diesel fuel or biodiesel. Nonpetroleum diesel fuel also includes other renewable fuel under 40 CFR part 80, subpart M, that is used or intended for use to power a vehicle or engine that is designed to operate using diesel fuel or that is made available for use in a vehicle or engine designed to operate using diesel fuel.

* * * * *

Responsible corporate officer (RCO) * * * Examples of positions in non-corporate business structures that qualify are owner, chief executive officer, or president.

* * * * *

■ 46. Amend § 1090.95 by revising and republishing paragraphs (a) and (c) to read as follows:

§ 1090.95 Incorporation by reference.

(a) Certain material is incorporated by reference into this part with the approval of the Director of the Federal Register under 5 U.S.C. 552(a) and 1 CFR part 51. All approved incorporation by reference (IBR) material is available for inspection at the U.S. EPA and at the National Archives and Records Administration (NARA). Contact the U.S. EPA at: U.S. EPA, Air and Radiation Docket and Information Center, WJC West Building, Room 3334, 1301 Constitution Ave. NW, Washington, DC 20460; (202) 566–1742; *a-and-r-Docket@epa.gov.* For information on the availability of this material at NARA, visit *www.archives.gov/federal-register/cfr/ibr-locations* or email *fr.inspection@nara.gov.* The material may be obtained from the sources in the following paragraphs of this section.

* * * * *

(c) ASTM International (ASTM), 100 Barr Harbor Dr., P.O. Box C700, West Conshohocken, PA 19428–2959; (877) 909–2786; *www.astm.org.*

(1) ASTM D86–23ae2, Standard Test Method for Distillation of Petroleum Products and Liquid Fuels at Atmospheric Pressure, approved December 1, 2023 (ASTM D86); IBR approved for § 1090.1350(b).

(2) ASTM D287–22, Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer/Method), approved December 1, 2022 (ASTM D287); IBR approved for § 1090.1337(d).

(3) ASTM D975–24a, Standard Specification for Diesel Fuel, approved August 1, 2024 (ASTM D975); IBR approved for § 1090.80.

(4) ASTM D976–21e1, Standard Test Method for Calculated Cetane Index of Distillate Fuels, approved November 1, 2021 (ASTM D976); IBR approved for § 1090.1350(b).

(5) ASTM D1298–24, Standard Test Method for Density, Relative Density, or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method, approved November 1, 2024 (ASTM D1298); IBR approved for § 1090.1337(d).

(6) ASTM D1319–20a, Standard Test Method for Hydrocarbon Types in Liquid Petroleum Products by Fluorescent Indicator Adsorption, approved August 1, 2020 (ASTM D1319); IBR approved for § 1090.1350(b).

(7) ASTM D2163–23e1, Standard Test Method for Determination of Hydrocarbons in Liquefied Petroleum (LP) Gases and Propane/Propene Mixtures by Gas Chromatography, approved March 1, 2023 (ASTM D2163); IBR approved for § 1090.1350(b).

(8) ASTM D2622–24a, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-ray Fluorescence Spectrometry, approved December 1, 2024 (ASTM D2622); IBR approved for §§ 1090.1350(b); 1090.1360(d); 1090.1375(c).

(9) ASTM D3231–25, Standard Test Method for Phosphorus in Gasoline, approved May 1, 2025 (ASTM D3231); IBR approved for § 1090.1350(b).

(10) ASTM D3237–22, Standard Test Method for Lead in Gasoline by Atomic Absorption Spectroscopy, approved October 1, 2022 (ASTM D3237); IBR approved for § 1090.1350(b).

(11) ASTM D3606–24a, Standard Test Method for Determination of Benzene and Toluene in Spark Ignition Fuels by Gas Chromatography, approved November 1, 2024 (ASTM D3606); IBR approved for § 1090.1360(c).

(12) ASTM D4052–22, Standard Test Method for Density, Relative Density, and API Gravity of Liquids by Digital Density Meter, approved May 1, 2022 (ASTM D4052); IBR approved for § 1090.1337(d) and (f).

(13) ASTM D4057–22, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, approved May 1, 2022 (ASTM D4057); IBR approved for §§ 1090.1335(b); 1090.1605(b).

(14) ASTM D4177–22e1, Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, approved July 1, 2022 (ASTM D4177); IBR approved for §§ 1090.1315(a); 1090.1335(c).

(15) ASTM D4737–21, Standard Test Method for Calculated Cetane Index by Four Variable Equation, approved November 1, 2021 (ASTM D4737); IBR approved for § 1090.1350(b).

(16) ASTM D4806–25, Standard Specification for Denatured Fuel Ethanol, approved April 1, 2025 (ASTM D4806); IBR approved for § 1090.1395(a).

(17) ASTM D4814–25a, Standard Specification for Automotive Spark-Ignition Engine Fuel, approved December 15, 2025 (ASTM D4814); IBR approved for §§ 1090.80; 1090.1395(a).
(18) ASTM D5134–21 (Reapproved 2025), Standard Test Method for Detailed Analysis of Petroleum Naphthas through n-Nonane by Capillary Gas Chromatography, approved October 1, 2025 (ASTM D5134); IBR approved for § 1090.1350(b).
(19) ASTM D5186–24, Standard Test Method for Determination of the Aromatic Content and Polynuclear Aromatic Content of Diesel Fuels By Supercritical Fluid Chromatography, approved July 1, 2024 (ASTM D5186); IBR approved for § 1090.1350(b).
(20) ASTM D5191–22, Standard Test Method for Vapor Pressure of Petroleum Products and Liquid Fuels (Mini Method), approved July 1, 2022 (ASTM D5191); IBR approved for § 1090.1360(d).
(21) ASTM D5453–25, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Spark Ignition Engine Fuel, Diesel Engine Fuel, and Engine Oil by Ultraviolet Fluorescence, approved July 1, 2025 (ASTM D5453); IBR approved for § 1090.1350(b).
(22) ASTM D5500–20a, Standard Test Method for Vehicle Evaluation of Unleaded Automotive Spark-Ignition Engine Fuel for Intake Deposit Formation, approved June 1, 2020 (ASTM D5500); IBR approved for § 1090.1395(c).
(23) ASTM D5599–22, Standard Test Method for Determination of Oxygenates in Gasoline by Gas Chromatography and Oxygen Selective Flame Ionization Detection, approved April 1, 2022 (ASTM D5599); IBR approved for § 1090.1360(d).
(24) ASTM D5769–25, Standard Test Method for Determination of Benzene, Toluene, and Total Aromatics in Finished Gasolines by Gas Chromatography/Mass Spectrometry, approved October 1, 2025 (ASTM D5769); IBR approved for §§ 1090.1350(b); 1090.1360(d).
(25) ASTM D5842–23, Standard Practice for Sampling and Handling of Fuels for Volatility Measurement, approved October 1, 2023 (ASTM D5842); IBR approved for § 1090.1335(d).
(26) ASTM D5854–25, Standard Practice for Mixing and Handling of Liquid Samples of Petroleum and Petroleum Products, approved July 1, 2025 (ASTM D5854); IBR approved for § 1090.1315(a).
(27) ASTM D6201–19a, Standard Test Method for Dynamometer Evaluation of Unleaded Spark-Ignition Engine Fuel for Intake Valve Deposit Formation, approved December 1, 2019 (ASTM D6201); IBR approved for § 1090.1395(a).
(28) ASTM D6259–23, Standard Practice for Determination of a Pooled Limit of Quantitation for a Test Method, approved May 1, 2023 (ASTM D6259); IBR approved for § 1090.1355(b).
(29) ASTM D6299–25a, Standard Practice for Applying Statistical Quality Assurance and Control Charting Techniques to Evaluate Analytical Measurement System Performance, approved July 1, 2025 (ASTM D6299); IBR approved for §§ 1090.1300(d); 1090.1370(c); 1090.1375(a), (b), (c), and (d); 1090.1450(c).
(30) ASTM D6550–25, Standard Test Method for Determination of Olefin Content of Gasolines by Supercritical-Fluid Chromatography, approved October 1, 2025 (ASTM D6550); IBR approved for § 1090.1350(b).
(31) ASTM D6667–21, Standard Test Method for Determination of Total Volatile Sulfur in Gaseous Hydrocarbons and Liquefied Petroleum Gases by Ultraviolet Fluorescence, approved April 1, 2021 (ASTM D6667); IBR approved for §§ 1090.1360(d); 1090.1375(c).
(32) ASTM D6708–24, Standard Practice for Statistical Assessment and Improvement of Expected Agreement Between Two Test Methods that Purport to Measure the Same Property of a Material, approved March 1, 2024 (ASTM D6708); IBR approved for §§ 1090.1360(c); 1090.1365(d) and (f); 1090.1375(c).
(33) ASTM D6729–25, Standard Test Method for Determination of Individual Components in Spark Ignition Engine Fuels by 100 Metre Capillary High Resolution Gas Chromatography, approved October 1, 2025 (ASTM D6729); IBR approved for § 1090.1350(b).
(34) ASTM D6730–22, Standard Test Method for Determination of Individual Components in Spark Ignition Engine Fuels by 100-Metre Capillary (with Precolumn) High-Resolution Gas Chromatography, approved November 1, 2022 (ASTM D6730); IBR approved for § 1090.1350(b).
(35) ASTM D6751–24, Standard Specification for Biodiesel Fuel Blendstock (B100) for Middle Distillate Fuels, approved March 1, 2024 (ASTM D6751); IBR approved for §§ 1090.300(a); 1090.1350(b).
(36) ASTM D6792–25, Standard Practice for Quality Management Systems in Petroleum Products, Liquid Fuels, and Lubricants Testing Laboratories, approved November 1, 2025 (ASTM D6792); IBR approved for § 1090.1450(c).
(37) ASTM D7717–11 (Reapproved 2021), Standard Practice for Preparing Volumetric Blends of Denatured Fuel Ethanol and Gasoline Blendstocks for Laboratory Analysis, approved October 1, 2021 (ASTM D7717); IBR approved for § 1090.1340(b).
(38) ASTM D7777–24, Standard Test Method for Density, Relative Density, or API Gravity of Liquid Petroleum by Portable Digital Density Meter, approved July 1, 2024 (ASTM D7777); IBR approved for § 1090.1337(d).

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Subpart C—Gasoline Standards

■ 47. Effective April 28, 2026, amend § 1090.215 by revising table 2 to paragraph (b)(3)(ii) to read as follows:

§ 1090.215 Gasoline RVP standards.

* * * * *

(b) * * *

(3) * * *

(ii) * * *

TABLE 2 TO PARAGRAPH (b)(3)(ii)—AREAS EXCLUDED FROM THE ETHANOL 1.0 PSI WAIVER

State	Counties	Effective date
Illinois	All	April 28, 2025.
Iowa	All	April 28, 2025.
Minnesota	All	April 28, 2025.
Missouri	All	April 28, 2025.
Nebraska	All	April 28, 2025.
South Dakota	All except Butte, Custer, Fall River, Harding, Lawrence, Meade, Oglala Lakota, Pennington, and Perkins.	April 28, 2025.
South Dakota	Butte, Custer, Fall River, Harding, Lawrence, Meade, Oglala Lakota, Pennington, and Perkins.	April 28, 2026.
Wisconsin	All	April 28, 2025.

* * * * *

Subpart D—Diesel Fuel and ECA Marine Fuel Standards

■ 48. Amend § 1090.300 by adding paragraph (a)(3) to read as follows:

§ 1090.300 Overview and general requirements.

(a) * * *

(3) Biodiesel that meets ASTM D6751 (incorporated by reference, see

§ 1090.95) is not subject to the cetane index or aromatic content standards in § 1090.305(c). Biodiesel blends or biodiesel that does not meet ASTM D6751 remain subject to the cetane index or aromatic content standards in § 1090.305(c).

* * * * *

■ 49. Amend § 1090.305 by revising paragraph (a) to read as follows:

§ 1090.305 ULSD standards.

(a) *Overview.* Except as specified in § 1090.300(a), all diesel fuel (including nonpetroleum diesel fuel) must meet the ULSD per-gallon standards of this section.

* * * * *

Subpart N—Sampling, Testing, and Retention

■ 50. Amend § 1090.1310 by revising paragraph (b)(1) to read as follows:

§ 1090.1310 Testing to demonstrate compliance with standards.

* * * * *

(b) * * *

(1) *Diesel fuel.* Perform testing for each batch of ULSD (including nonpetroleum diesel fuel), 500 ppm LM diesel fuel, and ECA marine fuel to demonstrate compliance with sulfur standards.

* * * * *

■ 51. Amend § 1090.1337 by revising paragraph (e) to read as follows:

§ 1090.1337 Demonstrating homogeneity.

* * * * *

(e) For testing of diesel fuel (including nonpetroleum diesel fuel) and ECA marine fuel to meet the standards in subpart D of this part, demonstrate homogeneity using one of the procedures specified in paragraph (d)(1) or (2) of this section.

* * * * *

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